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EXPLAINER: Why is Biden halting federal oil and gas sales?

By MATTHEW BROWN and MATTHEW DALY

BILLINGS, Mont. (AP) — President Joe Biden shut down oil and gas lease sales from the nation's vast public lands and waters in his first days in office, citing worries about climate change. Now his administration has to figure out what do with the multibillion-dollar program without crushing a significant sector of the U.S. economy — and while fending off sharp criticism from congressional Republicans and the oil industry.

The leasing ban is only temporary, although officials have declined to say how long it will last. And it's unclear how much legal authority the government has to stop drilling on about 23 million acres (9 million hectares) previously leased to energy companies.

Here are some questions hanging over Biden's Interior Department as it launches a months-long review of the government's petroleum sales with a virtual forum Thursday.

WHY IS BIDEN TARGETING OIL AND GAS LEASE SALES?

Burning of oil, gas and coal from government-owned lands and waters is a top source of U.S. emissions, accounting for 24% of the nation's greenhouse gases. Oil and gas account for the biggest chunk of human-caused fossil fuel emissions from federal lands following a drilling surge under former President Donald Trump.

Emission reductions from a permanent leasing ban would be relatively small -- about 100 million tons (91 million metric tons) annually, or less than 1% of global fossil fuel emissions, according to a study by a nonprofit research group.

But environmentalists and others who want more aggressive action against climate change say a ban would nudge the economy in a new direction. Biden wants to substitute fossil fuel production and consumption with policies that promote renewable energy on public lands, such as wind and solar power.

“The federal government is a huge player here. The government has market power,” said attorney Max Sarinsky with New York University Law School’s Institute for Policy Integrity. “If you restrict the supply (of oil and gas), you alter the market and you create a better environment for more sustainable fuels.”

Lease sales and royalties companies pay on extracted oil and gas brought in more than $83 billion in revenue over the past decade.

Half the money from onshore drilling goes to the state where it occurred. Money from offshore drilling gets shared with states at a lesser rate and pays for a conservation fund used to preserve land nationwide.

WHAT’S BEEN DONE SO FAR?

The administration postponed lease sales in the Gulf of Mexico and in Wyoming, Colorado, Montana and Utah. Biden earlier had suspended leasing in Alaska’s Arctic National Wildlife Refuge.

Interior officials say the fossil fuel program has failed to consider climate impacts and that irresponsible leasing practices carve up wildlife habitat, threaten Native American cultural and sacred sites and lock up public lands that could be used for recreation or conservation.

After what they call a “fire sale” of public energy reserves under Trump, Biden’s team argues that companies still have plenty of undeveloped leases — almost 14 million acres (6 million hectares) in western states and more than 9 million acres (3.6 million hectares) offshore.

Companies also have about 7,700 unused drilling permits — enough for years.

Despite the moratorium, the Biden administration has continued to issue new permits for existing leases, including more than 200 in March, records show.

Environmentalists want that to stop, but an outright drilling ban would raise thorny legal issues. Companies could claim they have the right to extract oil and gas after spending years and millions of dollars to secure leases.

WHAT ARE BIDEN'S OPTIONS?

A ban on new leases means drilling would fade out as existing ones expire. It would be a heavy blow for western and Gulf Coast states that heavily depend on oil and gas revenue to pay for schools, roads and other services.

Another option is to increase royalty fees to reflect the "social cost" of climate change — damage from rising seas, drought, wildfires and other global warming impacts. That would keep revenue flowing and make it more expensive to drill on federal land, forcing companies to concentrate on the most profitable reserves and reducing emissions, though by less than a ban.

"If it's not possible to have a carbon tax on all oil and gas extraction, at least we could do something akin to that on public lands," said James Stock, a Harvard University economist and former member of the White House Council on Economic Advisers under Obama.

HOW MANY JOBS COULD BE LOST?

Economists say claims by industry groups and allies in Congress that a leasing ban would trigger massive job losses are greatly exaggerated.

An industry-promoted University of Wyoming study projected almost 300,000 jobs lost by 2025. But historical data on energy jobs suggest a much smaller impact of about 60,000 jobs, said Jeremy Weber, former chief energy economist for Trump's White House Council of Economic Advisers and now a University of Pittsburgh associate professor.

That's still a significant number as the U.S. economy recovers from job losses in the pandemic. And even limited job losses could profoundly affect local economies in Wyoming, New Mexico and other oil-dependent states.

There's also no guarantee such impacts would be offset by Biden's promise to deliver millions of new green energy jobs, such as installing solar panels or helping with environmental cleanups of abandoned oil wells and coal mines.

Despite promises by renewable energy advocates, such jobs "don't fill the bucket like oil and gas does," said Jim Willox, a commissioner in Converse County, Wyoming, the state's top crude producer and home to several new wind farms.

Aware of such concerns, Biden climate adviser Gina McCarthy met with executives from Exxon Mobil, Chevron and other companies Monday to discuss ways to reduce greenhouse gas emissions. A White House statement said the administration "is not fighting the oil and gas sector" and wants to create jobs while addressing emissions.

American Petroleum Institute CEO Mike Sommers said independent forecasts show natural gas and oil will provide about half of the global energy mix for decades to come.

WHAT’S NEXT?

Interior Secretary Deb Haaland, sworn in last week as the first Native American to oversee the nation’s public lands and waters, will kick off Thursday’s forum, which will include representatives of industry, labor, conservationist groups, Indigenous people and others.

Haaland, a former two-term New Mexico congresswoman, said she wants to “strike the right balance” as Interior manages energy development while seeking to conserve public lands and address climate change.

An interim report to be completed this summer will outline recommendations for Interior and Congress to overhaul the fossil fuels program. A similar review of government coal sales during the Obama administration was to last three years, but was canceled by Trump.

Red states ask judge to compel Biden to hold offshore lease sale

BY **ALEX GUILLÉN** | 08/09/2021 08:24 PM EDT

A coalition of red states led by Louisiana on Monday asked a federal judge to compel the Biden administration give up its freeze and hold on oil and gas lease sale in the near future.

Background: Judge Terry Doughty of the U.S. District Court for the Western District of Louisiana issued a preliminary injunction in June that blocked a part of President Joe Biden's executive order delaying oil and gas lease sales on federal lands and waters.

Interior Secretary Deb Haaland on July 27 testified before the Senate Energy and Natural Resources Committee that, “technically, I suppose you could say the pause is still in place,” but that Interior was working to comply with the judge’s order.

Details: In the seven weeks since Doughty, a Trump appointee, issued his injunction, Interior “has taken no action… to implement Lease Sale 257 or any other oil and gas lease sale under the Five Year Plan,” the states wrote in their motion. Instead, they note, the Bureau of Ocean Energy Management has advanced several offshore wind projects "that are not mandated by the Five Year Plan, [the Outer Continental Shelf Lands Act], or this Court’s Order."

The states cited Haaland’s testimony as evidence that Interior had not complied with Doughty’s order, even though the steps needed would not be difficult or time-consuming.

“There is simply no excuse for Defendants’ brazen noncompliance with this Court’s Order,” the states argued.

They asked Doughty to issue "direct instructions" to restart the oil and gas leasing program and to hold Lease Sale 257 , which would offer up more than 78 million acres in the Gulf of Mexico, within 55 days of issuing an order. "Every day that passes without compliance irreparably harms Plaintiff States," they added.

Interior declined to comment on the filing.

What’s next: It is unclear how quickly Doughty may act on the states’ request. The states suggested having Interior respond within two weeks.

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Table 15 Oil and Gas Lease Sales, Fiscal Year 2018

Competitive oil and gas Lease Sales by BLM State Offices from October 1, 2017 through September 30, 2018.
For additional information, please contact the individual state offices.

BLM State Office	Date	Total Receipts *	Parcels Posted [1]	Acreage Posted [1]	Parcels Offered Day of Sale [2]	Acreage Offered Day of Sale [2]	Parcels Receiving Bids [3]	Acreage Receiving Bids [3]
FY 2018		**$1,149,823,689**	**3,119**	**12,869,200**	**3,073**	**12,836,231**	**1,336**	**1,351,287**
Wyoming	9/20/2018	$60,890,800	350	355,819	348	353,220	311	301,605
Eastern States	9/20/2018	$13,484	18	3,195	16	3,120	16	3,120
Utah	9/11/2018	$3,311,829	109	204,172	109	204,172	69	133,922
Montana	9/11/2018	$227,023	30	13,712	25	12,192	25	12,192
Nevada	9/11/2018	$0	144	295,174	144	295,174	0	0
New Mexico	9/6/2018	$972,483,620	142	50,797	142	50,797	142	50,797
Colorado	9/6/2018	$3,364,527	20	8,160	20	8,160	20	8,160
Arizona	9/6/2018	$10,960	3	4,201	3	4,201	2	3,040
Wyoming	6/27/2018	$35,991,151	162	198,589	159	193,300	158	192,860
Eastern States	6/21/2018	$15,815	26	2,248	26	2,248	22	1,888
Nevada	6/12/2018	$201,291	166	313,715	166	313,715	22	38,579
Utah	6/12/2018	$186,618	12	12,758	12	12,758	11	12,678
New Mexico	6/7/2018	$7,728,317	24	4,152	24	4,152	24	4,152
Colorado	6/7/2018	$1,395,024	64	58,694	62	55,810	59	50,573
Wyoming	3/22/2018	$19,879,038	170	170,510	170	170,550	152	151,678
Eastern States	3/22/2018	$4,629	5	485	5	485	4	465
Utah	3/20/2018	$1,560,640	43	51,401	43	51,483	43	51,483
Montana	3/13/2018	$193,342	109	63,496	83	46,175	35	26,665
Nevada	3/13/2018	$152,062	40	69,695	39	67,792	11	19,433
Colorado	3/8/2018	$10,064	8	2,545	4	1,400	4	1,400
Wyoming	12/14/2017	$2,582,342	45	72,844	45	72,844	41	68,819
Eastern States	12/14/2017	$1,014,726	7	1,185	7	1,185	7	1,185
Utah	12/12/2017	$5,959,807	75	94,041	74	93,946	49	53,764
Montana	12/12/2017	$666,900	204	99,266	204	99,266	55	25,169
Nevada	12/12/2017	$120,707	208	388,959	208	388,697	17	33,484
New Mexico	12/7/2017	$30,361,783	7	2,104	7	2,104	7	2,104
Colorado	12/7/2017	$337,840	28	27,284	28	27,284	23	22,073
Alaska	12/6/2017	$1,159,357	900	10,300,000	900	10,300,000	7	79,998

* **Total Receipts:** The total amount of money generated from the Competitive Oil and Gas Lease Sale. This includes rents, bonuses, and adminsitrative fees.
[1] **Parcels (and acreage) posted:** The number of parcels (and acreage) advertised for lease in the original Notice of Competitive Oil and Gas Lease Sale.
[2] **Parcels (and acreage) offered day of sale:** The number of parcels (and acreage) that were offered for lease at the competitive auction.
[3] **Parcels (and acreage) receiving bids:** The number of parcels (and acreage) that received bids and sold at the auction.

Note: Parcels offered that did not receive a bid at the competitive auction are available for filing of noncompetitive offers (43 CFR 3110.1(b)) for a 2-year period.

The New York Times

Decades-Old Government Loophole Gives Oil Companies an $18 Billion Windfall

By Hiroko Tabuchi

Oct 4, 2019, 30 a m ET

The United State government ha lo t billion of dollar of oil and ga revenue to fo il fuel companie becau e of a loophole in a decade old law, a federal watchdog agency said Thursday, offering the first detailed accounting of the consequences of a misstep by lawmakers that i expected to continue costing taxpayer for decade to come

The loophole date from an effort in 1995 to encourage drilling in the Gulf of Mexico by offering oil companie a temporary break from paying royalties on the oil produced. However, the rule was poorly written — and the temporary reprieve was accidentally made permanent on ome well

As a result, some of the biggest oil companies in the world, including Chevron, Shell, BP, Exxon Mobil and others, have avoided paying at lea t $18 billion in royaltie on oil and ga drilled ince 1996, according to a new report from the Government Accountability Office, a nonpartisan agency that works for Congress. The companies, which hold government leases to drill in the Gulf, continue to extract oil and ga from those well while not being required to pay royaltie , a right the indu try ha gone to court to defend

A poke man for the indu try group the American Petroleum In titute, which repre ent many of the companie affected, aid court had "ruled there was nothing ambiguous about the 1995 act." The companies "took Congress at its word," said the spokesman, Ben Marter, and any attempt to revi it the i ue would be "engaging in a dangerou game of bait-and witch"

The mistake cuts into federal coffers. Royalties from offshore oil and gas are a significant source of revenue, bringing in almost $90 billion from 2006 through 2018, according to the agency

Frank Rusco, a director of the G.A.O.'s Natural Resources and Environment team and the report's author, said the findings are an extreme example of the Department of Interior failing to en ure that American taxpayer received a fair market value for the oil and ga extracted from public property.

"These leases sold 20 years ago might keep producing for decades. The amount of forgone royalties is going to continue to increase," Mr. Ru co aid in an interview "It' a trong ca e for Interior to review how it collect revenue on oil and ga "

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The Interior Department said it "takes seriously" its responsibility to ensure that the American public receives a fair value for public re ource Still, ome part of the report "do not paint a repre entative picture" of the agency' effort , Ca ey Hammond, acting a i tant secretary for land and minerals, said in the agency's response, which was also released Thursday.

Department data shows that Chevron holds the most royalty-free leases in the Gulf, followed by Anadarko (now a part of Occidental Petroleum), Norway' Equinor and Shell Exxon Mobil, BP, and CNOOC, China' tate run off hore oil and ga company, al o own royalty free leases, the data shows.

Chevron declined to comment Shell, Occidental, BP, Exxon and Equinor referred querie to the American Petroleum In titute Call to CNOOC's Houston offices went unanswered.

The report of the windfall to oil companie come a the Trump admini tration ha moved to further reduce the co t of off hore drilling for the industry, proposing to significantly weaken safety rules put in place after the deadly 2010 Deepwater Horizon explosion in the Gulf of Mexico Pre ident Trump al o earlier pu hed to expand new off hore oil and ga drilling, though that plan wa put on hold after being challenged in court.

The fossil fuel industry is facing heightened scrutiny on several fronts. The United Nations has warned that oil and gas production must decline ub tantially in the coming year if humanity i to avoid the wor t effect of climate change worldwide, including more evere flooding, droughts and sea level rise. And Exxon Mobil this week is fighting charges in a New York City courtroom that the company lied to hareholder about the cost and con equence of global warming

This week at a hearing of a subcommittee of the House Committee on Oversight and Reform, Exxon and other oil giants came under further attack

“Major oil and gas companies, whose products are substantially responsible for global greenhouse emissions and the resulting climate emergency we now face, had early and repeated knowledge of the climate risk,” Sharon Y. Eubanks, who formerly directed tobacco litigation at the Department of Justice, told the committee. “They chose to mount a campaign of disinformation and denial.”

Exxon has said that the company has long acknowledged climate change is real and has called the charges “meritless” and “unconnected from the truth.”

The oil industry revenues detailed in Thursday’s report are a product of a very different era in America.

Today, thanks to the fracking boom, the United States is the largest oil producer in the world. But back in the late 1990s — when the country was heavily reliant on oil imports — the federal government wanted to boost American energy independence by encouraging more exploration in the Gulf. And since oil prices were low, Washington tried to make it worthwhile for oil companies by offering a brief reprieve on the royalties.

In 1995, Congress, working with oil executives, passed a law allowing companies that bid for new offshore leases to avoid paying the standard 12 percent royalty, or share of sales, on the oil and gas those leases eventually produced. The Interior Department leases tens of millions of acres of ocean territory to oil producers in exchange for an upfront bid for the lease, followed by royalties.

Supporters of the law argued that not only would the incentive reduce America’s dependence on foreign oil, but that it would in fact generate money for the government by prompting producers to bid higher prices for new leases.

But in what officials at the time said was an error, the law omitted a crucial clause that had been supported by both Republicans and Democrats: that if average prices for oil and gas climbed above a certain threshold, companies would be responsible for paying the royalties. In 2006, when the federal government tried to impose royalties, an oil producer sued and won.

The G.A.O. report lays out the long-lived consequences.

The report says that waiving royalties between 1996 and 2000, the final year royalty-free leases were offered, likely increased bidding for offshore leases by almost $2 billion. But forgone royalty revenue has been nine times greater, adding up to $18 billion through the end of 2018, the report found.

Because most of the leases are still producing oil, the financial benefits for oil companies will ultimately be higher, the report adds.

“This is handing out public money to special interests that don’t need them, don’t deserve them and aren’t paying their fair share,” said Raúl M. Grijalva, a Democrat from Arizona and chair of the House Natural Resources Committee. “Our laws and standards need to reflect the fact that public resources are there for the benefit of the public.”

The G.A.O. report recommends that Interior Department’s Bureau of Ocean Energy Management, which oversees offshore leases, enlist a third-party expert to assess whether government valuations of oil and gas resources is sound. The Interior Department has pushed back against some of the report’s findings and recommendations, including the need for a third-party examination.

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What's Next for Offshore Oil and Gas Leasing Under the Trump Administration?

By Tommy Beaudreau and Jason Bordoff

April 24, 2017

The Trump Administration's America First Energy Plan calls for "policies that lower costs for hardworking Americans and maximize the use of American resources, freeing us from the dependence on foreign oil." Last month, President Trump issued an Executive Order on Promoting Energy Independence and Economic Growth, which broadly targeted many of the Obama Administration's signature energy and environmental initiatives, including the Clean Power Plan, and called for a federal government-wide review of all agency actions that "potentially burden the safe, efficient development of domestic energy resources." While this Executive Order did not address access to offshore oil and gas resources on the federally managed outer continental shelf (OCS), several recent reports, including statements attributed to Interior Secretary Ryan Zinke, indicate that further executive action is imminent that may lead to additional offshore areas being opened to oil and gas leasing.

This paper (1) provides a brief overview of the offshore oil and gas leasing process under the Outer Continental Shelf Lands Act (OCSLA), (2) describes the Obama Administration's approach to the offshore oil and gas program, including areas in which the last administration scheduled – and did not schedule – potential new lease sales through 2022, and areas it withdrew indefinitely from consideration of oil and gas leasing in the future, and (3) discusses the potential paths forward the Trump Administration may take to reverse President Obama's actions and expand access to offshore conventional energy resources.

I. Offshore Oil and Gas Leasing Under OCSLA

OCSLA governs the management of offshore oil and gas resources in federal waters, generally defined as three miles from the coastline out to the 200-mile exclusive economic zone limit. Section 18 of OCSLA requires the Department of the Interior (DOI) to prepare a nationwide offshore oil and gas leasing program, including development of a five-year schedule of potential lease sales in accordance with certain criteria concerning the nation's energy needs, economic and environmental factors, and input from coastal states, the industry and a broad range of public stakeholders. The Bureau of Ocean Energy Management (BOEM) within DOI is the agency responsible for evaluating which regions, known as planning areas, on the OCS will be included in this schedule for offshore oil and gas lease sales. This schedule is referred to as the Five Year Program.

BOEM prepares the Five Year Program in accordance with a three-step winnowing process prescribed under OCSLA. The process begins with BOEM issuing a Draft Proposed Program, which broadly outlines the offshore planning areas to be evaluated for potential leasing and traditionally includes the most areas for public comment and consideration. Next, BOEM publishes a Proposed Program, which may narrow the areas to be evaluated further based on public input and balancing of the Section 18 factors. At the third and final stage, BOEM issues the Proposed Final Program, which is the final schedule of lease sales for areas included in the Five Year Program and goes into effect after a 60-day review period and approval of the Interior Secretary. In parallel with the OCSLA Section 18 process, BOEM prepares a programmatic environmental impact statement under National Environmental Policy Act (NEPA) that analyzes the potential environmental effects of the offshore oil and gas program in total and by region. At each step of the process, the Interior Secretary may remove any planning area from further consideration and analysis. Planning areas cannot be added to the program without starting the entire process over again, so that each of the areas that are ultimately included in the Five Year Program schedule of lease sales has been analyzed together through the complete OCSLA and NEPA processes. The Interior Secretary, however, may cancel a scheduled lease sale included in a Five Year Program at any time prior to the sale.

II. The Obama Administration's Evolving Approach to Offshore Oil and Gas Leasing

The Obama Administration finalized two Five Year Programs, the 2012-2017 Program and the 2017-2022 Program, which became effective on January 17, 2017. The final offshore oil and gas lease sale under the 2012-2017 Program is scheduled for the Cook Inlet Planning Area on June 21, 2017. The first lease sale under the 2017-2022 Program is scheduled for the Gulf of Mexico Regionwide Planning Area on August 16, 2017, which in a new approach to leasing in the Gulf of Mexico will make the entire leasable area across the Western, Central and Eastern Gulf of Mexico Planning Areas available in a single sale.[1]

Development of the 2012-2017 Program

In his 2012 State of the Union address, President Obama directed his "administration to open more than 75 percent of our potential offshore oil and gas resources" to leasing. Accordingly, the 2012-2017 Program scheduled annual lease sales in the Western and Central Gulf of Mexico, as well as two sales in the GOMESA region of the Eastern Gulf of Mexico and one potential sale each in the Chukchi Sea, Beaufort Sea and Cook Inlet Planning Areas off of Alaska. Together, these planning areas included more than 75% of the total undiscovered, technically recoverable oil and gas resources in the United States' OCS, according to BOEM's 2011 assessment. None of these areas was considered "new" in that in each area there already were active leases in federal waters or, in the case of Cook Inlet, in adjacent state waters.

Absent from the 2012-2017 Program were any potential lease sales in the Atlantic OCS, which has a history of leasing and exploration during the 1970s and 1980s, but has had no active leases since then. Between 1977 and 1984, industry drilled 46 exploration wells in the Atlantic OCS, all of which were abandoned as non-commercial at the time. Although BOEM evaluated the Mid and South Atlantic Planning Areas, the final program did not include a potential lease sale in those areas on the grounds of (1) the lack of current geological and geophysical (G&G) data to inform leasing decisions, including from modern seismic surveys, and (2) the need for further public input, as well as the development of information, concerning the infrastructure that would be necessary to support offshore oil and gas exploration, including emergency response, environmental concerns, and potential conflicts with existing uses on the Atlantic OCS, including in particular naval and other military activity.

[1] Most of the Eastern Gu f of Mex co P ann ng Area rema ns under a Congress ona eas ng morator um though June 2022, w th the except on of a s ver on the western s de of the P ann ng Area that was opened for eas ng under the Gu f of Mex co Energy Secur ty Act (GOMESA) of 2006

Implementation of the 2012-2017 Program and Development of the 2017-2022 Program

In its second term, the Obama Administration increasingly focused on leasing and development in the Gulf of Mexico, which is one of the most mature and prolific basins in the world. Although its relative significance in the mix of domestic oil sources has declined with the rise of shale developments onshore, the federal offshore Gulf of Mexico still accounts for approximately 17% of the United States' total crude oil production, and the U.S. Energy Information Administration projects overall production from the Gulf of Mexico OCS to continue to increase in the coming years. The Obama Administration ultimately did not lease, nor plan future lease sales, in more controversial or "new" areas, such as offshore Alaska and the Atlantic. Moreover, the Obama Administration used its authority under Section 12(a) of OCSLA in an effort to remove large areas in those regions from consideration for offshore oil and gas leasing even beyond 2022. We discuss each in turn.

Offshore Alaska

The Obama Administration cancelled the Beaufort Sea and Chukchi Sea offshore lease sales scheduled under the 2012-2017 Program. In light of a disappointing result with the exploration well drilled in the Chukchi Sea in the summer of 2015, and also citing "the high costs associated with the project, and the challenging and unpredictable federal regulatory environment offshore Alaska," Shell discontinued its offshore Alaska exploration program for "the foreseeable future." In October 2015, citing "current market conditions and low industry interest," DOI cancelled both the Beaufort Sea and Chukchi Sea lease sales scheduled under the 2012-2015 Program. By the following spring, the industry had relinquished all but one of the active federal leases in the Chukchi Sea Planning Area, for which it had paid a total of more than $2.6 billion in Lease Sale 193 in 2008.[2]

Unlike in the 2012-2017 Program, the Obama Administration scheduled no potential offshore oil and gas lease sales in the Alaskan Arctic in the 2017-2022 Program. Rather, the Chukchi Sea and Beaufort Sea Planning Areas were removed from the 2017-2022 Program at the Final Proposed Program stage in the OCSLA process. In removing the Arctic planning areas, BOEM cited a combination of factors, including that the "Arctic is a unique, sensitive and costly environment in which to operate" and that "the increase in domestic onshore production from shale formations, and other market factors, have shifted expectations regarding oil and gas price trajectories and substantially reduced the incentive for expensive Arctic exploration and production."

Moreover, the Obama Administration went even further than merely declining to hold lease sales or to schedule future sales through 2022. It sought to prevent future offshore oil and gas lease sales in certain areas offshore Alaska, including in most of the Arctic Ocean. Section 12(a) of OCSLA provides that "the President of the United States may, from time to time, withdraw from dispensation any of the unleased lands

[2] The nter or Department re aff rmed Chukch Sea Lease Sa e 193 tw ce dur ng the Obama Adm n strat on, f rst n 2011 and aga n n 2015, after comp et ng supp ementa NEPA ana yses to address def c enc es dent f ed by the cou ts n the or g na Lease Sa e 193 E S pub shed n 2007

of the outer Continental Shelf." Prior to the Obama Administration, Section 12(a) was a relatively obscure provision that had been used sparingly. President Obama, however, exercised authority under Section 12(a) on five occasions to withdraw areas offshore Alaska from consideration of offshore oil and gas leasing.

President Obama first used Section 12(a) on May 31, 2010 to withdraw the North Aleutian Basin Planning Area, which includes the rich Bristol Bay fishery off of western Alaska, from consideration of leasing through 2017. In December 2014, President Obama acted to make the Section 12(a) withdrawal for the North Aleutian Basin more permanent by extending the withdrawal "for a time period without specific expiration." Although the exercise of executive authority offshore Alaska is always a politically sensitive issue, the North Aleutian Basin Section 12(a) withdrawals were not controversial because (1) there was no real industry interest in offshore oil and gas leasing in that area, and (2) recognition of the importance of the Bristol Bay fishery to Alaska's economy and to Alaska Natives.

President Obama's subsequent use of the 12(a) authority for areas in the Alaskan Arctic were much more controversial, particularly within the State of Alaska and among the Alaskan Congressional delegation. In January 2015, President Obama used Section 12(a) to withdraw "for a time period without specific expiration" approximately 9.8 million acres within the Beaufort and Chukchi Sea Planning Areas from oil and gas leasing, including areas that had been identified as important to Alaska Native subsistence hunting and fishing as well as Hanna Shoal, a biological hotspot in the Chukchi Sea.

Two more rounds of withdrawals in the Alaskan Arctic occurred near the end of the Obama Administration. On December 9, 2016, President Obama issued an Executive Order on Northern Bering Sea Climate Resilience that, among other things, used Section 12(a) to withdraw, for a period without specific expiration, from oil and gas leasing the Norton Basin Planning Area and part of the St. Matthew Hall Plaining Area near St. Lawrence Island in the Bering Sea off northwest Alaska. Finally, and most expansively, President Obama on December 20, 2016 withdrew under Section 12(a) -- again for a period without a specific expiration -- the entire Chukchi Sea Planning Area and most of the Beaufort Sea Planning Area, with the exception of about 2.8 million acres of the nearshore Beaufort Sea. On the same day, Prime Minister Justin Trudeau announced that Canada would ban new licensing in the Canadian Arctic Ocean for a period of five years, and that future decisions regarding leasing in those waters would be based on a review of climate and marine science at the end of that period.

The Atlantic

As discussed above, although the Obama Administration did not include any offshore oil and gas lease sales in the Mid or South Atlantic in the 2012-2017 Program, it laid foundation for consideration of the Atlantic during the development of the next Five Year Program. In July 2014, BOEM finalized a Programmatic Environmental Impact Statement (PEIS) evaluating the potential effects of G&G activity, including seismic surveys, in the Mid and South Atlantic Planning Areas. The G&G PEIS established safeguards and mitigation measures designed to eliminate or reduce the environmental effects of survey activity that would be necessary to update decades-old G&G data in support of potential oil and gas exploration in the Atlantic. BOEM also included one potential offshore lease sale in the Mid and South Atlantic Planning Areas in its Draft Proposed Program for 2017-2022, published in January 2015.

By the Proposed Program stage in the development of the 2017-2022 Program, however, the Obama Administration again withdrew the Mid and South Atlantic from potential offshore oil and gas leasing, at least through 2022. In the Proposed Program, published in March 2016, BOEM based the decision to remove the Atlantic from the 2017-2022 Program on "[n]umerous stakeholders, including many citizens living along the Atlantic coast and their public officials, [who] expressed concern that oil and gas activities and their potential impacts could jeopardize existing economic activities and the health of important contributors to coastal economies," including ocean-dependent tourism, commercial and recreational fishing, and commercial shipping and transportation. BOEM also cited a 2015 assessment by the Department of Defense (DOD) that identified "much of the area offshore Virginia, as well as significant portions of the Program Area offshore North Carolina" as places where oil and gas activity would be incompatible with DOD's activities.

At the end of the Administration and on the same day as the last round of Section 12(a) withdrawals off of Alaska, President Obama also used the Section 12(a) authority to withdraw, for a period without specific expiration, from oil and gas leasing areas associated with 26 subsea canyons and canyon complexes along the eastern seaboard, totaling 3.8 million acres. In making these withdrawals, President Obama cited the "critical importance of the canyons along the edge of the Atlantic continental shelf for marine mammals, deepwater corals, other wildlife, and wildlife habitat." Near the end of the Obama Administration, BOEM also notified G&G contractors that had submitted permit applications to conduct surveys in the Atlantic that BOEM would not approve those applications.

III. Potential Paths Forward for Offshore Oil and Gas Leasing During the Trump Administration

The Obama Administration's decisions about the areas to include in – and exclude from – the completed 2017-2022 Program, and its exercise of authority under Section 12(a) to withdraw substantial areas off of Alaska and in the Atlantic, set the stage for the Trump Administration's executive action on access to offshore oil and gas resources. There are three potential avenues that the Trump Administration can take as it charts a path forward for offshore oil and gas. First, the Trump Administration can, through its own executive action, attempt to rescind some or all of the Obama Administration's withdrawals under Section 12(a). Second, the Trump Administration could initiate the OCSLA Section 18 planning process and develop a new Five Year Program to supersede the current 2017-2022 Program, which as discussed below is similar to what President Obama did when he took office. Finally, the Trump Administration could work with Congress to open areas and schedule offshore oil and gas lease sales legislatively.

Rescission of Section 12(a) Withdrawals

President Trump's anticipated executive order regarding access to offshore oil and gas resources likely will attempt to undo some or all of the Obama Administration's Section 12(a) withdrawals offshore Alaska and in the Atlantic. While the language of Section 12(a) speaks to the President's authority to "withdraw" areas from leasing, the President's ability to remove areas from consideration of oil and gas leasing in perpetuity on the one hand, or to rescind a predecessor's withdrawals on the other hand, has not been tested in the courts. Moreover, the rescission of certain of the withdrawals may be complicated from a stakeholder standpoint. For example, while the State of Alaska likely would welcome rescission of President Obama's December 20, 2016 withdrawal of the Chukchi Sea and most of the Beaufort Sea Planning Areas, undoing the North

Aleutian Basin withdrawal and potentially exposing the Bristol Bay fishery to oil and gas leasing in the future may be met with concern even in Alaska, including by Alaska Natives.

Action by President Trump to scale back, or to undo in their entirety, President Obama's Section 12(a) withdrawals likely will be met with legal challenges that will test the effectiveness of Section 12(a) as a mechanism to remove offshore areas from consideration under the Section 18 five year planning process and to make them off limits to oil and gas leasing in a lasting way. If President Obama's withdrawals under Section 12(a) are found to be easily rescinded by subsequent executive action, then an ironic legacy of the Obama Administration's efforts to protect sensitive offshore areas from the threats posed by oil and gas development will be that Section 12(a), which gained prominence in the last administration, would have a short life as an enduring tool for environmental protection.

Development of a New Five Year Program

In addition, President Trump may direct the Interior Department to initiate the process for developing a new Five Year Program that would supersede the current 2017-2022 Program. As discussed above, it is generally understood that OCSLA requires potential lease sales in any planning area to have been analyzed both individually, and in conjunction with the other potential sales included in the program, throughout the entire OCSLA and NEPA process. Specifically, OCSLA Section 18(e) provides that the Interior Secretary may "revise and reapprove" the Five Year Program at any time, but that any such revision must occur "in the same manner as originally developed" unless the revision is "not significant." It is for this reason that, for example, the Trump Administration probably would not be able to simply schedule a lease sale in a planning area – such as the Mid and South Atlantic – that the Obama Administration dropped from the current 2017-2022 Program. To administratively schedule a lease sale in a planning area not included in the current Five Year Program, the Trump Administration likely would have to re-initiate the OCSLA planning process from the beginning, by issuing a new Draft Proposed Program and starting a new PEIS.

It is not uncommon for a new administration to begin its own five year planning process soon after taking office. For example, in February 2009, then Interior Secretary Salazar extended public comment on the Draft Proposed Program for 2010 to 2015 published at the very end of the Bush Administration, and then published a narrower Proposed Program in November 2011 to cover the period 2012 through 2017. Because the current 2017-2022 Program has been finalized, the Trump Administration would have to start from the beginning of the OCSLA Section 18 process and go through each of the three steps in the development of new Five Year Program, which typically takes at least two years.

Legislative Action

An avenue available to the Trump Administration to schedule additional offshore oil and gas lease sales in areas not included in the current 2017-2022 Program, without having to re-initiate the OCSLA Section 18 process, would be to work through Congress. Congress has the ability to enact legislation to alter the Five Year Program, including by opening areas and mandating lease sales. In recent years, a number of bills have been introduced in Congress either to require additional offshore lease sales, or to impose moratoria on leasing in certain areas. For example, earlier this month Alaska's Senators introduced the Offshore Production and Energizing National Security Alaska ("OPENS Alaska") Act of 2017, which among other things, would rescind President Obama's December 20, 2016 12(a) withdrawals in the Arctic and require lease sales in both the Beaufort and Chukchi Sea Planning Areas.

*   *   *   *

It is apparent that the Obama Administration's policies and actions with respect to offshore oil and gas leasing are among the targets for executive action by the Trump Administration, in keeping with the President's America First Energy Plan. While the contours of the anticipated executive action remain to be seen, as discussed above there are several avenues available to the new administration to expand the oil and gas industry's access to areas offshore, including in the Alaskan Arctic and in the Atlantic off of the eastern seaboard. Any such action, however, likely will present a host of political, administrative and legal challenges – including some novel issues – for the new administration to wrestle with. Moreover, given how the oil market outlook has changed, it remains to be seen just how significant for U.S. production the opening of areas put off limits by President Obama might be.

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COMMENT

The Public's Interest and Durable Management of Energy Development on Public Lands

by Tommy Beaudreau, Janice Schneider, and Joshua Marnitz

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The United States owns, on behalf of all Americans, approximately 30% of the nation's land, totaling more than 600 million acres, including vast landscapes in the west and in Alaska. These lands include our national parks, national forests, wildlife refuges, national monuments, as well as other public lands that are overseen by the Bureau of Land Management (BLM) in the United States Department of the Interior (DOI or the Interior Department). In addition to managing more than 245 million surface acres—nearly one-half—of these public lands, the BLM is responsible for administering approximately 700 million acres of subsurface mineral estate. Offshore, the Interior Department manages and regulates the entire 1.7 billion-acre U.S. outer continental shelf (OCS), including for oil and gas exploration and development.

The Interior Department's stewardship responsibilities over these lands, and the diverse natural resources that they contain, are grounded in its authorizing statutes. For example, the BLM's fundamental mandate under the Federal Land Policy and Management Act of 1976 (FLPMA) is to administer public lands "on the basis of multiple use and sustained yield," which includes "meet[ing] the present and future needs of the American people."[1] Under the Mineral Leasing Act of 1920 (MLA), the Interior Secretary is charged with establishing terms for the leasing of oil, natural gas, and coal that are necessary "for the safeguarding of the public welfare."[2] Similarly, the Outer Continental Shelf Lands Act (OCSLA) establishes the OCS as a "vital natural resource" that should be "made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."[3]

In light of these statutory directives that DOI's management of public lands be, broadly speaking, in the public's interest, Prof. Jayni Foley Hein argues in *Federal Lands and Fossil Fuels: Maximizing Social Welfare in Federal Energy Leasing* that the Interior Department must rethink its programs for the leasing of fossil fuels—including coal, oil, and natural gas—on public lands "with the goal of maximizing social welfare."[4] She observes that DOI's regulatory programs for leasing coal, oil, and natural gas on public lands have been in place, relatively unchanged, for decades. Indeed, the laws and regulations that govern these programs have seen few updates since they were promulgated the late 1970s and early 1980s, even though the conventional energy industries, as well as arguably the country's policy imperatives, have evolved substantially since then.

Professor Hein also argues forcefully that the Interior Department's current fossil fuel leasing programs employ "no mechanism to account for many significant externalities associated with fossil fuel extraction, transportation, and consumption."[5] She discusses that these programs fail to properly quantify, let alone address, major environmental and social effects, including related to greenhouse gas (GHG) emissions and their effect on climate.[6]

In light of the broad requirement that public lands be managed in the public's interest, Professor Hein recommends that to "better fulfill its statutory mandates under FLPMA, the Mineral Leasing Act, and OCSLA, Interior should update its leasing process and fiscal terms."[7] These proposed reforms include (1) requiring the development of strategic leasing plans to evaluate whether leasing would earn fair market value for taxpayers, including after considering social and environmental costs by using tools such as Social Cost of Carbon and Social Cost of Methane analyses; (2) optimizing fiscal terms for new leases, including by adding social cost of carbon and social cost of methane royalty "adders" to maximize net benefits; (3) requiring the development of alternative leasing scenarios by modeling energy substitution and climate effects; and (4) other reforms intended to curb royalty rate reduction "loopholes" and require consideration of alternatives, such as delaying

1. 43 U.S.C. §§ 1702(c), 1712(c)(1).
2. 30 U.S.C. § 187.
3. 43 U.S.C. § 1332(3).
4. Jayni Foley Hein, *Federal Lands and Fossil Fuels: Maximizing Social Welfare in Federal Energy Leasing*, 42 Harv. Envtl. L. Rev. 1, (2018), at 4.
5. *Id.* at 5.
6. *Id.* at 3-7.
7. *Id.* at 49.

lease sales, as part of a land management agency's analysis under the National Environmental Policy Act (NEPA).

In sum, Professor Hein advocates a strategy for using existing administrative authorities governing the management of fossil fuel leasing on public lands to advance social welfare by addressing the social costs of GHG emissions related to the eventual combustion of those fuels. While the goals of using federal authorities to advance social welfare are laudable, we are skeptical that the proposed reforms can be implemented in a durable way in light of the absence of political consensus that the "public interest" and "social welfare" require that fossil fuel development on public lands be managed specifically to address GHG emissions and climate effects.

Absent clearer legislative authority establishing that the public's interests in managing oil, natural gas, and coal leasing and development on public lands includes GHG emissions reduction and advancing climate goals, administrative policy and even regulatory changes premised on the generalized statements about the nation's interests and needs—such as those currently contained in DOI's existing authorities under FLPMA, the MLA, OCSLA and other relevant statutes—are not likely to be durable. The advantages of using the interpretation and exercise of existing authority as a lever for action on emissions and climate change—i.e., the ability to act without seemingly unattainable new legislative mandates codifying these objectives—are the same features that make such action susceptible to significant policy swings between executive administrations. As we have seen in recent years, what is done administratively can be dismantled quickly.

I. Fossil Fuel Development on Public Lands

First, a brief discussion about the opportunity—and limitations—of using the management of fossil fuels leasing and development on public lands as a lever in climate policy. Professor Hein discusses the "fossil fuel boom" that has occurred in the United States over the past decade, and this is important context for the proposed administrative reforms and their potential to affect overall GHG emissions from fossil fuel development in the United States. Indeed, oil and natural gas production in the United States has increased dramatically since the mid-2000s, driven by technological advances such as horizontal drilling and hydraulic fracturing that have unlocked massive hydrocarbon resources found in shale formations. According to the U.S. Energy Information Administration (EIA), between 2008 and 2016, total U.S. oil production increased by 77% and natural gas production increased by 35%.[8] This trend in increased domestic oil production has continued in recent years, and the EIA reports that the U.S. produced nearly 12 million barrels of oil per day in March 2019, which is more than double the 5.5 million barrels per day produced in March 2010.[9]

However, this unprecedented growth in domestic oil and natural gas production has largely been a story about the rise of shale basins, which happen to coincide predominately with private and state managed lands. While federal onshore oil production has increased by 59% since 2008, that growth is dwarfed by what has happened on non-federal lands.[10] The EIA estimates that 90% of the growth in oil and natural gas development between 2011 and 2016 can be attributed to tight oil and shale gas plays located primarily on state and private (i.e., non-federal) lands.[11] Similarly, while offshore oil production from the federal OCS in the Gulf of Mexico has remained relatively steady, it has decreased as a percentage of overall domestic oil and gas production from approximately 29% in March 2010 to 16% in March 2019.[12]

Federal coal is a different picture altogether. Due largely to market forces, plant retirements, regulation, and the proliferation of cheap natural gas, total coal production in the United States declined approximately 23% from 2008 to 2015.[13] The production of federal coal, which accounts for nearly 40% of the coal produced in the United States, has declined approximately 19% during that same time period.[14]

Therefore, while public lands remain a source of significant oil, natural gas, and coal production, they are not responsible for the fossil fuel production boom that the United States has experienced over the past decade. Oil production in the U.S. has risen dramatically over the past 10 years, but public lands have not played a significant role in that growth. Meanwhile, for a variety of reasons, coal production from public lands continues to trend downward. Accordingly, public lands do not present a game-changing opportunity for advancing climate policy through administrative changes to federal oil, natural gas, and coal leasing programs, particularly under existing authorities.

II. Case Studies in the Limitations of Using Existing Administrative Authorities to Advance Social Welfare

The absence of political consensus supporting reinterpretation of the public's interest in how fossil fuels leasing is managed on public lands is illustrated by the short-lived reforms attempted during the Barack Obama Administration. In this comment, we discuss three examples, each of which highlights different aspects of the political, legal, and practical challenges that face Professor Hein's proposed

8. United States Government Accountability Office, Report to Congressional Committees Gao-17-540, Oil, Gas, and Coal Royalties: Raising Federal Rates Could Decrease Production on Federal Lands But Increase Federal Revenue, at 12 (June 2017) ("GAO Royalties Report") (citing EIA data).

9. EIA, Monthly Crude Oil and Natural Gas Report, *at* https://www.eia.gov/petroleum/production/ (last visited June 27, 2019).

10. *See supra* note 8, at 12. (citing Office of Natural Resources Revenue data).

11. *Id*. (citing EIA data).

12. *See supra* note 9.

13. *See supra* note 8, at 14.

14. *Id.*

reforms to manage fossil fuels leasing on public lands with an eye toward social welfare, as defined as reducing carbon pollution and addressing climate change.

First, we discuss the 2016 *Federal Coal Program Programmatic Environmental Statement—Scoping Report* (the Coal PEIS Scoping Report), which former Interior Secretary Jewell commissioned to provide a broad review of the federal coal leasing program similar to the comprehensive, programmatic evaluation and reorientation that Professor Hein recommends.

Second, we examine the Obama Administration's consideration of changes to onshore oil and gas royalty rates, including potentially to account for negative externalities associated with carbon pollution through analytical tools such as the Social Cost of Carbon, premised on the BLM's established authority to set royalty rates through regulation.

Finally, we discuss the BLM's 2016 *Final Rule on Waste Prevention, Production Subject to Royalties, and Resource Conservation* (the BLM Methane Rule), which hewed closely to BLM's traditional stewardship responsibilities to prevent waste and ensure a fair return to the taxpayer, as opposed to any climate-related emission reduction policy, and yet nevertheless was immediately targeted for rescission and revision following the 2016 election and change in the political party governing the federal Executive Branch.

A. The 2016 Federal Coal PEIS

The MLA affords the Secretary of the Interior substantial discretion in implementing the federal coal leasing program by authorizing the Secretary to manage federal lands for coal leasing "as he finds appropriate and in the public interests."[15] The Federal Coal Leasing Amendments Act of 1976 amended the MLA to require that all public lands available for coal leasing be offered competitively. The MLA also directs the federal government not to accept any bid on a coal lease tract that is less than the "fair market value."[16] On the royalties side, the MLA generally establishes a floor for surface coal royalties of 12.5%, and authorizes the Secretary to establish a lesser royalty rate for coal recovered from underground mining operations.[17] The BLM regulations implementing the federal coal leasing program were primarily developed in the late 1970s, and the program has not been subject to comprehensive review since the 1980s. Meanwhile, as discussed above, the coal industry and energy markets have changed substantially since that time. Additionally, in recent years the Government Accountability Office (GAO) and DOI Inspector General's Office have criticized the federal coal leasing program for failing to provide for a fair return to taxpayers.[18]

In January 2016, Interior Secretary Jewell issued Secretarial Order 3338, which directed BLM to prepare a Programmatic Environmental Impact Statement under NEPA to identify and analyze potential leasing and management reforms for the federal coal program (Coal PEIS).[19] Secretarial Order 3338 stated that the Coal PEIS would "provide a vehicle for the Department to undertake a comprehensive review of the program and consider whether and how the program may be improved and modernized to foster the orderly development of BLM administered coal on Federal lands in a manner that gives proper consideration to the impact of that development on important stewardship values, while also ensuring a fair return to the American public."[20] Secretarial Order 3338 highlighted three main concerns to be addressed in the Coal PEIS—fair return, climate change, and market conditions.[21] Secretarial Order 3338 also imposed a "pause on the issuance of new federal coal leases for thermal (steam) coal" administered by the BLM to "allow future leasing decisions to benefit from the recommendations that result" from the Coal PEIS.[22] Professor Hein points to the Coal PEIS directed under Secretarial Order 3338 as exactly the type of analysis that she recommends be done "regularly to determine whether taxpayers are receiving 'fair market value' and whether the program is aligned with climate change or other environmental goals."[23]

The problem, from the perspective of Professor Hein's recommendations, is that Secretarial Order 3338 and the Coal PEIS, which were premised on the Secretary's authorities under the MLA, FLPMA and other statutes to act in the public interest, resulted in no change to the way BLM administers the federal coal program.

Just before the end of the Obama Administration in January 2017, BLM published its Coal PEIS Scoping Report.[24] In the Coal PEIS Scoping Report, BLM found that "[c]onsideration of the implications of Federal coal leasing for climate change, as an extensively documented threat to the health and welfare of the American people, falls squarely within the factors to be considered in determining the public interest."[25] In fact, BLM in the Coal PEIS Scoping Report identified for additional analysis many of the same proposals made by Professor Hein, including accounting

15. 30 U.S.C. § 201(a)(1).
16. *Id.*
17. 30 U.S.C. § 207(a).
18. *See* Office of the Inspector General, U.S. Department of the Interior, Coal Management Program, U.S. Department of the Interior, Report No. CR-EV-BLM-0001-2012 (June 2013); Government Accountability Office, Coal Leasing: Blm Could Enhance Appraisal Process, More Explicitly Consider Coal Exports, and Provide More Public Information, Gao-14-140 (Dec. 2013); Government Accountability Office, Oil, Gas, and Coal Royalties: Raising Federal Rates Could Decrease Production on Federal Lands But Increase Federal Revenue, GAO-17-540 (June 2017).
19. U.S. Department of the Interior Secretarial Order No. 3338, *Discretionary Programmatic Environmental Impact Statement to Modernize the Federal Coal Program*, at 1 (Jan. 15, 2016).
20. *Id.*
21. *Id.* at 4-5.
22. *Id.* at 8-10. Secretarial Order 3338 also included numerous exceptions to this moratorium on new coal leasing by BLM, including for lease sales associated with applications in advanced stages of review, emergency leasing, and certain lease modifications and lease exchanges.
23. *See supra* note 4, at 27.
24. U.S. Department of the Interior, Bureau of Land Management, Federal Coal Program Programmatic Environmental Impact Statement—Scoping Report (Jan. 2017).
25. *Id.* at ES-2.

for social costs of coal production and pricing externalities associated with carbon emissions through either increased royalty rates or the imposition of a carbon "adder" equivalent to a per-ton fee to be paid in addition to the royalty.[26]

The Coal PEIS never advanced beyond scoping. One of the early acts of the Donald Trump Administration was to rescind Secretarial Order 3338, terminate the Coal PEIS review, and lift the moratorium on new coal leasing by BLM.[27] The Coal PEIS was politically contentious at the time it was proposed, and despite responding to calls for modernizing and reforming the federal coal program and purporting to be grounded in the Secretary's general authority under the MLA, FLPMA and other statutes to act in the public interest, it did not survive a presidential election and change in administration.[28]

B. *Onshore Oil and Natural Gas Royalty Rates and the Social Cost of Carbon*

Our next case study in the challenges of using existing authorities to implement durable change in the public's interest concerns the previous administration's attempts to adjust royalty rates for onshore oil and gas production from public lands, including consideration of the use of social cost of carbon calculations to quantify external costs. Those efforts were not a broad re-evaluation of the BLM's oil and gas program, such as contemplated by the Coal PEIS, but rather consideration of how existing authorities could be used to quantify and recoup social costs related to GHG emissions.

Under the MLA, the royalty rate for non-competitively issued oil and gas leases on BLM-managed lands is fixed at 12.5%.[29] For competitively issued oil and gas leases on BLM-managed lands, the MLA requires a royalty "at a rate not less than 12.5%."[30] In 2015, BLM issued an Advanced Notice of Proposed Rulemaking (ANPR) to assist BLM in preparing a proposed rule to provide the Interior Secretary with "the flexibility to adjust royalty rates in response to changes in the oil and gas market."[31] Among the questions BLM asked in the ANPR was whether BLM should "consider other factors in determining what royalty level might provide a fair return, such as life cycle costs, externalities, or the social costs associated with the extraction and use of the oil and gas resources."[32] BLM also asked commenters if the agency should consider factors such as externalities and social costs, and to "please explain how it should do so."[33]

Professor Hein proposes an answer. She explains that because "environmental externalities vary with the amount of fossil fuels that are produced," increased royalty rates on oil and gas could be used to recoup the social costs of carbon associated with these fuels. Accordingly, she recommends that DOI use "economic tools to measure the cost of these impacts, such as the Social Cost of Carbon and Social Cost of Methane" to help establish royalty rates as a "type of Pigouvian tax: a tax levied on activity that generates negative externalities."[34]

While BLM's consideration of oil and gas royalty rate adjustments during the Obama Administration never advanced to the point of implementing royalty rates at levels tied to recovery of the social costs of carbon pollution, the Obama Administration worked to develop the Social Cost of Carbon as a tool for federal agencies to use, including in evaluating GHG emissions and climate effects under NEPA. In August 2016, the White House Council on Environmental Quality (CEQ) published its *Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews*, which required federal agencies to consider GHG emissions and climate change issues when evaluating the potential impacts of a federal action under NEPA.[35] CEQ specifically suggested that federal agencies use the Social Cost of Carbon analytical tool.[36]

In March 2017, President Trump's Executive Order 13783 directed CEQ to rescind its 2016 guidance on analyzing GHG emissions and climate change under NEPA.[37] This Executive Order also disbanded the Interagency Working Group on Social Cost of Greenhouse Gases (IWG) and withdrew the technical analyses generated by the IWG as "no longer representative of governmental policy."[38] On June 21, 2019, CEQ issued its *Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions*, which among other things proposed advising federal agencies that they "need not weigh the effects of the various alternatives in NEPA in a monetary cost-benefit analysis using any monetized Social Cost of Carbon (SCC) estimates and related documents . . . or other similar cost metrics."[39]

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26. *Id*. at 6-13.
27. Presidential Executive Order 13783, *Promoting Energy Independence and Economic Growth* (Mar. 28, 2017); U.S. Department of the Interior Secretarial Order 3348, *Concerning the Federal Coal Moratorium* (Mar. 29, 2017); U.S. Department of the Interior Secretarial Order 3349, *American Energy Independence* (Mar. 29, 2017).
28. Indeed the Trump Administration recently doubled down on its position in the face of litigation over this issue. *See, e.g.,* Draft Environmental Assessment, *Lifting the Pause on the Issuance of New Federal Coal Leases for Thermal (Steam) Coal*, DOI-BLM-WO-WO2100-2019-0001-EA (May 2019).
29. 30 U.S.C. §226(c).
30. 30 U.S.C. §226(b)(1)(A).
31. Bureau of Land Management, Advanced Notice of Proposed Rulemaking, Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Red. 22148 (Apr. 21, 2015).
32. *Id.* at 22, 154.
33. *Id.*
34. *See supra* note 4, at 18.
35. Council on Environmental Quality, Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews, 81 Fed. Reg. 51866 (Aug. 5, 2016).
36. *Id.*
37. *See supra* note 27; *see also* 82 Fed. Reg. 16576 (Apr. 5, 2017) (CEQ notice withdrawing the guidance).
38. *See supra* note 27.
39. Council on Environmental Quality, Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions, 84 Fed. Reg. 30097 (June 26, 2019).

While BLM during the Obama Administration never went as far as to propose a rule that would allow for consideration of externalities associated with GHG emissions to be factored into royalty rates for oil and gas production, even the analytical tools, such as the Social Cost of Carbon, necessary for developing the calculation of such an approach to royalty rates were rejected following the 2016 election. Where even such tools are deemed not consistent with federal policy, it seems unlikely that BLM would enjoy the political support necessary to administratively use royalty rates as a form of tax to recoup external costs related to GHG effects on climate, particularly under the existing statutory framework.

C. BLM Methane Rule

This brings us to our final case study—the 2016 BLM Methane Rule. BLM attempted to use its existing authorities to directly address upstream methane emissions in the 2016 BLM Methane Rule.[40] The MLA specifically requires BLM to ensure that lessees "use all reasonable precautions to prevent waste of oil or gas developed in the land" and comply with rules "for the prevention of undue waste."[41] Coupled with BLM's obligation to obtain a fair return for the American public on produced resources such as natural gas, these waste prevention requirements are four square with the traditional exercise of BLM's authorities in the public interest.

The BLM Methane Rule hewed closely to that traditional understanding of BLM's responsibility to serve the public's interest by regulating oil and gas operations to prevent the waste of resources and to ensure a fair return to the taxpayer. For example, the BLM Methane Rule required operators to develop waste minimization plans; established clear criteria for when flared gas would be subject to royalties; generally prohibited venting and tightened rules on flaring of associated gas from oil wells; and established standards for detecting and/or addressing gas leaks from equipment at the well site or elsewhere on the lease, the operation of high-bleed pneumatic controllers and certain pneumatic pumps, controlling gas emissions from storage vessels, downhole well maintenance and liquids unloading, and well drilling and completions.[42] BLM also included provisions authorizing variances from requirements under the BLM Methane Rule where a state or tribe demonstrates that a state, local, or tribal regulation imposes equally effective requirements.[43]

Despite its grounding in traditional notions of the public interest in regulating emissions from oil and gas operations, as opposed to achieving goals related to climate policy, the BLM Methane Rule was immediately a target for rescission following the 2016 election. The BLM Methane Rule narrowly survived a rescission under the Congressional Review Act, and did so only because of concerns in the U.S. Senate about permanently impairing BLM's authority to regulate to prevent waste and ensure fair return.

The Interior Department then turned to revising the BLM Methane Rule through the Administrative Procedures Act notice and comment rulemaking process. In September 2018, BLM published the final revised Methane Rule, entitled *Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements* (Revised Methane Rule).[44] The Revised Methane Rule eliminated a number of provisions of the original BLM Methane Rule, including requirements related to waste management plans, leak detection and repair, and gas capture. The Revised Methane Rule also modified requirements related to gas capture and the flaring of associated gas royalty-free, downhole well maintenance and liquids unloading, and the measuring and reporting of volumes of gas vented or flared.

Despite being premised on preventing waste and ensuring fair return, BLM in the Trump Administration determined that the costs to industry of compliance with the original BLM Methane Rule outweighed its benefits. BLM originally estimated the BLM Methane Rule would result in a minimum annual net benefit of $46 million, and produce a minimum increase in oil and gas royalties of $3 million.[45] In the Revised Methane Rule, however, BLM estimated that the reduction of compliance costs would exceed the forgone cost savings from recovered natural gas and the value of the forgone methane emissions reductions, producing minimum benefits of $734 million.[46] BLM further estimated that the Revised Methane Rule would result in minimum forgone royalty payments to the federal government, tribal governments, states, and private landowners of $28.3 million.[47] Thus, not only were the social costs associated with fugitive emissions not a factor in the new cost benefit analysis, BLM eliminated or modified a number of provisions under the original BLM Methane Rule because the compliance cost to industry outweighed the value of prevented waste of gas or lost royalty revenue to the taxpayer.

III. Conclusion

Determining the public interest, in order to manage the United States' shared resources on public lands in a way that maximizes social welfare, is inherently political. As illustrated by efforts during the Obama Administration to exercise existing authorities related to the administration of energy development on public lands—efforts that fell along a continuum of executive authority from re-imagining the entire federal coal program through the lens

40. Department of the Interior, Bureau of Land Management, Final Rule, Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 83008 (Nov. 18, 2016).
41. 30 U.S.C. §§ 187, 225.
42. *See supra* note 40.
43. *Id.*
44. Bureau of Land Management, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements, 83 Fed. Reg. 49184 (Sept. 28, 2018).
45. *See supra* note 40, at 83014.
46. *See supra* note 44, at 49205.
47. *Id.*

of climate policy, to reinterpreting existing authority to include accounting for the social costs of GHG emissions in royalty rates and NEPA analyses, to hewing closely to traditional understanding of the public interest in curbing waste and ensuring fair return through regulation of fugitive emissions—absent political consensus, the reforms recommended by Professor Hein are unlikely to be durable or result in meaningful changes to the oversight of energy development on public lands.

This does not mean that changes to how the Interior Department manages energy development on public lands are impossible. But, recent experience does tell us that the U.S. Congress has a role to play. As Interior Secretary Bernhardt stated in his recent testimony during a U.S. House of Representatives budget hearing, there is not a clear statutory mandate, or even policy consensus, that public lands—and energy development on public lands in particular—must be managed with climate impacts in mind. When asked whether it is his job as Interior Secretary to help address climate change, he responded, "You know what, there is not a 'shall' for 'I shall manage the land to stop climate change' or something similar to that. You guys come up with the 'shalls.'"[48]

Exercising administrative authorities based on the interpretation of the public interest mandate under FLPMA, the MLA, OCSLA, and other existing statutes is not enough to accomplish the social welfare objectives that Professor Hein argues are necessary to reflect the true social cost of GHG emissions related to energy development on public lands and address the effects of climate change on our landscapes. Lasting and effective changes in the way public lands are managed—the kinds of changes that can survive swings in the political pendulum—would also require Congress to weigh in on defining the public's interest in energy development on public lands.

48. *Rep. Chellie Pingree Asks Secretary Bernhardt About Climate Change and Scientist Vacancies*, C-SPAN (May 7, 2019), https://www.c-span.org/video/?c4796445/rep-chellie-pingree-asks-secretary-bernhardt-climate-change-scientist-vacancies.

Center for American Progress

Protecting the Taxpayer's Share of Natural Resource Revenues on Public Lands and Oceans

The Costs, Benefits, and Risks of Natural Resource Revenue Proposals Before Congress

By Matt Lee-Ashley, Jessica Goad, Michael Madowitz, and Michael Conathan November 2013

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Introduction and summary

Each year, taxpayers earn more than $11 billion from the natural resources developed from the public lands and oceans that belong to them and which federal agencies manage on their behalf. This income—generated from activities ranging from deepwater drilling in the Gulf of Mexico to coal mining in Wyoming to geothermal plants in Nevada—is one of the largest nontax sources of revenue for U.S. taxpayers and is available for the benefit of all Americans.

Congress, however, is currently considering several proposed changes to U.S. natural resource revenue policy that, if enacted, would have profound budgetary and policy implications. These changes would fundamentally undermine the principle that the resources on and under public lands and waters belong to all Americans and should be shared equitably.

The leading proposal, the Fixing America's Inequities with Revenues, or FAIR, Act, would divert a greater share of oil and gas revenues from the federally owned 1.3 billion-acre Outer Continental Shelf, or OCS, to five energy-producing coastal states—Alaska, Louisiana, Mississippi, Texas, and Alabama. This revenue-sharing proposal, according to a recent Center for American Progress analysis, would increase the federal debt by more than $49 billion by 2040 while penalizing coastal states that oppose expanded offshore drilling. While the Congressional Budget Office has projected that the cost of this bill would be only $6 billion, it looks out only to 2023, before the revenue-sharing caps are lifted under the FAIR Act. Under the proposal, states such as Florida, which experienced extensive damage from the Deepwater Horizon oil spill despite having a moratorium on drilling near its coast, would be ineligible to receive any type of offshore energy revenue, conventional or renewable, from the OCS.

In addition, CAP's analysis shows that the FAIR Act is anything but fair and would result in a significant and arguably inequitable windfall for a handful of states. Under the proposed legislation, federal energy payments to Louisiana alone would rise to nearly $2 billion per year by 2025—33 times more than what the average energy-producing state is currently collecting and 12 times more than what either of two of the onshore energy-producing giants, Colorado and Utah, are receiving in federal oil, gas, and coal payments. This imbalance appears particularly indefensible in light of the fact that OCS resources belong to all Americans. Unlike onshore federal lands, OCS lands lie outside state boundaries, and the federal government is responsible for the full cost of their management, safety, and environmental protection.

Rather than creating new revenue-sharing entitlements, Congress should take a comprehensive, fiscally sound approach to addressing the natural resource revenue challenges facing the nation. In this report, we offer four recommendations that are in line with this type of common-sense and equitable approach.

1. Congress should put taxpayers first by reaffirming that the resources on and under federal lands and waters belong to all Americans. With U.S. taxpayers shouldering the impacts and costs of Washington's short-sighted and damaging across-the-board spending cuts under sequestration, and with ongoing budgetary constraints expected for the foreseeable future, taxpayers should not be asked to forgo any additional natural resource revenues.

2. Congress should establish a new mitigation fee that oil and gas companies would pay when drilling on the OCS. The environmental damage and costs of offshore oil and gas development must be accounted for and addressed. Instead of asking U.S. taxpayers to incur these costs through expanded revenue sharing, the revenues from this new fee would be dedicated specifically to the protection and restoration of coastal and environmental resources that are affected by oil and gas operations.

3. Congress should create a true conservation royalty by using OCS revenues to fully and permanently fund America's premier conservation program, the Land and Water Conservation Fund, or LWCF. Because the revenues from oil and gas development on federal lands and waters belong to taxpayers, they should be invested for the benefit of all Americans. In addition, Congress should act on President Barack Obama's proposal to establish an Energy Security Trust Fund—modeled on the LWCF—which would use revenues from the depletion of oil and gas reserves to help the country forge a sustainable and clean energy future.

4. Congress must address the expensive legacy of revenue-sharing agreements that were established during earlier natural resource booms. States and counties with federal lands within their jurisdiction, from which they cannot collect property taxes, face ongoing uncertainty related to whether Congress will extend county payments through the Secure Rural Schools and Payment in Lieu of Taxes programs. As Congress considers whether and how to reauthorize county payments, it should endeavor to simplify the programs and provide a clear path to reducing their costs to taxpayers over time.

Let's examine the issue of natural resource development on our public lands and oceans in greater detail.

Natural resource revenue landscape

A surge in revenues from America's recent oil and gas boom has been one of the few bright spots in the budgets of federal, state, and local governments since the 2008 financial collapse and recession. While 43 states encountered midyear budget shortfalls during the recession as a result of falling tax collections, a handful of energy-rich states weathered the storm with the help of rising oil and gas collections.[1] Rapid production growth in the Bakken Formation, a geologic formation that underlies Montana, North Dakota, and part of Canada, for example, yielded more than a tenfold increase in North Dakota's oil and gas tax collections since 2007, resulting in more than $3 billion in state severance tax collections in 2012 and an estimated $1.6 billion budget surplus.[2]

The opportunities that rising oil and gas collections present for cash-strapped states and local governments have prompted a renewed discussion in Congress of how natural resource revenues from federal lands and waters should be shared with state and local jurisdictions. In particular, lawmakers from energy-producing Gulf states and Alaska are pressing to further expand their states' shares of revenues from offshore drilling on the federally owned Outer Continental Shelf. In March of this year, Sen. Mary Landrieu (D-LA) and Sen. Lisa Murkowski (R-AK) introduced the FAIR Act—S. 1273—which received a hearing in the Senate in July and appears to be the most likely legislative vehicle for Congress to consider changes to existing revenue-sharing laws.

But the idea of diverting an even greater share of federal offshore oil and gas receipts to coastal energy-producing states has encountered opposition on several fronts. The Obama administration testified that it "could not support" the FAIR Act because it diminishes returns to the American taxpayers who own the resources, diverts money away from parks and land-conservation efforts, and adds to the federal deficit.[3] Taxpayers for Common Sense, the nonpartisan federal budget-watchdog organization, called the $6 billion revenue-sharing proposal "downright foolish" and criticized the legislation for directing nationally owned resources to specific states in a difficult fiscal climate.[4] A number of conservation groups have noted that the legislative proposal creates additional incentives for states to support offshore drilling over other economic activities such as tourism, fishing, and outdoor recreation, in addition to financial penalties for states that do not support drilling off their coasts.

Although the FAIR Act focuses primarily on the redistribution of offshore energy revenues, Congress faces two other major natural resource revenue questions that factor heavily in the revenue-sharing debate.

First, Congress is under pressure to address the expensive legacy of revenue-sharing agreements that were negotiated during earlier natural resource booms. Most notably, Congress must again determine whether to provide assistance to counties in Western states with economies tied to the timber industry. When logging in national forests and on public lands exploded during the post-World War II housing boom, these counties became heavily reliant on timber revenues to fund roads, schools, and public services. But when logging on federal lands began declining two decades ago, the federal government elected to provide direct payments to affected counties to help cushion the blow from falling timber revenues.[5] The most recent form of these direct-payment programs, the Secure Rural Schools program, or SRS[6], was recently extended in September 2013 for one more year. A similar direct-payment program—Payment in Lieu of Taxes, or PILT, which subsidizes counties that have federal lands on which they cannot collect property taxes—expires at the end of FY 2013.[7] Over the past five years, PILT has been funded at approximately $390 million per year, while SRS has been funded at approximately $350 million per year.[8]

Second, in contrast to FAIR Act proponents who want to divert offshore oil and gas revenues to coastal drilling states, the Obama administration and other lawmakers—both Democrats and Republicans representing noncoastal states—argue that rising offshore oil and gas revenues should be invested in ways that benefit all states. In particular, a bipartisan, bicameral coalition—with support from the administration—is advancing legislation to reauthorize and fully fund the LWCF, which since its establishment in 1964 has used offshore oil and gas revenues to build parks and protect open spaces, battlegrounds, and trails across the country.[9] Although $900 million from oil and gas receipts are deposited in the LWCF every year, the majority of the funds are typically diverted by Congress each year to support unrelated spending.[10]

How we got here: Background on revenues from offshore drilling

Royalties, rents, and bonus bids from oil and gas drilling on the federally owned, 1.3 billion-acre OCS are one of the largest sources of revenue for U.S. taxpayers and the Treasury.[11] In 2012, receipts from oil and gas activities on the OCS topped $6.8 billion, more than 95 percent of which came from federal waters in the Gulf of Mexico.[12]

In 1947, the U.S. Supreme Court determined that the federal government, representing American taxpayers, had "paramount rights" to the waters and resources on the OCS.[13] Congress, however, granted coastal states, through the Submerged Lands Act of 1953, title to submerged lands that are within three nautical miles of their coasts and provided that states receive all revenues from activities in that area. State title to land off the coast of Texas and the Gulf Coast of Florida extends nine nautical miles.[14]

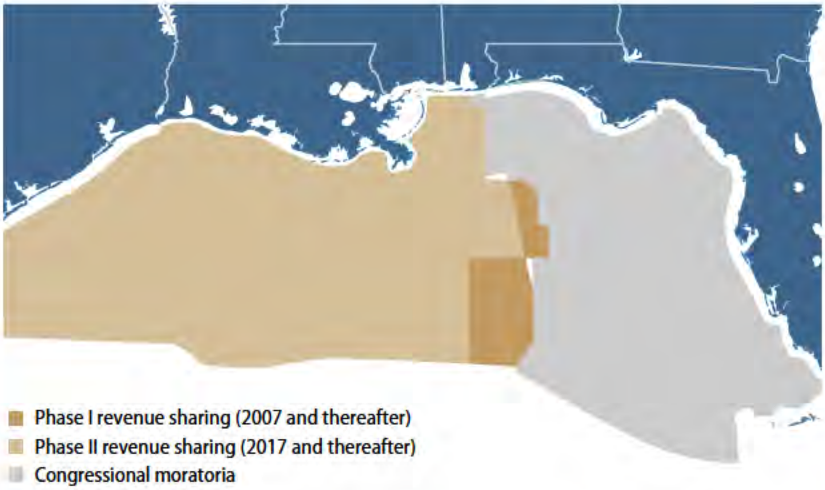
Furthermore, to compensate for any state-owned oil and gas that might drain outside of a state's submerged lands, Congress amended the Outer Continental Shelf Lands Act, or OCSLA, in 1985 to provide states with 27 percent of the revenues from oil- and gas-leasing activities in the area extending three miles seaward from the states' submerged-land boundaries.[15] This area is referred to as the "8(g) zone," for the provision in OCSLA that created it. Alaska and the four oil- and gas-producing states in the Gulf—Louisiana, Alabama, Mississippi, and Texas—collected approximately $300 million from oil and gas activities in the 8(g) zone between 2007 and 2012, of which Louisiana, with the largest share, collects an average of $25 million per year.[16] Since 1986, a total of more than $3.1 billion has been disbursed to coastal states through the 8(g) provision in OCSLA.[17]

In 2006, under renewed pressure from oil- and gas-producing states on the Gulf Coast, Congress again expanded the share of revenues from the OCS that is directed to select coastal states. The Gulf of Mexico Energy Security Act of 2006, or GOMESA, signed by President George W. Bush on December 20, 2006, granted the Gulf Coast states of Alabama, Mississippi, Texas, and Louisiana and their coastal political subdivisions 37.5 percent of all revenues, without a cap, from the 8.3 million acres of newly opened areas in the Eastern Gulf of Mexico. These payments are referred to as "Phase I" of GOMESA.[18]

Beginning in 2017, in the so-called Phase II of the program, the four Gulf Coast states are to also receive 37.5 percent of all revenues from leases that were entered ino since the enactment of GOMESA in all other areas of the Gulf of Mexico, up to $375 million per year. An additional 12.5 percent of revenues from Phase I and Phase II are to go directly to the stateside-grant program of the LWCF, up to $125 million per year.[19]

FIGURE 1

'Phase I' and 'Phase II' areas in the Gulf of Mexico subject to revenue sharing, under the Gulf of Mexico Energy Security Act



Source: Bureau of Ocean and Energy Management, "Gulf of Mexico Energy Security Act (GOMESA) Areas," available at http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Leasing/GOMESA_Phases.pdf.

The revenue-sharing provisions in GOMESA are projected to provide large and growing returns for the four oil-producing states in the Gulf—Alabama, Mississippi, Texas, and Louisiana. Since 2009, when the first revenues began coming in under Phase 1 of GOMESA, the four Gulf Coast states have received more than $30 million.[20] In 2017, however, the Gulf states are expected to receive $375 million each year under the provisions in Phase II of GOMESA.[21] Overall, CAP estimates that the revenue-sharing provisions under Phase II of GOMESA will cost American taxpayers $12 billion between 2014 and 2040.[22]

The FAIR Act

According to Sens. Landrieu and Murkowski, the bill's sponsors, the primary goal of the FAIR Act is to correct a perceived inequity between the share of revenues that states receive from oil and gas development on federal lands within state boundaries and what states receive from oil and gas development on the OCS outside of state jurisdiction. Said Landrieu when she introduced the bill:

> *For decades coastal energy producing states have faced a glaring inequity in federal energy policy that allows onshore producing states to keep 50 percent of revenues, while offshore producing states, like Louisiana and Alaska, keep virtually nothing.*[23]

Expanded revenue sharing, argue the bill's proponents, will help coastal producing states pay for infrastructure, support coastal restoration, and address the impacts of oil and gas development.

The bill proposes three primary changes to the current offshore oil and gas revenue-sharing formula:

1. It accelerates Phase II of GOMESA to immediately grant the four Gulf Coast states—Alabama, Mississippi, Texas, and Louisiana—up to 37.5 percent of all eligible revenues throughout the Gulf of Mexico.[24] Under GOMESA, Phase II of revenue sharing was to begin in 2017.[25]

2. It raises the cap on Phase II revenues that GOMESA prescribed for Gulf states to $500 million beginning in FY 2014 and raises the cap by $100 million per year, until the cap reaches $1.5 billion in 2024. The cap is fully removed after 2024.[26]

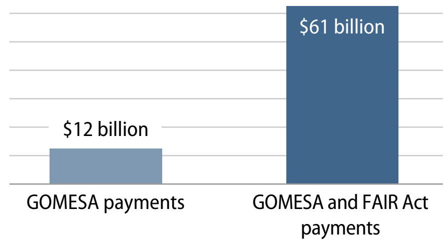
3. It reduces direct payments to the LWCF by 50 percent to $62.5 million per year, fixing the payments at 7 percent of the program's authorized level. The legislation permits these funds to be used for the stateside-grant program of the LWCF, not the federal program.

In addition, the FAIR Act creates a formula for sharing revenues from renewable and alternative energy sources on public lands and waters. Onshore, the legislation prescribes that 50 percent of revenues from alternative and renewable energy projects on public lands are to go to the states within which the energy source is located. Offshore, it prescribes that 37.5 percent of revenues from renewable energy production on the federal OCS is to go to coastal states and their coastal political subdivisions, provided that those states meet the eligibility requirements of the legislation.[27]

FIGURE 2

Payments from U.S. taxpayers to eligible coastal states, 2014–2040

GOMESA versus the FAIR Act



Source: CAP estimates based on EIA's Annual Energy Outlook. See endnote 29.

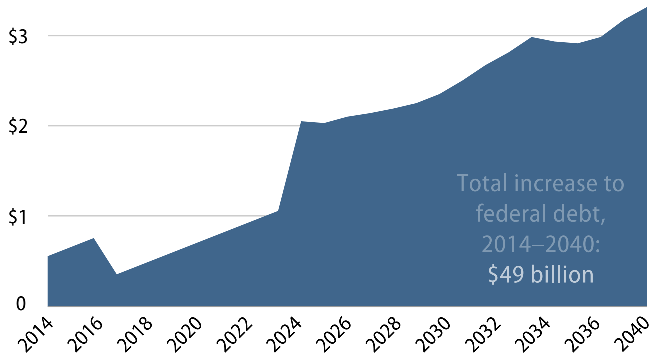
Effects of the FAIR Act

The FAIR Act's proposed redistribution of revenues from energy development on federal lands and waters has far-reaching budgetary and policy implications. The Congressional Budget Office, or CBO, estimates the bill will increase the federal budget deficit by $6 billion between 2014 and 2023.[28] A CAP analysis finds that—because all caps on revenue sharing are lifted under the FAIR Act—the legislation will actually increase the federal budget deficit by at least $49 billion between 2014 and 2040. It is important to note that CAP's estimate does not account for revenues from bonus bids at lease sales in the Gulf of Mexico or Alaska, which could result in several billion dollars in additional revenue-sharing payments to states before 2040. As a result, the FAIR Act's cost to taxpayers is likely to be even higher than our projections.[29]

FIGURE 3

Annual increase to budget deficit under the FAIR Act

In billions of dollars



Source: CAP estimates based on EIA's Annual Energy Outlook. See endnote 29.

In addition to expanding the share of OCS revenues that must be directed to coastal states, the FAIR Act also prescribes which states are eligible to participate in revenue sharing. To be eligible for funds, a state must be within 200 nautical miles of the geographical center of the leased tract. Furthermore—and importantly—a state cannot be eligible if the majority of its coastline is under a federal or state leasing moratorium.[30]

The only states that currently meet the eligibility requirements for receiving revenue sharing under the FAIR Act are Alaska, Alabama, Mississippi, Louisiana, and Texas. Although there is active energy production on the federal OCS offshore Southern California, state policies against new leasing in state waters—in addition to the fact that the federal government is no longer leasing offshore California—appear to make it ineligible to participate in revenue sharing under the FAIR Act.[31] Similarly, Florida, which is within 200 miles of active leases but the coastline of which is under a congressional drilling moratorium, would also not be eligible to receive funds under the FAIR Act.[32]

The FAIR Act's eligibility limitations for coastal states also apply to renewable energy revenues. States that encourage renewable energy development on the federal OCS but have policies opposing oil and gas drilling off their coasts would not be eligible to receive revenue from renewable energy activities.[33] This limitation could affect several Northern and Mid-Atlantic states that are actively pursuing wind-energy development on the OCS but have state policies against offshore drilling. The eligibility requirements are likely to create inequities between coastal renewable-energy-producing states based on whether they support drilling.

Proponents of the FAIR Act and other revenue-sharing legislation claim that granting states a larger share of federal OCS receipts is necessary to encourage other coastal states to support drilling off their coasts. Sen. David Vitter (R-LA), who has also introduced legislation to change revenue-sharing formulas, argues that "revenue sharing is a key tool that we need to use to increase domestic production. Step one is opening access … but step two of that is revenue sharing. To actually get the production going, I think you need to provide the incentive to host states, and this is a powerful incentive for coastal states."[34]

Opponents of expanded offshore drilling cite these same incentives in arguing against revenue sharing, observing that the additional money for states places a disproportionate priority on oil and gas activities at the expense of tourism, environmental values, public health, outdoor recreation, and other coastal activities, which have real economic value in their own right.[35] According to the National Oceanic and Atmospheric Administration, or NOAA, the so-called Blue Economy, which is comprised of industries that rely on healthy oceans and coasts to generate economic activity, supported more than 360,000 jobs in the Gulf of Mexico region in 2009 alone, contributing nearly $25 billion to the area's gross domestic product.[36]

Coastal states eligible to receive OCS renewable or conventional energy revenues under the FAIR Act

Eligible

- Alaska
- Alabama
- Louisiana
- Mississippi
- Texas

Not eligible

- California
- Connecticut
- Delaware
- Florida
- Georgia
- Hawaii
- Maine
- Maryland
- Massachusetts
- New Hampshire
- New Jersey
- New York
- North Carolina
- Oregon
- Rhode Island
- South Carolina
- Virginia
- Washington

Revenue sharing: What is fair?

Proponents of offshore revenue-sharing legislation raise important questions about whether revenues from federally owned oil and gas resources are, in fact, fairly apportioned among the federal government, states, local jurisdictions, and Indian nations. "The FAIR Act is about bringing parity to the federal revenue sharing program, both onshore and offshore," said Sen. Murkowski during a committee hearing about the FAIR Act in July, noting that states typically receive 50 percent of revenues from onshore energy development on federal lands.[37]

When considering the fairness of onshore and offshore revenue-sharing policies, however, a variety of additional considerations should be taken into account. These are discussed in detail below.

Differing financial and regulatory responsibilities onshore and offshore

Federal lands within a state are different than federal submerged lands on the OCS in at least one important respect: Federal submerged lands on the OCS are outside the jurisdictional boundaries of any one state. Unlike onshore federal lands, offshore federal lands do not diminish the property tax bases of states and local jurisdictions; the inability to collect tax revenue from federal lands inside state boundaries was a primary consideration in the establishment of revenue-sharing formulas for federal onshore lands.[38]

The U.S. Coast Guard Cutter Decisive is seen at the site of the Deepwater Horizon oil spill. The federal government is responsible for the costs relating to safety, regulation, emergency response, and management of the OCS. (AP/Gerald Herbert)

Moreover, while states share many regulatory, oversight, and enforcement duties with their federal counterparts on federal lands within state boundaries, their roles and responsibilities are far more limited on the federal OCS. State agencies, for example, prescribe and enforce many of the air-quality, wildlife, and water standards for drilling on public lands, sharing responsibilities and coordinating closely with the Bureau of Land Management, the U.S. Forest Service, and the Environmental Protection Agecy.

On the federal OCS, however, nearly all regulatory and enforcement activities—including leasing, permitting, environmental analysis, inspections, monitoring, and spill response—are carried out and paid for by federal agencies, including the Bureau of Safety and Environmental Enforcement, the Bureau of Ocean Energy Management, the Environmental Protection Agency, and the U.S. Coast Guard. To the extent that revenue-sharing policy aims to compensate states for costs incurred from energy development on federal lands and waters, these regulatory and enforcement costs are important to measure and consider.

An accurate accounting of federal payments to energy-producing states

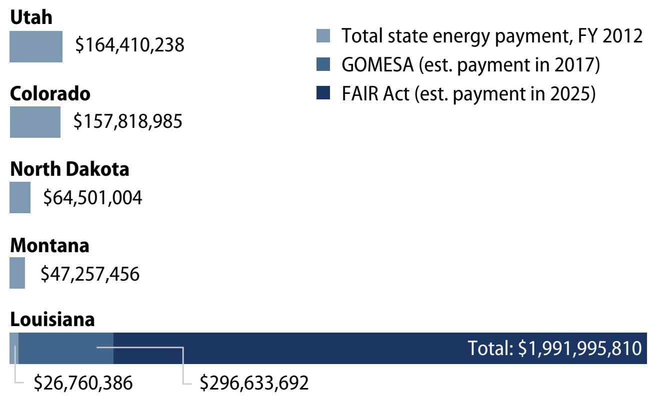
Proponents of expanded OCS revenue sharing claim that legislation such as the FAIR Act is needed because coastal energy-producing states currently receive "virtually nothing" from federal energy production.[39] A CAP analysis shows this claim to be inaccurate. Alaska collected more than $16 million in federal energy payments in 2012, while Louisiana collected more than $26 million.

Moreover, because of the revenue-sharing provisions in GOMESA, Louisiana's federal energy payments will—under current law—increase by an estimated $300 million beginning in 2017, giving it the third-highest federal energy payment in the United States, as it will collect five times the average payment of other energy-producing states.

Under the FAIR Act, Louisiana's federal energy payments will reach nearly $2 billion per year by 2025, more than 33 times the average of what other energy-producing states are currently col-

FIGURE 4

Projected revenue sharing payments by state



Source: CAP estimates based on EIA and ONRR data. See endnotes 29 and 40.

lecting in federal energy payments. When compared to the onshore federal energy giants of Colorado and Utah, Louisiana's total federal energy payments under the FAIR Act will be five times more than what either of those two states are receiving in federal oil, gas, and coal payments combined.

Differing state revenue policies

In considering arguments about equity and fairness, it is important to consider that energy-rich states with resources under state and private lands—including the Gulf coastal states and Alaska—already collect significant severance tax revenues from those resources, which help support state programs and budgets. Alaska, for example, has collected up to $11 billion per year from oil revenues in recent years, paying residents up to $3,000 each through dividend checks.[41] Interestingly, while pressing to receive a greater share of U.S. taxpayer revenues from the OCS, Alaska recently reduced its own oil-production taxes.[42]

More broadly, states with a proportion of federal land collect only 50 percent of the federal revenues on those lands, while states with a high proportion of state and private land collect 100 percent of the severance taxes from energy production on those lands.[43] As a result, a state such as Texas—which is less than 2 percent federal land—is arguably at a fiscal advantage over a state such as Montana—which is 35 percent federal land; unlike Montana, Texas does not have to share energy revenues from state and private lands with the federal government.[44]

Environmental costs of development on the OCS

Decades of oil and gas development in state and federal waters have, without question, contributed to environmental damage and coastal land loss along the Gulf Coast. One study by the U.S. Geological Survey estimates that 36 percent of coastal land loss in Louisiana's Mississippi River Delta can be attributed to oil and gas activity—largely in state waters—in the area since the 1930s.[45] Earlier this year, the board of the Southeast Louisiana Flood Protection Authority - East, a quasigovernmental entity, sued dozens of oil companies, alleging that the companies had failed to adequately repair damage caused by thousands of miles of canals and construction. This development has exacerbated erosion and deprived the region of natural storm-surge buffers, pollution-filtration systems, and critical habitat. More recently, of course, the Deepwater Horizon blowout and oil spill, which occurred in federal waters, caused billions of dollars of harm to coastal resources and economies.

Congress has, in recent years, attempted to address the environmental impacts of federal oil and gas activities in the Gulf of Mexico through legislation and programs that direct money to assist with coastal restoration and preservation. In 2005, with the Energy Policy Act, for example, Congress established the Coastal Impact Assistance Program, or CIAP, through which $1 billion has been paid out to the four energy-producing states on the Gulf Coast.[46] To address the impacts of the Deepwater Horizon spill on the Gulf Coast, Congress in 2012 passed the Resources and Ecosystems Sustainability, Tourist Opportunities, and Revived Economies, or RESTORE, Act, which directs 80 percent of Clean Water Act penalties from the spill to coastal restoration.[47]

While these laws attempt to address the costs and damage of oil and gas activities and incidents that have already taken place, there is no adequate policy mechanism to account and compensate for the full environmental costs of ongoing and future development activities on the OCS. If addressing the environmental externalities of offshore drilling is a high priority for policymakers, revenue sharing may not be the most effective or desirable policy option for correcting this problem.

Rather than referring the costs of these externalities to U.S. taxpayers through revenue sharing, lawmakers should require industry to pay the environmental costs of development by establishing a mitigation fee that would be used to fund coastal restoration projects. We will discuss this policy alternative in greater detail in the recommendations section of this report.

Determining the true revenues from the OCS

In assessing the fairness of the current OCS revenue-sharing structures, policymakers should consider the revenues states are receiving, not simply from the federal OCS but also from state-managed waters and the 8(g) zone. Congress's decision in 1953 to cede the areas within three nautical miles of the coasts to states—and within nine nautical miles off the shores of Texas and the Gulf Coast of Florida—as well as its decision to grant states 27.5 percent of revenues in the 8(g) zone, had the effect of providing a division of revenues from offshore energy development. The revenues to states from these areas, therefore, should be factored into a broader assessment of what revenues states are receiving from submerged lands, all of which were at one time under the exclusive jurisdiction of the federal government.

Is revenue sharing good policy?

As Congress examines the merits of expanding revenue sharing from energy development on the OCS, the legacies and ongoing costs of previous revenue-sharing agreements provide some important lessons.

More than a century of timber, mining, and energy booms and busts have left a tangle of policies for collecting and distributing natural resource revenues. In some cases, such as hard-rock mining on public lands, Congress has not made a significant change to revenue structures since the passage of the 1872 Mining Law. As a result, American taxpayers are missing out on an estimated $160 million of revenue each year from gold, silver, uranium, and other mining activities on federal lands.[48]

In the case of timber production on public lands, however, Congress established policies to grant states and counties a large share of what became a major revenue stream for the U.S. government during the post-World War II housing boom. The 18 counties that include former Oregon and California railroad-trust lands that are managed by the Bureau of Land Management within their borders collected 50 percent of the federal timber harvest revenues on those lands.[49] On national forest lands, the U.S. Forest Service provided states 25 percent of revenues to be used on roads and schools in counties with federal timberland.[50]

With timber production in national forests and on public lands at record levels in the decades after World War II, some timber counties were receiving millions of dollars per year. Douglas County, a heavily forested county in Southern Oregon, received more than $84 million in Bureau of Land Management and Forest Service payments in 1988, accounting for approximately 60 percent of its entire county budget.[51] With such high timber payments, counties often reduced collections of property taxes, creating a dependence on federal timber harvests. A 2012 study by the Oregon secretary of state found that Oregon counties that once relied on timber payments still had some of the lowest property tax rates in the state. Josephine County, for example, collects only $191 per capita in income from residents—the lowest in Oregon—while collecting more than $7 million per year in federal land payments.[52]

After four decades of heavy logging in U.S. forests and high revenues for counties, timber production on federal lands in the Northwest collapsed at the end of the 1980s, following a court-ordered halt to federal timber production until an adequate plan could be put in place to protect the northern spotted owl. The plan that was put in place—the Northwest Forest Plan—scaled logging back, which caused revenues for counties to plummet. The Clinton administration and Congress moved to provide temporary assistance to counties with the creation in 1993 of a 10-year direct-payment program that aimed to provide a financial bridge for counties as they transitioned away from reliance on timber payments.[53]

Still concerned about declining timber revenues and payments, Congress acted again in 2000 to create an alternative payment program through the Secure Rural Schools and Community Self-Determination Act, or SRS. The program served to alleviate fiscal crises in counties and avert painful cuts to critical service providers such as schools and police officers.[54] Although it was intended to be temporary, the affected counties have become a powerful political constituency and have repeatedly secured extensions and changes to SRS. The average annual SRS payments between 2001 and 2011 totaled $383 million.[55]

The ongoing challenges of addressing the legacy of revenue sharing for timber in federal forests should give pause to policymakers as they consider an expansion of OCS revenue sharing. Like revenue sharing for timber during the boom years of logging, expanded OCS revenue sharing would result in a significant financial windfall for states and local jurisdictions. But the scale of the revenues is so great that it is likely to create a budget dependency. As long as OCS revenues stay steady or rise, eligible state and local jurisdictions will be able to count on the federal revenues to pay for new spending or to cut taxes in other areas. If OCS revenues sharply decline at any point, however, the state and local jurisdictions that rely on them will be in fiscal difficulty and, if history is any guide, will likely ask for Congress to intervene with direct payments.

Recommendations

The collection and distribution of revenues from natural resource revenues present federal, state, and local governments with opportunities, challenges, and risks. At its best, good natural resource revenue policy ensures that the external costs of development are paid for, that revenues are being collected in an accurate and transparent manner, and that the government's collections are invested sustainably and soundly in ways that advance the long-term interests of taxpayers. At its worst, natural resource revenue policy can promote corruption, distort budget policy, create fiscal dependencies, and enable poor spending decisions.

In this section, we offer four recommendations for Congress as it weighs whether to make adjustments to federal natural resource revenue policy. Overall, we believe that if Congress decides to reform existing policy, it must do so in a comprehensive manner that addresses three interrelated issues:

- Managing and investing growing revenue streams from oil, gas, and renewables responsibly

- Addressing the legacy of natural resource payment programs including Secure Rural Schools and Payment in Lieu of Taxes

- Strengthening programs that translate near-term revenues from natural resource development into long-term investments that benefit all taxpayers, such as the LWCF and the president's proposal for an Energy Security Trust Fund

Our four recommendations are discussed in detail below.

Congress should put taxpayers first by reaffirming that the resources from federal lands and waters belong to all Americans

In considering any proposed change to natural resource revenue policy, Congress must remember first and foremost that the revenues collected from the development of federal resources onshore and offshore belong to U.S. taxpayers. The law and the courts do not acknowledge any state or local right to federal energy resources under federal lands; natural resource payments to states and counties are entirely discretionary.

With U.S. taxpayers shouldering the impacts and costs of Washington's short-sighted and damaging automatic across-the-board spending cuts under sequestration, we question the wisdom and timing of asking taxpayers to forgo any additional natural resource revenues by granting states and counties a larger share of federal receipts. Of particular concern are proposals to establish uncapped revenue-sharing entitlements on the OCS that we estimate will cost taxpayers more than $49 billion over the next 26 years. Not only are uncapped revenue-sharing schemes fiscally irresponsible from the perspective of U.S. taxpayers, but the scale of the redistribution of revenues will also likely create budgetary dependencies and distort fiscal policy among the states and local jurisdictions that are receiving the transfers.

Congress should establish a new mitigation fee that oil and gas companies would pay when drilling on the OCS

Proponents of expanded revenue sharing from the OCS cite the long-term impacts of oil and gas development on wetlands, coastlines, and environmental resources as a reason that states and local governments should receive a larger share of existing revenue collections.

We agree that new policy is needed to better mitigate the impacts of OCS oil and gas development on coastal resources, but we believe that expanded revenue sharing is not the right tool to use because it requires U.S. taxpayers, instead of oil and gas companies, to pay for the damages caused by industrial activities. Instead of using new revenue sharing to address this problem, Congress should create a new mitigation fee for developers on the OCS. The fees assessed on oil and gas companies who wish to drill federal resources would supplement existing royalty payments and be dedicated specifically to the protection and restoration of coastal and environmental resources that are affected by oil and gas operations. A mitigation fee for the OCS could be modeled on mitigation programs that the Department of the Interior is developing for renewable energy projects on public lands.

Congress should create a true conservation royalty by using OCS revenues to fully and permanently fund America's premier conservation program, the LWCF

In 1964, Congress created one of the most forward-thinking natural resource programs in U.S. history by establishing the LWCF. The idea, which passed through Congress with bipartisan support, was that the revenues from the extraction and depletion of one type of taxpayer-owned resource—oil and gas from the OCS—should be used to permanently protect other natural resources that taxpayers value, namely parks, open spaces, coastal areas, and wildlife habitat. This so-called conservation royalty has, in its half-century of existence, permanently protected more than 5 million acres of public land and helped create or protect more than 41,000 parks, ball fields, beaches, trails, and open spaces in every state and nearly every community across the country.[56] The LWCF has earned the distinction of being the nation's premier conservation program.

The law that created the LWCF mandated that $900 million per year from OCS revenues be directed to the fund. Each year, however, Congress typically diverts the vast majority of the money in the LWCF to other unrelated spending, diminishing the program's potential reach and effectiveness. The program's current authorization expires in 2014, meaning that without action from Congress, local communities, states, and land-management agencies will lose their most effective tool to protect at-risk lands and expand outdoor recreation opportunities.

As Congress reauthorizes the LWCF, it should recommit to the program's original principle, which was to dedicate OCS revenues to the permanent protection of natural resources around the country. Moreover, the LWCF should be updated and expanded to reflect America's growing population and the rising demand for more outdoor recreation opportunities. Congress, therefore, should end the practice of diverting revenues from the LWCF to unrelated spending and instead mandate that the full $900 million in the fund be dedicated each year to conservation investments across the country.

In addition to renewing the LWCF for the conservation challenges of the 21st century, Congress should use rising OCS revenues to establish a fund for renewable energy research. The concept, which the Obama administration has put forward as a proposal for an Energy Security Trust Fund, follows a principle similar to the LWCF: The revenue from the depletion of oil and gas reserves should be used to help the United States forge a sustainable and clean energy future.

Congress must address the expensive legacy revenue-sharing agreements that were established during earlier natural resource booms

States and counties with federal lands within their jurisdiction from which they cannot collect property taxes face ongoing uncertainty related to whether Congress will extend the Secure Rural Schools and Payment in Lieu of Taxes programs. This uncertainty transfers to the schools, police officers, firefighters, and other public services that counties must fund.

As Congress considers whether and how to reauthorize county payments, it should also endeavor to simplify the programs and provide a clear path to reducing their costs. Headwaters Economics, a nonpartisan, independent research group, has conducted a thorough analysis of revenue-sharing and county payments and has developed a range of policy proposals, including a single-payment approach that we believe is worth considering.[57]

Conclusion

Against the backdrop of painful and unnecessary automatic across-the-board spending cuts and the ongoing debate about how to put the nation's finances on a more sustainable track, Congress needs to ensure that taxpayers are receiving the full benefit and return from the natural resources that belong to them.

Costly diversions of OCS revenues away from taxpayers would have far-reaching policy implications and, in a budget-constrained world, would limit Congress's ability to address other natural resource priorities, including addressing the legacy of timber revenue-sharing agreements in the Northwest and reauthorizing the nation's premier land-conservation program, the LWCF.

Still, Congress possesses a range of budget-neutral tools to achieve many of the policy aims of expanded revenue sharing. Establishing an OCS mitigation fee, for example, would help coastal states respond to ongoing environmental impacts of offshore energy development. Raising royalty rates, rents, or state-level severance taxes are also alternatives that would result in higher revenues without negative budgetary impacts for U.S. taxpayers.

Rather than create new revenue-sharing entitlements, Congress should take a comprehensive, fiscally sound approach to addressing the natural resource revenue challenges facing the nation.

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A Turning Point for the Bureau of Land Management

By Matt Lee-Ashley and Jessica Goad December 18, 2013

In 2014, the Obama administration's effort to clean up, fix, and modernize the federal government's oil and gas leasing program on public lands will reach its most critical milestones since the Department of the Interior's reform agenda launched in 2009. From tests of the administration's signature oil and gas reforms to looming endangered-species decisions and overdue environmental protection rules, Secretary of the Interior Sally Jewell will have a full plate as she works to restore balance between energy development and the protection of land, water, and wildlife.

In this brief, we assess the long-term impacts of a controversial decision by the Bush administration—one that took place five years ago this week—to lease lands near national parks in Utah for oil and gas development. We present new public opinion data that provide greater detail on Americans' current priorities for their public lands and help explain why the Utah leasing debacle in 2008 provoked such a strong public outcry.

In addition, we identify six areas to watch that, taken together, demonstrate the extent to which the Obama administration's reforms to the nation's oil and gas leasing program are resulting in meaningful and lasting changes in priorities, values, and decision making within the Bureau of Land Management, or BLM, the nation's largest land-management agency. These areas are:

- The creation of Master Leasing Plans to guide drilling to the right places
- The revision of Resource Management Plans on 140 million acres of public land
- The progress of environmental protection rules for oil and gas extraction
- The development of a strong new policy to mitigate the impacts of oil and gas drilling
- The restoration of balance between oil and gas leasing and the permanent protection of public lands
- The protection of sagebrush habitat to alleviate drilling impacts on wildlife

The legacy of the 2008 Utah leasing debacle

When President Obama took office, the BLM's oil and gas leasing program was in crisis. Just one month earlier on December 19, 2008, the Bush administration had auctioned off oil and gas leases on more than 103,000 acres of public land near Arches and Canyonlands National Parks, Dinosaur National Monument, Desolation Canyon, Nine Mile Canyon, and wilderness study areas in Utah.[1]

The decision provoked a firestorm of opposition. *The Salt Lake Tribune* said the BLM acted with "blatant disregard for its mission to protect Americans' special and irreplaceable lands."[2] A federal court agreed and, citing the "threat of irreparable harm to public land if the leases are issued,"[3] granted a temporary restraining order blocking the BLM from moving ahead with the leases.[4] Obama's new Interior Secretary, Ken Salazar, ordered a top-to-bottom review of the federal government's oil and gas leasing program and the parcels in question on February 4, 2009, just two weeks after taking office.[5]

Five years later, the controversy over the 2008 Utah lease sale appears as a watershed moment for public land management in at least two regards. First, the outcry against the Bush administration's decision signaled a growing divide between the public's rising demand—particularly in the West—for more protections and recreational opportunities on public lands versus the Bush administration's focus on maximizing oil and gas production at the expense of competing uses.

Though oil and gas have long been and continue to be an economic lynchpin in many Western communities, less than 2 percent of the region's workforce is now in traditional natural resource sectors, such as mining, timber, and oil and gas, while more than 70 percent work in service-related sectors, according to research by Colorado College.[6] With the outdoor recreation economy contributing billions of dollars to their states each year, voters now overwhelmingly see public lands as integral to their quality of life and attracting high-quality employers and good jobs.[7]

New research suggests that the public outcry against the Bush administration's 2008 actions in Utah reflected broader public opinion trends in the West and nationally that continue today. At the request of the Center for American Progress, Hart Research Associates conducted more than 1,000 interviews with voters across the country from October 31 to November 4 to better understand the public's preferred uses for public lands.[8]

The researchers concluded that "Two pillars define what is at stake for public lands for voters across the country: permanently protecting public lands for future generations and ensuring access to recreational activities."[9] These priorities were most strongly felt in the West, where 74 percent of voters say the permanent protection of public lands is very important to them, and 65 percent say that ensuring recreational access is very important. In contrast, only 27 percent of voters nationally say that ensuring that public lands are available to oil and gas development is a high priority.[10]

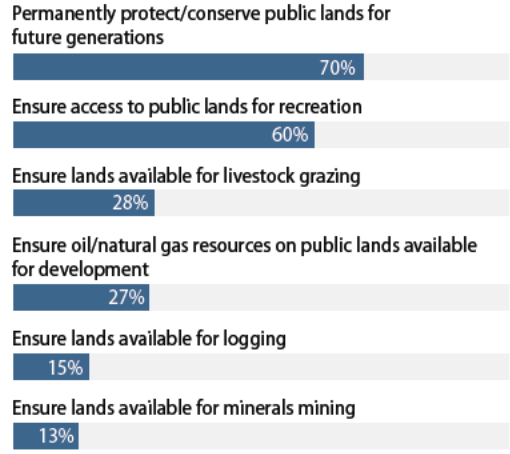
While the controversy and outcry over the 77 parcels in Utah were evidence of shifting public values, they also marked a turning point for the BLM's approach to oil and gas management. Under the Bush administration, the BLM was tasked with implementing the recommendations of Vice President Dick Cheney's Energy Task Force, which called for rewriting land-management plans to prioritize energy development, expediting or sidestepping environmental reviews, and doubling the oil and gas production on federal lands.[11]

By the end of the Bush administration's tenure, Western communities were weary of its oil and gas policies. "For years," wrote the *Salt Lake Tribune* editorial board in early 2009, "Bush administration officials have been hell-bent on handing out drilling rights to energy companies with little regard for the long-term consequences of ravaging the natural landscapes of the West for short-term gain."[12]

FIGURE 1

Two standout priorities for public lands: Access to recreational activities and permanent protection

Priorities rated 9–10 on a 10-point scale with 10 being an extremely important priority for public lands managed by the federal government



Source: Hart Research Associates, "Voters' Views on Balancing Conservation and Drilling on America's Public Lands" (2013), available at http://www.americanprogress.org/wp-content/uploads/2013/12/Hart-Research-public-lands.pdf.

The Obama administration's oil and gas leasing reforms: A progress report

The Obama administration—led by then-Secretary of the Interior Ken Salazar—reviewed the 77 parcels of BLM's oil and gas leasing program in early 2009. The findings were documented in reports by Deputy Secretary of the Interior David J. Hayes[13] and by an interdisciplinary and interagency team of natural resource professionals.[14] The reviewers found a leasing system that was overwhelmed: Agency professionals were under pressure to process leases faster than they could be appropriately reviewed, other values and uses on public lands were being discounted, and the oil and gas industry dominated the process. The program had become so controversial that 40 percent of all leasing parcels were formally protested by local communities, recreational users, and conservation organizations by 2008, up from just 1 percent in 1998.[15] In Utah, New Mexico, Colorado, and Wyoming, the problem was even worse. A review by the Government Accountability Office found that 74 percent of all proposed leasing parcels in those four states from 2007 to 2009 were protested.[16]

Based on these growing problems and the findings of the interdisciplinary review team, the Obama administration and the BLM launched the most significant reforms to the oil and gas leasing program in the agency's 67-year history.[17] The reforms help advance two fundamental philosophical changes for the agency:

1. They affirm that, under the BLM's multiple-use mission in the Federal Land Policy and Management Act of 1976, oil and gas development is to be balanced with other values and uses of public lands to ensure "the health and productivity of the public lands for the use and enjoyment of present and future generations."[18] "Under applicable laws and policies," reads the BLM instruction memorandum implementing the reforms, "there is no presumed preference for oil and gas development over other uses."[19] This statement represented a major about-face after the culture and actions of the Bush administration's BLM.

2. The reforms call for a landscape-level approach to oil and gas planning and decision making. Under the reforms, the agency tells industry up front which areas of public lands are best suited for drilling, have the fewest environmental concerns, and minimize potential conflict with other high-value uses, such as recreation. This early planning approach is aimed at reducing the risk of costly and time-consuming conflicts that arise when industry nominates parcels—without good guidance from the agency—that prove to be highly controversial.

The BLM leasing reforms have begun to deliver promising returns since their issuance in May 2010. Only 10 percent of oil and gas lease sales were protested nationwide in 2011, and this rose to only 12 percent in 2012.[20] Additionally, a higher percentage of the parcels nominated by industry are now being sold, suggesting that agency professionals are focusing their time and resources on nominations that are more likely to sell.[21] Meanwhile, oil and gas production is still high. In fact, crude oil production on onshore federal lands was higher in each of the last four years than it was in 2008.[22]

The BLM's leasing reforms, however, should not be measured simply by the reduction of protests and lawsuits but by whether the agency's decisions better reflect its statutory mandate and the public's evolving priorities for the management of public lands. In this regard, whether the reforms have taken hold and, indeed, the management of public lands is coming more into line with the public's priorities will be clear in the next year. In 2014, the BLM will face the most significant policy and management decisions it has encountered since 2009, when this administration took office.

We have identified six areas to watch over the coming year for indications of the success of the 2010 oil and gas leasing reforms and extent to which the 2008 Utah leasing controversy has spurred an enduring shift in principles and values within the BLM.

Master Leasing Plans

The 2010 leasing reforms created a new planning tool, called a Master Leasing Plan, or MLP, that BLM land managers are encouraged to use to identify which areas of the landscape are best suited for oil and gas leasing and which areas are to be protected for other uses such as recreation, hunting, and fishing.[23] The BLM has identified 17 places where it will consider undertaking a master leasing plan, of which it has begun work on 13.[24] Completing work on MLPs over the coming year will be a key milestone for the administration's oil and gas leasing reforms. The outcome of the Moab MLP will be particularly important to watch, as it was the site of the 2008 leasing controversy in Utah and the protection of outdoor recreation opportunities is vital to the health of the area's economy.

Resource Management Plans

The management of nearly 140 million acres of BLM lands will be under review and revision as part of the agency's planning process in 2014.[25] The BLM is required to update the plans for each of its 136 different management areas every 10 to 15 years. With so many Resource Management Plans under revision in the coming year, the BLM and the Obama administration have an opportunity to adjust to shifting public priorities, incorporate new science and information about the landscape, and better account for the economic and intrinsic values of protecting public lands from development.

Environmental protection rules

According to the Office of Management and Budget's "Unified Agenda" released this fall, the BLM currently is at work on at least eight key rulemakings, four of which are aimed at reducing the environmental impacts of fossil-fuel extraction on public lands. These are:

- "Onshore Oil and Gas Order 9: Waste Prevention and Use of Produced Oil and Gas for Beneficial Purposes": This rule would reduce and limit the amount of methane, a greenhouse gas more potent than carbon dioxide, released from oil and gas facilities on public lands. In particular, it would "establish standards to limit the waste of vented and flared gas."[26]

- "Hydraulic Fracturing": To ensure that this widely used drilling practice is conducted with adequate protections for humans, water, and wildlife, this rule provides for public disclosure of chemicals used in the process and strengthens "regulations related to well-bore integrity."[27]

- "Onshore Oil and Gas Order 4: Oil Measurement": This short but critically important rule would ensure that oil and gas extracted from federal lands is "accurately measured and reported," in order to ensure that taxpayers are getting a fair return. It was last updated in 1989.[28]

- "Oil Shale Management": Oil-shale extraction technologies remain untested and unproven at the commercial scale. It is therefore important that this rule to guide the nation's oil-shale program recognizes the speculative nature of the technologies, protects communities and water supplies during potential development, and enables the government to set an appropriate royalty rate if the technology is ever proven on a commercial scale.[29]

In addition to finalizing these rules to provide protection to our air, water, land, and wildlife, we recommend that the BLM initiate a new rulemaking process to increase the royalty rate on oil and gas from public lands, which is at the same rate that was set in the 1920s, to provide a fairer return for taxpayers.[30]

Secretarial order on mitigation

Secretary Jewell proposed her first secretarial order in November, which established a "Department-wide mitigation strategy to ensure efficiency, consistency, conservation in infrastructure development."[31] This is an important first step, but work remains to develop agency-level policymaking to implement it. To make the secretarial order as effective as possible, the policy that the BLM develops should recognize that avoiding drilling in special places is the first step to an effective mitigation strategy.

Balancing drilling with land conservation

To provide a balanced approach to the management of public lands, the federal government should not only be working to provide opportunities for oil and gas development but also permanently protecting new areas for the public to use and enjoy. Unfortunately, the pace of land conservation has fallen behind the pace of oil and gas leasing in recent years. Since President Obama took office, 7.3 million acres of public lands have been leased to oil and gas companies for drilling, while only 2.9 million acres have been permanently protected.[32] This imbalance is largely caused by Congress's inability to pass the common-sense wilderness and national park bills that members of both parties have introduced. As a result, the Obama administration should respond to the desires of local communities by accelerating its efforts to permanently protect public lands using executive authority.

Sage-grouse protections

The fragmentation of the West's iconic and vast sagebrush habitat over several decades has caused populations of the once ubiquitous greater sage grouse to collapse. As a result, the U.S. Fish and Wildlife Service will decide in 2015 whether the species should be protected under the Endangered Species Act.[33] To provide better protections for the sage grouse and sagebrush habitat—on which hundreds of other species, including game such as elk and deer also rely—the BLM is revising 28 of its resource management plans.[34] To avoid the need to list the species as threatened or endangered, these plan revisions will have to include strong protections for the sage grouse and set aside areas that are not to be developed or disturbed.

Conclusion

Interior Secretary Sally Jewell and the president's nominees to lead the BLM and oversee land-management policy at the Department of the Interior are well prepared to address these six challenges and follow through on the reform agenda launched in the wake of the Utah leasing debacle.

In a recent speech at the National Press Club, Secretary Jewell reflected on what she called "a fundamental issue for Interior as a land manager: how we balance the inherent tensions that can exist with development and conservation." She noted, "Part of the answer is encouraging development in the right ways and in the right places. Part of the answer is recognizing that there are some places that are too special to develop."[35]

The principles that Secretary Jewell articulated, if fully applied to the six areas to watch that we outline above, will help complete a BLM's remarkable transformation in five short years, yield smarter and better oil and gas policies for the country, and forge a pillar of President Obama's energy and conservation legacy.

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Center for American Progress

Backroom Deals

The Hidden World of Noncompetitive Oil and Gas Leasing

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Contents

Introduction and summary

Last year, the Bureau of Land Management (BLM) held a massive oil and gas lease sale, putting more than 300,000 acres of public lands in Nevada up for auction.[1] The sale was largely in response to a request to lease the land from an anonymous individual, a routine way onshore oil and gas leasing is kicked off for the federal government.

On the day of the lease sale, however, that anonymous individual did not show up to bid—nor did anyone else, for that matter. The BLM did not sell an acre of land, not even for the minimum bid of $2.

The sale raised eyebrows. Sen. Catherine Cortez Masto (D-NV) admonished the BLM for attempting to sell off public lands with "little to no potential for drilling."[2] The head of an oil and gas industry association blamed "a bad actor" for the failed auction, hinting that the nomination was from someone trying to make the BLM or the industry look bad.[3]

A little more than a month later, however, the BLM updated an obscure database to reflect that several parcels had been purchased after the auction by a handful of small, private oil and gas companies and speculators.[4] The BLM sold the leases through its noncompetitive leasing process, whereby parcels unsold at auction are available for purchase for two years. The $2 per acre bonus bid requirement is completely waived for these parcels, so lessees simply have to pay an administrative fee, and a $1.50 per acre rental fee, making noncompetitive leasing the bargain bin of the oil and gas world.[5]

The newly issued leases raise more questions. Did one of the companies nominate the parcels, knowing that it was likely the company could purchase a lease for next to nothing after the failed auction? Could the companies have colluded, agreeing on the front end not to participate in the auction so they could reap the savings later? And given the area's low oil and gas potential and the companies' poor track records for energy development, what do they intend to do with the public lands for which they now own 10-year leases?

It's a curious case that lays bare some of the inherent flaws in the BLM's onshore leasing program. Oil and gas companies are able to legally stockpile public land at low prices, often without public scrutiny. This is especially true of the BLM's noncompetitive leasing program, a scheme that few people know exists, let alone understand. However, the Center for American Progress determined that nearly one-quarter of all acres leased by the BLM in the past 10 years have been through the noncompetitive leasing process.[6]

In addition to comprising a surprisingly large percentage of the BLM's leasing portfolio in terms of land, the authors found that leases sold noncompetitively generate little revenue and rarely end up in production. Instead, the public lands largely sit idle for the duration of a lease's 10-year term—or longer, due to routine lease extensions—or the BLM terminates the lease when the lessee fails to pay rent. In other words, the BLM is wasting taxpayer resources to run an over-the-counter oil and gas leasing program that does not actually produce oil and gas.

At a minimum, these findings point to a wasteful and unnecessary leasing program that siphons away the BLM's limited resources and shortchanges taxpayers. But the findings may also provide evidence of an underground business model in which companies buy cheap leases—not with the intent to develop oil and gas but in order to resell the parcels at profit or to pad their balance sheets with unexplored subsurface reserves. The companies or individuals that engage in this speculating and stockpiling are not in keeping with the intent of the Mineral Leasing Act, and such activity should be considered in violation of BLM regulations, which require lessees to "exercise reasonable diligence in developing and producing" oil and gas.[7]

This report seeks to answer some basic questions about this hidden leasing process:

- What is noncompetitive leasing, and how does the process work?
- Who is leasing public lands through this process, and what, if anything, are they doing with them?
- Who stands to benefit from this practice, and what are the impacts to American taxpayers and public lands?

The report also explores how the noncompetitive leasing process hurts taxpayers by giving away public lands at a lower rate and locking them up indefinitely so that they cannot be managed for other purposes, including conservation and outdoor recreation.

The report highlights the authors' challenges in researching noncompetitive leasing due to the program's lack of transparency and the BLM's inconsistent records. Finally, the report offers recommendations to bring accountability to the BLM's oil and gas program to ensure better stewardship of America's public lands.

A vestige of the past: The unnecessary noncompetitive leasing program

The Bureau of Land Management manages the subsurface rights on approximately 700 million acres of federal, state, tribal, and private lands, or the equivalent of 1 out of every 3 acres in the country.[8] The Mineral Leasing Act of 1920 governs the onshore oil and gas program, providing a general framework for how leases are sold, renewed, canceled, and even what royalty rates the BLM can charge companies when the leases produce oil and gas.[9]

For more than 60 years, the Mineral Leasing Act required that lands with "known" oil and gas deposits be leased through a competitive process, but it allowed for all other lands to be leased noncompetitively. Under this regime, 93 percent of all lands were leased noncompetitively—often through a lottery system, whereby the BLM chose a company's winning bid at random.[10]

Over the years, the noncompetitive program was roundly criticized "for encouraging fraud, misleading the public, and generating insufficient revenues."[11] In one egregious example from 1983, the BLM opted to sell leases in Wyoming noncompetitively, even though there were data available revealing that the area had high oil and gas potential.[12] The BLM collected $1.2 million in fees for 14 leases, and the winner immediately turned around and resold the leases closer to market value for $50 million to $100 million.[13]

In response to the program's mismanagement, Congress passed a major amendment to the Mineral Leasing Act in 1987 that required the BLM to offer all lands competitively, not just those with known oil and gas reserves.[14] More competition, it reasoned, would better ensure taxpayers received a fair, market-based return for private industry's use of public lands.

A path remains, however, that allows the BLM to continue to cheaply sell vast areas of public lands on a noncompetitive basis: Any acres left unsold after a competitive auction are available for purchase the very next day on a first come, first served basis. These parcels sit on the shelf, available for purchase, for a period of two years, after which the land again could be nominated for oil and gas leasing. What's more, the statutory minimum bid requirement of $2 per acre is waived for these parcels; a company simply must pay a nominal administrative fee and the first month's rent of $1.50 per acre.[15]

TABLE 1

Comparison of competitive and noncompetitive leases

	Competitive	Noncompetitive
Sale method	Online auction; the parcel goes to the highest bidder	First-come, first-served basis; the parcel is sold in person or by mail
Parcel's window of availability	Typically available for a matter of hours	Available for two years
Bonus bid (one-time payment)	$2 per acre minimum	None
Lease application fee	$165	$425
Annual rental fee	$1.50 per acre for first five years of a 10-year lease; $2 per acre for second five years of a 10-year lease	$1.50 per acre for first five years of a 10-year lease; $2 per acre for second five years of a 10-year lease
Royalty rate on extracted oil and gas resources	Minimum of 12.5 percent, at the Bureau of Land Management's discretion to adjust higher	Fixed at 12.5 percent; no Bureau of Land Management discretion to adjust higher
Leases under production at the end of a 10-year term	10%	3%
Termination rate (Bureau of Land Management ends lease early for cause)	30%	55%

Sources: U.S. Bureau of Land Management, "General Oil and Gas Leasing Instructions," available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/leasing/general-leasing (last accessed May 2019); Cornell Law School Legal Information Institute, "43 CFR § 3000," available at https://www.law.cornell.edu/cfr/text/43/3000.12 (last accessed May 2019); Congressional Budget Office, "Options for Increasing Federal Income From Crude Oil and Natural Gas on Federal Lands" (Washington: April 2016), available at https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51421-oil_and_gas_options-OneCol-3.pdf.

In practice, this backdoor leasing process allows for any individual to walk into the BLM office and—for about the price of a pack of gum per acre—own a 10-year lease on America's public lands.[16]

One can imagine scenarios in which this secondary leasing process might be justified: if lease sales are such a rare occurrence that years pass before companies can bid on parcels; if it is difficult to nominate parcels for auction in response to more favorable market conditions or technological advances that change a company's investment calculations; or if the government needs to incentivize leasing to meet the nation's energy needs.

But none of these scenarios are applicable. The BLM has, for the duration of its existence, run an industry-first leasing system where anyone—at any time, for free—can anonymously nominate a parcel of land and kick the leasing process into gear. Outside of the BLM's cursory environmental review of a parcel's nomination, there are few parameters on what public land the oil and gas industry can access or when. (see the "No money?" text box below)

The Trump administration has put this already flawed leasing process on steroids, requiring BLM state offices to include nearly all nominated parcels in statewide quarterly lease sales, slashing opportunity for public comment, and reducing internal review of nominations before they go up for auction.[17]

The BLM is offering for lease more acres, more often, and it is doing so at a time when the oil and gas industry is sitting on a glut of unused leases.[18] In fact, there are currently nearly 26 million acres under lease to oil and gas companies—an area larger than the state of Indiana—but half of those acres are idle.[19]

The practice of noncompetitive leasing appears to be a vestige of the past, providing another avenue for the oil and gas industry to buy cheap leases when it already enjoys near-unfettered access to public lands and owns more leases than it knows what to do with. The cheap leases particularly benefit companies looking to inflate their value by stockpiling undeveloped reserves, as well as those that operate in the margins—buying leases on a speculative basis in order to sell them later for profit or to attract investors to unproved opportunities.

No money? No name? You, too, can nominate a parcel

BLM state offices hold oil and gas lease sales four times per year—and sometimes more frequently. What the agency offers at auction is largely determined by the private individuals and corporations who nominate public lands through what is called an expression of interest.[20] To consider a nomination, the BLM simply requires a legal land description and map of the desired parcels.

The BLM does not charge any fees to submit an expression of interest. Nor does the BLM require the submitter of an expression of interest to provide a name or address. Seventy-five percent of nominations are made anonymously, and in the state of Nevada, nearly every nomination—96 percent—has been made anonymously since 2017.[21] Consequently, before dedicating staff time and taxpayer resources to review an expression of interest or hold a sale, the BLM conducts no screen for whether the submitter has the intent or ability to explore or develop the oil and gas resources.

The free-for-all nature of the nomination process lends itself to abuse. An unscrupulous company or individual can easily and anonymously nominate parcels that they have no intention of bidding for in the competitive auction in order to buy it cheaply later. As-is, the system is rigged to allow for—and even encourage—speculation.

To what end?: A day in the life of a noncompetitive lease

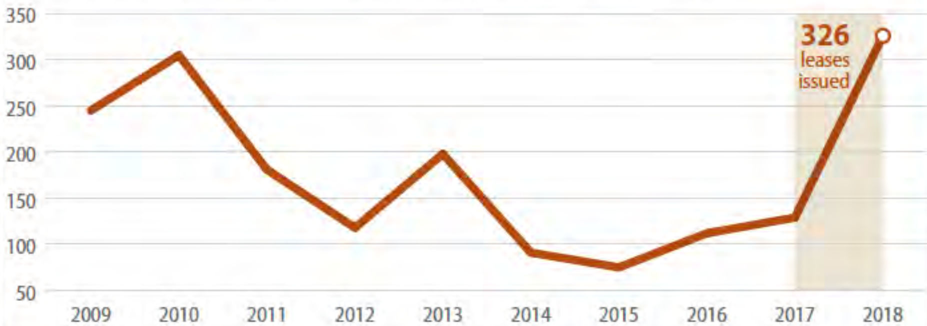
The authors examined whether there are any notable trends in noncompetitive lease activity, as well as whether there is a discernible difference—outside of the method of sale—between leases sold competitively versus noncompetitively. To do so, CAP reviewed lease activity data in states where the Bureau of Land Management conducts leasing—other than Alaska, for which data are not readily available—and identified all noncompetitive leases issued from 2009 through 2018. The authors also reviewed the case files of 63 noncompetitive leases that the BLM Nevada State Office terminated in the past 10 years.

Despite Congress' intent in 1987 to minimize the acres of public land sold noncompetitively, the data show that the BLM is still leasing a high proportion of public lands through this manner. About one-quarter of acres leased in the past 10 years were issued noncompetitively, amounting to nearly 3 million acres across the West.[22]

FIGURE 1

Noncompetitive leasing has spiked during the Trump administration

Number of issued noncompetitive leases in each of the past 10 years



Source: Center for American Progress analysis of Bureau of Land Management, "Land and Mineral System Reports: LR2000," available at https://reports.blm.gov/reports.cfm?application=LR2000 (last accessed May 2019).

The number of acres leased noncompetitively fluctuates every year but is on the rise again under the Trump administration. From 2017 to 2018, the acres sold noncompetitively more than doubled—from approximately 141,000 acres to nearly 379,000 acres—and the number of leases issued noncompetitively was higher in 2018 than it had been in any other year over the previous decade.[23] This bump is due, in part, to the fact that the Trump administration is offering more land for lease and more of it—about 2 million acres since 2017—is unsold at auction and immediately available for noncompetitive leasing.

Noncompetitive leasing happens in a number of Western states, but the practice is particularly active in Nevada, where more than 2 million acres have been sold in this manner since January 2009.[24] One might expect there to be little competition for parcels in Nevada, given the state's low mineral potential.[25] By the same token, this explanation falls short of justifying why the BLM is going through the motions to effectively tie up vast amounts of public lands in Nevada and elsewhere with private companies that are unlikely to produce an economic return for taxpayers.

CAP found two hallmark characteristics of noncompetitive leases that suggest the process is particularly wasteful:

1. **The vast majority of noncompetitive leases sit idle.** A 2016 Congressional Budget Office analysis that looked at noncompetitive leases issued from 1996 to 2003 found that only a sliver—a mere 3 percent—were developed by the end of their 10-year term.[26] By comparison, leases sold competitively during that time period were developed at triple the rate, at about 10 percent.[27]

2. **Noncompetitive leases are routinely terminated by the BLM.** Over the course of a 10-year lease, the BLM has the authority to terminate the agreement for a variety of reasons, including failure to pay rent. The BLM has terminated more than 1.6 million acres of the noncompetitive leases it issued since January 2009, or more than 55 percent.[28] That's nearly double the termination rate of leases sold competitively, which is closer to 30 percent.[29] Many of the terminations occurred just a year or two after the BLM initially issued the lease noncompetitively.

   The 63 case files of terminated leases reviewed at the Nevada BLM office provide further insight into what happens once companies buy leases noncompetitively. In every case, without exception, the BLM terminated the lease because the lessee simply stopped paying rent.[30] An illustrative example: A company called

TABLE 2

Noncompetitive leases by state, 2009–2018

State	Total acreage of noncompetitive leases
Colorado	80,749
Montana	262,768
Nevada	2,069,490
New Mexico	16,869
Utah	182,070
Wyoming	263,570
All other states	45,272
Total	**2,920,788**

Source: Center for American Progress analysis of Bureau of Land Management, "Land and Mineral System Reports: LR2000," available at https://reports.blm.gov/reports.cfm?application=LR2000 (last accessed May 2019).

> American General Energy Exploration Corp. purchased 17 noncompetitive oil and gas leases from December 2014 to January 2016. Within two years, the BLM terminated every lease because the company failed to make the first rental payment owed after buying the parcel.[31]

The noncompetitive leasing program resembles a hamster wheel in which the BLM reviews parcel nominations; holds an auction; issues unsold oil and gas leases noncompetitively; terminates the leases when the companies fail to pay rent—and then repeats the cycle, often recycling the same parcels over again.

Some may argue that these statistics and anecdotes prove there is no harm in noncompetitive leasing, as it rarely results in any damaging development to public lands and waters. But the harm, while perhaps less tangible, is no less relevant: The BLM is spending taxpayer money on an ineffective and unnecessary program. Furthermore, Americans are losing out on a fair return for the use of their resources, and the BLM's hands are tied from actively managing the public lands for conservation, recreation, or other beneficial purposes.

The BLM is already stretched thin, lacking adequate staff and resources to fulfill its complex multiple use mission on public lands, of which oil and gas development is a fraction. Devoting significant time to this program that, for all intents and purposes, appears to mainly benefit companies looking to pad their books or engage in speculative practices, takes away much-needed resources that the BLM could better use for public benefit elsewhere.

Gaming the system: The winners and losers in noncompetitive leasing

A review of the noncompetitive leasing program reveals a system in which the scales are tilted heavily in favor of the oil and gas industry and speculators, who risk next to nothing by exploiting the cheap leasing on public lands. The short- and long-term costs, instead, are borne by the BLM, which must devote some of its limited resources to administering the program; by the American taxpayers, who receive little in return for use of their public lands; and by the lands themselves, which are effectively off the table to be managed for other uses for which they may be better suited, such as recreation or renewable energy.

Winners

- **Oil and gas industry, speculators:** An entire industry may have sprung up to take advantage of cheap leases on public lands, including those available through noncompetitive leasing. A recent *New York Times* story contained a revealing anecdote: In 2017, a London-based company, Highlands Natural Resources, nominated tens of thousands of acres for lease in Montana, hoping that no one would bid on them during auction.[32] No one did, so the company was able to scoop them up the following day for the $1.50 per acre rental fee. Highlands is now seeking investors for a "prospective" opportunity to develop the area for natural gas and helium.[33]

  A Taxpayers for Common Sense examination of Highlands' leasing activity shows that this approach has worked on more than one occasion. In fiscal year 2018, the company bought leasing rights on more than 113,000 acres of public land in Montana for $187,000. Because the noncompetitive leases were not subject to a bonus bid, Taxpayers for Common Sense estimates that the American public lost out on $246,000 to $3.6 million in revenue that year—the range between the $2 per acre minimum bid requirement and the average bid in Montana that year of $32 per acre.[34]

TABLE 3

Leases bought by many of the companies participating in noncompetitive leasing are frequently terminated

Top 10 companies leasing noncompetitively since 2009

Company	Acres leased noncompetitively	Percentage of total acres owned that were bought noncompetitively	Acres owned that the Bureau of Land Management terminated early	Percentage of acres terminated early
Kirkwood Oil and Gas/ Kirkwood Exploration LLC	308,179	40%	218,285	71%
Liberty Petroleum Corp.	194,206	54%	97,644	50%
Stephen Smith Inc.	168,714	84%	0	0%
Freeport McMoran Oil & Gas LLC	163,961	66%	163,961	100%
Highlands Montana Corp.	113,563	100%	0	0%
Venture Energy LLC	106,977	100%	96,476	90%
Petro Hunt LLC	104,649	33%	15,811	15%
Witmac Oil & Gas LLC	87,932	98%	0	0%
Baldwin Lynch Energy Corp.	87,857	95%	87,857	100%
Noble Energy Inc.	72,813	48%	6,250	9%
Total	**1,408,851**	**58%**	**686,284**	**49%**

Note: The authors considered Kirkwood Oil and Gas LLC and Kirkwood Exploration as the same company for this report because although they lease as separate companies, they share a website, address, and executives. Some of the acreage represented may be owned by multiple companies, but because the Bureau of Land Management does not readily identify what proportion of these leases are owned by which companies, the authors considered all leases that are owned either alone or in partnership to belong to a given company.

Source: Center for American Progress analysis of Bureau of Land Management, "Land and Mineral System Reports: LR2000," available at https://reports.blm.gov/reports.cfm?application=LR2000 (last accessed May 2019).

Highlands is one of more than 300 companies or individuals that purchased leases noncompetitively during the 10-year period CAP reviewed. Notably, the largest oil and gas companies—Chevron, BP, Exxon Mobil, ConocoPhillips, and Anadarko—do not appear anywhere on the list. Instead, the companies that participate in this backdoor leasing exercise are primarily small, low-profile entities, and many of them have very high rates of terminated leases and portfolios that consist primarily of noncompetitive leases.

Nearly half of the leases—accounting for more than 1.4 million acres—were purchased by just 10 companies during the 10-year window.[35] Only three of the companies are publicly traded, and many of them have no identifiable websites or have websites that are outdated and skeletal. Liberty Petroleum Corp., for example, has purchased nearly 200,000 acres of public lands over the past 10 years but has not updated its website since 2013.[36] For many companies, including Liberty, the addresses listed online do not match up with addresses used when buying the leases.

Finding reliable information about many of the companies was difficult for the authors and raises questions about the BLM's ability to determine whether the actors are capable of developing the parcels—"exercising reasonable diligence," per BLM regulations—before the agency signs over the rights to develop public lands.

In a previous report, CAP explored how cheap leases provide companies an opportunity to bolster their balance sheets superficially in order to boost their market valuation and attractiveness to shareholders and investors, thanks to a 2008 shift in U.S. Securities and Exchange Commission policy.[37] Padding the books with undeveloped reserves to strengthen a company's position in a merger or in negotiating terms of a loan may very well be a motivating factor behind some of the noncompetitive lease purchases.

Losers

- **Taxpayers:** Noncompetitive leasing cheats taxpayers out of receiving a fair return for the use of their public lands. Without collecting a bonus bid, and without competition to better ensure that the price reflects market value, the process effectively gives away public lands to speculators or private industry. Once the leases are sold, taxpayers also lose out on the opportunity cost of the ability to auction the acres under more favorable conditions for a higher price in the future.

  CAP calculates that companies are only paying, on average, $1.74 per acre leased noncompetitively to access the land, including bonus bids, rental fees, and administrative fees. This is compared with $344 for those acres leased through the regular auction process.[38] Some may shrug off this revenue gap as merely a reflection of market value: Lands with higher development potential garner competitive bidding, and some lands with lower development potential receive no bids at auction. But this explanation ignores the possibility that the same low-potential land could be offered later under stronger market conditions for a better return to taxpayers. The explanation also ignores the myriad values of public lands beyond oil and gas development potential, including their contributions to clean air, clean water, and healthy wildlife. These contributions are hard to put a price tag on, but compromising them for $1.74 per acre is tough to defend.

During the nine-year period that CAP examined, the authors estimate that the BLM collected only $4 million in leasing revenue from noncompetitive lease sales, amounting to just one-tenth of 1 percent of its total leasing revenue.[39] In other words, the noncompetitive leasing revenue alone does not appear to validate the program's existence.

- **The BLM:** The BLM has the largest portfolio but the smallest budget of all the land management agencies in the federal government; it should invest its limited resources in programs to benefit the American public, not in wasteful ones where the only clear beneficiary is the oil and gas industry. From reviewing parcel nominations that do not receive a single bid to terminating the leases when the lessee fails to pay rent, administering the noncompetitive leasing program spreads thin an already stretched agency. Quantifying how much money is wasted on this program is difficult. The noncompetitive leasing program is not a specific budget line item, for example. Moreover, according to the Government Accountability Office, the Department of the Interior does not effectively track the costs of environmental reviews in agency decision-making.[40] An accurate accounting of BLM staff time spent processing expressions of interest, auctions, and terminations would be nearly impossible to gather without a specific directive to the agency to track this work. Lack of data notwithstanding, it is hard to justify directing any of the BLM's scarce time and resources to administer an unnecessary program, particularly given the paltry returns in terms of revenue or oil and gas.

- **Public land users:** Competitive and noncompetitive leases alike afford a lessee 10 years to develop the public land for oil and gas. Frequently, lessees seek extensions from the BLM, called suspensions, which can stop that clock, sometimes for decades.[41] If a parcel is in production, the lease can also last for decades. Illustratively, in 2013, about half of royalty income from onshore oil and gas came from parcels that were leased more than 50 years earlier.[42] When an acre is under lease, the American public effectively loses some measure of control over the land that it owns, and the BLM cannot actively manage it for other valuable uses, including renewable energy, outdoor recreation, or conservation. The rinse-and-repeat cycle of noncompetitive leasing can stall important planning and management efforts on public lands across the West.

Across the West: What the BLM is leasing for next to nothing

Noncompetitively leased parcels dot the West, including in areas where energy development is in direct conflict with natural, cultural, or wildlife resources. Some recent examples include:

Wyoming: After a "lukewarm" competitive oil and gas lease sale in September 2018, the BLM sold eight parcels noncompetitively—more than 16,000 acres—found in the Red Desert-to-Hoback migration corridor for mule deer.[43] Liberty Petroleum Corp. and Kirkwood Oil and Gas snatched up the leases for $1.50 per acre in rent, far below the statewide average bonus bid of $202 per acre.[44] Studies have shown that should the leases be developed, the drilling activity stands to disrupt the large mule deer population that travels the corridor.[45]

Arizona: In 2018, the BLM noncompetitively leased more than 1,000 acres at the doorstep of Petrified Forest National Park to Rare Earth Exploration LLC. Local officials have expressed concerns that development in the area could threaten healthy water sources, including the tributaries to the Colorado River.[46]

Utah: Precisely one day after the BLM unsuccessfully offered 15 parcels at auction in 2017, Liberty Petroleum purchased three of the leases, or approximately 5,000 acres, for the $1.50 per acre rental fee. The leases are near the Molen Reef area, a region known as a "treasure trove of ancient rock art" and cultural treasures.[47]

Recommendations to end the noncompetitive leasing program and to minimize waste and abuse

There is a simple solution to the endemic problems in the Bureau of Land Management's noncompetitive oil and gas program: eliminate it altogether. The costs to taxpayers and the agency far outweigh any benefits that come from providing the oil and gas industry around-the-clock, cheap access to America's public lands. Given the abysmally low amount of revenue and development on noncompetitive leases, as well as the built-in incentive for speculators to game the system, abolishing noncompetitive leasing is the simplest, best, and most cost-effective action for Congress to take.

Ending noncompetitive leasing is not a radical recommendation. A comprehensive oil and gas reform bill introduced in previous sessions of Congress suggests taking the same action.[48] The authors of this report expect that eliminating the backdoor leasing process would have a negligible impact on energy production or on the oil and gas industry itself, given the industry would still have the ability to regularly nominate and bid on parcels with a next-to-nothing minimum bid of $2.

Short of eliminating noncompetitive leasing altogether, there are several reforms the BLM or Congress could pursue that would bring much needed transparency and accountability to the entire onshore oil and gas program—noncompetitive and competitive leasing programs alike.

Improve data collection and transparency

Collecting more reliable and fulsome data, and making it publicly available, would help policymakers ensure the BLM's oil and gas program is best serving the American public and public lands. First, the BLM should track the costs of administering a lease—from an expression of interest submission through the point of sale and beyond. The approximate staff time and resources needed to conduct the analyses and perform due diligence related to an oil and gas lease should be made public to understand the true costs of the program.

Second, the BLM should move quickly to replace LR2000 with a modern, user-friendly database. It should also standardize its guidance to state offices to ensure reliable data collection regarding oil and gas leasing activity.

Third, the BLM should release a quarterly report on noncompetitive oil and gas leasing with details including where and when parcels were leased and by whom.

Roadblocks to understanding the BLM's noncompetitive leasing program

The BLM does not make it easy to get a full picture of the noncompetitive leasing program. Unlike leases sold through competitive auctions where the agency posts lease sale- or quarterly-specific statistics, the BLM does not provide regular updates on what is being leased noncompetitively. There is no annual report or one-stop-shop where one can gain an understanding of the practice's scope and scale. The program's opacity adds an unnecessary roadblock for the public, watchdogs, or Congress to ensure that the BLM is fairly administering the program.

The main way to understand oil and gas leasing activity on public lands is a cranky, outdated database housed on the BLM website called the Legacy Rehost System 2000—or LR2000, for short. The database is notoriously difficult to use—even with the BLM's 22-page tutorial—whether to find specific information or to manipulate data for analytical purposes.[49]

The database also has serious content shortcomings. It does not, for example, include any data about lease sales in Alaska. LR2000 does not reliably track the reasons for lease suspensions, which is helpful information in understanding the life of a particular lease or larger leasing trends.[50]

When it comes to noncompetitive leases in particular, there are significant barriers to information. The only way to identify newly issued noncompetitive leases is to manually query them in LR2000, but the system sometimes takes weeks to reflect lease sales. There are coding inconsistencies that result in incomplete results unless one knows the various BLM state offices' data entry idiosyncrasies. In short, the LR2000 is a wholly inadequate public information tool.

Encouragingly, in a recent Government Accountability Office report that recommended the BLM better standardize data collection, the BLM says it intends to "significantly update or replace LR2000 but has not set a definitive date for doing so."[51] This will be a major endeavor, so the Interior Department and Congress must make funding for the database upgrade a priority.

End anonymous nominations

Anonymous nominations should be banned across the oil and gas leasing program. Short of that, anonymously nominated parcels should not be available for noncompetitive leasing. This would shine light on companies that exploit the system by nominating a parcel, sitting out the auction, and then buying the lease later for a fraction of the cost.

Assess fees

The BLM should assess fees to recoup costs of running the program. This could be a meaningful filing fee for an expression of interest, instead of allowing anyone to nominate a parcel for free. The BLM could also consider imposing a per-acre fee on noncompetitive leases, similar to the bonus bid structure for competitive leases. These administrative fees would help deter casual speculators and shift some of the costs of administering lease sales to the oil and gas industry, instead of taxpayers.

Implement a bidder prequalification requirement and punish bad actors

Companies that are repeated bad actors should be held accountable. Under the current system, companies that routinely fail to pay rent are welcome to lease additional public lands. The BLM should implement a requirement that in order to lease more public land, a company must comply with the terms of its existing leases, including rental payments. There could also be a penalty box for companies that consistently fail to pay rent—a BLM-mandated waiting period before the company can access public lands again. These measures would cut down on the number of acres that are held in limbo for speculative reasons.

Call for an investigation

The Government Accountability Office, then the General Accounting Office, has not done a comprehensive review of the BLM's noncompetitive leasing program since the late 1980s, when it examined the success of the 1987 amendment to minimize leases sold noncompetitively.[52] Congress should request that the Government Accountability Office conduct an analysis of noncompetitive leasing related to: impacts to taxpayers; impacts to the agency budgets and resources; evidence of companies exploiting the system; and the effect on the oil and gas industry's and the nation's energy portfolios if the BLM were to abolish the practice.

Conclusion

Noncompetitive leasing is an outdated, wasteful, and unnecessary program that shortchanges taxpayers and provides an avenue for companies to game the system. In 1987, Congress recognized these issues and took an important step to sharply reduce the acres of public lands issued noncompetitively. More than 30 years later, however, the practice continues to account for about one-quarter of all acres leased by the Bureau of Land Management. CAP found that the program does not contribute meaningfully to the nation's energy portfolio; rather, it puts strain on a threadbare agency, ties up public lands that could be managed for other purposes, and incentivizes speculation and abuse. Congress should take the next step and end the BLM's noncompetitive leasing program altogether.

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ENERGY AND ENVIRONMENT

Not Even the Oil and Gas Industry Is Buying What the Trump Administration Is Selling

By Mary Ellen Kustin | Posted on January 17, 2018, 10:25 am

Getty/Tom Williams/CQ Roll Call

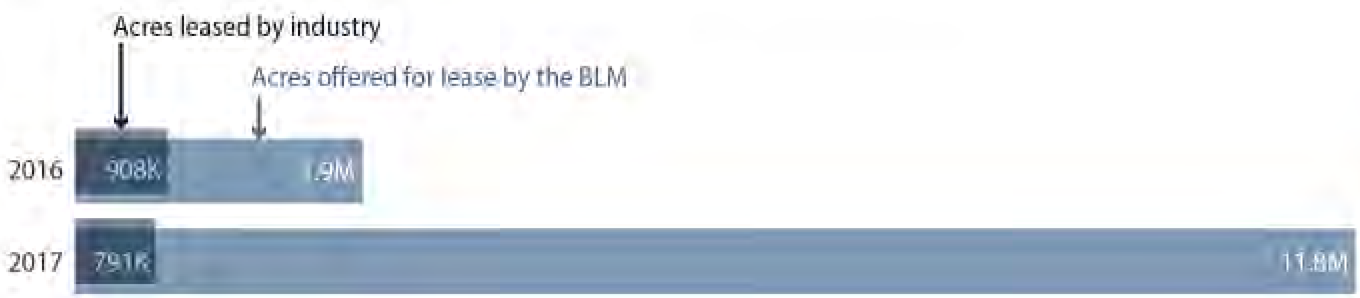
Interior Secretary Ryan Zinke testifies during a Senate Energy and Natural Resources Committee hearing on June 20, 2017.

President Donald Trump's Interior Secretary, Ryan Zinke, has not been shy about his desire to sell more of America's public lands to the oil and gas industry. In October, he boasted about a forthcoming sale of oil and gas leases on federal lands in the National Petroleum Reserve: "This large and unprecedented sale in Alaska will help achieve our goal of American Energy Dominance." But the Alaska lease sale, like the Trump administration's broader 2017 federal oil and gas leasing strategy, was by all measures a failure.

The Center for American Progress analyzed the federal Bureau of Land Management's (BLM) oil and gas leasing data and found that the oil and gas industry purchased only 7 percent of the public land acres the BLM offered in 2017. (In Zinke's touted lease sale of the National Petroleum Reserve, less than 1 percent of the acres sold.) In fact, industry leased fewer acres in 2017 than it did in 2016—even though the BLM offered six times more land for auction in 2017.

FIGURE 1

The Trump administration offers significantly more acres than oil and gas industry wants



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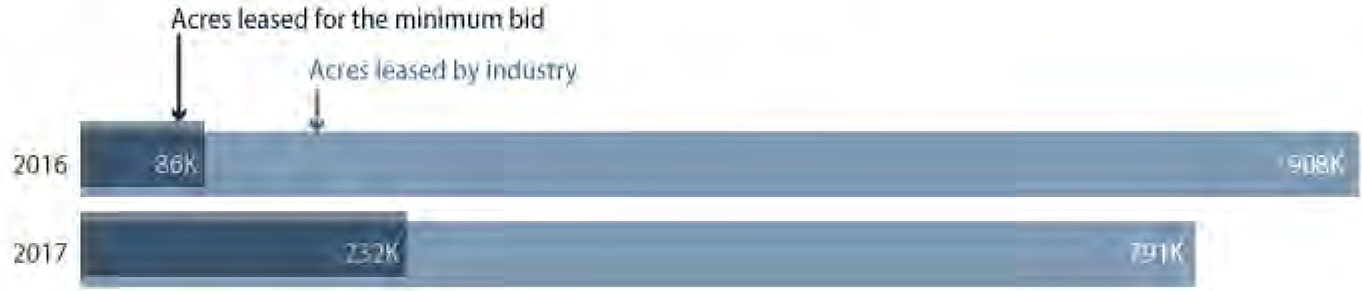
The BLM data show that the Trump administration's oil and gas leasing program is not only failing in its goal of selling more acres of public lands for drilling, but a higher proportion of those parcels are selling at bargain-basement prices, which shortchanges taxpayers of revenues from publicly-owned resources. In fact, more than one in three acres leased by the Trump administration in 2017 went for \$10 per acre or less. What's more, the BLM sold more than twice as many acres for the minimum bid of \$2 per acre in 2017 than it did in 2016. According to the Congressional Budget Office, industry drills a mere 8 percent of leases sold for \$10 per acre or less . In other words: The oil and gas industry is using the Trump administration's oil and gas leasing program to stockpile public lands with little intention of actually drilling them. With these warehoused parcels, taxpayers are shortchanged twice: first by low bonus bids at auction and again when nonproducing leases deliver no royalty payments.

FIGURE 2

The Trump administration leased more public lands at $2 acre

Fewer acres leased overall and more acres at the minimum bid



Source: The Bureau of Land Management, "Programs: Energy and Minerals: Oil and Gas: Leasing," available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/leasing (last accessed January 2018).

The poor business results that Secretary Zinke is delivering in the federal oil and gas leasing program are compounded by his unwillingness to diversify the Interior Department's energy portfolio. On federal lands, Zinke has taken no initiative to expand clean energy production, but is instead going all-in on oil and gas development. Basic investment principles hold that past performance does not predict future returns. In the energy sector specifically, experienced analysts anticipate a leveling off of oil and gas production. Zinke, however, is counting on such production retaining its robust growth of the past decade.

In his first year in office, Zinke has seemingly gone out of his way to please the oil and gas industry. Yet his systematic rollback of oil and gas safety measures, his opening of loopholes favorable to industry, and even his willingness to offer most any and all public lands for oil and gas drilling have not delivered what he hoped or promised. Rather, Zinke's efforts have resulted in lower oil and gas leasing and poor returns to taxpayers. Nearly one year after Zinke took office as Trump's chief natural resource manager, he has proven himself to be an unartful failure of deals.

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Center for American Progress

Federal Oil and Gas Royalty and Revenue Reform

By Nicole Gentile June 19, 2015

When the federal government last changed its royalty rate for oil and gas production on America's public lands, Standard Oil's monopoly had only recently been broken, Ford's Model A still had not rolled off the assembly line, the Teapot Dome scandal had yet to erupt and rock the U.S. Department of the Interior and the administration of President Warren G. Harding, and the 20s had just begun to roar. In the 95 years since the Mineral Leasing Act first set the federal royalty rate for oil and gas at 12.5 percent, the federal government's oil and gas revenue policies have remained firmly fixed in the past while state governments and private landowners have, time and again, updated the terms for development on their lands.

As a result of the federal government's failure to modernize its oil and gas program, U.S. taxpayers are losing out on more than $730 million in revenue every year.[1] At the same time, oil and gas companies are stockpiling leases and sitting idle on the rights to drill on tens of millions of acres of public lands. When companies have drilled for oil and gas, the American public has often been left footing the bill to clean up the environmental damage that has been left behind.

On April 17, the Obama administration signaled that it would undertake much-needed reforms to bring the federal government's oil and gas program into the 21st century.[2] Through what is known as an Advanced Notice of Proposed Rulemaking, or ANPR, the Bureau of Land Management, or BLM, is accepting ideas on how to reform its royalty rates, bonding requirements, minimum bids, and rental rates. These reforms will ensure that taxpayers are fairly compensated for the development of their resources and that companies are held responsible for paying for any clean up related to their drilling activity.

This issue brief provides a short introduction to current oil and gas revenue policy, looks at the specific areas of that policy the Obama administration has pledged to examine, and finally, suggests some common sense ideas for reform.

Royalties

U.S. federal oil and gas royalties are payments made by companies to the federal government for the oil and gas extracted on public lands and waters. With a royalty, owners of the resource—in this case, U.S. taxpayers—collect a share of the profits based on the value or volume of the oil and gas extracted.[3] On taxpayer-owned federal lands such as those managed by the U.S. Forest Service and BLM, oil and gas companies pay royalties to the U.S. Treasury, making royalties one of the federal government's largest nontax sources of revenue.[4] With the exception of Alaska, the revenue is split with about half going to the Treasury and half going to the state where the federal lease is located.[5] While all taxpayers have a financial interest in ensuring that royalties on federal lands deliver a fair return, oil and gas producing states—primarily those concentrated in the West—have a particular high stake, as this money goes to fund schools, roads, and other priorities.[6]

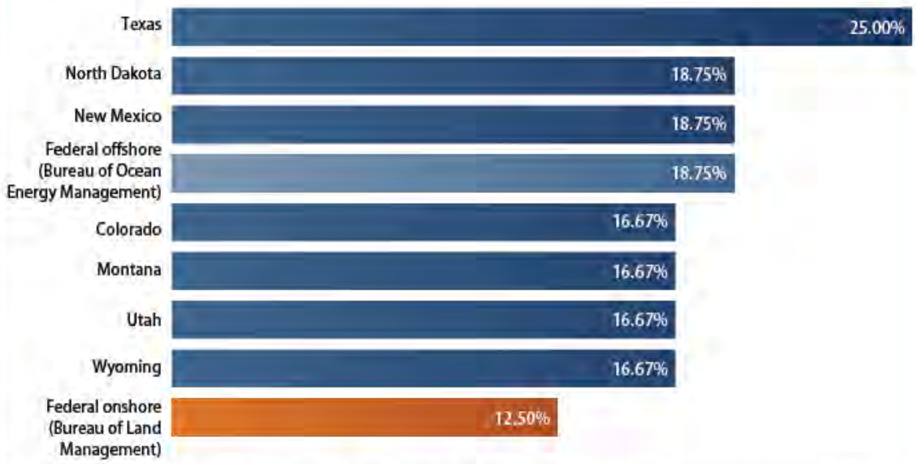
Currently, the federal government charges a royalty of only 12.5 percent on oil and gas extracted from public land.[7] This rate has not been updated since 1920;[8] since then, technological advances and changing markets have made oil and gas extraction more efficient and much more lucrative. In 2014, the big five oil companies—BP, Chevron, ConocoPhillips, Exxon Mobil, and Shell—made $90 billion in profits.[9]

In response to changing market dynamics and to better reflect modern drilling practices, state and private landowners have updated their royalty rates. Texas charges a 25 percent royalty for leases on the state's university and school lands[10]—state land set aside to financially support these state institutions[11] –while New Mexico and North Dakota charge 18.75 percent for oil and gas production on public lands.[12] Many western states, including Wyoming, Utah, Montana, and Colorado, charge a 16.67 percent royalty rate on state-owned leases.[13] A CAP review found that private landowners are also charging higher royalty rates than the federal government. For example, lease documents in Texas and Louisiana show private landowners charging oil and gas companies a 25 percent royalty on resources extracted from their land.[14]

What's more, the royalty rate on federal lands is 50 percent lower than the royalty rate for drilling in federal waters on the Outer Continental Shelf.[15] The administration of former President George W. Bush twice increased the royalty rate for offshore drilling to its current level of 18.75 percent.[16] According to the Center for Western Priorities, if the onshore federal royalty rate were the same as the offshore rate, the U.S. government would collect an additional $730 million every year.[17] A review by the Government Accountability Office, or GAO, also found that, when compared to other countries, the royalty rate for drilling on U.S. federal lands is one of the lowest in the world.[18]

FIGURE 1

Comparing federal and state royalty rates for oil and gas extraction



Source: Center for Western Priorities, "A Fair Share: The Case for Updating Federal Royalties" (2013), available at westernpriorities.org/wp-content/uploads/2013/07/A-Fair-Share.pdf.

In its ANPR announcement that it will publish a new rule to modernize the BLM's oil and gas revenue policies, the Obama administration asked for input on a range of potential royalty structures, including a fixed royalty rate and a flexible royalty rate that could be adjusted in response to changing market conditions.[19] Based on a review of royalty provisions on state and private lands, CAP recommends that the new regulations set a floor of 18.75 percent for the royalty rate, while allowing the secretary of the Interior the discretion to raise the rate in response to market conditions, without further rulemaking. In a recent report—"A Fair Share: The Case for Updating Federal Royalties"—the Center for Western Priorities suggested a sliding-scale royalty where the secretary of the Interior can increase rates based on either oil and natural gas prices or the location of known resources where the rate might increase in an area of known production versus an area that is more speculative.[20]

The concept of setting a new floor for the royalty rate while allowing discretion to increase the rate above that floor is similar to the policies governing the surface mining of coal on public lands.[21] This rule change would also represent a common sense expansion of the authority of the secretary of the Interior to implement a sliding-scale royalty on particular oil and gas leases in limited circumstances.[22] It is vital, however, that the administration set a higher floor than 12.5 percent for the royalty rate; without a floor, future royalty policy will be highly susceptible to political pressure to provide royalty breaks at the expense of American taxpayers.

For its part, the oil and gas industry has long argued that higher royalty rates will result in a major decrease in production; however, the evidence does not support their claims. The Permian Basin in west Texas, for example, has been the site of the greatest regional increase in oil and gas production in the past eight years with daily oil output more than doubling during that time from 850,000 barrels per day to nearly 2 million barrels per day.[23] Much of the development and production in the Permian Basin is occurring on the University of Texas System's University Lands, on which oil and gas companies pay a 25 percent royalty.[24]

From a resource perspective, the Permian Basin is no outlier. According to the U.S. Geological Survey and the Potential Gas Committee—composed of oil and gas industry experts—advances in drilling and exploration technology give the Rocky Mountains and other areas in the West similar hydrocarbon potential to the Permian Basin; that is to say, they have strong potentials for significant and economically viable oil and gas reservoirs.[25] Given that much of these future plays for oil and gas extraction are on U.S. public lands, it is all the more urgent that the Obama administration raise royalty rates before taxpayers miss out on their share of the profits.

Bonding

When an oil and gas company successfully bids on a lease, it must post a bond—or insurance—to guarantee that it will comply with the terms of the lease, including cleanup costs for unseen disasters during production and after the well stops producing. The bonding requirements on federal land have not been updated in more than 50 years. Currently, under regulations set in 1951, a company can secure a nationwide bond for all its oil and gas wells on public lands for only $150,000.[26] Adjusting for inflation, that $150,000 fee would be nearly $1.4 million in 2015 dollars.[27] Following this same inflation calculation, statewide bonding would increase from $25,000 to $270,500, and an individual lease bond—set in 1960—would increase from $10,000 to $80,000.[28]

Because companies are able to pay so little for statewide and nationwide bonds, bonding for individual wells can be as low as $50 per well.[29] In Wyoming in 2008, the cost of cleaning up a single gas or oil well was as high as $582,829.[30] The state of Wyoming estimates that the average cost of clean up and reclamation of a single well is between $2,500 and $7,500; this estimate does not include reclamation costs for other parts of oil and gas operations such as decommissioning roads, compressor station sites, and containment ponds.[31] Some estimates are much higher. According to the head of the University of Wyoming's Agriculture and Applied Economics Department, it costs around $30,000 to reclaim just one oil or gas well.[32]

CAP recommends that the Obama administration update current rules to set bonding requirements based on the number of wells that would need to be reclaimed. The Texas Railroad Commission, for example, requires that a company post $25,000 for 10 or fewer wells; $50,000 for between 10 and 100 wells; and $250,000 for 100 or more wells.[33] Based on reclamation cost estimates, even these requirements appear to be too low to cover potential cleanup costs. The required bond per well should reflect the average cost of reclamation for each site to shield taxpayers from the cost of cleanup. Some experts have called for a bond of $20,000 per well, and further bond requirements for additional facilities associated with the drilling operations.[34]

Minimum acceptable bonus bids

A bonus bid is the payment that an oil and gas company offers to purchase a lease on public lands. If accepted by the federal government, the bonus bid grants the company the right to drill on the leased land for a period of 10 years. The BLM currently requires a company's bonus bid to be at least $2 per acre—known as the minimum bid—to win the right to drill on a lease.[35]

Under the current federal leasing process, the land parcels that the BLM offers for lease are typically nominated, or suggested to the BLM, by the oil and gas companies.[36] By nominating a parcel, companies are expressing a financial interest in the land and, in theory, should be willing to pay a fair price for the leases. Yet, in the first quarter of 2015, 25 percent of the federal leases sold in seven western states were sold for $2 per acre, the minimum bid.[37] Further, noncompetitive issued leases—where there was no bid offered for at least two years[38]—account for 40 percent of BLM leases in place today.[39] This large proportion of leases going for the minimum bid of $2 per acre should be of concern to both policymakers and taxpayers.

In many cases, bonus bids on federal public lands are significantly higher than the minimum bid,[40] suggesting that the floor can and should be raised. For example, the highest bid in the most recent lease sale for federal parcels in Colorado, held in May 2015, was $10,100 per acre.[41] For federal parcels in Montana, the highest bonus bid was also in a May 2015 lease sale and was $825 per acre.[42] In Utah, it was $500 an acre.[43] Similarly, the average bonus bids per acre were also much higher than the minimum bid in the most recent lease sales in Wyoming, where the average bonus bid was $21 per acre[44] and in Utah, with the average bid at $19 per acre.[45] Bonus bids on state-owned lands also appear to be well above the federal government's minimum bid. The highest bid in the most recent lease sale in Texas for University Lands went for $6,503 per acre.[46]

According to some experts, the minimum acceptable bid should be raised to account for the so-called option value of the resource.[47] The option value—or ability to delay a decision until more information is available—is a concept that has long been incorporated into natural resources law to account for the uncertainty around markets, technology, and environmental and social costs. When the federal government sells a lease, it sells the taxpayers' future option to develop those resources, even if the lease would be more lucrative at some future date. When the federal government leases a parcel for oil and gas drilling, for example, it also sells the public's future option to use that land in some other way and for some other purpose. Therefore, the minimum bid should be raised to ensure taxpayers are fairly compensated for losing the ability to exploit these resources in the future when conditions may be more favorable or to prevent the loss of a more valuable use of the land. It can similarly be argued that the government should not issue noncompetitive leases. If the market is not driving a fair price for these lands, the government should take full advantage of the option value and steward taxpayers' resources for a more favorable time or use.

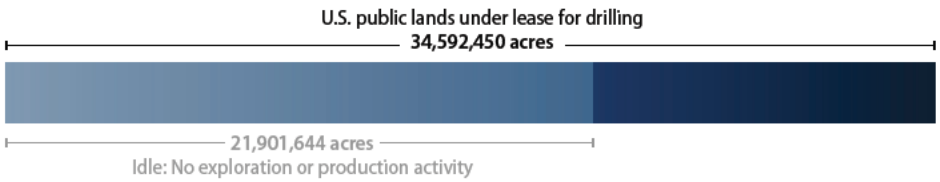
Rental rates

To preserve their rights to drill on a lease, the leaseholder is required to pay an annual rental fee to the federal government.[48] Current rental rates are set at $1.50 per acre for the first five years of a lease, and $2 per acre thereafter.[49] In its announcement of the upcoming rulemaking on oil and gas, the Obama administration asked for input on how to create "greater financial incentive for oil and gas companies to develop their leases promptly or relinquish them."[50] Indeed, oil and gas companies routinely sit idle on nonproducing leases, placing these areas off limits to the American public, which owns them. At the end of fiscal year 2014, more than 34.5 million acres of federal lands were under lease for oil and gas, yet only about 12.7 million of those acres—less than 37 percent—were actually producing oil or gas. [51]

FIGURE 2

Warehoused acreage

Acres of U.S. public lands that were under lease to oil and gas companies but sat idle as of the end of FY 2014



Source: Bureau of Land Management, "Oil & Gas Statistics," available at http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html (last accessed June 2015).

The Texas General Land Office, which manages the land owned by the state for the benefit of public education, has created an incentive to use or relinquish leases on the state's school lands by using a graduated rental rate. In the first two years of a lease, the rental rate is $5 per acre.[52] In the third year of the lease, that rate jumps to $2,500 per acre to incentivize drilling or turning the lease back over to the citizens of Texas.[53] Leases on federal public lands have 10-year terms, but the federal government could adopt an approach similar to Texas. CAP recommends that the federal government raise rental rates in the fourth or fifth year of a lease to disincentivize leaseholders from sitting idle on their rights to drill on public lands.

In Texas, oil and gas leases on University Lands require companies to prepay rental fees for all three years of the lease term,[54] as do many private landowners.[55] This discourages oil and gas companies from buying leases for the purpose of holding them and then reselling them when the market improves, undercutting the American taxpayer. However the deterrent effect of a "paid-up" lease would require that rental rates be high enough to more accurately represent the value of the land. One oil and gas company in New Mexico has argued that rental rates should be at least $100 per acre, noting that this price would not dissuade companies from bidding on leases.[56] This company also argues that paying a full rental payment up front eliminates the confusing and time-consuming process of paying rental fees each year.

Conclusion

Under the current royalty rates, bonding requirements, minimum bids, and rental rates on public lands—some of which have not been updated in nearly a century—American taxpayers and energy-producing states are not receiving a fair return from the development of their valuable resources. From a business perspective, the federal government is lagging behind states and private landowners in defending the financial interests of their shareholders: American taxpayers. The upcoming rulemaking that addresses the federal oil and gas leasing process is a critical opportunity for the Obama administration to reevaluate how public lands are leased and ensure that the public receives a fair and equitable share of these shared resources.

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Center for American Progress

A Continued Push for Reform Is Needed on Public Lands' Energy Leasing

Tom Kenworthy
May 13, 2013

Presidents and their secretaries of the interior have considerable latitude in how they handle resource development. The secretary of the interior oversees the agency's Bureau of Land Management, which manages oil, gas and coal development on federal lands. As former secretary Ken Salazar noted in his final public web chat before leaving office last month, presidential administrations can take quite different approaches.

Under President George W. Bush's administration, former Secretary Salazar said that, "There was an agenda on oil and gas that basically allowed oil and gas to be developed anywhere no matter what the environmental consequences were." Under President Obama, he said:

> *We have brought a balanced approach. … There are places that have special ecologies and environmental values and history that we need to protect. That's the approach we've taken, it is the approach we've embedded in our rules and regulations and our planning efforts here at Interior.*[1]

As important as the changes outlined by former Secretary Salazar are, they remain a work in progress. A report on the Obama administration's reforms prepared by The Wilderness Society concluded that, "[W]hile important progress has been made under the reforms, additional work is required to make the reforms successful and to provide a lasting 'fix' to the onshore oil and gas leasing and development program."[2] This issue brief takes a look at fossil-fuel development on public lands and explores options for how the new secretary of the interior can oversee this exploration in ways that ensure public health and safety and limit environmental damage.

Fossil-Fuel Leasing on Federal Lands: A Primer

The Mineral Leasing Act of 1920, as amended, governs the leasing of oil, natural gas, and coal on federal lands, excluding national parks, national monuments, and congressionally created wilderness areas.[3] The law is administered by the Department of the Interior's Bureau of Land Management, or BLM, which oversees leasing on the 258 million acres it manages; on the 385 million acres managed by other federal agencies, such as the U.S. Forest Service; and on 57 million acres of land where the surface is privately owned but the mineral rights are owned by the federal government.

For the lands it directly controls, the BLM, under the 1976 Federal Land Management and Policy Act, must prepare resource-management plans to govern land uses, including which areas are suitable for leasing.[4] This management is generally for large areas of land, and for periods of 10 to 15 years. According to the law, the BLM must apply the principle of multiple use, which means utilization "in the combination that will best meet the present and future needs of the American people." It also requires the agency to take into account:

> *… the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.*[5]

For its part, the U.S. Forest Service develops its own land-management plans under the same general principles.

Most oil and gas leasing is done through a competitive process. The BLM identifies areas available for leasing, and energy companies then nominate land parcels within those areas, generally no more than 2,560 acres, for quarterly auctions. Minimum bids of $2 an acre are required. Leases require the payment of at least 12 5 percent of the value of oil or gas that is produced. There are also annual rental fees, starting at $1.50 an acre for the first 5 years of the 10-year lease, increasing by $2 an acre every year thereafter. Half of the funds from royalties and fees go to the U S. Treasury and half to the state where the minerals are located, except in Alaska, where the state gets 90 percent.[6]

Owners of oil and gas leases must submit an application for a permit to drill for each well and cannot begin operations until the permit is approved by the BLM. The application must include a drilling plan and a surface-use plan showing locations of drilling pads and how the area will be reclaimed. The BLM must allow public inspection of those applications and prepare an environmental review. The Forest Service has similar requirements.

The BLM also administers coal leasing on federal lands, under the Mineral Leasing Act as amended—primarily by the 1976 Federal Coal Leasing Amendments Act—and through its own land-use planning. Leasing takes place under two procedures established by regulation: regional coal leasing, where the BLM selects tracts to meet regional requirements determined by teams of BLM officials and state and local officials, and through so-called leasing by application, which means energy companies apply for specific areas. Leases initially are in effect for 20 years, but can be automatically extended as long as coal is being produced in commercial amounts. No one company may own leases of more than 75,000 acres in a state or 150,000 acres nationally.[7]

By 1990 the BLM had all but abandoned the regional coal-leasing program, and today virtually all coal leases are done through leasing by application. As a 2012 study by the Institute for Energy Economics & Financial Analysis noted, "By 1990, BLM's regional coal teams had successfully lobbied to disband, or decertify, all 12 coal production regions," and this "gave coal companies nearly complete control of coal mining," most notably in the Powder River Basin, the source of most federal coal.[8]

The Obama administration's oil- and gas-drilling reform efforts

Bringing fundamental change to the way that the Interior Department's Bureau of Land Management, or BLM, manages energy development was never going to be an easy task. The bureau oversees mineral resources on 700 million acres of public lands and on private lands where the federal government owns the mineral rights. But in some ways and in some places it still has a cultural bias in favor of resource extraction. As a result, some BLM leaders in the West have been less than enthusiastic about the Obama administration's reform agenda, making implementation of the changes uneven and slower than it should be.

Another part of the Department of the Interior's energy portfolio is coal production, with the great bulk of it coming from federal lands in the Powder River Basin region of Wyoming and Montana. Here too, the Obama administration has a long way to go in ensuring that the program is consistent with its stated climate change goals and that it is operating in the public interest by providing a fair dollar return to the Treasury Department.

Without a doubt, Secretary Salazar quickly set a different and refreshing tone when he took charge of the Interior Department in 2009. Saying that there was a "new sheriff in town"[9] who would no longer let the oil and gas industry treat public lands as its private "candy store,"[10] Secretary Salazar slammed the brakes on oil- and gas-lease sales on 77 tracts of land in Utah, one of the Bush administration's most controversial sales. Many of these tracts were close to national parks and other treasured lands.[11]

After scuttling those sales, the Interior Department undertook a formal internal review of BLM's leasing program, which led to the reforms that were unveiled in May 2010.[12] Those reforms called for a better balance between developing oil and gas resources and the protection of other public lands resources, including nearby parks and refuges, wildlife, and historic and archaeological sites. "There is no presumed preference for oil and gas development over other uses," states the reform document.[13]

A key element of the reforms was ensuring that BLM would assume more responsibility for identifying parcels of land suitable for oil and gas development rather than ceding that important task to industry. As a result, a new procedure was developed for more comprehensive planning in some areas where large-scale leasing could be expected but has not yet taken place and where conflicts with other resources such as recreation or water supplies are likely. This process enables BLM to review large landscapes in order to identify areas suitable for oil and gas development and areas where other uses such as recreation and protecting wildlife habitat should take precedence.

This new process is similar to the broader, landscape-level approach used by the Interior Department in planning for large-scale development of solar energy in the desert Southwest. It offers the promise of far more cohesive land-use planning driven by science, and it is attentive to other needs and values besides the extraction of fossil fuels. But it has been unevenly applied, with some BLM field offices less willing than others to employ it.

While the leasing reforms represent a good start, the BLM and its parent, the Department of the Interior, can and should do more. Keeping the leasing reform agenda on track ought to be one of the key items on the task list of new Secretary of the Interior Sally Jewell, who was sworn into office on April 12, 2013. It could also help the Obama administration to achieve a better balance between drilling and conservation on the public lands owned by all Americans. So far during the Obama presidency, the administration has won permanent protection for far fewer acres than many of its recent predecessors, and as of the beginning of this year, it had drilled about 2.5 acres for every acre preserved from development.[14] That compares to the 1-to-1 ratios of drilling to conservation by both the George H. W. Bush and Bill Clinton administrations.[15]

Problems in the Colorado state office of the BLM highlight the challenges facing Secretary Jewell. That office has been decidedly reluctant to implement some key elements of the reforms, provoking a number of high-profile controversies. These include plans—recently deferred, at least temporarily—to allow oil and gas drilling close to Mesa Verde National Park and Dinosaur National Monument, as well as in a highly valued agricultural area known as the North Fork Valley. The state BLM office was also moving to permit drilling in a region known as South Park, which is a critical watershed for the cities of Denver and Aurora and is a valued recreation area.[16] The same BLM office recently extended some oil and gas leases in the Thompson Divide region that were about to expire because they had not yet been developed during their 10-year term.[17] That gift to the industry came despite the Obama administration's rhetorical commitment to making energy companies "use it or lose it" on leases rather than allowing them to sit on lands indefinitely without actually drilling.[18]

Beyond the problems in advancing leasing reforms in individual states, the Department of Interior has also failed to make good on pledges to increase the royalties it collects on publicly owned oil and gas that is developed by private industry. It has been four years since former Secretary Salazar—who can raise royalty rates on his own without congressional approval—said that he would increase the royalty rate of 12.5 percent,[19] but no action has yet been taken. Most of the major oil- and gas-producing states charge significantly higher royalties on energy produced from state lands.[20]

Sticking to the status quo on coal-mining regulations

In contrast to the oil- and gas-leasing program, the Obama administration has shown little interest in altering the status quo when it comes to leasing public lands for the development of coal resources. Most of the leasing of this land occurs in the Powder River Basin region of northeastern Wyoming and southeastern Montana. It accounts for about 40 percent of total U.S. coal production—and about 13 percent of total U.S. greenhouse-gas emissions when burned for electricity.[21] Since 2011 BLM has leased land producing more than 2 billion tons of coal in the Powder River Basin, and approvals for leases producing another 3.5 billion tons could come relatively soon.[22]

While demand for coal to generate electricity in the United States is on the decline—its share of electricity production has fallen in a decade from about 50 percent to just 37 percent[23]—the industry is increasingly looking to export to Asia and other regions of the world to make up for the decline.[24]

Because of coal's leading role in climate change and controversy regarding the industry's recent attempts to build new coal-export facilities on the West Coast, the Interior Department's coal-leasing program has come under increasing scrutiny. Among the issues at play are whether taxpayers are getting fair value for the sale of publicly owned coal being mined in the Powder River Basin; the incongruity between the Obama administration's stated commitment to battle climate change and its aggressive selling of leases in the Powder River Basin; and whether coal companies are resorting to accounting gimmicks to avoid paying fair royalties on coal they export.[25]

The United States by law is supposed to receive fair market value on the coal it sells to the industry, but the program has been periodically beset by scandal over the years,[26] and even now there are many who question whether taxpayers are getting a fair return on federal coal sales. Most coal lease sales over the past two decades have drawn only a single bidder.[27] A report issued last year by the Institute for Energy Economics and Financial Analysis in Cambridge, Massachusetts, estimated that this system may have cost taxpayers as much as $28.9 billion over the past three decades.[28] Publication of that report prompted Rep. Edward Markey (D-MA) to request an investigation by the Government Accountability Office,[29] which last did a thorough audit of the coal-leasing program in 1983, when it uncovered a $100 billion loss to the Treasury Department because of bidding manipulation.[30]

Two other investigations of the coal program are also underway. An Interior Department task force is investigating whether coal companies are ducking fair royalty payments by selling coal cheaply to affiliates, paying royalties based on that low price, and then having the affiliates export it overseas at much higher prices. That investigation was created at the request of Rep. Markey and Sen. Ron Wyden (D-OR) after Reuters published a story looking into the industry practices.[31] In addition, the inspector general's office at the Department of the Interior is looking into issues of fair market value and royalties.

While the issues of fair market value and taxpayer return are important, ultimately they are less critical than the role that massive sales of publicly owned coal play in carbon emissions and whether the Obama administration will adjust the lease-sale program to square with its rhetorical commitment to fighting climate change.

Conclusion

In his second inaugural address, the president said that, "We will respond to the threat of climate change, knowing that failure to do so would betray our children and future generations."[32] Less than a month later, he issued an ultimatum to Congress in his State of the Union speech, saying:

> *[I]f Congress won't act soon to protect future generations, I will. I will direct my Cabinet to come up with executive actions we can take, now and in the future, to reduce pollution, prepare our communities for the consequences of climate change, and speed the transition to more sustainable sources of energy.*[33]

The actions that the president and his administration can take, which have been endorsed by the Center for American Progress, include the following.

Adopting a 'clean resources standard'

The administration should adopt a "clean resources standard" to reduce the dominant role that fossil fuels play in the energy portfolio from public lands. This promises to ramp up the share of overall federal-lands energy coming from renewable sources such as wind and solar to 35 percent by 2035. As detailed in the Center for American Progress's 2012 report, "Using Public Lands for the Public Good,"[34] about 66 percent of the energy currently coming off of federal lands is from coal, and renewables, including hydropower, are at 15 percent.

Raising royalty rates and leasing rates

If the administration raises both the royalty rates that companies must pay on federal coal and the separate fees they pay for federal coal leases, the prices would better reflect the true economic costs of burning coal. These costs include the very expensive health impacts of coal-fired electricity.

Including the impact on climate change in reviews

The administration should require environmental reviews of federal-land management decisions, including energy developments, to include their impacts on climate change,[35] specifically whether the actions will exacerbate global warming.

More than 20 environmental groups have urged even more dramatic administrative action in a recent letter to Interior Secretary Sally Jewell. They call on her to impose "an immediate moratorium on new coal leasing in the Powder River Basin" and to conduct a "comprehensive review" of the entire coal-leasing program to:

> *...ensure that coal companies do not cheat U.S. taxpayers, existing mines do not endanger our air, water and wildlife and are properly reclaimed, and the greenhouse gas emissions from federal coal leases do not conflict with the Administration's stated commitment to reduce the country's contribution to climate change.*[36]

Even without imposing a coal-leasing moratorium, there is much that the new secretary of the interior can do to ensure that fossil-fuel development on federal lands is done in ways and with limits that better protect public health, safety, and the environment. Secretary Jewell should start down that road as soon as possible.

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Center for American Progress

THE WILDERNESS SOCIETY

Cutting Greenhouse Gas from Fossil-Fuel Extraction on Federal Lands and Waters

Claire Moser, Joshua Mantell, Nidhi Thakar, Chase Huntley, and Matt Lee-Ashley
March 18, 2015

Since taking office, President Barack Obama and his administration have taken unprecedented action to address the threat of climate change. Through policies to improve energy efficiency, increase vehicle emissions standards, encourage renewable energy production, and reduce pollution from coal-fired power plants, the administration has made remarkable progress toward meeting the president's new goal of reducing emissions of greenhouse gases, or GHGs, by 26 percent below 2005 levels by 2020, as part of an agreement with China.[1] However, even with these remarkable actions, there is still a blind spot in U.S. efforts to address climate change.

Today, taxpayer-owned gas, oil, and coal extracted from federal lands and waters by private companies are one of the nation's most significant sources of GHG emissions, accounting for more than one-fifth of all U.S. GHG emissions.[2] The U.S. Department of the Interior, or DOI, which has jurisdiction over the nation's public lands, has no comprehensive plan to measure, monitor, and reduce the total volume of GHG emissions that result from the leasing and development of federal energy resources.

In light of the lack of a comprehensive accounting of GHG emissions from energy development on federal lands and waters, the Center for American Progress and The Wilderness Society, or TWS, commissioned Stratus Consulting, to conduct an independent analysis of this issue by updating a similar analysis conducted in 2012.[3] This issue brief reviews these new estimates from Stratus Consulting, finding that:

- Federal lands and waters could have accounted for 24 percent of all energy-related GHG emissions in the United States in 2012.
- Combustion of coal from federal lands accounts for more than 57 percent of all emissions from fossil-fuel production on federal lands.
- Methane pollution from venting and flaring from onshore federal leases rose more than 51 percent onshore between 2008 and 2013, according to government data.

In addition to summarizing the new estimates provided by Stratus Consulting, this issue brief recommends a comprehensive plan to address the blind spot in the administration's plan to fight global climate change.

America's public lands and waters are still major sources of GHG emissions

Comprising more than one-fifth of the country's landmass and 1.7 billion offshore acres, U.S. public lands and waters are the source for almost 30 percent of U.S. annual energy production.[4] In addition to providing the backdrop for more and more renewable energy projects, public lands remain a large source for coal, oil, and natural gas. However, these same fossil fuels contribute high levels of GHG emissions to the atmosphere, exacerbate climate change, and have serious implications for U.S. climate policy.

The DOI has yet to develop a plan to accurately account for, manage, and mitigate the GHG pollution that results from the extraction and combustion of fossil fuels from public lands and waters. In 2010, the White House Council on Environmental Quality, or CEQ, released its "Federal Greenhouse Gas Accounting and Reporting Guidance," which was subsequently updated in 2012. This document laid out the greenhouse gas footprint for the federal government, but it explicitly left out emissions associated with or resulting from the use of public lands and waters by private entities.[5] The guidance gave land-management agencies the option to report "activities associated with land management agencies," including emissions from "third-party oil, gas, and coal mine leasing activities."[6] However, in CEQ's "Federal Government Greenhouse Gas Inventory by Agency for fiscal year 2010," the DOI only reported that its largest sources of GHG emissions were from purchased electricity, federal employee commuting, and its passenger vehicle fleet.[7]

It seems as if the Obama administration has started to recognize this gaping hole in their emissions accounting and reporting structure. In December 2014, CEQ issued new "Revised Draft Guidance for Greenhouse Gas Emissions and Climate Change Impacts," calling for federal agencies to consider the impacts of GHG emissions and climate change in environmental reviews and impact statements under the National Environmental Policy Act, or NEPA, and to specifically include emissions associated with private activities on public lands and waters.[8]

While this new draft guidance is an important step in the right direction to account for emissions from public lands, it does not directly address existing leases on federal lands and will not result in a full picture of the carbon emissions resulting from energy resources extracted from the nation's public lands and waters. Instead, it still leaves third parties to determine the extent that public lands and waters are contributing GHGs.

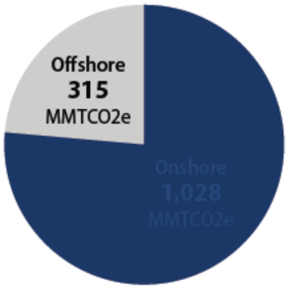
Independent estimates of GHG emissions from fossil fuels extracted from federal lands and waters suggest that these energy resources contribute a large share of overall U.S. GHG emissions. According to Stratus Consulting's new estimates, these energy resources could have accounted for more than 1,340 million metric tons of carbon dioxide equivalent, or MMTCO2e, in 2012; an amount equal to annual emissions from more than 280 million cars on the road.[9] Ultimate emissions of carbon dioxide, methane, and nitrous oxide from the combustion of these fossil fuels could have accounted for almost 21 percent of all U.S. GHG emissions or 24 percent of all energy-related U.S. GHG emissions.

As shown in Figure 1, more than three-quarters of these estimated emissions, or a total of more than 1,028 MMTCO2e, are associated with onshore energy resources.

Estimated emissions from fossil fuels extracted on public lands and waters have decreased slightly over the past few years likely due to a change in the mix of energy produced from federal lands. A prior study by Stratus Consulting found that fossil fuels extracted on public lands in 2010 could have accounted for 1,154 MMTCO2e of U.S. emissions—126 MMTCO2e more than in 2012.[10] Market forces have reduced demand for coal and increased demand for natural gas and oil, and technological advancements have further made these resources more economical to develop. These changes in production on public lands and waters would therefore result in a significant reduction in estimated emissions because natural gas has a substantially smaller carbon footprint than coal when combusted—not accounting for fugitive emissions, meaning unintentional leakage during production. Also, the administration has prioritized investments in expanding renewable energy technologies and expediting the pace at which utility-scale solar and other renewable energy projects are developed on federal lands.

FIGURE 1

Onshore and offshore emissions from fossil-fuel production on federal lands in 2012



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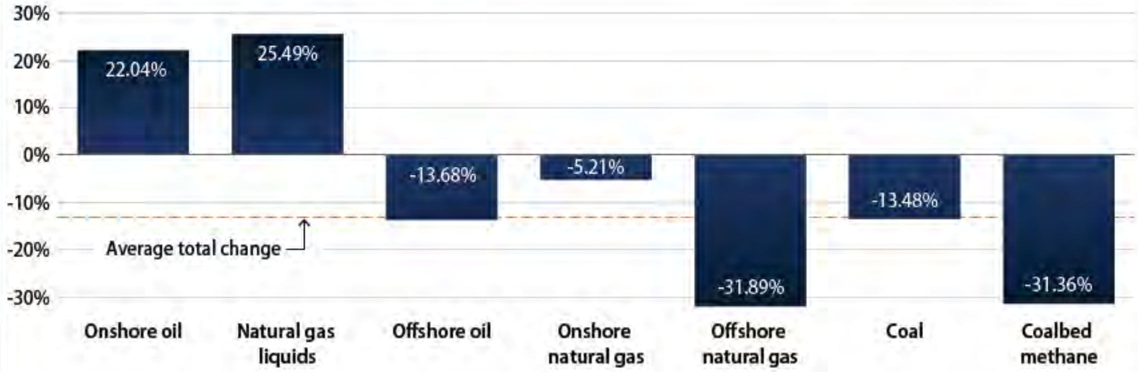
Public lands provide many benefits in a changing climate, including connectivity for wildlife migration and the potential for absorbing carbon released. However, estimated GHGs emitted from public lands energy resources dwarf these benefits and outweigh the amount of carbon that can be absorbed by public lands. According to an earlier analysis by CAP, public lands in the lower 48 states in 2010 were contributing nearly 4.5 times more carbon to the atmosphere than these lands were able to absorb.[11]

Increases in estimated emissions from natural gas liquids and onshore oil

Even as estimated emissions from fossil fuels extracted on public lands have seen moderate decreases, it appears emissions from onshore oil and natural gas liquids have increased by more than 20 percent. Specifically, estimated emissions of onshore oil increased 22 percent from 2010 to 2012, and estimated emissions from onshore natural gas liquids increased more than 25 percent during this period.[12]

FIGURE 2

Percent change in estimated greenhouse gas emissions from fossil-fuel production on federal lands and waters, 2010–2012



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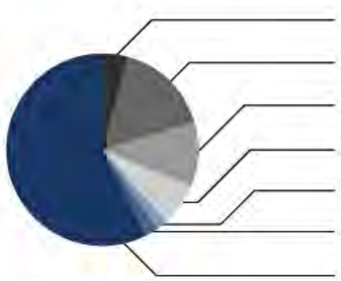
Coal extraction is more than half of estimated greenhouse gas emissions on public lands

Despite the slight overall decreases in production—and therefore emissions—in recent years, estimated emissions from the use of federal coal is still one of the largest sources of potential GHGs from federal lands. As depicted in Figure 3, in 2012, coal from federal lands was the source of more than half of all estimated emissions from fossil-fuel production on federal lands—totaling 57 percent. Coal from federal lands was responsible for an estimated 769 MMTCO2e of emissions in 2012, which is the equivalent of annual emissions from more than 161 million cars on the road.

FIGURE 3

Estimated GHG emissions by fossil-fuel resource extracted on federal lands and waters in 2012



Fossil fuel	Total MTCO2e	Percent of total
Onshore oil	57,311,142	4%
Offshore oil	217,212,051	16%
Onshore natural gas	144,587,927	11%
Offshore natural gas	98,158,313	7%
Natural gas liquids	26,563,487	2%
Coalbed methane	31,070,559	2%
Coal	769,155,909	57%
Total	**1,344,059,388**	**100%**

Stratus Consulting, "Greenhouse Gas Emissions from Fossil Fuel Energy Extracted from Federal Lands and Waters: An Update" (Washington: Stratus Consulting, 2014), XX LINK TK XX.

Figure 3 shows the 2012 estimated GHG emissions and the total emissions of MMTCO2e by type of fossil fuel extracted.

While accounting for more than half of all estimated emissions, coal production on federal lands occurs in a few key western states. In 2012, coal production in Wyoming, Colorado, and Montana contributed 93 percent of all estimated emissions related to coal produced from federal lands. Table 1 provides an overview of the estimated emissions from coal extracted on federal lands by state.

TABLE 1

Coal production on federal lands

Type and estimated emissions by state

State	Sales volume, in short tons	Type of coal	CO2e, in metric tons
Wyoming	354,972,808	Sub-bituminous	633,039,334
Colorado	20,586,124	Bituminous	49,566,232
Montana	21,811,626	Sub-bituminous	38,897,676
Utah	13,392,915	Bituminous	32,246,786
New Mexico	4,957,756	Sub-bituminous	8,841,394
Alabama	1,934,725	Bituminous	4,658,333
Oklahoma	352,171	Bituminous	847,940
North Dakota	3,839,502	Lignite	557,567
Kentucky	207,931	Bituminous	500,646
Total	**422,055,558**		**769,155,909**

Note: Totals may not sum due to rounding.

Source: Stratus Consulting, "Greenhouse Gas Emissions from Fossil Fuel Energy Extracted from Federal Lands and Waters: An Update" (Washington: Stratus Consulting, 2014), XX LINK TK XX.

A significant portion of these estimated emissions can be attributed to coal production in the Powder River Basin, which stretches across southeast Montana and northeast Wyoming. In fact, emissions from coal extracted from public lands in Wyoming and Montana alone notably contributes almost 50 percent of total GHG emissions from fossil fuels on federal lands and waters—and more than 65 percent of total emissions from onshore fossil fuels.

The Powder River Basin produces more coal than anywhere else in the country, providing 40 percent of all U S. coal to more than 200 power plants in 35 states.[13] Coal from federal lands in Wyoming and Montana, including the Powder River Basin, contributed more than 13 percent of all GHG emissions from fossil fuels in the United States and more than 10 percent of all U.S. GHG emissions.[14] A July 2014 CAP report also found that there are serious economic and social costs of burning Powder River Basin coal that policymakers have generally overlooked.[15]

Reducing methane pollution from energy development on public lands and waters

Methane emissions are particularly concerning because methane is a much more powerful GHG: Over a 100-year period, the effect of methane is 34 times greater per metric ton than that of carbon dioxide and even greater in the near term.[16] According to the EPA, 29 percent of all U.S. methane emissions come from natural gas and petroleum systems, and 10 percent come from coal mining in the United States.[17]

In October 2014, CAP and TWS both released reports analyzing the emissions of methane from different phases of the production and processing of fossil fuels on public lands and waters.[18] Both reports explored the significant uptick in industry-reported data disclosing emissions from venting and flaring of natural gas over a five-year period, from 2008 to 2012, and also discussed recent literature showing even higher levels of methane released from fugitive emissions, or the unintentional leakage of methane during production, transportation and distribution activities.

The Bureau of Land Management, or BLM, is currently in the process of proposing regulations to curtail the waste of natural gas resources through venting and flaring activities on public lands. A groundbreaking, independent technical analysis estimated that up to 50 percent of wasted methane can be captured cost effectively.[19] Taxpayers deserve a strong rule that updates venting and flaring practices to ensure these preventable emissions are reduced. The BLM should also look to curb fugitive emissions from production and delivery systems through better and more accurate monitoring, accounting, and curtailment.

Increasing 'wasted' gas from venting and flaring

Policymakers should be concerned about the practices of venting—directly releasing natural gas into the atmosphere, which primarily emits methane—and flaring—burning natural gas to release into the atmosphere, which primarily emits carbon dioxide. These practices waste natural gas that could be captured for consumption or sale and add significant levels of GHGs to the atmosphere. In 2010, the Government Accountability Office, or GAO, found that more than 40 percent of vented and flared natural gas could be "economically captured" with currently available technology.[20]

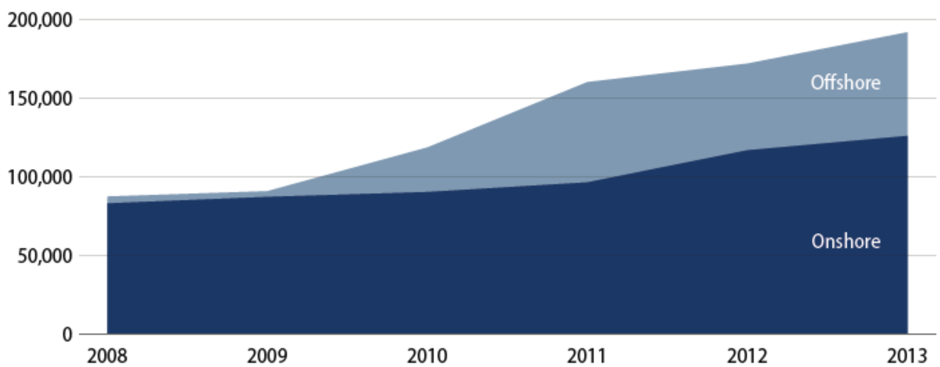
Oil and gas companies operating on federal lands and waters are required to report volumes of natural gas vented and flared to DOI's Office of Natural Resources Revenue, or ONRR. A variety of factors, including the continued use of out-of-date monitoring systems, make accurate accounting of venting and flaring volumes a significant challenge. ONRR collects the only industry-reported data available, although an independent audit found that these data likely underestimate total volumes because they do not include all sources of emissions.[21] Nevertheless, based on these industry data collected through the Oil and Gas Operations Reports, or OGOR, estimated methane emissions from reported venting and flaring on public lands and waters have more than doubled between 2008 and 2013.[22]

Following the October 2014 reports, CAP and TWS asked Stratus Consulting to provide additional analysis of the industry data in the OGOR reports and to compare trends in estimated emissions from reported venting and flaring volumes onshore with venting and flaring volumes offshore.

Figure 4 shows the trends in onshore and offshore levels of estimated pollution from reported levels of venting and flaring.

FIGURE 4

Trends in onshore and offshore pollution from venting and flaring on federal lands and waters, in metric tons



Stratus Consulting, "Greenhouse Gas Emissions from Fossil Fuel Energy Extracted from Federal Lands and Waters: An Update" (Washington: Stratus Consulting, 2014), XX LINK TK XX.

This new breakout of onshore and offshore methane emission estimates, based on industry-reported data, provides additional insights that are relevant to policymakers. Of particular note, estimated emissions based on reported volumes from offshore areas jumped dramatically between 2009 and 2011. This increase coincides in time with the implementation of a 2010 DOI rule requiring that offshore oil and gas operators install meters to record volumes of gas released through venting and flaring, and an additional requirement that operators submit OGOR data parsed out by volumes of gas vented or flared.[23] These data suggest that metering results in higher and presumably more accurate reporting of vented and flared gas. It is also worth noting that, even with meters in place, methane pollution from venting and flaring from offshore operators rose an estimated 19 percent between 2012 and 2013.[24]

Unlike the Bureau of Safety and Environmental Enforcement, however, the BLM does not require all producers to install meters to monitor the volume of gas that is vented or flared and to ensure the accuracy of reporting to government regulators. But presuming that companies are complying with federal laws and regulations that require them to provide accurate information to the BLM, then it is estimated that methane pollution from venting and flaring on federal onshore leases increased 51 percent between 2008 and 2013.[25] This increase appears to be consistent with a recent EPA report that states venting and flaring of associated gas across federal, state, and private lands has risen in recent years.[26]

Because the BLM does not currently require meters, which would aid in independently verifying third-party data, there are still large uncertainties related to the total volume of gas that is being wasted through venting and flaring. Still, it is clear that the volume of wasted gas is high and that the resulting methane pollution is a major problem that is rightly being addressed as part of the Obama administration's "Strategy to Reduce Methane Emissions." As part of this larger strategy, the BLM is currently developing a rule to reduce methane emissions from the venting and flaring of oil and natural gas on public lands. The rule is a critical piece of the larger climate change puzzle; it is a needed step to better account for and reduce overall methane and GHG emissions from federal lands and waters.

Largest source of methane pollution remains unaddressed

Although wasted gas from venting and flaring practices continues to contribute to GHG pollution, fugitive emissions from the production, processing, and distribution of fossil fuels from public lands remain a much more significant source of methane. As noted by CAP and TWS in previously issued reports, methane pollution released from fugitive emissions at the well site, or upstream; during processing, or midstream; and in storage, transmission, and distribution processes, or downstream, is significantly higher than the overall amount of methane released from venting and flaring of natural gas and oil. The amount is at least 3.5 times more than methane emitted from the combustion of extracted fossil fuels from public lands.[27] The lack of a consistent and accurate process for measuring or reporting fugitive emissions has resulted in great uncertainty in accounting for these emissions. In fact, the extreme range of estimated fugitive emissions—200,000 metric tons to more than 8 million metric tons of methane—illustrates this uncertainty.[28]

Nevertheless, even the lowest estimates of methane from fugitive emissions are well above the highest estimates of methane pollution from other sources related to fossil-fuel extraction, emphasizing that fugitive emissions are a real problem. It is critical that the Obama administration take action to address this significant source of methane pollution.

Emissions-reduction strategy for America's public lands and waters

In its Priority Agenda for Enhancing the Climate Resilience of America's Natural Resources, released in October 2014, the administration took a noteworthy step forward in recognizing the critical importance of America's lands and waters in climate policy.[29] The priority agenda is aimed at making "the Nation's natural resources more resilient to a changing climate" and outlines actions to "foster climate-resilient lands and waters."[30] Of particular note, the agenda prioritizes measuring and enhancing the ability of land and waters to absorb carbon dioxide and directs the U.S. Department of Agriculture, or USDA, along with the EPA, the State Department, and the DOI to "establish a robust capacity to provide projections of greenhouse gas emissions and carbon sequestration from agricultural lands, forests, and grasslands on a biennial basis."[31] However, the priority agenda fails to mention the need for better accounting and future estimation of GHG emissions from the development of energy resources on public lands.

The goals set out in the administration's priority agenda are a needed step for the country to begin to rein in runaway emissions. While it is clear that the United States is making progress in reducing GHG emissions and beginning to recognize the importance of natural resources in addressing climate change, total levels of emissions resulting from fossil-fuel production on America's lands and waters remain uncertain at best. Thus, it is critical that the administration act to account for and reduce these emissions. A comprehensive method of mandatory accounting for carbon and methane emissions from proposed resource extraction projects on public lands is necessary to understand the full scope of the problem the nation faces. The administration should finalize the "Revised Draft Guidance for Greenhouse Gas Emissions and Climate Change Impacts" that requires project reviews to recognize the climate footprint of projects on public lands and to fully account for the impacts that occur from developing these resources. Additionally, the administration should take steps to develop and maintain an inventory of the carbon committed to extraction through leases and other means.

A successful emissions-reductions strategy would build on the administration's current initiatives and progress, focusing efforts on accounting for and reducing GHG emissions from all stages of fossil-fuel production on America's lands and waters. There are many opportunities for the Obama administration to take action as part of a comprehensive public lands emissions strategy. While the most important step is to understand the scope of the emissions that can be traced to public lands, there are significant opportunities to build off of these data to ensure that the causes of climate change from public lands are taken into account. These opportunities include: [32]

- Setting royalty rates for fossil fuels to account for the full costs of carbon pollution and externalities in order to ensure taxpayers receive a fair return.

- Curtailing fugitive emissions from oil and gas operations on public lands as part of the BLM's venting and flaring rule, by requiring companies to pay for the right to vent and flare.

- Requiring onshore operators to install vent and flare meters to adequately account for volumes of vented and flared gas to ONRR.

- Requiring oil and gas operators to install best-available technology to reduce the practice of venting and flaring.

- Requiring industry to measure fugitive methane emissions from upstream, midstream, and downstream production activities.

- Implementing President Obama's plan to reduce methane by at least 45 percent by 2025 in part by requiring the aforementioned measures on the part of operators to reduce methane emissions from venting, flaring, and fugitive emissions.

These actions would provide taxpayers a fair return on their resources that are now senselessly wasted and would also reduce emissions of climate-change-inducing-pollutants into the atmosphere.

Actions the Obama administration is currently taking, including implementing the priority agenda, promulgating a venting and flaring rule for natural gas production, and exploring measures to address fugitive emissions are steps in the right direction. Nonetheless, fossil fuels extracted on public lands and waters continue to result in significant amounts of GHG emissions at all stages of production. In order to ensure the success of the administration's Climate Action Plan, it is critical that the administration account for and address these emissions and work to restore balance to America's public lands and waters.

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CONGRESS OF THE UNITED STATES
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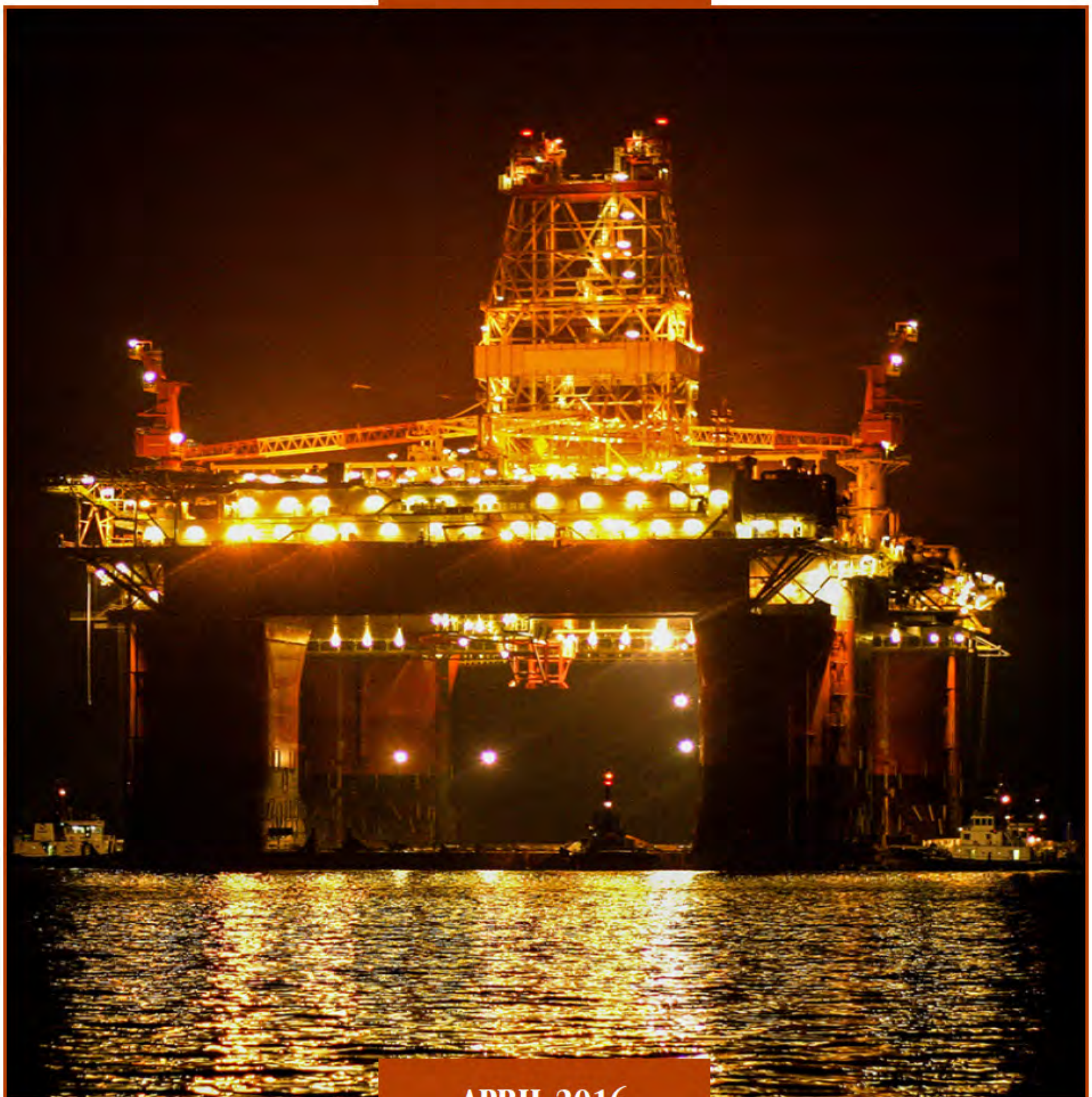
CBO

Options for Increasing Federal Income From Crude Oil and Natural Gas on Federal Lands



APRIL 2016

Notes

Numbers in the text may not add up to totals because of rounding.

Unless otherwise indicated, all years referred to in this report are federal fiscal years, which run from October 1 to September 30 and are designated by the calendar year in which they end.

The photograph on the cover shows the Thunder Horse semisubmersible platform moored in the Gulf of Mexico. The platform is a production and oil drilling facility with crew quarters. The photograph, taken on January 26, 2005, was provided courtesy of BP public affairs staff.

Contents

Summary

The production of oil and natural gas in the United States has increased rapidly over the past decade. As of 2014, domestic production of crude oil had grown to about half of total consumption, and domestic production of natural gas represented almost 95 percent of total consumption. Domestic oil and gas production occurring on federal lands or in federal waters off the coast of the United States represented about one-fifth of total U.S. production in 2014.[1]

Federal lands and waters (referred to collectively as federal lands in this report) are managed by the Department of the Interior (DOI), which allows private firms to compete for the right to produce oil and gas in those areas. The firms that receive those rights make payments to the federal government, which distributes some of the money to states; over the 2005–2014 period, those payments averaged $11 billion per year. (The firms' payments—which are income to the government—are recorded in the federal budget as offsetting receipts, which reduce outlays.) Two types of approaches could be used to increase federal income from oil and gas on federal lands. One approach is to increase the amount of land available for oil and gas production.[2] A second approach, and the one considered in this report, is to revise the rules governing access to the oil and gas resources.

How Does the Government Currently Manage Access to Crude Oil and Natural Gas on Federal Lands?

The Department of the Interior, charged with ensuring that the United States receives a fair return for the oil and gas underlying federal lands, uses a three-stage process (or fiscal regime) to manage private firms' access to those lands.

- *Leasing.* The federal government makes a set of approved parcels available for private leasing and uses an auction to identify the firm willing to pay the most for the right to explore and develop each parcel. The winning firm makes a onetime payment (its bonus bid) in exchange for exclusive access to explore the parcel.
- *Exploration.* Having leased a parcel, the federal government charges an annual rental fee for each year the lease is held without production of oil or gas.
- *Production.* For those parcels that produce oil or gas, the federal government collects royalty payments, which represent a share of the value of the extracted resources.

The maximum length of the exploration period is specified in the lease; once a parcel enters production, the lease continues in effect until production ends, which may be decades later.

Onshore Resources

For development of onshore oil and gas, the Department of the Interior operates under terms set by the Mineral Leasing Act of 1920, as amended, which have remained largely unchanged since 1987. Since that time, the minimum bid in auctions for access to federal lands has been $2 per acre, the rental fee has been $1.50 per acre for the first five years of the 10-year lease term and $2 per acre for the second five years, and the royalty rate has been 12.5 percent of production value.

Between 2003 and 2012, the federal government leased about 25,000 parcels (averaging 1,000 acres in size), about half of which were leased for less than $10 per acre,

1. Federal waters begin 3 marine leagues (about 9 nautical miles) from the low-water line in Texas and parts of Florida, and 3 nautical miles from the low-water line elsewhere.

2. For a discussion, see Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

including about 4,000 parcels that received no bids and were leased noncompetitively for no fee. Most leased parcels have no exploratory drilling or production during the lease term. For parcels leased between 1996 and 2003, all of which have reached the end of their 10-year exploration period, only about 10 percent of onshore leases issued competitively and 3 percent of those issued noncompetitively entered production.

Offshore Resources

For development of offshore oil and gas resources, the Outer Continental Shelf Lands Act gives the Department of the Interior significant flexibility to adjust the leasing terms. DOI currently sets terms for each lease that are designed to encourage exploration and production. In the leasing stage, the department establishes a minimum bid based on the relative cost of exploration and development; if the highest bid is found to be below estimates of a fair (market-based) return to taxpayers, it is rejected. In the exploration stage, the rental fee is higher for parcels in deep water, reducing slightly a leaseholder's incentive to wait to see whether additional information becomes available before undertaking costly exploratory drilling. (The effect is slight because the fee is very small relative to drilling costs.) For the production stage, DOI has set a royalty rate of 12.5 percent for offshore parcels near Alaska and recently increased the royalty rate to 18.75 percent for newly leased parcels in the Gulf of Mexico; the difference reflects the higher cost of development off the coast of Alaska.

How Much Income Has the Government Collected From Oil and Gas Leasing?

All told, the gross income (before payments to states) from onshore oil and gas resources averaged $3.0 billion annually from 2005 to 2014, comprising the following amounts:

- About $230 million per year in bonus bids,
- $50 million per year in fees for nonproducing leases, and
- $2.7 billion per year in royalties from production.

Total gross income from offshore oil and gas resources averaged $8.0 billion per year over the 2005–2014 period:

- Lease auctions generated about $1.8 billion,
- Rental fees generated about $230 million, and
- Royalties from production yielded about $6.0 billion.

Production from parcels and associated royalty payments can continue for many years, and thus leases issued in any given year represent only a small share of annual royalty income. In 2013, about 6 percent of royalty income from onshore oil and gas came from parcels that were leased in the previous 10 years; in contrast, about half came from parcels that were leased more than 50 years earlier. For offshore resources, about 8 percent of royalty income in 2013 came from parcels that were leased in the previous 10 years, and the majority came from parcels that were leased more than 20 years earlier.

Some of the income collected by the federal government in the three-stage process is shared with the governments of the states where (or nearest to where) the oil and gas were extracted. The states' shares of the income averaged almost 40 percent between 2005 and 2014.

How Could Lawmakers Change the Process to Increase Federal Income?

The Congressional Budget Office analyzed eight ways in which lawmakers could change the fiscal terms for oil and gas development on federal lands so as to increase federal income (see Summary Table 1). Some of the options would change qualitative features of the leasing process, such as auction formats and rules, whereas others would affect quantitative features, such as minimum bids or royalty rates. The specific versions of the quantitative options analyzed here for illustrative purposes are relatively modest, so as not to put federal lands at a competitive disadvantage relative to state-owned or privately owned lands. Smaller or larger versions of those options would yield smaller or larger increases in federal income. (Decreases in production that could result from larger changes would affect more than federal income and raise issues outside the scope of this report, such as possible environmental benefits or concerns about national security.)[3]

3. Such concerns are addressed in Congressional Budget Office, *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012.

Summary Table 1.

Policy Options for Oil and Natural Gas Production on Federal Lands

Millions of Dollars

Option		Increase in Federal Income Over 10 Years
	Onshore Parcels	
1	Require onshore parcels to be auctioned through a sealed-bid process	100
2	Allow BLM to establish lease-specific fiscal terms	a
3	Increase the minimum bid for auctions and noncompetitive leases	50
4	Impose a fee of $6 per acre on nonproducing parcels	200
5	Increase the royalty rate to 18.75 percent for all new onshore parcels	200
	Offshore Parcels	
6	Require parcels to be nominated for auction	150
7	Impose a fee of $6 per acre on nonproducing parcels	500
8	Increase the royalty rate when the price of oil or gas rises above a threshold	Less Than 25

Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

All estimates represent net federal receipts after distributing appropriate shares of gross proceeds to the states.

BLM = Bureau of Land Management.

a. The effect on receipts would depend on details of the authorizing legislation and its implementation.

For onshore resources, CBO considered the following approaches:

- Lawmakers could direct DOI to adopt an alternative form of auction that would encourage more intense competition between firms; greater competition would probably generate a small increase in the winning bids.
- The prohibition against setting lease-specific fiscal terms could be lifted, allowing DOI to set terms that were more advantageous for the government when there was greater certainty that parcels contained oil or gas reserves.
- Policymakers could instruct DOI to raise the minimum bid, the fee on nonproducing leases, or the royalty rate for all leases.

The options considered here would generate increases of between $50 million and $200 million in net income (after payments to states) over 10 years, CBO estimates. Reductions in production would be small or even negligible over that period or later.

For offshore resources, there are fewer policy options that DOI is not already considering.[4] One such option, designed to increase competition, would require firms to nominate parcels before they can be scheduled for auction, as is the case for onshore parcels. Other policies would impose a new fee on nonproducing leases or adopt a royalty rate that increased if the price of oil or gas rose. Those policies, at commonly discussed magnitudes, would boost net income by amounts ranging from less than $25 million over 10 years to $500 million over that period, CBO estimates. Effects on production would be negligible.

One important factor affecting CBO's estimates of budgetary effects over 10 years is the long lag time between leasing a parcel and beginning production from that parcel. The effects on net income of some options—for example, those that would change royalty rates—could be significantly larger outside of the 10-year period generally used for budget estimates, depending on future prices and other market conditions. But attempts to estimate budgetary effects beyond 10 years are hindered by greater uncertainty about those future conditions.

4. CBO's baseline budget projections account for actions that an agency is likely to take under current law; therefore, CBO's estimates of the budgetary effects of legislation that would merely accelerate such actions or make them more certain to occur may be substantially smaller than if the actions were not under consideration.

CHAPTER

1

The Current Process for Managing Access to Crude Oil and Natural Gas on Federal Lands

Since 2008, the production of oil and natural gas in the United States has increased rapidly (see Figure 1-1). Crude oil production in the United States rose from an average of 5.0 million barrels per day in 2008 to 8.3 million barrels per day in 2014. With that increase, domestic production rose from about 25 percent to about 45 percent of the oil consumed by U.S. households and businesses, and imports of oil fell by 3.6 million barrels per day (or about 30 percent). The production of natural gas rose by a similar amount, climbing from 9.9 million barrels of oil equivalent (BOE) per day in 2008 to 12.4 million BOE per day in 2014, which was almost 95 percent of domestic consumption. The Energy Information Administration (EIA) projects that the United States will become a net exporter of natural gas by 2017.

That growth in production reflected technological developments that allowed the development of shale resources, which are found mainly outside of federal lands.[1] Consequently, the shares of oil and gas production coming from federal lands declined over the past decade, falling below 20 percent for oil and gas production combined in 2014. Specifically, production on federal lands in 2014 accounted for about 2.1 million of the total 8.3 million barrels of oil per day, and about 1.8 million of the total 12.4 million BOE of gas. The rest came from oil or gas underlying lands owned by state governments, private landowners, and Native American tribes (see Figure 1-2). (Offshore resources near the shoreline are owned by state governments; resources in other waters controlled by the United States are owned by the federal government.)[2]

Federally owned resources are managed on behalf of U.S. taxpayers according to a set of rules established in law and, when the law is not specific, by rules adopted by the Department of the Interior. Within that department, the Bureau of Land Management (BLM) manages onshore resources, and the Bureau of Ocean Energy Management (BOEM) manages offshore resources.[3] Those agencies are directed to generate a fair return to taxpayers (one that approximates a market-based return) in exchange for providing private firms with access to those resources.[4] Agencies' gross collections deriving from leasing, exploration, and production averaged $11 billion per year from 2005 to 2014—consisting of $3 billion from onshore resources and $8 billion from offshore resources.

The Three Stages of the Process

The process, sometimes called the fiscal regime, used by the two agencies to govern access to oil and natural gas resources on federal lands has three stages (see Figure 1-3 on page 8):

1. See Department of the Interior, *Economic Report FY 2012*, Chapter 4 (July 2013); and Congressional Budget Office, *The Economic and Budgetary Effects of Producing Oil and Natural Gas From Shale* (December 2014), www.cbo.gov/publication/49815.

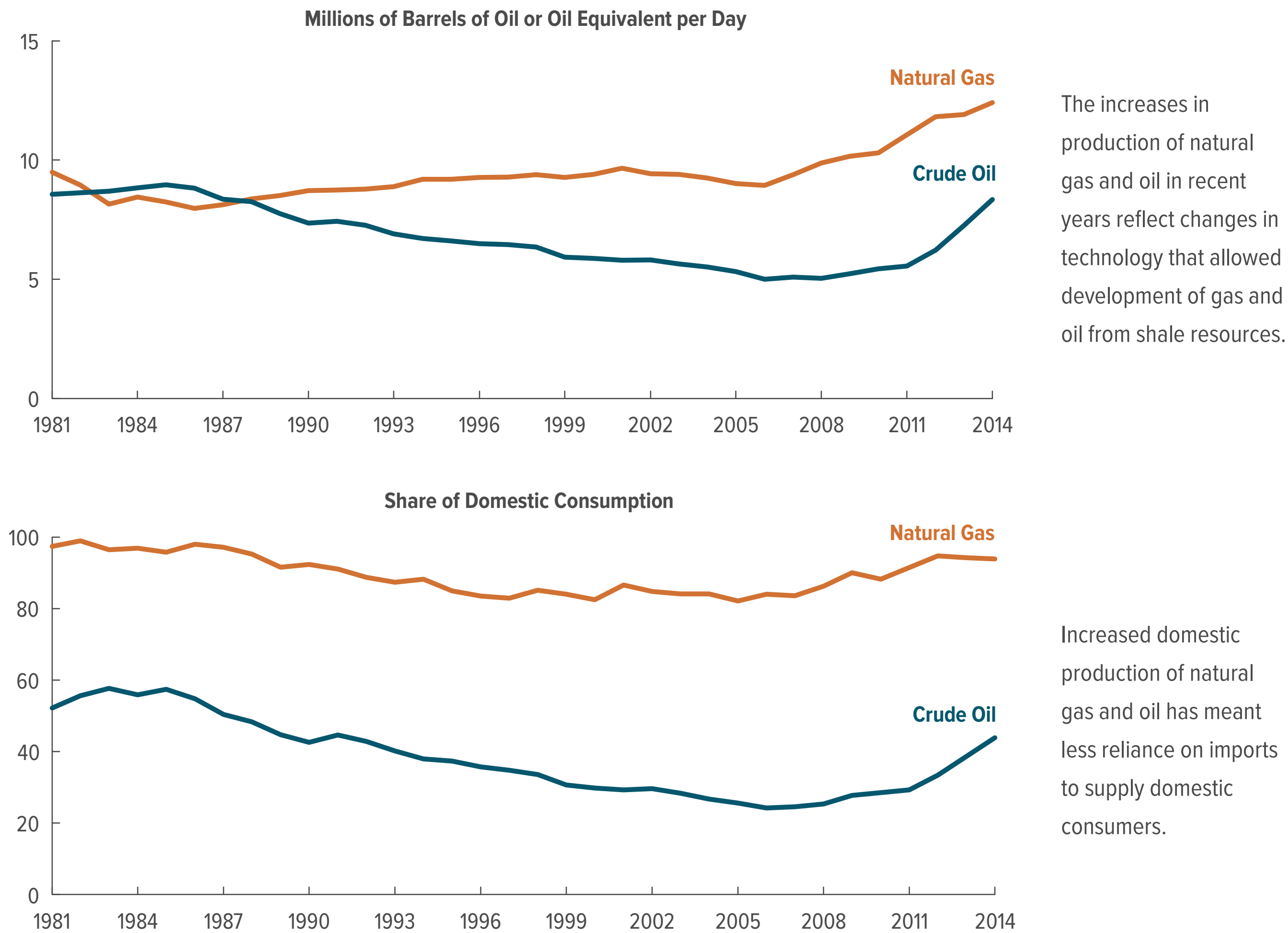
2. State ownership of offshore resources extends to 3 nautical miles from the low-water line except in Texas and parts of Florida, where it extends to 3 marine leagues, or about 9 nautical miles, from the low-water line. Federal waters include the rest of the Outer Continental Shelf, which "would appear to comprise an area extending at least 200 nautical miles from the official U.S. coastline and possibly farther where the geological continental shelf extends beyond that point." See Adam Vann, *Offshore Oil and Gas Development: Legal Framework*, Report for Congress RL33404 (Congressional Research Service, December 30, 2015), p. 2.

3. BLM manages 700 million acres of mineral resources but only about 250 million acres of surface access. The difference represents 400 million surface acres managed by other federal agencies and about 60 million acres owned by state or private landowners.

4. For federal waters, the Outer Continental Shelf Lands Act stipulates, "The Secretary [of the Interior] shall establish royalties, fees, rentals, bonuses, or other payments to ensure a fair return to the United States for any lease, easement, or right-of-way granted [for energy and related purposes]" (43 U.S.C. §1337). For onshore lands, the Federal Land Policy and Management Act of 1976 specifies that "the United States receive fair market value of the use of the public lands and their resources" (43 U.S.C. §1701).

Figure 1-1.

Production of Oil and Natural Gas in the United States



Source: Congressional Budget Office, using data from the Energy Information Administration (EIA).

Production of natural gas before 1997 and consumption of natural gas before 2001 are CBO's estimates, using weighted averages of EIA data for calendar years.

Oil production includes natural gas liquids; gas production excludes those liquids, as well as gas that is flared, reinjected, or lost when extracted.

- *Leasing.* Several times each year, the federal government makes land available to private firms, which compete for the right to explore and develop specific parcels for oil and gas extraction. The firm willing to pay the most for that right (in the form of having the highest bid in an auction) pays its bid, commonly called the bonus bid, and is granted an exclusive lease for a set period of time.

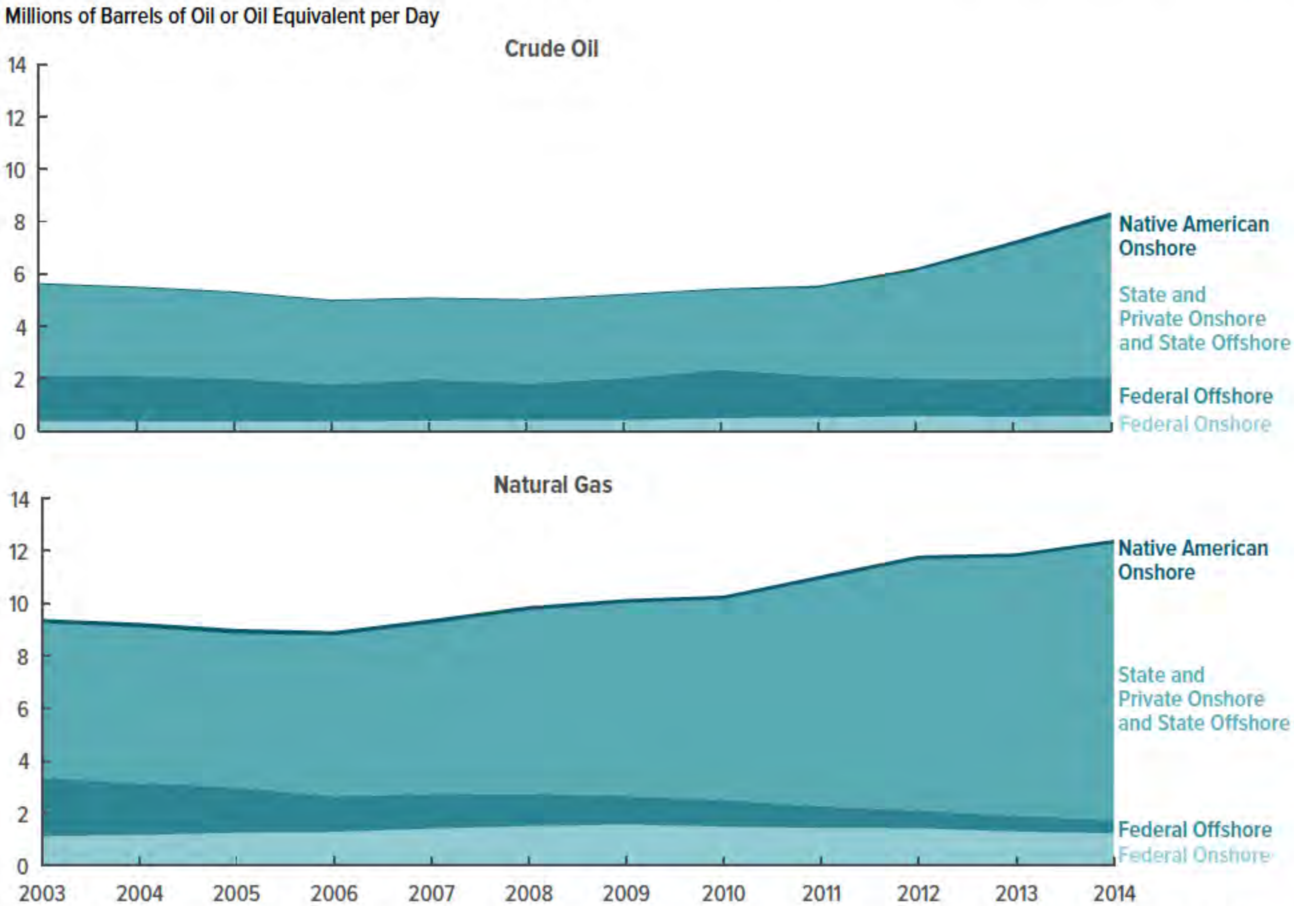
- *Exploration.* The firms that win leases have a set period of time, typically 5 to 10 years, to decide whether to drill one or more exploratory wells on their parcels. For the period of time between the award of the lease and the date on which the parcel begins to produce oil or gas, the leaseholder pays the federal government an annual rental fee. If no production occurs, the leaseholder pays the rental fee until the lease expires or until the leaseholder voluntarily returns the lease to the federal government.

- *Production.* If firms find oil and gas on their leased parcels, they can extract and sell those resources. The leaseholder pays the federal government a share of the income generated from the sales, called a royalty payment. (Royalties are paid on the value of production after taking allowable deductions, such as the cost

Figure 1-2.

Production of Oil and Natural Gas on Federal, State and Private, and Native American Lands

Production of oil and natural gas from federal lands has not increased as it has elsewhere because shale resources are found primarily on lands owned by state governments and private landowners.



Source: Congressional Budget Office, using data from the Energy Information Administration and the Department of the Interior's Office of Natural Resources and Revenue.

Oil production includes natural gas liquids.

State and private production are combined because there is no database of production for only state land or only private land.

of transporting oil and gas to the market.) After production begins, rental payments are no longer made, but firms are required to make at least a minimum royalty payment that is equal to the rental fee. The lease remains in effect indefinitely while production continues; when the leaseholder chooses to end production, it cleans up the site and the lease ends.[5]

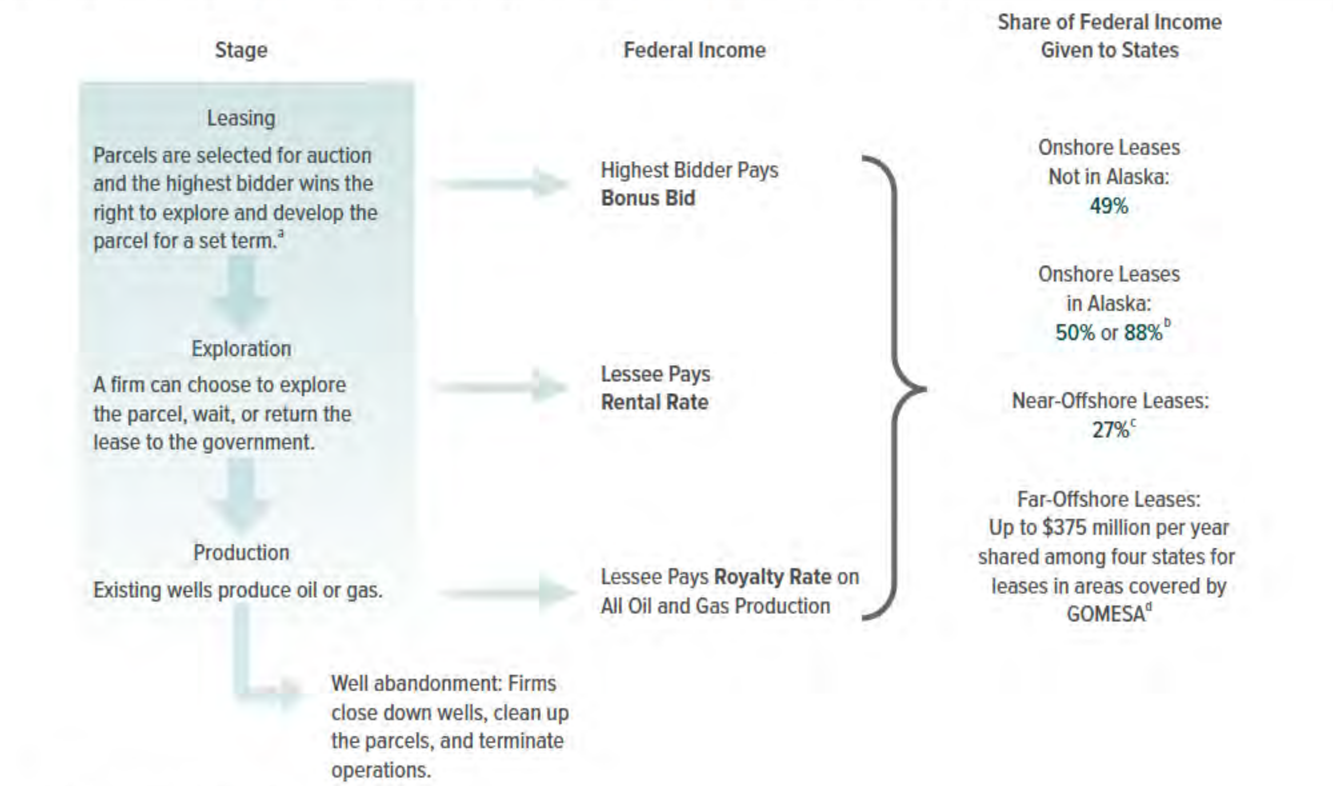
The three stages can be analyzed not only for their contributions to the goal of generating a fair return to taxpayers, but also in terms of the economic incentives they provide and their effects on economic efficiency (see Box 1-1 on page 10).

Despite the similarities in the general structure of the three stages used by BLM and BOEM to manage onshore and offshore oil and gas resources, their processes differ in two important ways.

5. The Department of the Interior has been criticized for problems associated with the reporting and collection of royalty payments for both onshore and offshore federal lands. See the testimony of Frank Rusco, Director, Natural Resources and Environment, Government Accountability Office, before the Subcommittee on Energy Policy, Health Care, and Entitlements of the House Committee on Oversight and Government Reform, *Oil and Gas Management: Continued Attention to Interior's Revenue Collection and Human Capital Challenges Is Needed*, GAO-13-647T (May 2013), www.gao.gov/products/GAO-13-647T.

Figure 1-3.

Process for Managing Access to Federally Owned Oil and Natural Gas Resources



Source: Congressional Budget Office.

a. Onshore parcels are included in an auction if they are nominated by a firm and approved for leasing by the Bureau of Land Management. Offshore parcels are included in an auction if they are part of an area specified for auctioning by the Bureau of Ocean Energy Management.

b. The 50 percent and 88 percent shares apply to leases within and outside of the National Petroleum Reserve in Alaska, respectively (42 U.S.C. 6508).

c. Near-offshore leases are on parcels less than 3 nautical miles seaward of the boundary between state and federal waters. (A nautical mile is 6,080 feet.) That boundary is 3 nautical miles from the low-water line for all states except Texas and the west coast of Florida, where it is 3 marine leagues, or about 9 nautical miles, from the low-water line. Leases within state waters are granted by the respective states.

d. Far-offshore leases are on parcels more than 3 nautical miles from state waters. Under the Gulf of Mexico Energy Security Act (GOMESA), proceeds from certain leases in the Gulf will be shared with Alabama, Louisiana, Mississippi, and Texas, and with the federal Land and Water Conservation Fund (LWCF), starting in 2018. Through 2055, payments from those leases will be subject to caps of $375 million in total for the four states and $125 million for the LWCF; afterward, the caps will be lifted and the four states and the LWCF will receive 37.5 percent and 12.5 percent of the proceeds, respectively. Those percentages are already used to share income received from two other small areas in the Gulf, but the amount of income has not been significant.

First, BLM's governing statute gives it significantly less flexibility to change certain terms associated with the process—such as the duration of leases—than BOEM is afforded by its governing statutes. In addition, BLM has written rules that require it to undertake more rulemaking to change any fiscal terms, whereas BOEM has adopted rules that allow it to adjust various terms by issuing a notice, which is a much simpler process (see Table 1-1 on page 12 and Table 1-2 on page 13). Consequently, BOEM has made many changes to the fiscal terms governing offshore development over the past decade, but those governing onshore development have remained largely unchanged since 1987.

Second, offshore wells, particularly those in deep or ultradeep water (more than 400 or 1,600 meters below sea level, respectively), are much more expensive to drill than onshore wells; that cost differential limits the number and types of firms that can develop offshore parcels. For example, drilling a typical onshore well in Texas and making it ready for production could cost between $3 million and $10 million and be accomplished in a few weeks, but drilling a well in deep water in the Gulf of Mexico could cost $300 million and take many months to complete.[6] In acknowledgment of those higher costs for offshore wells and the resulting limited competition, BOEM attempts to increase competition by allowing smaller firms to submit joint bids for parcels during the leasing stage of the process.[7]

For those reasons, the onshore and offshore processes are discussed separately below.

Effects on Federal and State Budgets

Between 2005 and 2014, gross governmental income from oil and natural gas leases on federal lands—-including bonus bids paid in auctions, rental fees collected during the exploration stage, and royalties paid during the production stage—was $110 billion.[8] Offshore leases generated most of that income; for both onshore and offshore leases, royalty payments were the largest source of income (see Figure 1-4 on page 14). Of the $110 billion, the federal government retained $70 billion, or about 63 percent, and distributed the rest to the states in which the resources were extracted (for onshore leases) or near where they were extracted (for offshore leases). The percentages shared with the states depend on where the extraction occurs:

- *Onshore.* For most onshore parcels, 49 percent of total income (from bonus bids, rents, and royalties) is given to the state in which the resource was extracted. The exception is federal lands in Alaska, where the state's share of receipts is 88 percent for leases outside the National Petroleum Reserve of Alaska (NPR-A) and 50 percent for leases within the NPR-A.[9]
- *Near Offshore.* Federal jurisdiction over offshore parcels starts at the seaward boundary, which is 3 nautical miles from the low-water line for all states except Texas and parts of Florida, where it begins 3 marine leagues, or about 9 nautical miles, from that line.[10] (Leasing of offshore parcels between the low-water line and the seaward boundary is done by the states, which keep 100 percent of the resulting income.) For near-offshore parcels—those no more than 3 nautical miles beyond the seaward boundary—27 percent of all collected income is given to the nearest state.[11]
- *Far Offshore.* Starting in 2018, proceeds from certain leases in the Gulf of Mexico will be shared with Alabama, Louisiana, Mississippi, and Texas, and indirectly with all the states through a mandatory appropriation to the state grants program of the federal Land and Water Conservation Fund (LWCF).[12] Through 2055, payments from the proceeds of those leases will be limited to no more than $375 million in total for the four states and $125 million for the LWCF; afterward, the four states and the LWCF will receive 37.5 percent and 12.5 percent of the proceeds, respectively.[13] Those percentages are already used to share income received from leases in two other small areas in the Gulf, but the amounts have not been significant. Receipts from leases in other far offshore waters are not shared with states.

6. For more on onshore drilling costs, see Trey Cowan, "Costs for Drilling the Eagle Ford," *RigZone* (June 20, 2011); and for offshore drilling costs, see Jennifer Dlouhy, "Gulf's Bounty Commands Attention Amid Shale Drilling Boom," *FuelFix* (May 4, 2014).
7. BOEM publishes a list of bidders that are restricted from entering into joint bidding arrangements, unless bidding is with an affiliate or subsidiary from the same group of restricted bidders. In 2014, the bidders excluded from entering into joint bids were BP, Chevron, Eni, Exxon, Nexen, Petrobras, Shell, Statoil, and Total; see Notice of Outer Continental Shelf Oil and Gas Lease Sales, 78 Fed. Reg. 64243 (October 28, 2013).
8. Those payments from private firms are classified in the federal budget as "offsetting receipts," that is, as a reduction in net outlays; they are not "revenues," like income taxes, because they result from voluntary transactions, rather than from the government's exercise of sovereign authority.
9. 30 U.S.C. §191 and 42 U.S.C. §6506a(l), respectively.
10. Low-water lines in the United States, also called baselines, are defined as "the mean of the lower low tides as depicted on the largest scale NOAA nautical charts." See National Oceanic and Atmospheric Administration, Office of General Counsel, "Maritime Zones and Boundaries" (accessed March 10, 2016), www.gc.noaa.gov/gcil_maritime.html#base.
11. 43 U.S.C. §1337(g)(2).
12. The fund was established by the Land and Water Conservation Act of 1965 to help preserve, develop, and ensure access to outdoor recreation resources. Monies appropriated to the LWCF are used for land acquisition by various federal agencies and for grants to the states. See Carol Hardy Vincent, *Land and Water Conservation Fund: Overview, Funding History, and Issues*, Report for Congress RL33531 (Congressional Research Service, June 17, 2015).
13. See Bureau of Ocean Energy Management, "Gulf of Mexico Energy Security Act (GOMESA)," www.boem.gov/revenue-sharing/.

Box 1-1.

The Effects of the Federal Leasing System on Incentives and Economic Efficiency

Most oil and natural gas development in the United States occurs under contractual agreements between those who own the rights to mineral resources and companies that have the expertise and financial capability to develop those resources. Typically, rights holders are interested in the financial benefit they get from the agreements and in maintaining the value of their land. The federal government has additional interests—including environmental protection, national security, and maximizing economic efficiency, which is a benefit to the economy as a whole. That benefit reflects many factors, including the effects of oil and gas activity on other uses of federal lands, the value of resources left in the ground for production in the future, and the interactions of the leasing system with provisions of the tax code affecting the oil and gas industry. This box considers the narrower question of how the incentives provided by the leasing system affect the economic efficiency of current oil and gas production.

Incentives Provided by the Leasing System

Each of the decisions made by firms that produce oil and gas—where to try to acquire rights, where and when to drill exploratory wells, whether to begin production once oil or gas has been found, and when to stop production at a producing well—is shaped primarily by physical and technical factors and market forces, including the estimated probability of finding oil or gas at a given location, the expected amount of oil or gas available if found, expected or observed extraction costs, current and expected future prices for oil and gas, and firms' costs of capital. But the incentives provided by the leasing system—including the auction rules, rental fees, and royalty rates—can influence those decisions to some degree, particularly to the extent that they make federal lands more or less attractive for leasing than nonfederal lands.

Bidding on Parcels. At the auction stage, firms must decide which available parcels they are interested in and how much to bid for them. To do so, they consider the auction's structure and rules, which affect the amounts firms expect to have to bid, the possibility that winning bids may not be recouped if no oil or gas resources are found during the lease term, the potential profits (influenced to a degree by the lease terms, as discussed below) if resources are found, and the alternatives available for leasing nonfederal lands.[1]

Retaining Parcels and Drilling Exploratory Wells. During the lease term, a firm's decision about whether to drill an exploratory well, return the lease, or wait and revisit those two choices later depends on the physical and economic factors noted above, and also on the configuration of other leases held by that firm. The more parcels the firm has leased that are near one another, the greater the potential value of the information that an exploratory well on one parcel could provide about the prospects for the others.

In addition, three aspects of the leasing system have some bearing on firms' decisions at this stage, though the effects may be small:

- A higher rental fee increases the cost of holding a lease, giving leaseholders an incentive to either explore parcels or return them to the government. In practice, the current incentive is weak because the fees are small relative to the cost of developing a lease. For example, rental fees of $11 to $16 per acre on a deepwater offshore lease cost less than $1 million over a 10-year period, whereas drilling a well costs hundreds of millions of dollars.
- A longer lease gives firms more time to wait for prices to rise or additional information to arrive, at the cost of making more rental payments.

As with other types of operating costs, the higher the royalty rate, the lower the value to firms of any oil or gas that is found, and hence the lesser the incentive to drill exploratory wells or hold on to parcels for possible exploration later.

1. Some changes in lease terms may have little or no effect on bidding decisions: The Department of the Interior found that demand for leases in the Gulf of Mexico remained strong after the royalty rate was increased from 16.67 percent to 18.75 percent in 2008. See Government Accountability Office, *Oil and Gas Resources: Actions Needed for Interior to Better Ensure a Fair Return*, GAO-14-50 (December 2013), p. 14, www.gao.gov/products/GAO-14-50.

Continued

Box 1-1. Continued

The Effects of the Federal Leasing System on Incentives and Economic Efficiency

Beginning Production. Once exploration has indicated the presence of oil or gas, the decision to begin production is typically not sensitive to lease terms except for parcels that appear only marginally valuable—that is, those for which the firm's anticipated rate of return is close to the minimum level it considers acceptable.

Shutting Down a Producing Well. In addition to the dominant physical and economic factors listed above, the royalties charged during production may influence the decision to end production at a well: The higher the royalty rate, the sooner a well with declining production becomes unprofitable, taking into account the cost of closing it. However, producers may apply for an end-of-life reduction in the applicable royalty rate.[2] The incentive effect of a given royalty rate is greater when oil and gas prices are lower, because then the rate represents a larger percentage of profits.[3]

Economic Efficiency

The incentives provided by the leasing system have implications for the extent to which capital and labor are used efficiently—so as to yield the greatest surplus of benefits over costs—in current oil and gas exploration and production. The main implications are as follows:

- Awarding leases to winning auction bidders tends to promote efficiency in current operations because the high bid for a given parcel may reflect better information about the availability of oil or gas, lower-cost production methods, or more leases on nearby parcels.
- The limited time allowed for exploration and the rental fees charged before production begins can promote efficiency by discouraging firms from "warehousing" parcels simply to prevent competitors from exploring them. In principle, if the period is too short or the fees are too high, firms may be discouraged from bidding on some parcels, thus delaying the potential benefits of getting additional information about nearby parcels. But rental fees would have to be far greater than they are now to have such an effect.
- The leasing system does not provide explicit incentives for firms to drill exploratory wells on parcels that could provide information about parcels that are not yet leased or are leased by someone else. Firms may do less exploration on such parcels than would be economically efficient, because they would take little or no account of the potential benefit of information about those nearby parcels.
- Although federal royalty rates may lead firms to shut down wells earlier than they would in the absence of royalties, they may promote efficient decisions about where exploration and production should occur, because state, tribal, and private landowners also typically require compensation for activities on their properties.[4]

Whether the fact that most parcels go unexplored during the term of their leases represents inefficient warehousing is difficult to determine. In some cases, firms that would have made more productive use of given parcels during the lease term may have been outbid by other firms that sought the leases primarily for strategic reasons—that is, to keep the parcels away from competitors. In other cases, leaving a leased parcel unexplored is efficient, because evidence from nearby parcels has suggested that drilling would be unproductive or because drilling would be premature until more information is obtained.

2. See Production Incentives, 43 C.F.R. §3103.4 (2009) for onshore wells and Relief or Reduction in Royalty Rates, 30 C.F.R. §203 (2012) for offshore wells.

3. Conversely, when oil and gas prices are higher, a given royalty rate gives the government a smaller share of profits. Royalty payments as a share of profits would be even more sensitive to those prices if royalty rates were specified in terms of dollars per unit of production. In principle, leases could specify payments as a percentage of profits, but those would be harder for the government to verify.

4. Efficient royalty rates on federal lands reflect many factors and need not equal those charged by other landowners.

Table 1-1.

Statutory and Administrative Governance of Onshore Oil and Natural Gas Leasing

	Statutory Requirements	Regulatory Terms	Subject to Administrative Change?
Leasing			
Auction type	Open outcry[a]	Open outcry[a]	No
Minimum bid per acre	$2 until 1989; may be increased afterward	$2	Yes, by rulemaking
Noncompetitive leases	Payment of a nonrefundable application fee	Fee increased annually ($390 in fiscal year 2013)	No
Lease term	10 years	10 years	No
Exploration			
Annual rental fee per acre	At least $1.50 for the first 5 years and at least $2 thereafter	$1.50 for the first 5 years and $2 thereafter	Yes, by rulemaking
Production			
Royalty rate	Not less than 12.5 percent	12.5 percent	Yes, by rulemaking
Royalty relief	No mechanism specified	n.a.	No

Source: Congressional Budget Office.

Onshore oil and gas legislation is codified at 30 U.S.C. §226, and the corresponding regulations are at 43 C.F.R. Parts 3100–3120.

n.a. = not applicable.

a. The auctions are open outcry because bidders show their interest publicly, specifically by raising their hands or numbered paddles.

The oil and gas income distributed to states can be significant in some state budgets. For example, in 2013 that income accounted for about 5 percent of Wyoming's budget and 3 percent of New Mexico's budget.[14]

Various analysts have compared the combined federal and state share of the value of oil and natural gas resources on federal lands with the shares captured by various state governments for resources on their lands and with the shares captured by the governments of other countries.[15] The three-stage process used in the United States resembles the systems used by countries such as Canada, England, and Norway but differs from those used by countries that operate state-owned national oil companies, such as Saudi Arabia, China, and Russia. In general, analysts find that the combined governmental share—including taxes received from resource producers—of the value of oil and natural gas from federal lands ranks in the lower half of the list of large oil-producing countries and U.S. states for onshore resources and for offshore leases overall (see Box 1-2 on page 16).

Onshore Oil and Gas Leases

The process through which onshore oil and gas resources are developed follows the three stages of leasing, exploration, and production. The fiscal terms for each stage are determined by legislation or by subsequent rulemaking (see Table 1-1).[16] Between 2005 and 2014, the federal government collected, on average, more than $230 million per year at the leasing stage (in the form of bonus bids for auctioned parcels), about $50 million per year

14. According to CBO's calculations, using 2013 data on disbursements to states for all mineral resources from http://statistics.onrr.gov/reporttool.aspx, on shares of federal mineral receipts from oil and gas, by state, from http://useiti.doi.gov, and on states' spending (for state fiscal years starting July 1, 2012) from http://ballotpedia.org/state_budget_and_finance_pages.

15. Government Accountability Office, *Oil and Gas Resources: Actions Needed for Interior to Better Ensure a Fair Return*, GAO-14-50 (December 2013), www.gao.gov/products/GAO-14-50; and Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), http://go.usa.gov/cwznH.

16. The legislation is codified at 30 U.S.C. §226, and the corresponding regulations are at 43 C.F.R. Parts 3100–3120.

Table 1-2.

Statutory and Administrative Governance of Offshore Oil and Natural Gas Leasing

		Administrative Terms		Subject to
	Statutory Requirements	For the Gulf of Mexico[a]	For Waters Near Alaska[b]	Administrative Change?
Leasing				
Auction type	Sealed bid; specifies nine variations with selected variant submitted to the Congress[c]	Sealed bid; bid on bonus	Sealed bid; bid on bonus	Yes, by a new plan submitted to the Congress that is subject to a resolution of disapproval
Minimum bid per acre	Not specified	Depth less than 400 meters, $25; Depth more than 400 meters, $100	$10 ($15 for some leases closer to existing infrastructure)	Yes, in notice of lease sale
Noncompetitive leases	All leases issued competitively	n.a.	n.a.	No
Lease term	5 to 10 years	5, 7, or 10 years, depending on water depth; extensions of 3 years may be earned on 5- and 7-year leases	10 years	Yes (within statutory limits), in notice of lease sale
Exploration				
Annual rental fee per acre	Not specified	For the first 5 years, $7 for parcels less than 200 meters deep and $11 for others; fees higher after 5 years[d]	$5.26	Yes, in notice of lease sale
Production				
Royalty rate	Not less than 12.5 percent	18.75 percent	12.5 percent	Yes, in notice of lease sale
Royalty relief	Various royalty relief programs are required or allowed	None (other than lease terms to implement legislative requirements)	None (other than lease terms to implement legislative requirements)	Yes (within statutory limits), in notice of lease sale

Source: Congressional Budget Office.

Offshore oil and gas legislation is codified at 43 U.S.C. §1337, and the corresponding regulations are at 30 C.F.R. Parts 560 and 556.

n.a. = not applicable.

a. Terms for leases auctioned in August 2014; see Western Gulf of Mexico (WPA) Outer Continental Shelf (OCS) Oil and Gas; Lease Sale 238, 79 Fed. Reg. 42041 (July 18, 2014).

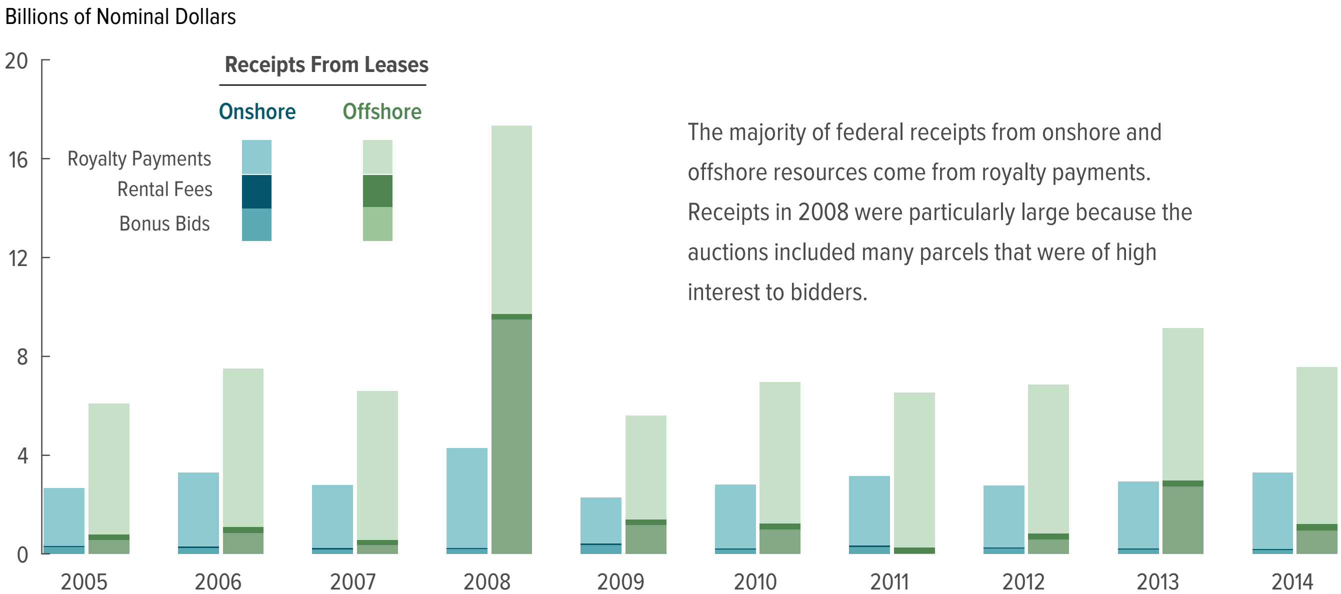
b. Terms are based on the two most recent auctions: Beaufort Sea Sale 202 on April 18, 2007, and Chukchi Sea Sale 193 on February 6, 2008. The minimum bid and rental rate were quoted in dollars per hectare, which CBO converted to acres.

c. The Outer Continental Shelf Lands Act stipulates that the Secretary of Energy can consider nine different types of auction designs. They all involve a sealed bid but can have bidders competing on the bonus bid, royalty rate, and net profit sharing, among other options. The bidding system selected must be submitted by the Secretary to the Congress. If the Congress does not pass a resolution of disapproval within 30 days, the bidding system can be implemented.

d. Holders of leases in water less than 400 meters deep pay higher rates each year of a three-year extension; rates in the final year reach $28 per acre for parcels less than 200 meters deep and $44 per acre for parcels between 200 and 400 meters deep. Holders of leases in deeper water see a single increase to $16 per acre starting in year six.

Figure 1-4.

Gross Federal Receipts From Onshore and Offshore Oil and Natural Gas Resources



Source: Congressional Budget Office, using data from the Department of the Interior's Office of Natural Resources and Revenue.

at the exploration stage (in rental fees), and about $2.7 billion per year at the production stage (in royalty payments).

Leasing

Before a parcel can be leased in an auction, it must be nominated by a private firm. The nominated parcel can range in size from a few acres up to 2,560 acres in the continental United States or 5,760 acres in Alaska. BLM then conducts an environmental assessment of the parcel to determine what conditions, if any, need to be added to the lease before development can begin. For example, a condition might be added to the lease that any oil or gas development include a plan for avoiding or mitigating damage to endangered species present on the parcel. Once the parcel with its accompanying conditions is approved for leasing, it is offered at one of the BLM auctions held in each state quarterly. (Some states hold auctions for parcels on their own lands more frequently.) The list of parcels approved for auctioning is typically made available to the public at least 90 days before the auction. Leases allow up to 10 years for exploration.

Auctions for onshore parcels are conducted using an open-outcry ascending auction format, which is similar to that commonly used in estate sales or livestock auctions. In that type of auction, an auctioneer offers the parcel at a low starting price, called the minimum bid. The minimum bid for onshore parcels is currently $2 per acre. After a bidder indicates his or her interest in the parcel to the auctioneer at that price, the auctioneer raises the price by small increments until no bidder expresses interest at a higher price. (The auction is described as open-outcry because bidders express their interest publicly by raising their hand or raising a paddle with their bidder number.) The bidder who was last to indicate interest in the parcel pays the amount of his or her highest bid, which is commonly called the bonus bid. If no bidder expresses interest in the parcel at the minimum bid, BLM makes the parcel available the next day on a noncompetitive "first-come, first-served" basis. Such parcels remain available for leasing for two years, and no bonus bid is paid for them.

The amount that any particular bidder is willing to pay for a parcel depends primarily on expectations about the future market price of oil or gas, and expectations about the volume of oil or gas underlying the parcel and the difficulty and cost of extracting it; it also depends to some extent on the terms of the lease. Because all potential bidders know the lease terms stipulated by BLM, those terms can influence the amount that bidders in general are willing to pay to lease a parcel but do not explain why some bidders value a parcel more highly than others do.

Also, bidders tend to have similar expectations about future market prices over the lifetime of a potential new well, based on the same publicly available long-run projections.

In contrast, potential bidders may come to an auction with very different estimates of a parcel's value based on their expectations about the amount of oil or gas underlying it or about extraction costs. Those expectations, which are the main sources of differences in bids, reflect private information from a firm's own experience with nearby parcels as well as three other sources of public and private information:

- The United States Geological Survey (USGS) provides some information, typically on a broad scale, that sheds light on general resource availability but not on the specific potential of any particular parcel.[17]

- Many states' oil and gas commissions collect information about all the wells drilled in their state and the production data from those wells; the states tend to make that information available to the general public. For example, the North Dakota Oil and Gas Division provides well data and production volumes, among other information, to subscribers for an annual fee of $50.[18] Such data can be valuable for determining the resource potential of a particular parcel.

- Potential bidders sometimes pay for seismic surveys, which are conducted by sending sound pulses into the ground and recording information about how they are reflected back. Such surveys provide a type of visual map of the geology underlying a parcel or group of parcels.

17. See, for example, Departments of the Interior, Agriculture, and Energy, *Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development* (2008); and Daniel J. Soeder, Catherine B. Enomoto, and John A. Chermak, "The Devonian Marcellus Shale and Millboro Shale" (GSA Field Guides, 2014), vol. 35, pp. 129–160.

18. Other states, particularly those with significant oil and gas production, offer similar services. For North Dakota's website that provides that information, see www.dmr.nd.gov/oilgas. BLM also requires that firms holding federal leases submit the same information about wells drilled and production from those wells, but the agency does not share the well information and rarely shares with the public production information for particular leases.

Auction results indicate that parcels vary widely in their attractiveness to bidders. Of the more than 25,000 federal leases issued between 2003 and 2012, approximately 85 percent were leased competitively, yielding bonus bids. Of those competitive leases, slightly more than one-quarter were leased at the minimum of $2 per acre.[19] For the other three-quarters, the median bonus bid was $37 per acre, and the average bonus bid was $300 per acre; the average is much higher than the median because some parcels were leased at bids above $5,000 per acre.

Exploration

Holders of onshore leases have the option to explore the parcel for oil and gas for up to the primary term of 10 years, but they are not required to do so. A leaseholder can drill one or more exploratory wells after acquiring the necessary permit; alternatively, the leaseholder can defer deciding whether to drill, or return the lease to BLM. After 10 years, the lease is returned to BLM if no exploratory well has been drilled. If exploration has occurred and production is planned, the leaseholder can apply for a short extension of the primary term to begin production.

To encourage firms to drill exploratory wells and begin production, BLM charges firms a rental fee for parcels that have been leased but have not yet begun production. The rental fee is waived once production begins; at that time, however, firms are required to make a minimum royalty payment set equal to the rental fee. For all onshore federal leases, the rental fee is $1.50 per acre per year for the first five years and $2 per acre per year for the second five years of the primary term, or about $4,000 to $5,000 per year for the largest parcels in the continental United States. Because the fee is small relative to the several million dollars required to drill an exploratory well, firms often wait before drilling to see if other, relevant information—for example, results of drilling activity on a neighboring parcel—becomes available. (When a firm has leased multiple parcels in the same vicinity, an exploratory well on one parcel may yield some benefit to the drilling firm even if it does not reach any oil or gas, by helping the firm redirect additional exploration away from nearby parcels that have become less promising.)

19. Numerical figures in this paragraph are CBO's calculations, using data from BLM.

Box 1-2.

Management of Oil and Gas Resources in Other Countries

Oil and gas resources around the world are managed in various ways. In the United States, Canada, and the United Kingdom, resources are both publicly and privately owned and the governments allow private parties to develop those resources. Conversely, countries such as China, Russia, and the members of the Organization of Petroleum Exporting Countries use state-owned national oil companies almost exclusively to develop their oil and gas resources. The latter countries tend to capture a larger portion of the value of the extracted resources because the government does not share profits with privately owned firms.

The primary components of a government's share vary, but they tend to be based on the amount of resources produced, firms' profits, or the extent of the government's equity participation. Production-based receipts are generated by royalties, severance taxes, and export duties, whereas profit-based receipts are accrued through a share in profit or the collection of windfall taxes. In an equity participation agreement, the government receives a share of income in exchange for partaking in some of a project's risk. In some cases, the government collects additional funds through bonus bids (amounts paid for the right to enter into a lease), rental fees, and research fees.

For countries that allow privately owned firms to develop resources, the financial arrangements can vary widely. For example, some jurisdictions in Canada award licenses to explore parcels not on the basis of cash bonus bids but on the basis of "work proposal bids"—commitments to spend a certain amount of money to develop the parcel. The winning bidder then submits a fraction of that amount to the government as a deposit, which is refunded as exploration costs are incurred.[1] No cash bonus bids are made in the United Kingdom either; licenses there are awarded on the basis of financial and technical criteria.[2]

The basis for determining the government's income associated with production of oil and gas also differs by country. The United Kingdom charges no royalty but levies a standard corporate tax on net income and also a supplementary charge, which together yield a marginal tax rate of 50 percent on net income.[3] In Alberta, Canada, royalties are charged on sliding scales that consider both resource prices and production per well; the royalty rate for oil can be as low as zero or as high as 40 percent, and the rate for gas can range from 5 percent to 36 percent.[4]

In 2011, the Department of the Interior commissioned a study to compare the federal U.S. process for managing access to oil and gas resources with those of selected countries and states in this country.[5] One of the factors considered in the study was the share of the net cash flows—that is, gross revenues from production minus capital and operating expenses—retained by the different governments. (Those shares are not directly comparable to the royalty rates cited in this report, which are percentages of gross revenues minus certain allowable deductions, such as the cost of transporting the oil or gas to the market. The U.S. royalty rate of 12.5 percent for onshore parcels, for example, corresponds to 15.6 percent of the net cash flow if capital and operating expenses equal 20 percent of gross revenues, and to 25 percent if those expenses equal half of gross revenues.) For onshore oil and gas resources on U.S. federal lands,

1. For example, see Northwest Territories Department of Industry, Tourism, and Investment, *NWT Oil and Gas: Annual Report 2014* (June 2, 2015), pp. 6 and 11, http://tinyurl.com/zfcdeu7. Rental fees charged after the first five years are also refundable as costs are incurred.

2. See United Kingdom Oil and Gas Authority, *Applications for Production Licences—General Guidance* (2014), p. 6, http://tinyurl.com/jnhvnj9.

3. United Kingdom Oil and Gas Authority, *Oil and Gas: Taxation* (updated October 9, 2015), http://tinyurl.com/jguo5rk.

4. Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), pp. 189–191, http://go.usa.gov/cwznH.

5. Ibid.

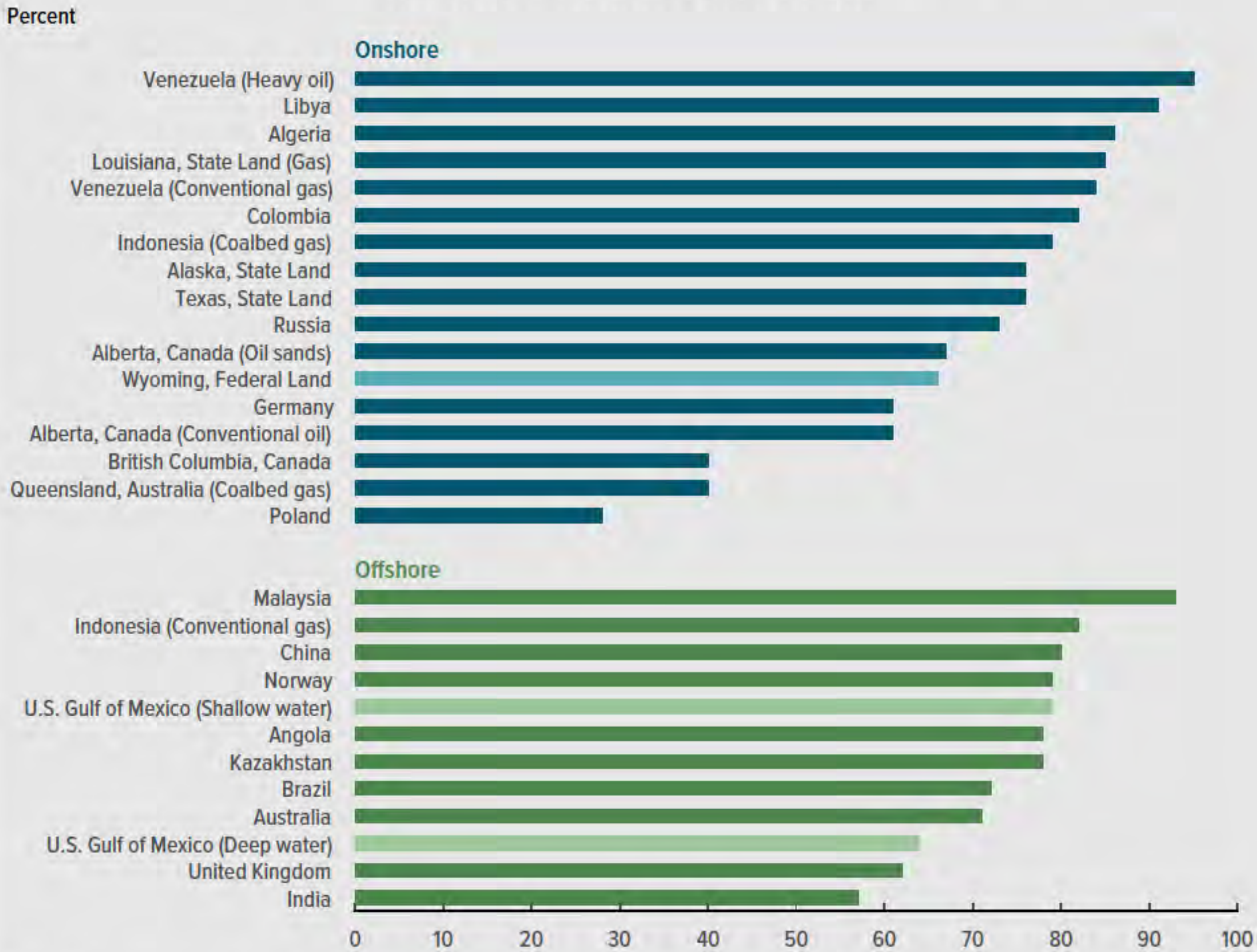
Continued

Box 1-2. Continued

Management of Oil and Gas Resources in Other Countries

the total share of the resources' value (the net cash flow) retained by governments, including federal income taxes and applicable state and local taxes, is about 66 percent; that share ranks in the lower half of nations and states evaluated (see the figure). For offshore resources, the overall share of value retained by governments in the United States is again in the bottom half of the countries evaluated, taking into account the different shares for resources in shallow water (79 percent) and deep water (64 percent).

Governments' Shares of Resources' Value for Oil and Natural Gas Produced on U.S. Federal Lands and Elsewhere

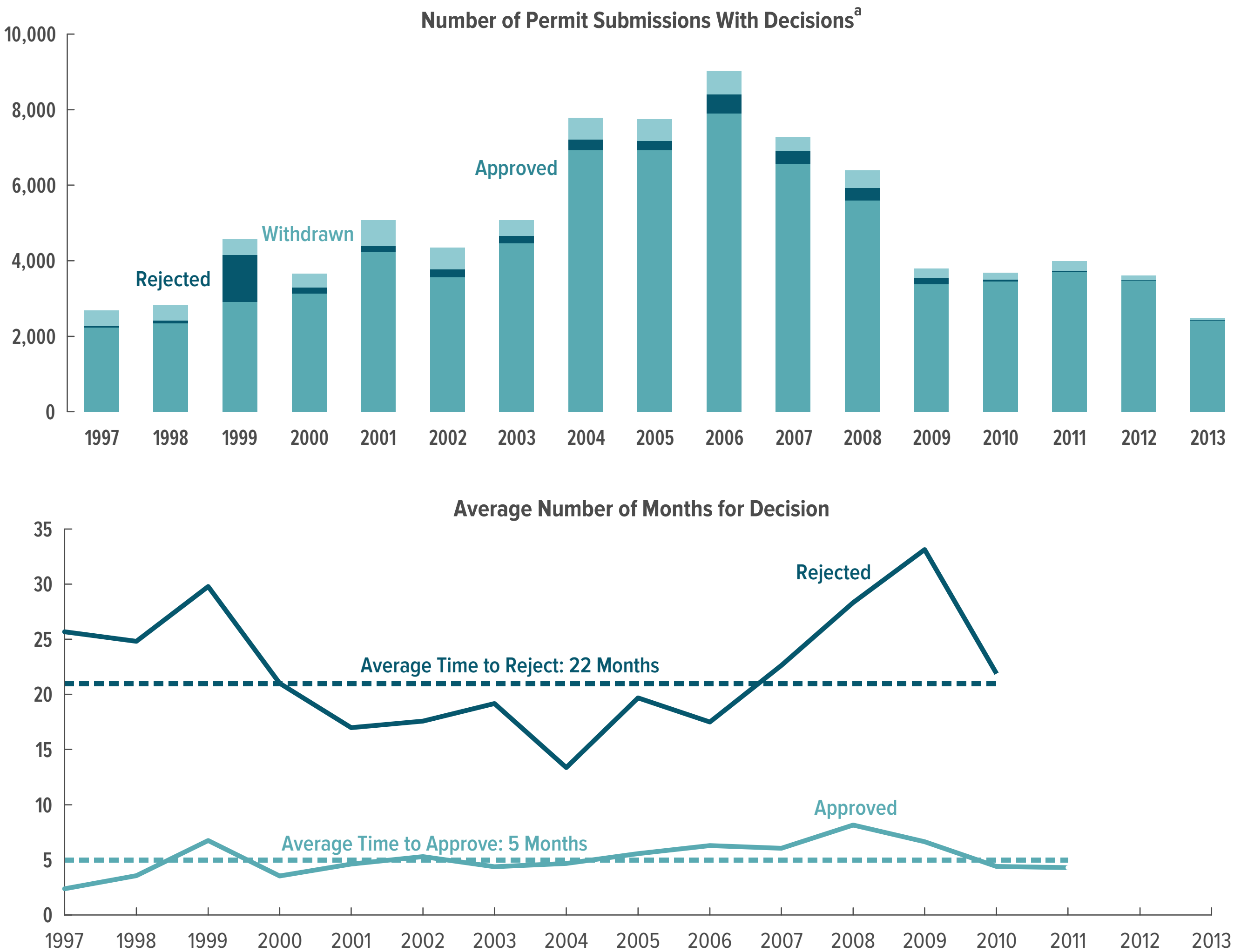


Source: Congressional Budget Office, using data from Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), http://go.usa.gov/cwznH.

The share of resources' value (gross revenues from production minus capital and operating expenses) retained by the government includes income taxes, fees, royalties, and other financial charges associated with oil and natural gas development.

Figure 1-5.

Number of Onshore Drilling Permits Submitted and Average Decision Times



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management (BLM) through February 20, 2014.

a. The number of applications with no decision is not shown. After 2005, between 50 and 200 applications each year did not have a decision noted in the database maintained by BLM. That could be the result of recordkeeping errors, an incomplete application, or insufficient time to make a decision. In 2013, there were 887 applications with no action, probably because of insufficient time for BLM to make a decision. For that same reason, in the bottom panel, completion times are shown only through 2010 for rejections and 2011 for approvals.

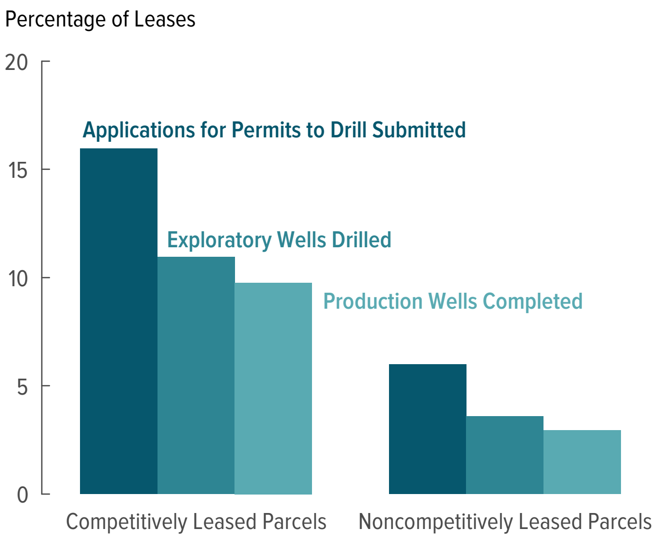
Once a leaseholder decides to drill an exploratory well, the firm must submit an application for a permit to drill (APD). To receive a permit, the leaseholder must provide a plan that complies with the National Environmental Policy Act and all other conditions of the lease, which may include building new roads or pipelines. In addition, a bond of $10,000 is required in case the leaseholder abandons the parcel and the federal government must provide remediation. Since 1997, among applications for which a decision has been made, more than 85 percent of APDs submitted in any year have been approved, typically within about 5 months (see Figure 1-5). About 5 percent of APDs submitted each year have been denied; on average, rejection occurs 22 months after submission. (Before rejecting an application, BLM may request additional information or clarification of a leaseholder's compliance plans.) The other applications have been withdrawn.

Most onshore leases see no activity for the duration of the lease—in some cases, because market conditions prove to be less favorable than the leaseholder had projected, or

Figure 1-6.

Share of Onshore Federal Leases From 1996 Through 2003 With Applications for Drilling and Production

The share of parcels where exploration and production occurred was higher for competitively leased parcels than for noncompetitively leased parcels because the latter are generally those that are considered less likely to contain significant resources.



Source: Congressional Budget Office, using data through February 2014 from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

Well completion is strongly correlated with production, but the share of leases that have started production may be slightly smaller than the share completed.

because exploratory wells on nearby properties reduce expectations of the value of oil or gas available on the unexplored parcel. The Congressional Budget Office analyzed leases issued between 1996 and 2003 and examined all subsequent activity on the leased parcels through February 2014. (Because many leases have no activity until the last few years of the primary term, the analysis focuses on leases for which there is a complete history of activity for the entire 10-year period.) On average, wells are drilled on about 11 percent of parcels leased competitively and less than 4 percent of parcels leased noncompetitively (see Figure 1-6). Production of oil or gas occurs on about 10 percent of the competitively leased parcels and 3 percent of the noncompetitively leased parcels. Most leaseholders do not choose to return the lease to BLM early but instead pay the rental fee and wait to see if new information becomes available that increases the likelihood that the parcel contains oil or gas.

Production

If exploratory drilling finds oil or gas resources on a parcel under conditions believed to be economically viable for production, the leaseholder usually decides to begin production of that oil or gas. In that case, the well is finished by encasing the outside in cement so that oil or gas does not migrate into the surrounding soil as it travels up the well. Once production begins, the leaseholder pays a share of the value of that production—the royalty rate—to the federal government, after deducting certain allowable expenses. For federal onshore leases, the royalty rate is 12.5 percent (set by law and unchanged since 1987), which is less than the royalty rate imposed by many states for production of oil and gas on state-owned land. For example, current state royalty rates are 25 percent in Texas, 18.75 percent in Oklahoma, and 16.67 percent in Colorado, Montana, and Wyoming; New Mexico and North Dakota use both 16.67 percent and 18.75 percent rates.[20]

Although oil and gas resources have been found underlying land in more than 30 states, federally owned oil and gas tends to be concentrated in a few states, particularly New Mexico and Wyoming (see Table 1-3). Since 2005, four states have accounted for about 85 percent of oil production on federal lands, and four states have accounted for about 95 percent of natural gas production on federal lands.

Once production of oil or gas begins, it tends to increase for a time and then decrease as the resources are exhausted. Between 1996 and 2010, resource production from parcels leased in 1996 in Colorado, New Mexico, Utah, and Wyoming (the top four states producing natural gas) climbed for the first decade and then began to fall (see Figure 1-7 on page 21). That pattern of a slow increase in production occurs in part because leaseholders are waiting for more information about potential oil and gas resources before developing their parcels. In addition, once oil and gas reserves are identified, leaseholders drill additional wells over time to extract oil or gas from different areas of the parcel. (Production rates

20. Center for Western Priorities, *A Fair Share: The Case for Updating Oil and Gas Royalties on Our Public Lands—Update* (June 18, 2015), http://tinyurl.com/j296qzt. Some of those royalty rates reflect increases since 2005, as many Western states have changed their lease terms to increase state revenues.

Table 1-3.

Onshore Production of Oil and Natural Gas for the 15 States With the Highest Production on Federal Lands, by Owner, 2005 to 2014

Oil (Millions of barrels)			Natural Gas (Millions of barrels of oil equivalent)		
	Federal Owner	Any Owner		Federal Owner	Any Owner
New Mexico	633	729	Wyoming	2,438	3,637
Wyoming	536	561	New Mexico	1,406	2,486
California	153	2,096	Colorado	493	2,608
Utah	141	250	Utah	447	751
North Dakota	104	1,381	Texas	56	12,020
Colorado	97	395	Montana	44	164
Montana	33	298	Louisiana	41	3,483
Louisiana	7	717	Alaska	38	713
Kansas	4	403	Oklahoma	26	3,377
Oklahoma	4	777	Arkansas	22	1,266
Texas	4	5,522	North Dakota	18	199
Nevada	4	4	Kansas	12	607
Mississippi	3	221	California	11	506
Alaska	3	2,360	Michigan	5	303
South Dakota	2	16	West Virginia	3	704
Total U.S. Onshore Production	**1,731**	**21,355**		**5,064**	**38,280**

Source: Congressional Budget Office, using data from the Energy Information Administration and the Department of the Interior's Office of Natural Resources and Revenue.

Oil totals include natural gas liquids.

from a single well tend not to be controlled by the leaseholder but are instead determined by the geologic conditions and the quantity of oil or gas underlying a parcel.)[21] Production may also increase over time as new methods of drilling, such as hydraulic fracturing (or fracking), become available and cause parcels with declining production to see an increase or cause parcels that were believed to be unprofitable for development to become profitable. Finally, sometimes market conditions, such as a low price for natural gas or oil, may cause a leaseholder to halt further development of a lease or shut in (or close) a producing well until market conditions improve, although reopening a well can be as expensive as drilling a new one.

In general, a productive parcel will continue to produce for much longer than 10 years, the typical period considered by CBO when estimating the income or costs associated with legislation. For leases auctioned in 1996 in the four top natural gas–producing states, about two-thirds of the total production over the first 15 years (through 2010) occurred after the first 10 years (see Figure 1-7). The government receives royalty income while production continues, and that is thus the only source of leasing income that can extend more than a decade after a parcel is auctioned. Of all the royalty payments collected in 2013, about half of those payments came from parcels that were leased more than 50 years earlier, whereas 6 percent came from parcels that were leased in the previous 10 years (see Figure 1-8 on page 22).

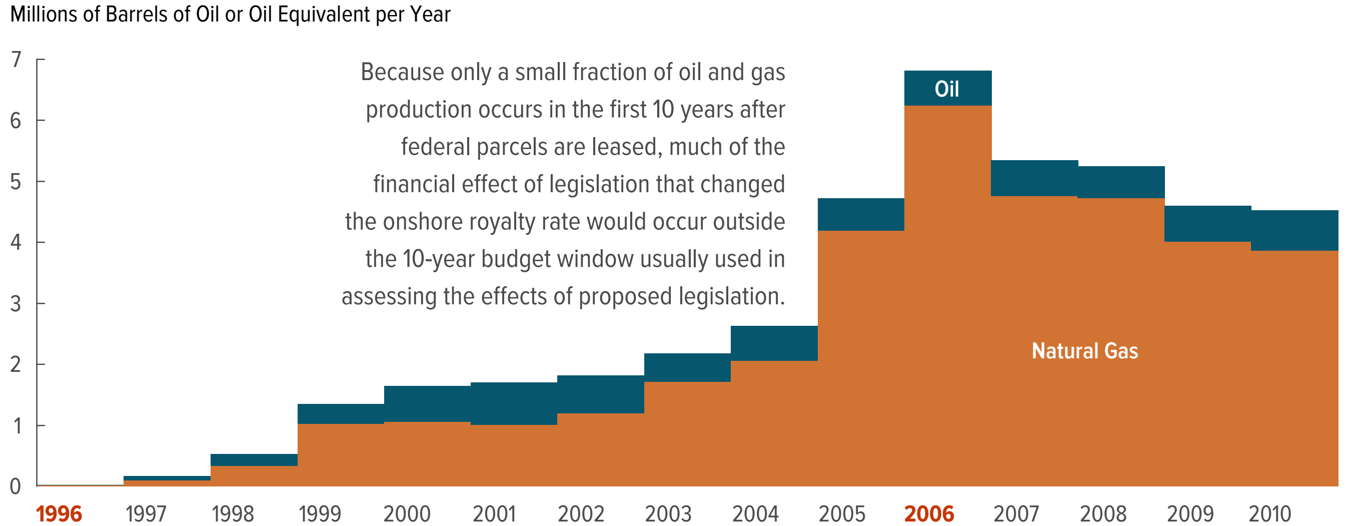
21. For more explanation, see Soren T. Anderson, Ryan Kellogg, and Stephen W. Salant, *Hotelling Under Pressure*, Working Paper 20280 (National Bureau of Economic Research, July 2014). According to that report, "oil production from existing wells in Texas does not respond to price incentives. Drilling activity and costs, however, do respond strongly to prices."

Offshore Oil and Gas Leases

Because the federal government (through BOEM) controls and manages all drilling between the seaward boundary and 200 nautical miles offshore, nearly all offshore production is federal. In 2014, offshore drilling accounted for roughly 70 percent of the oil and 30 percent of the gas produced on federal lands. Nearly all offshore drilling occurs in the central and western Gulf of Mexico and off the coast of California, although no new leases have been issued for areas off the coast of California since 1984. Some activity has occurred elsewhere—such as in the Atlantic Ocean, offshore Alaska, and off the west

Figure 1-7.

Production Profiles Associated With All Leases Issued in 1996 for Federal Lands in Colorado, New Mexico, Utah, and Wyoming



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

The four states included here account for most of the oil and almost all of the natural gas produced from onshore federal lands; see Table 1-3 for details.

The data extend through December 31, 2010.

coast of Florida—but most of those areas have not been available for leasing since the 1980s; the only exception is certain areas off the coast of Alaska that have been made available for leasing over the past decade.

On average, production of oil and gas from offshore parcels generates more than two-thirds of gross federal income from all domestic oil and gas activities. Between 2005 and 2014, the government collected an annual average of about $1.8 billion in bonus bids, $230 million in rental fees, and $6.0 billion in royalty payments.

Leasing

Offshore leasing is managed through a planning process called the Five-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program.[22] Each five-year plan describes the areas from which parcels will be auctioned and the dates of each auction. The current plan expires in August 2017; the proposed plan for 2017 through 2022 would offer leases in three areas in the Gulf of Mexico (central, western, and eastern) and three areas off the cost of Alaska (the Chukchi Sea, Beaufort Sea, and Cook Inlet). The acreage offered in the Alaska OCS will be subject to certain exclusion and mitigation zones to protect sensitive areas.

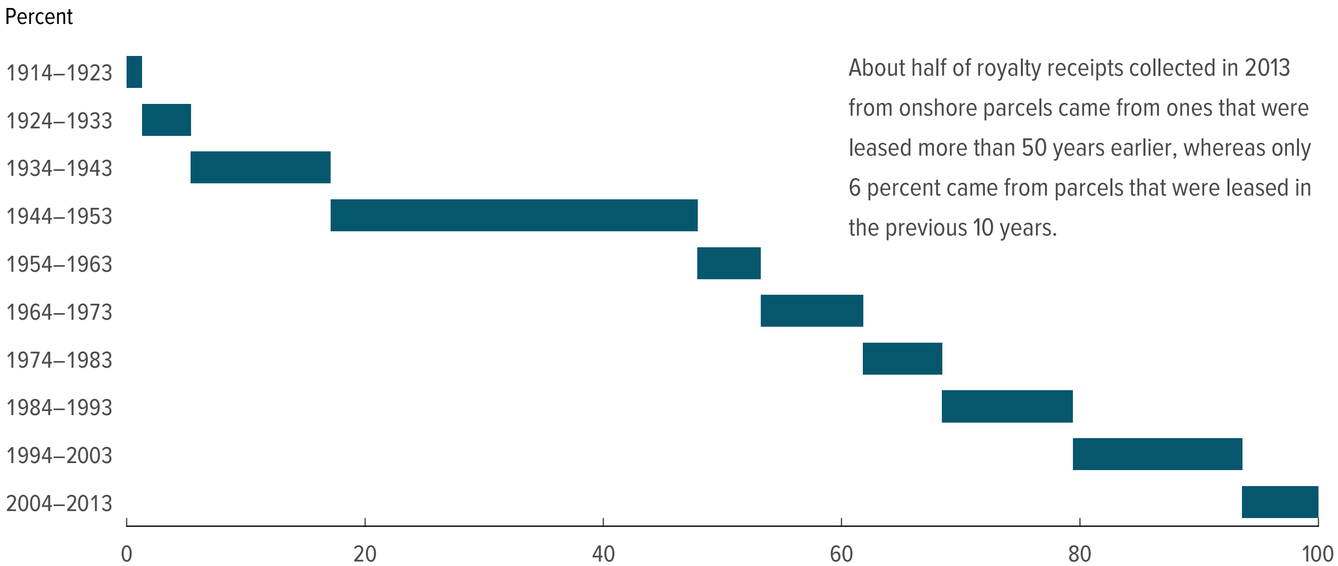
Recognizing the increased complexity of drilling wells in certain offshore areas and wanting to encourage development of parcels, BOEM sets different terms for leases based on the parcels' location. For example, leases for parcels in areas of the Gulf of Mexico that are less than 400 meters deep have a primary term of five years plus an additional three years for drilling if the bottom of the well is more than 7,600 meters below sea level; leases for parcels in ultradeep water in the Gulf of Mexico or anywhere off the coast of Alaska have a 10-year primary term. In addition, parcels off the coast of Alaska that are closer to existing infrastructure, and thus less expensive to develop, tend to have a higher minimum bid.

Auctions for offshore parcels use a sealed-bid format in which all bidders simultaneously submit bids for all the parcels they would like to lease in an area. Most parcels are 5,760 acres and have a minimum bid (set by BOEM) of $25 to $100 per acre depending on the depth of the

22. For more details on how the program was created, see Adam Vann, *Offshore Oil and Gas Development: Legal Framework*, Report for Congress RL33404 (Congressional Research Service, December 30, 2015).

Figure 1-8.

Shares of Royalty Receipts Collected in 2013 From Onshore Parcels, by Decade of Original Lease



Source: Congressional Budget Office, using data from the Department of the Interior's Office of Natural Resources and Revenue.

The total amount collected in 2013 was $2.7 billion.

ocean floor in that area; deeper parcels have higher minimums to discourage less serious bidders. After all bids are received, BOEM determines the highest bidder for each parcel and then evaluates whether that bid equals or exceeds the fair value of the parcel (an amount above the minimum bid). To make that determination, BOEM relies on the bids of other firms and on seismic data collected by private firms and confidentially shared with BOEM as a condition of collection. Because such surveys offshore can cost more than $100 million, multiple firms will often commission a survey and share the results. BOEM stipulates that such surveys can be done, as long as the results are also shared with the agency. (BOEM does not release the surveys to the public for 25 years.) The agency uses the surveys to determine whether the highest bid for an auctioned parcel exceeds its fair value and for large-scale assessments of resources' availability (as USGS uses seismic surveys onshore).

If the highest bid exceeds the fair value, then the lease is awarded. If the highest bid does not exceed the fair value, which tends to happen for a few parcels in each auction, then the parcel is returned for leasing at the next scheduled auction. In general, less than 12 percent of the total acreage available in any given auction is leased in that auction. In the Gulf of Mexico, that rate of leasing means that about a third of total available parcels were under lease at the end of 2014.

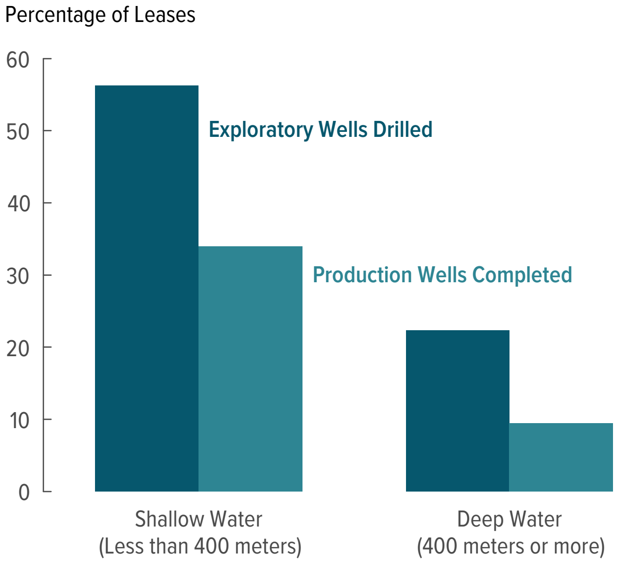
As with auctions for onshore parcels, four factors largely determine the amount a firm is willing to pay to lease a parcel: the terms of the lease, the firm's expectations about the future market price of oil or gas, its expectations about the amount of oil or gas underlying a parcel, and its expectations about the difficulty and cost of extracting oil or gas from the parcel. Differences in the amounts firms are willing to pay for a lease arise mainly from differences in the last two factors.

Federal income from offshore bonus bids can vary significantly over time. In 2008, for example, income from bonus bids spiked to almost $10 billion (see Figure 1-4 on page 14), much higher than the 2005–2014 average of $1.8 billion. Three factors contributed to that surge in auction income. First, the five-year plan included a lease sale for parcels underlying the Chukchi Sea, an area in the Arctic that was thought to contain significant oil and gas reserves and for which leases had not been made available since 1991. Second, delay of a fiscal year 2007 auction resulted in two auctions for leases in the central Gulf of Mexico in fiscal year 2008, both of which contained

Figure 1-9.

Share of Federal Leases in the Gulf of Mexico From 1980 Through 2000 With Drilling and Production Activity

Exploration and development rates for offshore parcels vary by location; parcels in deep water are less likely to be explored because costs are higher there.



Source: Congressional Budget Office, using data from Kenneth Hendricks, University of Wisconsin.

Shallow and deep waters each include about half of all parcels leased in the Gulf between calendar years 1980 and 2000.

numerous parcels believed to be highly valuable.[23] Third, oil prices in 2008 peaked at $140 per barrel, so firms selling oil had more cash to spend on auctions. Those high oil prices also may have increased firms' expectations about future oil prices and thus about the profitability of new discoveries.

Exploration

During the primary term of a lease, the leaseholder can pursue one of three options, which are identical to those for onshore leases: drill an exploratory well (after securing BOEM's approval for its exploration and development plans), wait, or return the lease.

The rental fees on offshore parcels that have been leased but not yet begun production depend on the parcel's location, ranging initially from about $5 per acre to $11 per acre (increased from $3 per acre in the mid-1990s); fees on parcels in the Gulf of Mexico increase after five years (see Table 1-2 on page 13). The high cost of developing offshore parcels, particularly those in deep water, gives leaseholders an incentive to wait to see if additional information—from newly commissioned seismic surveys or other wells drilled on neighboring parcels—becomes available before drilling. The higher rental rate for deepwater parcels reduces that incentive to wait, but only slightly, because the annual fee is small—typically less than 0.1 percent of the costs of exploration.

Exploration and development rates for offshore parcels vary by location. In the Gulf of Mexico, 56 percent of parcels in shallow water leased between 1980 and 2000 were explored during their initial lease term, compared with 22 percent of parcels in deep water, even though the term for parcels in shallow water is shorter (see Figure 1-9). About a third of all leases in the Gulf of Mexico since 1983 have been voluntarily returned to the government before their initial term expired; those leases were then offered for sale in subsequent auctions, during which 60 percent of them attracted bids.[24]

Production

If an exploratory well identifies oil or gas resources of sufficient volume to make a completed well economically viable, the leaseholder usually decides to build the infrastructure necessary to begin production. Only 34 percent of shallow-water parcels and 9 percent of deepwater parcels leased between 1980 and 2000 have produced oil or gas (see Figure 1-9). The construction of offshore infrastructure can be expensive; the leaseholder requires an oil or gas platform in addition to a mechanism to transport the recovered oil or gas to a processing facility on land. Sometimes firms build a pipeline that connects the producing well to onshore facilities. At other times, firms rely on large ships to transport the oil to land.

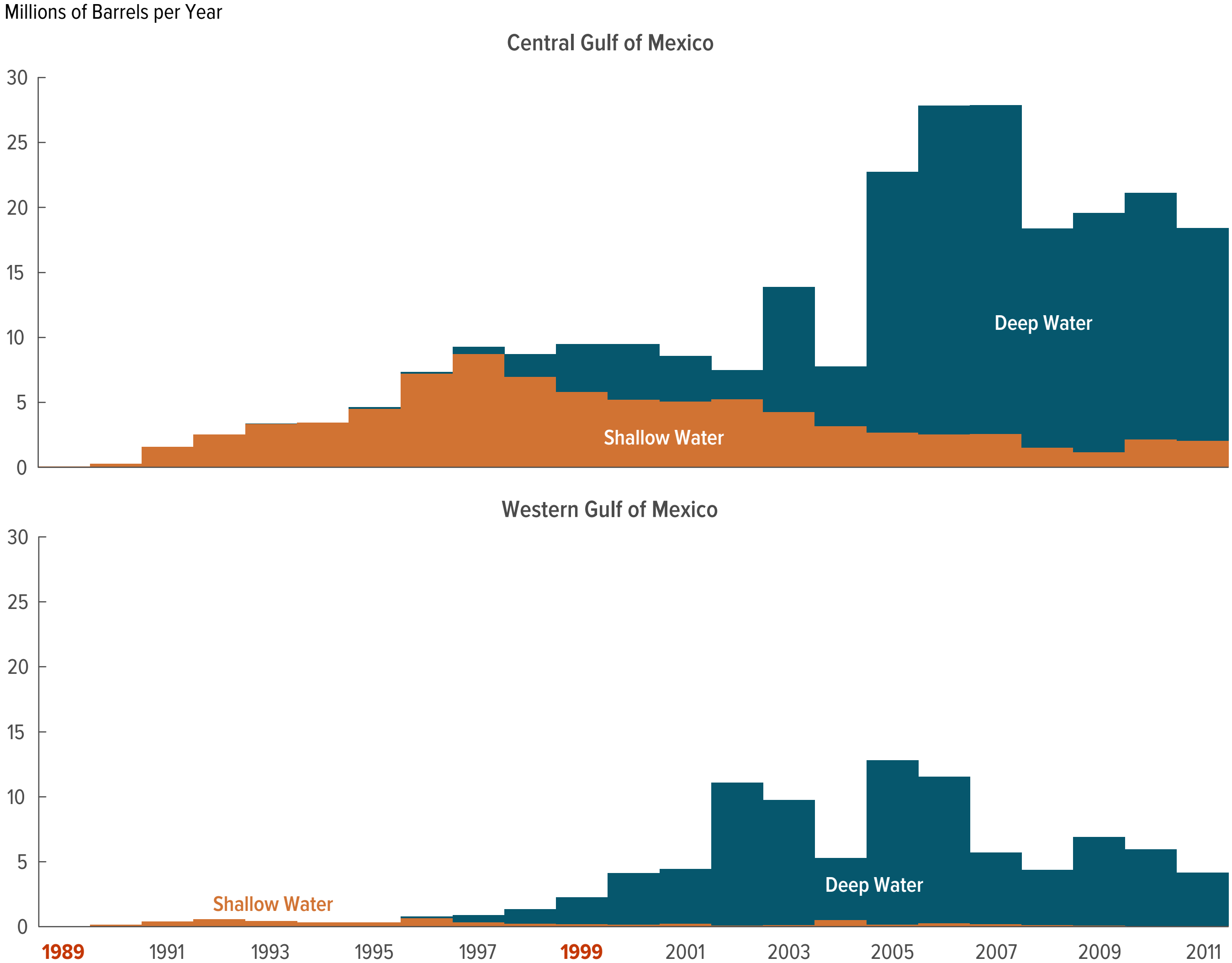
23. The 2007 Central Gulf of Mexico auction was delayed until October 3, 2007, which was in fiscal year 2008. Both auctions included many parcels that were up for re-auction after having first been leased between 1996 and 2000, under legislation that eliminated royalties on production (below certain volume limits) from parcels in water more than 200 meters deep leased during those years. That legislation led firms to lease many more parcels than could be developed during the 10-year primary term. See the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, title III of Public Law 104-58, 109 Stat. 563.

24. Bureau of Ocean Energy Management data as of June 23, 2014, provided to the Congressional Budget Office, on leases with completed initial terms.

Figure 1-10.

Oil Production From All Parcels Leased in Two 1989 Auctions in the Gulf of Mexico

Of the oil production occurring within 22 years of these auctions, production in the first 10 years (through 1999) represented about half of the total for wells in shallow water and very little of the total for wells in deep water.



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

Deep water is defined as an average parcel depth greater than 400 meters.

The data extend through December 31, 2011.

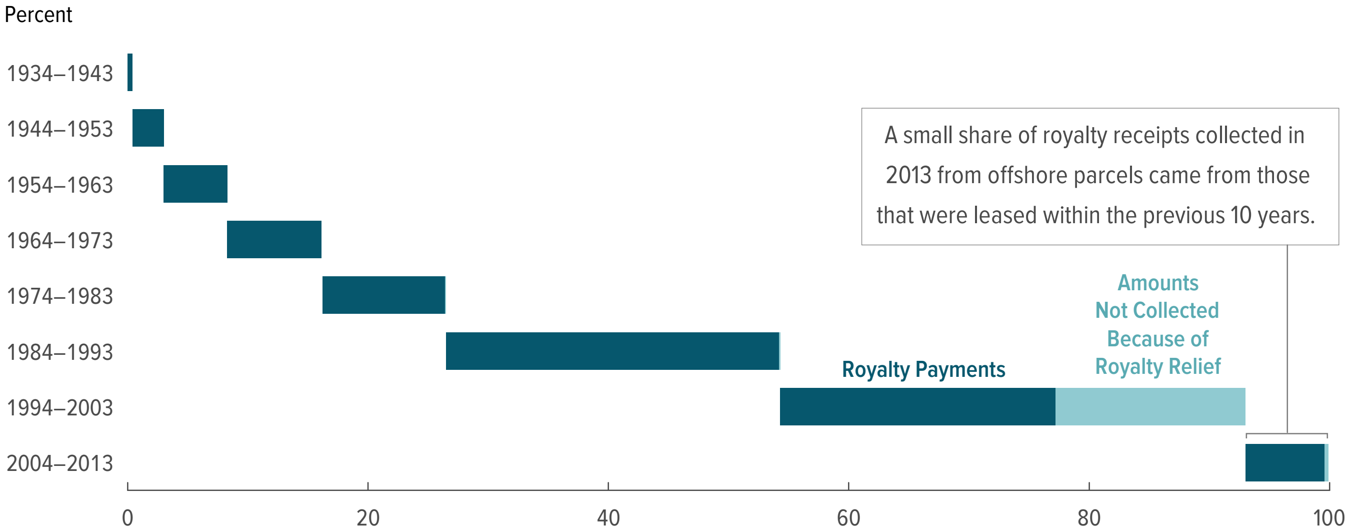
Once production begins, the lease specifies a royalty rate that must be paid to the federal government based on the market value of the oil or gas after certain allowable costs are deducted. The current royalty rates for offshore parcels are 18.75 percent for the Gulf of Mexico and 12.5 percent for Alaska, although BOEM waives royalty payments for some leases if the market price of oil or gas falls below certain thresholds, as it has for gas in the past few years.[25]

For all types of offshore parcels, much of the production—and hence much of royalty income—occurs more than 10 years after the parcel was leased. The production

25. The thresholds are adjusted annually for inflation; a preliminary estimate of the adjustment for 2015 showed that the thresholds for oil remained below the average price for that year. See Bureau of Ocean Energy Management, "Prices Above Which Full Royalties Are Due Notwithstanding Any Remaining Royalty Suspension Volumes" (accessed on March 7, 2016), www.boem.gov/current-price-thresholds-determination (PDF, 100 KB).

Figure 1-11.

Shares of Royalty Receipts Collected in 2013 From Offshore Parcels, by Decade of Original Lease



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

The amount collected in 2013 totaled $6.0 billion. Another $1.2 billion was excluded from collection because of the royalty relief program of 1996, which eliminated royalty payments for all leases sold between 1996 and 2000, and smaller relief programs in other decades.

history for parcels in the Gulf of Mexico following two representative auctions in 1989 illustrates that pattern: For shallow-water parcels, between 40 percent and 50 percent of production occurred more than 10 years after the auctions; for deepwater parcels, more than 98 percent of production occurred more than 10 years after the auctions (see Figure 1-10). Conversely, about two-thirds of the royalty income collected in 2013 was generated from parcels leased more than 20 years earlier. That figure was higher than it would have been otherwise because the government leased a large number of parcels between 1996 and 2000 on a royalty-free basis: If production from those parcels had occurred at the observed levels and been subject to the royalty rate included in leases before and after that period, then parcels leased more than 20 years earlier would have accounted for about 55 percent of royalty income in 2013 (see Figure 1-11). In either case, parcels leased from 2004 to 2013 generated less than 10 percent of that income.

CHAPTER

2

Selected Policy Options to Increase Federal Income

Legislative and administrative proposals to amend the rules governing access to oil and natural gas on federal lands often involve changes intended to raise additional federal income. In this report, the Congressional Budget Office focuses on policies that would increase the income associated with development and extraction of given volumes of oil and gas, by changing either the qualitative rules for the auctions—in particular, the auction type and nomination process—to increase the competition for available parcels, or the quantitative terms of the auctions and leases, such as the minimum bid, the rental fee, and the royalty rate. The policies analyzed here would generate additional income to the federal government (net of payments to states) ranging from less than $25 million to $500 million over 10 years, CBO estimates, with negligible effects on production over that period or later. For comparison, CBO's March 2016 current-law baseline includes $20 billion in net federal income from onshore oil and gas leasing between fiscal years 2017 and 2026 and $72 billion from offshore leasing over that period.

Quantitative lease terms can be changed to a lesser or greater degree, so CBO selected particular changes to illustrate the potential effects on federal income. The options considered here are relatively small changes, chosen to minimize the likelihood that oil and gas producers would be induced to shift operations from federal to nonfederal lands. Larger or smaller changes could have larger or smaller budgetary effects; larger changes could lead to decreases in production, which could affect other policy objectives that are beyond the scope of the analysis. One such objective—increasing the ability of U.S. households and businesses to accommodate disruptions of supply in energy markets—was evaluated in another CBO report.[1] Other objectives include increasing the flexibility to choose not to import oil from countries associated with terrorism or from countries that might seek to use their exports of oil to influence international affairs; reducing the price of oil or gas in the United States; and avoiding negative environmental consequences that may result from greater production of oil and gas. Estimates of the budgetary effects of larger changes would be subject to greater uncertainty because the size of any decreases in production would depend on future market conditions (for example, a particular change might have little effect on production when prices are high but a large effect when they are low) and on responses by other parties (including states and private landowners).

Two other approaches to increasing federal income from oil and gas produced on federal lands are outside the scope of this report. One approach would be to immediately open additional onshore and offshore federal lands for leasing; in 2012, CBO estimated that doing so would increase receipts (before any revenue sharing with the states) by about $7 billion over 10 years (see Box 2-1).[2] The government could also attempt to promote oil and gas production in general—on private, state, and tribal lands as well as federal lands—by changing the tax treatment of oil and gas development (for a brief examination of that approach, see Box 2-2 on page 30).

Options for Onshore Oil and Gas

The fiscal process governing onshore oil and gas production was largely promulgated in 1987 under an amendment to the Mineral Leasing Act and has not been changed since (see Table 1-1 on page 12). Recent advances in technology and changes in the terms offered by state agencies and other governments for access to their oil and gas resources may offer the Bureau of Land Management an opportunity to increase federal income, albeit by small amounts, with minor or negligible negative effects on production (see Table 2-1 on page 31). One category of policies would change the process by which BLM leases parcels. For example, BLM could be authorized to do the following:

1. See Congressional Budget Office, *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012.

2. Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

Box 2-1.

Increasing Production by Opening New Federal Lands

One approach to increasing oil and gas production on federal lands and thus boosting federal income from bonus bids, rental payments, and royalties would be to immediately open additional federal lands to oil and gas leasing. Doing that would entail making changes to two categories of lands now closed to development:

- Lands where leasing is now statutorily prohibited, notably, the Arctic National Wildlife Refuge (ANWR), and
- Lands that are unavailable for leasing under current administrative policies, such as sections of the Outer Continental Shelf (OCS) and certain onshore areas in which oil and gas leasing is either restricted or temporarily prohibited.[1]

In August 2012, the Congressional Budget Office estimated that immediately opening most federal lands to oil and gas leasing would generate $7 billion in additional gross receipts to the federal government, before any sharing with the states, between 2012 and 2022.[2] The $7 billion comprised about $5 billion associated with opening federal lands in ANWR and about $2 billion from expanded development in areas affected by current administrative policies. (Most of that $2 billion was expected to come from the OCS leases; a portion of the proceeds would be shared with the states. Most legislative proposals related to ANWR have specified that a significant portion of receipts from leases there would be shared with Alaska.)

In its 2012 report, CBO estimated that most of the $5 billion in additional receipts obtained between 2012 and 2022 as a result of opening ANWR to development would take the form of bonus bids. The federal government also would collect royalties on oil and natural gas eventually produced from those lands, but most royalty payments would not be collected until much later because of the long lag time between

1. The Outer Continental Shelf consists of submerged lands that are within 200 nautical miles of the official U.S. coastline and may include additional lands where the geological continental shelf extends beyond 200 nautical miles. It does not include waters under state jurisdiction, which extends either 3 or 9 nautical miles from the coastline. See Adam Vann, *Offshore Oil and Gas Development: Legal Framework*, Report for Congress RL33404 (Congressional Research Service, December 30, 2015), p. 2.

2. Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

Continued

- Adopt an alternative form of auction that would encourage more intense competition between firms for parcels and thus generate more income, or
- Use discretion to set terms that are more advantageous for the government on parcels that are more likely to have oil or gas reserves underlying them. If implemented similarly to approaches used by state governments, that option could allow BLM to increase the minimum bid, rental fee, or royalty rate only when such increases were most likely to boost federal income with negligible effects on production.

A second category of policies could require BLM to adjust the specific terms of the leasing process—for example, by making these changes:

- Increasing the minimum bid,
- Establishing a new fee for nonproducing leases, or
- Raising the royalty rate for all leases.

In addition to the option-specific arguments noted below, two general arguments are commonly made against the eight options discussed here, despite the increase in federal income they would produce. First, increased federal income would necessarily reduce the profitability of holding a lease, which would lessen the returns to shareholders and employees of firms that produce oil and gas from federal lands. Second, increased income in the near term could be offset by lower bidding (because expected returns would be smaller) and less production in later years: If firms cut back on their leasing and exploration of speculative parcels (those for which the availability of oil

Box 2-1. Continued

Increasing Production by Opening New Federal Lands

the initial leasing agreement and the time when production began. Thus, most of the receipts eventually collected would probably occur outside of the 10-year period generally used for budget estimates. Using estimates of potential resources from the Energy Information Administration and taking into account a range of probable oil prices, CBO estimated in 2012 that gross royalties from leasing in ANWR would probably total between $25 billion and $50 billion (in 2010 dollars) during the 13-year period from 2023 to 2035, or roughly $2 billion to $4 billion a year.

If CBO were to revisit its August 2012 analysis today, the estimates of federal receipts would be affected by the significant reduction in the price of oil, which was about $100 per barrel then and is currently about $40 per barrel. The effect of the change in oil prices on CBO's estimates would be proportionately smaller, because most of the receipts collected within the 10-year budget window would come from bonus bids, not royalty payments, and bids depend more on expected future oil prices than on current prices.

One argument in favor of opening more federal lands to oil and gas production is that preparing the newly available parcels for development could boost employment and economic output, especially in the affected regions. Additional leasing could also raise income for state and local governments; the exact amounts would depend on states' tax policies, the amounts of oil and gas expected to be available in each leasing area and the amounts actually produced, and the formulas for distributing portions of federal oil and gas proceeds to the states. The primary argument against expanded leasing is that the areas involved are environmentally sensitive, and exploration and production of oil and natural gas could pose a threat to wildlife, fisheries, and tourism. Another argument against expanded leasing is that increased development of resources in the near term would reduce the oil and gas available for production in the future, when prices might be higher and the resources might be valued more highly by households and businesses.[3]

3. For those and other arguments for and against oil and gas development, see Robert B. Jackson and others, "The Environmental Costs and Benefits of Fracking," *Annual Review of Environment and Resources*, vol. 39 (October 2014), pp. 327–362, http://tinyurl.com/kq4endz.

or gas is particularly uncertain), less information would be generated about the resources on nearby parcels, potentially reducing bidding on those parcels in future auctions and delaying production from them once leased.

However, CBO expects that the effects on production and federal income of reduced activity on speculative parcels would be small, for two reasons. First, the parcels not leased would be among those most likely to remain unexplored even if leased. Second, the parcels not leased would be available for leasing in the future, and some of them would become more valuable because of oil or gas discoveries on nearby parcels or information from new seismic surveys. Thus, any losses in production and income in the near term might be offset or outweighed by gains in later years.

Option 1. Require Onshore Parcels to Be Auctioned Through a Sealed-Bid Process

Onshore parcels are leased through an open-outcry auction, as mandated by the authorizing legislation. In some settings, such a design has been found to be vulnerable to collusion, particularly when the number of bidders is small.[3] Maybe more important, when there is only a single bidder, as is often the case in auctions for onshore parcels, the open-outcry format has no mechanism to

3. See, for example, R. Preston McAfee and John McMillan, "Bidding Rings," *American Economic Review*, vol. 82, no. 3 (June 1992), pp. 579–599, www.jstor.org/stable/2117323; and Daniel A. Graham and Robert C. Marshall, "Collusive Bidder Behavior at Single-Object Second-Price and English Auctions," *Journal of Political Economy*, vol. 95, no. 6 (December 1987), pp. 1217–1239, http://dx.doi.org/10.1086/261512.

Box 2-2.

Increasing Income by Repealing Tax Preferences

In addition to changing the leasing system associated with development of oil and gas on federal lands, lawmakers could consider reducing the tax preferences that are available to private firms that develop oil and gas resources, regardless of whether the lands are owned by the federal government. Two primary tax preferences are available to those firms.[1] One allows producers of oil, gas, coal, and minerals to expense (or deduct) some of the costs associated with exploration and development as they are incurred, rather than waiting for those activities to generate income. In 2014, the staff of the Joint Committee on Taxation (JCT) estimated that repealing that provision that year would increase revenues by $15 billion between 2015 and 2024. The other tax preference allows producers of oil, gas, coal, and minerals to deduct from their taxable income between 5 percent and 22 percent of the dollar value of oil and gas extracted during the year. (The precise amount of the deduction depends on the type of resource and applies only up to certain limits.) JCT estimated that repealing that tax preference would increase revenues by $21 billion over the 2015–2024 period.

An argument in favor of reconsidering the tax preferences available for firms that produce oil or gas is that they distort the allocation of resources between the extractive industries and other industries. When making investment decisions, companies consider the tax advantages associated with those decisions. By favoring extractive industries, tax preferences encourage some investments in drilling and mining that produce a smaller market value of output than the investments would produce elsewhere. In addition, the preferences encourage producers to extract more resources in a shorter time, accelerating the depletion of the nation's oil and gas resources and causing greater reliance on foreign producers in the long run.

An argument against making such changes is that the current system treats exploration and development costs for extractive industries similarly to research and development costs for other industries, which can be expensed by all businesses. Another argument against making changes is that such tax benefits increase the profitability of exploring and developing domestic energy resources, which can increase economic growth in the United States.

1. For an analysis of some aspects of the tax treatment for extractive industries, including the estimates of revenue effects cited in the text, see Congressional Budget Office, "Option 65: Repeal Certain Tax Preferences for Extractive Industries," in *Options for Reducing the Deficit: 2015 to 2024* (November 2014), p. 43, www.cbo.gov/budget-options/2014/49647.

cause the bid to rise above the minimum amount. Conversely, sealed-bid auctions (such as those that are used for offshore parcels) are less vulnerable to collusion and maintain an incentive for participants to bid above the minimum amount, because they do not know how many other participants might be bidding on the same parcel when they submit their bid.

Changing to a sealed-bid design would increase net federal income by $100 million over the subsequent 10 years, the Congressional Budget Office estimates, by increasing competition between firms for parcels. That additional competition would probably increase the amount that firms would have to pay to lease more valuable parcels and, as a result, could reduce the funds available in firms' exploration budgets for bidding on less valuable parcels. But CBO expects that any reduction in the number of parcels leased would have a negligible effect on production. Again, the parcels that firms would not lease under the new design would probably have gone unexplored even if leased. And they would be available for leasing in the future, when they might be more valuable and more likely to be developed.

An argument against the option might be this: Because the value of resources underlying a parcel is unknown, the open-outcry format allows firms to learn something about the estimates of other firms on the basis of their decision to remain in or exit the auction. However, the open-outcry approach currently used by BLM does not

Table 2-1.

Policy Options for Oil and Natural Gas Production on Federal Lands

Millions of Dollars

Option		Increase in Federal Income Over 10 Years
	Onshore Parcels	
1	Require onshore parcels to be auctioned through a sealed-bid process	100
2	Allow BLM to establish lease-specific fiscal terms	a
3	Increase the minimum bid for auctions and noncompetitive leases	50
4	Impose a fee of $6 per acre on nonproducing parcels	200
5	Increase the royalty rate to 18.75 percent for all new onshore parcels	200
	Offshore Parcels	
6	Require parcels to be nominated for auction	150
7	Impose a fee of $6 per acre on nonproducing parcels	500
8	Increase the royalty rate when the price of oil or gas rises above a threshold	Less Than 25

Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

All estimates represent net federal receipts after distributing appropriate shares of gross proceeds to the states.

BLM = Bureau of Land Management.

a. The effect on receipts would depend on details of the authorizing legislation and its implementation.

allow firms to observe the number of other firms that exit the auction at a particular price, only whether the firm willing to pay the highest bid continues to bid when the price increases. That information is less valuable, particularly if some firms are waiting until the end of the auction before submitting a bid.[4]

4. Analysts have examined other types of multiround auctions that could be less susceptible to collusion than open-outcry auctions and yet give bidders more information about the potential value of a parcel than sealed-bid auctions. See, for example, Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics,* vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752; and Peter Cramton, "How Best to Auction Oil Rights," in Macartan Humphreys, Jeffrey D. Sachs, and Joseph E. Stiglitz, eds., *Escaping the Resource Curse* (Columbia University Press, 2007).

Option 2. Allow BLM to Establish Lease-Specific Terms

Under current law, BLM is prohibited from considering the quality of a parcel in setting any of the terms of the leasing process. If that restriction was eliminated by legislation, BLM could keep the terms unchanged for parcels about which little is known or that are unlikely to be developed but make the terms more advantageous to the government for parcels that are most likely to contain oil or gas resources.

Giving BLM such flexibility would probably increase net federal income, particularly if the legislation prohibited changes that would tend to lower income, such as reductions in rental fees. Because the amount of increased income would depend on what the legislation required and how BLM implemented it, CBO has not estimated the amount of additional income that might result. If the terms were changed only for parcels with a high likelihood of development, the effect on production would probably be negligible.

One argument against this option is that implementation would be administratively expensive and difficult for BLM. However, other federal agencies and states already are establishing such parcel-specific terms. For example, BOEM sets different primary terms, rental fees, and minimum bids for offshore parcels on the basis of water depth (see Table 1-2 on page 13). Also, the state of North Dakota auctions leases with a royalty rate of 16.67 percent in counties where the presence of oil and gas is more speculative and a rate of 18.75 percent elsewhere.[5] As a more complex example, New Mexico categorizes all state leases into one of five types, each of which has a different rental rate, minimum bid, and royalty rate.[6] BLM could start by implementing a fairly simple rule and add complexity as managerial resources permitted.

Option 3. Increase the Minimum Bid for Onshore Auctions and Noncompetitive Leases

As set by BLM, the current minimum bonus bid for onshore parcels is $2 per acre, an amount that could be

5. Diane Nelson, North Dakota Department of Trust Lands, Minerals Management Division, personal communication (October 28, 2015).

6. New Mexico State Land Office, *Oil and Gas Manual* (May 2013), www.nmstatelands.org/oil-and-gas-manual.aspx.

increased through future rulemaking or legislation. If a parcel is leased noncompetitively, no bonus bid is paid; adding a minimum bonus bid for noncompetitive leases could also be done through rulemaking or legislation. Only a small share of parcels leased noncompetitively or for prices near the minimum bid are explored and developed: Among onshore parcels leased between 1996 and 2003, for instance, drilling permits were submitted for 8 percent of parcels leased for less than $10 per acre, compared with 25 percent of parcels leased for more than $10 per acre.[7]

Raising the minimum bid in an auction to $10 per acre and requiring that same amount to be paid for parcels leased noncompetitively would boost net federal income by an estimated $50 million over 10 years, CBO estimates. That effect is the net result of increases in federal income from higher bonus bids for some parcels, including all parcels leased noncompetitively, and decreases in rental and royalty income for parcels that attract no bids (though such parcels would have generated relatively little production and royalty income).

Notwithstanding that estimated increase in federal income, the general arguments against all of the options apply here: Returns to producing firms would be lower; and reductions in the number of parcels leased could mean that new information about the locations of oil and gas resources would become available more slowly, in turn reducing future production. Again, experience suggests that the latter effect would be negligible, in part because parcels that go unleased as a result of the higher minimum bid would have had relatively little exploration in any case.

Option 4. Impose a Fee on Nonproducing Parcels

The current rental fee for nonproducing onshore parcels is $1.50 per acre for the first five years and $2 per acre for the next five years; legislation that established a separate new fee of $6 per acre on nonproducing leases would increase net federal income by $200 million over 10 years, CBO estimates.[8] That effect is the net result of increases in income from fees and decreases in income from bonus bids, because the new fee would slightly reduce the amount private firms would be willing to bid in an auction for leases. That fee might also give firms a financial incentive to be more selective in acquiring parcels and to explore and develop those parcels more quickly (as discussed in Box 1-1 on page 10), although that effect is probably small because fees would typically be less than 1 percent of the costs of development. For that reason, CBO anticipates that such a fee would have a negligible effect on production.

Option 5. Increase the Royalty Rate

The royalty rate for onshore oil and gas production is 12.5 percent, which is the lowest royalty rate allowed under current law. That rate is lower than the 18.75 percent charged for offshore oil and gas production, and lower than the rates charged by many key Western states, including Wyoming, New Mexico, Colorado, and Utah.[9] (Many states have increased their royalty rates over the past decade.) Although BLM has the statutory authority to increase the royalty rate, it has not done so.

Raising the royalty rate for onshore parcels to 18.75 percent to match the rate for offshore parcels would generate $200 million in net federal income over the next 10 years, CBO estimates. Income generated in the following decade could be much greater, depending on market conditions: Because the higher rate would apply only to new leases and the affected parcels would not go into production immediately, the effect on federal income would be small initially but increase over time as the number of producing parcels subject to the new rate grew.

7. Offshore leases won with low bids also have low rates of development. In analysis supporting a 2011 increase in the minimum bid for offshore leases in the Gulf of Mexico from $37.50 per acre to $100 per acre, BOEM stated, "the last 15 years of lease sales in the Gulf of Mexico showed that deep water leases that received high bids of less than $100 per acre, adjusted for energy prices at the time of each sale, experienced virtually no exploration and development drilling." See Department of the Interior, *Oil and Gas Lease Utilization, Onshore and Offshore: Updated Report to the President* (May 2012), p. 9, http://go.usa.gov/ctCgW (PDF, 1.25 MB).

8. The estimate reflects an assumption that receipts from the new fee could not be spent without subsequent appropriations. If some or all of the receipts were available for direct spending (for example, to be distributed to the states), the net effect on the budget would be smaller or zero.

9. Center for Western Priorities, *A Fair Share: The Case for Updating Oil and Gas Royalties on Our Public Lands—Update* (June 18, 2015), http://tinyurl.com/j296qzt. From 2005 through 2014, those states were the top four producers of gas and four of the top six producers of oil from federal lands onshore; see Table 1-3 on page 20.

The effect on income is the net result of increases in royalty receipts and decreases in income from bonus bids. Such an increase in the royalty rate would also reduce the profitability of exploring speculative parcels compared with parcels owned by other jurisdictions, so CBO expects that some exploration would shift away from federal lands. But the subsequent decrease in production on federal lands would in all likelihood be small or negligible, particularly if the federal royalty rate remained equal to or below the royalty rates that apply to nearby state and private lands.[10] In addition, the higher royalty rate would probably cause firms to end production at wells with declining volumes earlier than they would with a lower royalty rate. That effect would probably also be small or negligible and occur several decades in the future.

Although federal income is estimated to increase under this option, one argument against it is that the effect on production could be large if oil or gas prices were very low, as they currently are. To address that issue, BLM could establish separate royalty rates for oil and gas that increased or decreased as the prices of those commodities rose or fell. That approach would give firms some relief in periods of low prices but would generate more federal income when prices rose; however, it could be more difficult and costly for BLM to implement.

Options for Offshore Oil and Gas

CBO evaluated three policy options for offshore oil and gas production (see Table 2-1 on page 31).[11]

- Requiring parcels to be nominated before auctioning (as are onshore parcels),
- Imposing a fee on nonproducing parcels, and
- Increasing royalty rates when the price of oil or gas rises.

10. For a review of the effects that increases in royalty rates can have on oil and gas production, see Ujjayant Chakravorty, Shelby Gerking, and Andrew Leach, "State Tax Policy and Oil Production: The Role of the Severance Tax and Credits for Drilling Expenses," in Gilbert E. Metcalf, ed., *U.S. Energy Tax Policy* (Cambridge University Press, 2011), pp. 305–337.

11. For an analysis of other options, see Economic Analysis, Inc., and Marine Policy Center, *Policies to Affect the Pace of Leasing and Incomes in the Gulf of Mexico Technical Report*, OCS Study BOEMRE 2011-014 (December 2010), http://go.usa.gov/cAEWF.

In CBO's estimation, the options as specified below would increase federal income by relatively small amounts and have negligible effects on production.

Not included in the analysis are changes already under consideration by BOEM. (The legislation authorizing the leasing process for offshore oil and gas production gives BOEM significant flexibility, which the agency has used to change the process several times over the past decade, on the basis of its research and analysis.)[12] CBO's baseline takes into account administrative actions that are likely to occur under current law; therefore, estimates of the budgetary effects of legislation directing BOEM to take actions that were likely to occur in any event would reflect only changes in the timing or certainty of those actions.

The two general arguments often made against the options for onshore parcels discussed earlier can also apply to the options for offshore parcels. First, the options would reduce income to shareholders and employees of oil and gas producers. Second, production (and thus government income) could be reduced over time: As lease-related costs increased, firms would probably reduce their inventory of the most speculative parcels, which would slow the accumulation of new information about those parcels and hence the identification of some oil and gas reserves.

For the changes considered in this report, the effects on production would probably be negligible because the relatively few parcels that would go unleased are those that would have been least likely to be explored under current law. Moreover, some of those parcels would be leased and developed later, after discoveries of oil or gas on nearby parcels made them more attractive. Larger changes to the fiscal terms could affect production, however, as happened when BOEM eliminated the royalty rate for deepwater leases issued between 1996 and 2000. That change most likely contributed to increased leasing of speculative parcels, which were then explored and developed when oil prices rose from less than $50 per barrel in the late 1990s to more than $100 per barrel a decade later.

12. See Department of the Interior, *Oil and Gas Lease Utilization, Onshore and Offshore: Updated Report to the President* (May 2012), http://go.usa.gov/ctCgW (PDF, 1.25 MB).

Option 6. Require Parcels to Be Nominated for Auction

Starting in 1983, BOEM began leasing parcels through an approach called areawide leasing, which divides all offshore acreage into discrete areas and then makes most parcels within each area available for auction according to the schedule devised in each five-year leasing program. That approach represented a change from a system in which BOEM (known as the Mineral Management Service at the time) largely determined which offshore parcels would be made available for leasing. Areawide leasing was adopted as a more efficient way to allow the private market to allocate expenditures for exploration, development, and production across acreage. That change increased the average number of auctioned parcels from 175 offered and 80 leased per auction before 1983 to several thousand offered and 400 leased per auction between 1983 and 2006.[13] The increase in acreage available for auction reduced competition for any single parcel and contributed to decreases in the price of each parcel and in total income from auction bids. Legislation that required BOEM to implement a nomination process to determine which parcels were auctioned, instead of including all parcels under areawide leasing, would probably increase competition for the nominated parcels.[14] In addition, firms would be more likely to bid on nominated parcels because they would assume that such parcels had a higher likelihood of containing oil and gas reserves.

Requiring nomination of offshore parcels could generate an additional $150 million over 10 years in net federal income, CBO estimates, depending on what the legislation required and how BOEM implemented it. CBO's analysis incorporates an assumption that BOEM would charge a small fee to nominate parcels, which would discourage firms from nominating many parcels as a way of distracting other bidders from their targeted parcels. Again, arguments against the option are that it would reduce earnings for leaseholders and decrease production, but the effect on production would probably be negligible.

Option 7. Impose a Fee on Nonproducing Parcels

As of the end of 2014, only about 17 percent of offshore parcels were producing oil or gas.[15] Some analysts speculate that firms are not gathering much information about parcels until after they have acquired leases for them.[16] A new fee on nonproducing parcels could encourage firms to gather more information before an auction, to focus on the most promising parcels, and to bid more competitively for those parcels. The effects would be similar to those of an increase in rental rates; in recent years, BOEM has raised base rental rates and established rate schedules that increase over the course of a lease to encourage faster exploration and development of parcels, as well as earlier decisions to return parcels that current leaseholders do not plan to explore.[17]

Legislation that established a new fee of $6 per acre on nonproducing parcels would increase net federal income by $500 million over 10 years, CBO estimates.[18] That effect is the net result of increases in income from fees and decreases in income from bonus bids, because the new fee would slightly reduce the amount firms would be

13. See Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics*, vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752; and Philip Haile, Kenneth Hendricks, and Robert Porter, "Recent U.S. Offshore Oil and Gas Lease Bidding: A Progress Report," *International Journal of Industrial Organization*, vol. 28, no. 4 (July 2010), pp. 390–396, http://dx.doi.org/10.1016/j.ijindorg.2010.02.010.

14. In the five-year leasing plan for 2012 to 2017, BOEM adopted a policy of "targeted leasing" for waters off the coast of Alaska. That policy requires that an interested party "provide specific information to support its nominations of areas to be considered for leasing"; see Bureau of Ocean Energy Management, "Enhancements to Alaska Outer Continental Shelf Lease Sales Process" (accessed March 18, 2016), http://go.usa.gov/cAmhw. The policy differs from the option considered here in that it does not require nominations of individual parcels to be auctioned.

15. See Bureau of Ocean Energy Management, "Combined Leasing Report as of January 1, 2015" (January 1, 2015).

16. See Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics*, vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752.

17. Statement of Tommy P. Beaudreau, Director, Bureau of Ocean Energy Management, before the Subcommittee on Interior, Environment, and Related Agencies, Committee on Appropriations (March 7, 2012), http://go.usa.gov/cAyq5. In the August 2014 auction of parcels in the Gulf of Mexico, the initial rental fee for parcels in water over 200 meters deep was $11 per acre; in contrast, the fee was $7.50 per acre a decade ago and $3 per acre in the 1990s.

18. The estimate incorporates the assumption that receipts from the new fee could not be spent without subsequent appropriations. If some or all of the receipts were available for direct spending (for example, to be distributed to the states), the net effect on the budget would be smaller or zero.

willing to bid at auction. Again, an argument against the option is that those increases in federal income would be decreases in income to the oil and gas firms. The fee's effects on production would probably be small, because the fee would typically be less than 0.1 percent of the costs of development.

Option 8. Increase the Royalty Rate When the Price of Oil or Gas Rises Above a Threshold

BOEM imposes a single royalty rate for all offshore leases, regardless of whether the parcel is producing oil, gas, or both. Various laws have reduced or eliminated royalty payments in certain areas if prices fall below a particular threshold: In 2014, for parcels in deep water or deep wells in shallow water, the threshold was set at about $5 per thousand cubic feet for gas and about $40 per barrel for oil.[19] In addition, BOEM has the authority to waive royalty payments for leaseholders who request such a waiver. The value of a productive parcel decreases as the price of oil or natural gas falls; however, when a parcel is leased in an auction, bidders do not know the future market price of oil or natural gas and thus bid on the basis of their best estimates of future prices. If prices fall unexpectedly, the leaseholder makes less profit than anticipated; conversely, if prices rise unexpectedly, the leaseholder makes more profit than anticipated. The current approach offers some leaseholders protection from falling oil and gas prices but does not benefit the government if prices rise. One alternative would be to create a royalty schedule that increased with prices.

If the royalty rate for oil rose to 25 percent when the real (inflation-adjusted) price of oil climbed above $100 per barrel and the rate for natural gas rose to 25 percent when its real price rose above $8 per thousand cubic feet, additional net federal income would be less than $25 million over the next decade, CBO estimates; it could be significantly larger in the following decade, depending on market conditions. That effect is the net result of increases in income from royalties and decreases in income from bonus bids, because the option would reduce slightly the expected profitability of leases. Because leases become more profitable for the firm holding the lease at higher oil or gas prices, the option would probably have a negligible effect on production.

In addition to the above general arguments, a specific argument against this option is that a tiered royalty system would be more complicated for BOEM to administer. But such systems have been implemented elsewhere: For example, Alberta, Canada, has set royalties for conventional oil that depend on both price and well production.[20]

19. The price of natural gas is currently below that threshold of $5 per thousand cubic feet. To qualify as a deep well in shallow water, the well must be more than 15,000 feet below sea level. For more information on the program and specific thresholds, see Department of the Interior, "Prices Above Which Full Royalties Are Due Notwithstanding Any Remaining Royalty Suspension Volumes," www.boem.gov/current-price-thresholds-determination (PDF, 100 KB).

20. For an evaluation, see Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), pp. 189–191, http://go.usa.gov/cwznH.

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About This Document

This report was prepared in response to a request from the Ranking Member of the House Committee on Natural Resources. In keeping with the Congressional Budget Office's mandate to provide objective, impartial analysis, the report makes no recommendations.

Andrew Stocking (formerly of CBO) and Perry Beider wrote the report with guidance from Joseph Kile and Chad Shirley. Jeff LaFave prepared the estimates for the policy options for onshore leasing, and Kathleen Gramp prepared the estimates for the policy options for offshore leasing. Terry Dinan, Kathleen Gramp, Jeff LaFave, Mark Lasky, Chayim Rosito, Kurt Seibert, and Rebecca Verreau provided useful comments. Lydia Cox and Andre Barbe (both formerly of CBO) provided help with data analysis. Tristan Hanon fact-checked the document.

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Jeffrey Kling and Robert Sunshine reviewed the report, Christine Bogusz edited it, and Maureen Costantino and Gabe Waggoner prepared it for publication. An electronic version is available on CBO's website (www.cbo.gov/publication/51421).

Keith Hall
Director

April 2016

CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

CBO

Options for Reducing the Deficit: 2017 to 2026

DECEMBER 2016

Notes

Unless otherwise indicated, all years referred to in this report regarding budgetary outlays and revenues are federal fiscal years, which run from October 1 to September 30 and are designated by the calendar year in which they end.

The numbers in the text and tables are in nominal (current year) dollars. Those numbers may not add up to totals because of rounding. In the tables, for changes in outlays, revenues, and the deficit, negative numbers indicate decreases, and positive numbers, increases. Thus, negative numbers for spending and positive numbers for revenues reduce the deficit, and positive numbers for spending and negative numbers for revenues increase it.

The baseline budget projections discussed in this report are those published in Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384. Such projections over the longer term are those in Congressional Budget Office, *The 2016 Long-Term Budget Outlook* (July 2016), www.cbo.gov/publication/51580. Budgetary results for 2016 reflect data published in Department of the Treasury, Bureau of the Fiscal Service, *Final Monthly Treasury Statement of Receipts and Outlays of the United States Government for Fiscal Year 2016 Through September 30, 2016, and Other Periods* (October 2016), http://go.usa.gov/x8X5v (PDF, 598 KB).

The estimates for the various options shown in this volume may differ from any previous or subsequent cost estimates for legislative proposals that resemble the options presented here.

As referred to in this report, the Affordable Care Act comprises the Patient Protection and Affordable Care Act, the health care provisions of the Health Care and Education Reconciliation Act of 2010, and the effects of subsequent judicial decisions, statutory changes, and administrative actions.

CBO's website includes a "Budget Options search" that allows users to search for options by major budget category, budget function, topic, and date (www.cbo.gov/budget-options).

The photographs of tax forms, rockets at Cape Canaveral, a home, and a health care professional are, respectively, © Gary L./Shutterstock.com, hbpictures/Shutterstock.com, Lindasj22/Shutterstock.com, and Have a nice day Photo/Shutterstock.com. The photograph of school buses comes from Flickr Creative Commons and is attributed to JohnPickenPhoto. The photograph of Carrier Strike Group 5 in formation with allied ships, provided courtesy of the Department of Defense, was taken by Navy Seaman Jamaal Liddell.

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CHAPTER

1

Introduction

The Congress faces an array of policy choices as it confronts the challenges posed by the amount of federal debt held by the public—which has more than doubled relative to the size of the economy since 2007—and the prospect of continued growth in that debt over the coming decades if the large annual budget deficits projected under current law come to pass (see Figure 1-1). To help inform lawmakers, the Congressional Budget Office periodically issues a compendium of policy options that would help to reduce the deficit.[1] This edition reports the estimated budgetary effects of various options and highlights some of the advantages and disadvantages of those options.

This volume presents 115 options that would decrease federal spending or increase federal revenues over the next decade (see Table 1-1 on page 6). The options included in this volume come from various sources. Some are based on proposed legislation or on the budget proposals of various Administrations; others come from Congressional offices or from entities in the federal government or in the private sector. The options cover many areas—ranging from defense to energy, Social Security, and provisions of the tax code. The budgetary effects identified for most of the options span the 10 years from 2017 to 2026 (the period covered by CBO's March 2016 baseline budget projections), although many of the options would have longer-term effects as well.[2]

1. For the most recent previous compilation of budget options, see Congressional Budget Office, *Options for Reducing the Deficit: 2015 to 2024* (November 2014), www.cbo.gov/publication/49638. That document included a brief description of the policy involved for each option. For additional information, including a description of each option's advantages and disadvantages, see Congressional Budget Office, *Options for Reducing the Deficit: 2014 to 2023* (November 2013), www.cbo.gov/publication/44715.

Chapters 2 through 5 present options in the following categories:

- Chapter 2: Mandatory spending other than that for health-related programs,
- Chapter 3: Discretionary spending other than that for health-related programs,
- Chapter 4: Revenues other than those related to health, and
- Chapter 5: Health-related programs and revenue provisions.

Chapter 6 differs from the rest of the volume; it discusses the challenges and the potential budgetary effects of eliminating a Cabinet department.

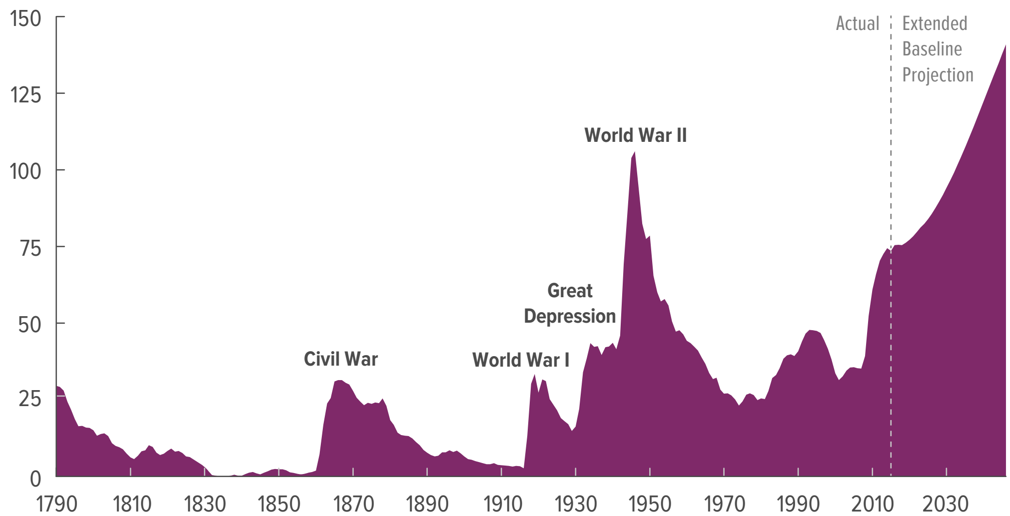
Chapters 2 through 5 begin with a description of budgetary trends for the topic area. Then, entries for the options provide background information, describe the possible policy change, and summarize arguments for and against that change. As appropriate, related options in this volume are referenced, as are related CBO publications. As a collection, the options are intended to reflect a range of possibilities, not a ranking of priorities or an exhaustive list. Inclusion or exclusion of any particular option does not imply an endorsement or rejection by CBO, and the report makes no recommendations. This volume does not contain comprehensive budget plans; it would be possible to devise such plans by combining certain options in various ways (although some would overlap and would interact with others).

2. Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

Figure 1-1.

Federal Debt Held by the Public

Percentage of Gross Domestic Product



High and rising federal debt would reduce national saving and income in the long term; increase the government's interest payments, thereby putting more pressure on the rest of the budget; limit lawmakers' ability to respond to unforeseen events; and increase the likelihood of a fiscal crisis.

Source: Congressional Budget Office.

CBO's most recent long-term projection of federal debt was completed in July 2016. See Congressional Budget Office, *The 2016 Long-Term Budget Outlook* (July 2016), www.cbo.gov/publication/51580. For details about the sources of data used for past debt held by the public, see Congressional Budget Office, *Historical Data on Federal Debt Held by the Public* (July 2010), www.cbo.gov/publication/21728.

The extended baseline generally reflects current law, following CBO's 10-year baseline budget projections through 2026 and then extending most of the concepts underlying those baseline projections for the rest of the long-term projection period.

CBO's website includes a "Budget Options search" that allows users to search for options by major budget category, budget function, topic, and date.[3] The online search is updated regularly to include only the most recent version of budget options from various CBO reports. All of the options in this volume currently appear in that online search. In addition, other options that appear in that search were analyzed in the past but not updated for this volume. Among those other options are ones that would yield comparatively small savings and ones discussed in recently published CBO reports analyzing specific federal programs or aspects of the tax code in detail. Although those other options were not updated in this volume, they represent approaches that policymakers might take to reduce deficits.

3. See Congressional Budget Office, "Budget Options," www.cbo.gov/budget-options.

The Current Context for Decisions About the Budget

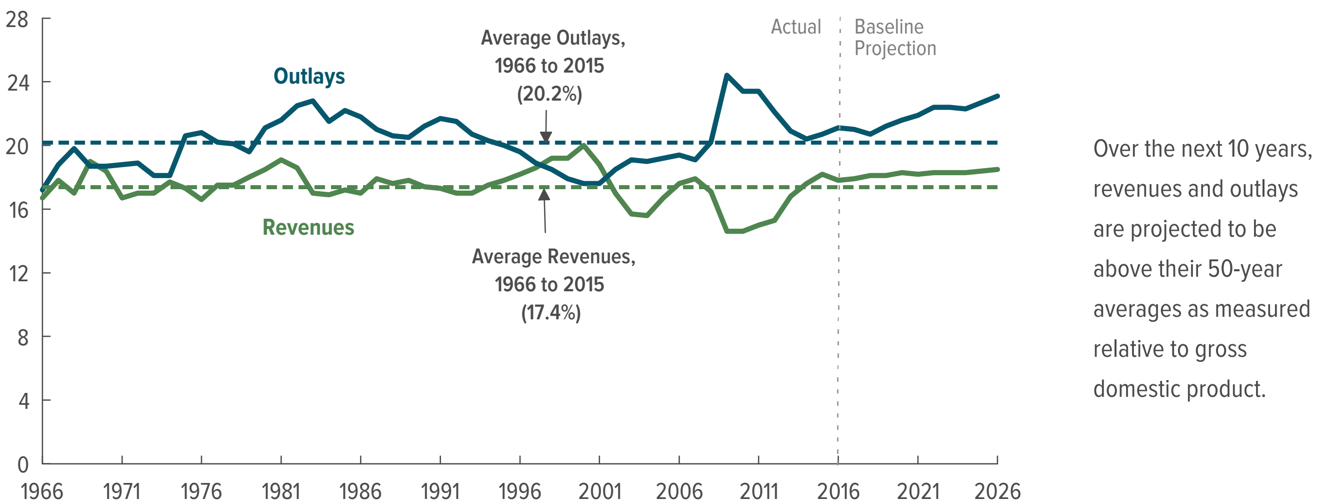
The federal budget deficit in fiscal year 2016 totaled $587 billion, or 3.2 percent of gross domestic product (GDP), up from 2.5 percent in 2015.[4] Last year's deficit marked the first increase in the budget shortfall, measured as a share of the nation's output, since 2009. As a result, debt held by the public increased to 77 percent of GDP at the end of 2016—about 3 percentage points higher than the amount in 2015 and the highest ratio since 1950.

4. About $41 billion of the deficit increase resulted from a shift in the timing of some payments that the government would ordinarily have made in fiscal year 2017; those payments were instead made in fiscal year 2016 because October 1, 2016 (the first day of fiscal year 2017), fell on a weekend. If not for that shift, CBO estimates, the deficit in 2016 would have been about $546 billion, or 3.0 percent of GDP—still considerably higher than the deficit recorded for 2015.

Figure 1-2.

Total Revenues and Outlays

Percentage of Gross Domestic Product



Source: Congressional Budget Office.

CBO's most recent budget projections (through 2026) were completed in August 2016. See Congressional Budget Office, *An Update to the Budget and Economic Outlook: 2016 to 2026* (August 2016), www.cbo.gov/publication/51908.

As specified in law, CBO constructs its baseline projections of federal revenues and spending under the assumption that current laws will generally remain unchanged. Under that assumption, annual budget shortfalls in CBO's projection rise substantially over the 2017–2026 period, from a low of $520 billion in 2018 to $1.2 trillion in 2026 (see Table 1-2 on page 10).[5] That increase is projected to occur mainly because growth in revenues would be outpaced by a combination of significant growth in spending on retirement and health care programs—caused by the aging of the population and rising health care costs per person—and growing interest payments on federal debt. Deficits are projected to dip from 3.1 percent of GDP in 2017 to 2.6 percent in 2018 and then to begin rising again, reaching 4.6 percent at the end of the 10-year period—significantly above the average deficit as a percentage of GDP between 1966 and 2015. Over the next 10 years, revenues and outlays alike are projected to be above their 50-year averages as measured relative to GDP (see Figure 1-2).

As deficits accumulate in CBO's baseline, debt held by the public rises to 86 percent of GDP (or $23 trillion) by 2026. At that level, debt held by the public, measured as a percentage of GDP, would be more than twice the average over the past five decades. Beyond the 10-year period, if current laws remained in place, the pressures that contributed to rising deficits during the baseline period would accelerate and push up debt even more sharply. Three decades from now, for instance, debt held by the public is projected to be about twice as high, relative to GDP, as it is this year—which would be a higher ratio than the United States has ever recorded.[6]

Such high and rising debt would have serious consequences, both for the economy and for the federal budget. Federal spending on interest payments would rise substantially as a result of increases in interest rates, such as those projected to occur over the next few years. Moreover, because federal borrowing reduces national saving over time, the nation's capital stock ultimately

5. For CBO's most recent budget and economic projections, see Congressional Budget Office, *An Update to the Budget and Economic Outlook: 2016 to 2026* (August 2016), www.cbo.gov/publication/51908.

6. See Congressional Budget Office, *The 2016 Long-Term Budget Outlook* (July 2016), www.cbo.gov/publication/51580. CBO's long-term projections, which focus on the 30-year period ending in 2046, generally adhere closely to current law, following the agency's March 2016 baseline budget projections through the usual 10-year projection period and then extending the baseline concept into later years.

would be smaller and productivity and income would be lower than would be the case if the debt was smaller. In addition, lawmakers would have less flexibility than otherwise to respond to unexpected challenges, such as significant economic downturns or financial crises. Finally, the likelihood of a fiscal crisis in the United States would increase. Specifically, the risk would rise of investors' becoming unwilling to finance the government's borrowing unless they were compensated with very high interest rates. If that occurred, interest rates on federal debt would rise suddenly and sharply relative to rates of return on other assets.

Not only are deficits and debt projected to be greater in coming years, but the United States also is on track to have a federal budget that will look very different from budgets of the past. Under current law, in 2026 spending for all federal activities other than the major health care programs and Social Security is projected to account for its smallest share of GDP since 1962.[7] At the same time, revenues would represent a larger percentage of GDP in the future—averaging 18.3 percent of GDP over the 2017–2026 period—than they generally have in the past few decades. Despite those trends, revenues would not keep pace with outlays under current law because the government's major health care programs (particularly Medicare) and Social Security would absorb a much larger share of the economy's output in the future than they have in the past.

Choices for the Future

To put the federal budget on a sustainable long-term path, lawmakers would need to make significant policy changes—allowing revenues to rise more than they would under current law, reducing spending for large benefit programs to amounts below those currently projected, or adopting some combination of those approaches.

Lawmakers and the public may weigh several factors in considering new policies that would reduce budget deficits: What is an acceptable amount of federal debt, and hence, how much deficit reduction is necessary? How rapidly should such reductions occur? What is the proper size of the federal government, and what would be the best way to allocate federal resources? What types of policy changes would most enhance prospects for near-term and long-term economic growth? What would be the distributional implications of proposed changes—that is, who would bear the burden of particular cuts in spending or increases in taxes, and who would realize long-term economic benefits?

The scale of changes in noninterest spending or revenues would depend on the target level of federal debt. If lawmakers set out to ensure that debt in 2046 would equal 75 percent of GDP (close to the current share), cutting noninterest spending or raising revenues in each year (or both) beginning in 2017 by amounts totaling 1.7 percent of GDP (about $330 billion in 2017, or $1,000 per person) would achieve that result.[8] Increases in revenues or reductions in noninterest spending would need to be larger to reduce debt to the percentages of GDP that are more typical of those in recent decades. If lawmakers wanted to return the debt to 39 percent of GDP (its average over the past 50 years) by 2046, one way to do so would be to increase revenues or cut noninterest spending (in relation to current law), or do some combination of the two, beginning in 2017 by amounts totaling 2.9 percent of GDP each year. (In 2017, 2.9 percent of GDP would be about $560 billion, or $1,700 per person.)

In deciding how quickly to implement policies to put federal debt on a sustainable path—regardless of the chosen goal for federal debt—lawmakers face trade-offs. Reducing the deficit sooner would have several benefits: less accumulated debt, smaller policy changes required to achieve long-term outcomes, and less uncertainty about which policies lawmakers would adopt. However, if lawmakers implemented spending cuts or tax increases quickly, people would have little time to plan and adjust to the policy changes, and the ongoing economic expansion would be weakened. By contrast, waiting several years to implement reductions in federal spending or increases in taxes would mean more accumulated debt over the long run, which would slow long-term growth

7. The major health care programs consist of Medicare, Medicaid, and the Children's Health Insurance Program, along with federal subsidies for health insurance purchased through the marketplaces established under the Affordable Care Act and related spending.

8. The amounts of those reductions are calculated before macroeconomic feedback is taken into account. The projected effects on debt include both those direct effects of the specified policy changes and the resulting macroeconomic feedback to the budget.

in output and income. Also, delaying would mean that reaching any chosen target for debt would require larger policy changes.[9]

Caveats About This Volume

The ways in which specific federal programs, the budget as a whole, and the U.S. economy will evolve under current law are uncertain, as are the possible effects of proposed changes to federal spending and revenue policies. Because a broad range of results for any change in policy is plausible, CBO's estimates are designed to fall in the middle of the distribution of possible outcomes.

The estimates presented in this volume could differ from cost estimates for similar proposals that CBO might produce later or from revenue estimates developed later by the staff of the Joint Committee on Taxation (JCT). One reason is that the proposals on which those estimates were based might not precisely match the options presented here. Another is that the baseline budget projections against which such proposals would ultimately be measured might have changed and thus would differ from the projections used for this report.

In addition, some proposals similar to options presented in this volume would be defined as "major" legislation and thus would require CBO and JCT, to the greatest extent practicable, to incorporate the budgetary impact of macroeconomic effects into 10-year cost estimates. (Major legislation is defined as either having a gross budgetary effect, before incorporating macroeconomic effects, of 0.25 percent of GDP in any year over the next 10 years, or having been designated as such by the Chair of either Budget Committee. CBO projects that 0.25 percent of GDP in 2026 would be about $70 billion.) Those macroeconomic effects might include, for example, changes in the labor supply or private investment. Incorporating such macroeconomic feedback into cost estimates is often called dynamic scoring. The estimates presented in this volume do not incorporate such effects.

Many of the options in this volume could be combined to provide building blocks for broader changes. In some cases, however, combining various spending or revenue options would produce budgetary effects that would differ from the sums of those estimates as presented here because some options would overlap or interact in ways that would change their budgetary impact. And some options would be mutually exclusive. In addition, some options are flexible enough to be scaled up or down, leading to larger or smaller effects on households, businesses, and government budgets. Other options, such as those that eliminate programs, could not be scaled up.

To reduce projected deficits (relative to the baseline) through changes in discretionary spending, lawmakers would need to decrease the statutory funding caps below the levels already established under current law or enact appropriations below those caps. The discretionary options in this report could be used to accomplish either of those objectives. Alternatively, some of the options could be implemented to help comply with the existing caps on discretionary funding that are in place through 2021.

In some cases, CBO has not yet developed specific estimates of secondary effects for some options that would primarily affect mandatory or discretionary spending or revenues but that also could have other, less direct, effects on the budget.

The estimated budgetary effects of options do not reflect the extent to which those policy changes would reduce interest payments on federal debt. Those savings may be included as part of a comprehensive budget plan (such as the Congressional budget resolution), but CBO does not make such calculations for individual pieces of legislation or for individual options of the type discussed here.

Some of the estimates in this volume depend on projections of states' responses to federal policy changes, which can be difficult to predict and can vary over time because of states' changing fiscal conditions and other factors. CBO's analyses do not attempt to quantify the impact of options on states' spending or revenues.

Some options might impose federal mandates on other levels of government or on private entities. The Unfunded Mandates Reform Act of 1995 requires CBO to estimate the costs of any mandates that would be imposed by new legislation that the Congress considers. (The law defines mandates as enforceable duties imposed on state, local, or tribal governments or the private sector as well as certain types of provisions affecting large mandatory programs that provide funds to states.) In this volume, CBO does not address the costs of any mandates that might be associated with the various options.

9. For additional discussion, see Congressional Budget Office, *Choices for Deficit Reduction: An Update* (December 2013), www.cbo.gov/publication/44967.

Table 1-1.

Options for Reducing the Deficit

Option Number	Title	Savings, 2017–2026[a] (Billions of dollars)
	Mandatory Spending (Other than that for health-related programs)	
Option 1	Change the Terms and Conditions for Oil and Gas Leasing on Federal Lands	3
Option 2	Limit Enrollment in the Department of Agriculture's Conservation Programs	10
Option 3	Eliminate Title I Agriculture Programs	25
Option 4	Reduce Subsidies in the Crop Insurance Program	27
Option 5	Eliminate ARC and PLC Payments on Generic Base Acres	4
Option 6	Limit ARC and PLC Payment Acres to 50 Percent of Base Acres	11
Option 7	Raise Fannie Mae’s and Freddie Mac’s Guarantee Fees and Decrease Their Eligible Loan Limits	6
Option 8	Eliminate the Add-On to Pell Grants, Which Is Funded With Mandatory Spending	60
Option 9	Limit Forgiveness of Graduate Student Loans	19
Option 10	Reduce or Eliminate Subsidized Loans for Undergraduate Students	8 to 27
Option 11	Eliminate Concurrent Receipt of Retirement Pay and Disability Compensation for Disabled Veterans	139
Option 12	Reduce Pensions in the Federal Employees Retirement System	7
Option 13	Convert Multiple Assistance Programs for Lower-Income People Into Smaller Block Grants to States	367[b]
Option 14	Eliminate Subsidies for Certain Meals in the National School Lunch, School Breakfast, and Child and Adult Care Food Programs	10
Option 15	Tighten Eligibility for the Supplemental Nutrition Assistance Program	88
Option 16	Reduce TANF's State Family Assistance Grant by 10 Percent	14
Option 17	Eliminate Supplemental Security Income Benefits for Disabled Children	104[b]
Option 18	Link Initial Social Security Benefits to Average Prices Instead of Average Earnings	72 to 114
Option 19	Make Social Security's Benefit Structure More Progressive	8 to 36
Option 20	Raise the Full Retirement Age for Social Security	8
Option 21	Reduce Social Security Benefits for New Beneficiaries	105 to 190
Option 22	Require Social Security Disability Insurance Applicants to Have Worked More in Recent Years	45
Option 23	Eliminate Eligibility for Starting Social Security Disability Benefits at Age 62 or Later	17
Option 24	Narrow Eligibility for Veterans’ Disability Compensation by Excluding Certain Disabilities Unrelated to Military Duties	26
Option 25	Restrict VA’s Individual Unemployability Benefits to Disabled Veterans Who Are Younger Than the Full Retirement Age for Social Security	40
Option 26	Use an Alternative Measure of Inflation to Index Social Security and Other Mandatory Programs	182
	Discretionary Spending (Other than that for health-related programs)	
Option 1	Reduce the Size of the Military to Satisfy Caps Under the Budget Control Act	251
Option 2	Reduce DoD’s Operation and Maintenance Appropriation, Excluding Funding for the Defense Health Program	49 to 151
Option 3	Cap Increases in Basic Pay for Military Service Members	21
Option 4	Replace Some Military Personnel With Civilian Employees	13
Option 5	Cancel Plans to Purchase Additional F-35 Joint Strike Fighters and Instead Purchase F-16s and F/A-18s	23
Option 6	Stop Building Ford Class Aircraft Carriers	15
Option 7	Reduce Funding for Naval Ship Construction to Historical Levels	27
Option 8	Reduce the Size of the Nuclear Triad	9 to 13

Continued

Table 1-1. Continued

Options for Reducing the Deficit

Option Number	Title	Savings, 2017–2026[a] (Billions of dollars)
	Discretionary Spending (Other than that for health-related programs) (Continued)	
Option 9	Build Only One Type of Nuclear Weapon for Bombers	6 to 8
Option 10	Defer Development of the B-21 Bomber	27
Option 11	Reduce Funding for International Affairs Programs	117
Option 12	Eliminate Human Space Exploration Programs	81
Option 13	Reduce Department of Energy Funding for Energy Technology Development	16
Option 14	Eliminate Certain Forest Service Programs	6
Option 15	Convert the Home Equity Conversion Mortgage Program From a Guarantee Program to a Direct Loan Program	23[b]
Option 16	Eliminate the International Trade Administration’s Trade Promotion Activities	3
Option 17	Eliminate Funding for Amtrak and the Essential Air Service Program	16[b]
Option 18	Limit Highway Funding to Expected Highway Revenues	40
Option 19	Eliminate Federal Funding for National Community Service	8
Option 20	Eliminate Head Start	84
Option 21	Restrict Pell Grants to the Neediest Students	4 to 65[b]
Option 22	Increase Payments by Tenants in Federally Assisted Housing	18
Option 23	Reduce the Number of Housing Choice Vouchers or Eliminate the Program	16 to 111
Option 24	Reduce the Annual Across-the-Board Adjustment for Federal Civilian Employees’ Pay	55
Option 25	Reduce the Size of the Federal Workforce Through Attrition	50
Option 26	Impose Fees to Cover the Cost of Government Regulations and Charge for Services Provided to the Private Sector	24
Option 27	Repeal the Davis-Bacon Act	13[b]
Option 28	Eliminate or Reduce Funding for Certain Grants to State and Local Governments	56
	Revenues (Other than those related to health)	
Option 1	Increase Individual Income Tax Rates	93 to 734
Option 2	Implement a New Minimum Tax on Adjusted Gross Income	66
Option 3	Raise the Tax Rates on Long-Term Capital Gains and Qualified Dividends by 2 Percentage Points	57
Option 4	Use an Alternative Measure of Inflation to Index Some Parameters of the Tax Code	157
Option 5	Convert the Mortgage Interest Deduction to a 15 Percent Tax Credit	105
Option 6	Curtail the Deduction for Charitable Giving	229
Option 7	Limit the Deduction for State and Local Taxes	955
Option 8	Limit the Value of Itemized Deductions	119 to 2,232
Option 9	Change the Tax Treatment of Capital Gains From Sales of Inherited Assets	68
Option 10	Eliminate the Tax Exemption for New Qualified Private Activity Bonds	28
Option 11	Expand the Base of the Net Investment Income Tax to Include the Income of Active Participants in S Corporations and Limited Partnerships	160
Option 12	Tax Carried Interest as Ordinary Income	20
Option 13	Include Disability Payments From the Department of Veterans Affairs in Taxable Income	38 to 94
Option 14	Include Employer-Paid Premiums for Income Replacement Insurance in Employees' Taxable Income	336
Option 15	Further Limit Annual Contributions to Retirement Plans	92

Continued

Table 1-1. Continued

Options for Reducing the Deficit

Option Number	Title	Savings, 2017–2026[a] (Billions of dollars)
	Revenues (Other than those related to health) (Continued)	
Option 16	Tax Social Security and Railroad Retirement Benefits in the Same Way That Distributions From Defined Benefit Pensions Are Taxed	423
Option 17	Eliminate Certain Tax Preferences for Education Expenses	195
Option 18	Lower the Investment Income Limit for the Earned Income Tax Credit and Extend That Limit to the Refundable Portion of the Child Tax Credit	7
Option 19	Require Earned Income Tax Credit and Child Tax Credit Claimants to Have a Social Security Number That Is Valid for Employment	37
Option 20	Increase the Maximum Taxable Earnings for the Social Security Payroll Tax	633 to 1,008
Option 21	Expand Social Security Coverage to Include Newly Hired State and Local Government Employees	78
Option 22	Increase the Payroll Tax Rate for Medicare Hospital Insurance by 1 Percentage Point	823
Option 23	Tax All Pass-Through Business Owners Under SECA and Impose a Material Participation Standard	137
Option 24	Increase Taxes that Finance the Federal Share of the Unemployment Insurance System	13 to 15
Option 25	Increase Corporate Income Tax Rates by 1 Percentage Point	100
Option 26	Capitalize Research and Experimentation Costs and Amortize Them Over Five Years	185
Option 27	Extend the Period for Depreciating the Cost of Certain Investments	251
Option 28	Repeal Certain Tax Preferences for Energy and Natural Resource-Based Industries	24
Option 29	Repeal the Deduction for Domestic Production Activities	174
Option 30	Repeal the "LIFO" and "Lower of Cost or Market" Inventory Accounting Methods	102
Option 31	Subject All Publicly Traded Partnerships to the Corporate Income Tax	6
Option 32	Repeal the Low-Income Housing Tax Credit	34
Option 33	Determine Foreign Tax Credits on a Pooling Basis	82
Option 34	Require a Minimum Level of Taxation of Foreign Income as It Is Earned	301
Option 35	Further Limit the Deduction of Interest Expense for Multinational Corporations	68
Option 36	Increase Excise Taxes on Motor Fuels by 35 Cents and Index for Inflation	474
Option 37	Impose an Excise Tax on Overland Freight Transport	343
Option 38	Increase All Taxes on Alcoholic Beverages to $16 per Proof Gallon	70
Option 39	Impose a 5 Percent Value-Added Tax	1,770 to 2,670
Option 40	Impose a Fee on Large Financial Institutions	98
Option 41	Impose a Tax on Financial Transactions	707
Option 42	Impose a Tax on Emissions of Greenhouse Gases	977
Option 43	Increase Federal Civilian Employees' Contributions to the Federal Employees Retirement System	48

Continued

Table 1-1. Continued

Options for Reducing the Deficit

Option Number	Title	Savings, 2017–2026[a] (Billions of dollars)
	Health	
Option 1	Adopt a Voucher Plan and Slow the Growth of Federal Contributions for the Federal Employees Health Benefits Program	31[b]
Option 2	Impose Caps on Federal Spending for Medicaid	370 to 680
Option 3	Limit States' Taxes on Health Care Providers	16 to 40
Option 4	Repeal All Insurance Coverage Provisions of the Affordable Care Act	1,236
Option 5	Repeal the Individual Health Insurance Mandate	416
Option 6	Introduce Minimum Out-of-Pocket Requirements Under TRICARE for Life	27
Option 7	Change the Cost-Sharing Rules for Medicare and Restrict Medigap Insurance	18 to 66
Option 8	Increase Premiums for Parts B and D of Medicare	22 to 331
Option 9	Raise the Age of Eligibility for Medicare to 67	18
Option 10	Reduce Medicare's Coverage of Bad Debt	15 to 31
Option 11	Require Manufacturers to Pay a Minimum Rebate on Drugs Covered Under Part D of Medicare for Low-Income Beneficiaries	145
Option 12	Consolidate and Reduce Federal Payments for Graduate Medical Education at Teaching Hospitals	32
Option 13	Limit Medical Malpractice Claims	62[b]
Option 14	End Congressional Direction of Medical Research in the Department of Defense	9
Option 15	Modify TRICARE Enrollment Fees and Cost Sharing for Working-Age Military Retirees	18[b]
Option 16	End Enrollment in VA Medical Care for Veterans in Priority Groups 7 and 8	54[b]
Option 17	Increase the Excise Tax on Cigarettes by 50 Cents per Pack	35
Option 18	Reduce Tax Preferences for Employment-Based Health Insurance	174 to 429

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

ARC = Agriculture Risk Coverage; DoD = Department of Defense; LIFO = last in, first out; PLC = Price Loss Coverage; SECA = Self-Employment Contributions Act; TANF = Temporary Assistance for Needy Families; VA = Department of Veterans Affairs.

a. For options affecting primarily mandatory spending or revenues, savings sometimes would derive from changes in both. When that is the case, the savings shown include effects on both mandatory spending and revenues. For options affecting primarily discretionary spending, the savings shown are the decrease in discretionary outlays. That same approach applies for the savings shown for health options; most are mandatory spending options or revenue options, although 14, 15, and 16 are discretionary spending options.

b. Savings do not encompass all budgetary effects.

Table 1-2.

CBO's Baseline Budget Projections

	Actual												Total	
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017-2021	2017-2026
							In Billions of Dollars							
Revenues	3,250	3,267	3,421	3,600	3,745	3,900	4,048	4,212	4,385	4,574	4,779	4,993	18,714	41,658
Outlays	3,688	3,854	4,015	4,120	4,370	4,614	4,853	5,166	5,373	5,574	5,908	6,235	21,973	50,229
Deficit	-438	-587	-594	-520	-625	-714	-806	-954	-988	-1,000	-1,128	-1,243	-3,258	-8,571
Debt Held by the Public at the End of the Year	13,117	14,173	14,743	15,325	16,001	16,758	17,597	18,584	19,608	20,649	21,824	23,118	n.a.	n.a.
							As a Percentage of Gross Domestic Product							
Revenues	18.2	17.8	17.9	18.1	18.1	18.2	18.2	18.3	18.3	18.3	18.4	18.5	18.1	18.3
Outlays	20.6	20.9	21.0	20.7	21.2	21.6	21.9	22.4	22.4	22.3	22.7	23.1	21.3	22.0
Deficit	-2.4	-3.2	-3.1	-2.6	-3.0	-3.3	-3.6	-4.1	-4.1	-4.0	-4.3	-4.6	-3.2	-3.8
Debt Held by the Public at the End of the Year	73.6	77.0	77.2	77.0	77.5	78.4	79.3	80.5	81.7	82.7	84.0	85.5	n.a.	n.a.

Source: Congressional Budget Office. CBO's most recent budget projections (2017 through 2026) were completed in August 2016. See Congressional Budget Office, *An Update to the Budget and Economic Outlook: 2016 to 2026* (August 2016), www.cbo.gov/publication/51908.

n.a. = not applicable.

CHAPTER

2

Mandatory Spending Options

Mandatory spending—which totaled about $2.4 trillion in 2016, or about 60 percent of federal outlays, the Congressional Budget Office estimates—consists of spending (other than that for net interest) that is generally governed by statutory criteria and is not normally constrained by the annual appropriation process. Mandatory spending also includes certain types of payments that federal agencies receive from the public and from other government agencies. Those payments are classified as offsetting receipts and reduce gross mandatory spending.[1] Lawmakers generally determine spending for mandatory programs by setting the programs' parameters, such as eligibility rules and benefit formulas, rather than by appropriating specific amounts each year.

The largest mandatory programs are Social Security and Medicare. Together, CBO estimates, those programs accounted for about 60 percent of mandatory outlays, on average, over the past 10 years. Medicaid and other health care programs accounted for about 15 percent of mandatory spending over that same period. The rest of mandatory spending is for income security programs (such as unemployment compensation, nutrition assistance programs, and Supplemental Security Income), certain refundable tax credits, retirement benefits for civilian and military employees of the federal government, veterans' benefits, student loans, and agriculture programs.[2]

1. Unlike revenues, which the government collects through exercising its sovereign powers (for example, in levying income taxes), offsetting receipts are generally collected from other government accounts or from members of the public through businesslike transactions (for example, in assessing Medicare premiums or rental payments and royalties for extracting oil or gas from federal lands).

2. Tax credits reduce a taxpayer's overall tax liability (the amount owed). When a refundable credit exceeds the liability apart from the credit, the excess may be refunded to the taxpayer. In that case, that refund is recorded in the budget as an outlay.

Trends in Mandatory Spending

As a share of the economy, mandatory spending more than doubled between 1966 and 1975, from 4.5 percent to 9.4 percent of gross domestic product (GDP). That increase was attributable mainly to growth in spending for Social Security and other income security programs, and to a lesser extent for Medicare and Medicaid. From 1975 through 2007, mandatory spending varied between roughly 9 percent and 10 percent of GDP. Such spending peaked in 2009 at 14.5 percent of GDP, boosted by effects of the 2007–2009 recession and policies enacted in response to it. Mandatory spending as a share of GDP dropped to 12.2 percent by 2014—as the effects of a gradually improving economy, the expiration of temporary legislation enacted in response to the recession, and payments from Fannie Mae and Freddie Mac partially offset the longer-run upward trend—and then started to rise again (see Figure 2-1). If no new laws were enacted that affected mandatory programs, CBO estimates, mandatory outlays would increase as a share of the economy, from 13.3 percent of GDP in 2016 to 15.2 percent in 2026.[3] By comparison, such spending averaged 9.4 percent of GDP over the past five decades.

Spending for Social Security and the major health care programs—particularly Medicare—drives much of the growth in mandatory spending.[4] CBO projects that, under current law, spending for Social Security and

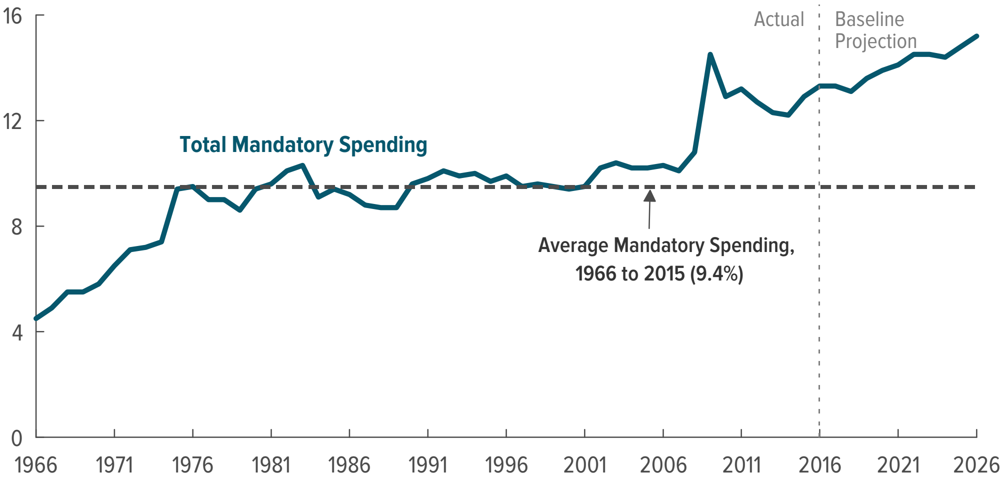
3. For more on the components of mandatory spending and CBO's baseline budget projections, see Congressional Budget Office, *An Update to the Budget and Economic Outlook: 2016 to 2026* (August 2016), www.cbo.gov/publication/51908.

4. Outlays for the major health care programs consist of spending for Medicare (net of premiums and other offsetting receipts), Medicaid, and the Children's Health Insurance Program, as well as spending to subsidize health insurance purchased through the marketplaces established under the Affordable Care Act and related spending.

Figure 2-1.

Mandatory Spending

Percentage of Gross Domestic Product



Under current law, mandatory spending will continue to rise as a percentage of gross domestic product over the next decade.

Source: Congressional Budget Office (as of August 2016).

Data include offsetting receipts (funds collected by government agencies from other government accounts or from the public in businesslike or market-oriented transactions that are recorded as offsets to outlays).

the major health care programs will increase from 10.4 percent of GDP in 2016 to 12.6 percent in 2026, accounting for almost two-thirds of the total increase in outlays over that period. (Those percentages reflect adjustments to eliminate the effects of shifts in the timing of certain payments.) Factors driving that increase include the aging population and rising health care costs per person. In particular, over the next decade, as members of the baby-boom generation age and as life expectancy increases, the number of people age 65 or older is expected to rise by more than one-third, boosting the number of beneficiaries of those programs. Moreover, CBO projects that spending per enrollee in federal health care programs will grow more rapidly over the coming decade than it has in recent years. As a result, projected spending for people age 65 or older in the three largest programs—Social Security, Medicare, and Medicaid—increases from roughly one-third of all federal noninterest spending in 2016 to about 40 percent in 2026.

In contrast, outlays for all other mandatory programs would decline as a share of GDP, from 2.8 percent in 2016 to 2.5 percent by 2026. That projected decline would occur in part because benefit levels for many programs are adjusted for inflation each year, and in CBO's economic forecast, inflation is estimated to be well below the rate of growth in nominal GDP.

Analytic Method Underlying the Estimates of Mandatory Spending

The budgetary effects of the various options are measured in relation to the spending that CBO projected in its March 2016 baseline.[5] In creating its mandatory baseline budget projections, CBO generally assumes that federal fiscal policy follows current law and that programs now scheduled to expire or begin in future years will do so. That assumption applies to most, but not all, mandatory programs. Following procedures established in the Balanced Budget and Emergency Deficit Control Act of 1985 and the Balanced Budget Act of 1997, CBO assumes that some mandatory programs scheduled to expire in the coming decade under current law will instead be extended. In particular, in CBO's baseline, all such programs that predate the Balanced Budget Act and that have outlays in the current year above $50 million are presumed to continue. For programs established after 1997, continuation is assessed on a program-by-program basis in consultation with the House and Senate Committees on the Budget. The Supplemental Nutrition Assistance Program is the largest expiring program assumed to be extended in the baseline.

5. See Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

Another of CBO's assumptions involves the federal government's dedicated trust funds for Social Security and Medicare.[6] If a trust fund is exhausted and the receipts coming into it during a given year are not enough to pay full benefits as scheduled under law for that year, the program has no legal authority to pay full benefits. Benefits then must be reduced to bring outlays in line with receipts. Nonetheless, in accordance with section 257 of the Deficit Control Act, CBO's baseline incorporates the assumption that, in coming years, beneficiaries will receive full payments and all services to which they are entitled under Social Security or Medicare.

6. Social Security's beneficiaries receive payments from the Old-Age and Survivors Insurance Trust Fund and the Disability Insurance Trust Fund. Medicare's Hospital Insurance Trust Fund pays for care in hospitals and other institutions under Part A; its Supplementary Medical Insurance Trust Fund pays for care by physicians and other providers under Part B and for prescription drugs under Part D. Both Medicare trust funds also pay benefits for people who join private Medicare Advantage plans under Part C.

Options in This Chapter

The 26 options in this chapter encompass a broad array of mandatory spending programs, excluding those involving health care. (Chapter 5 presents options that would affect spending for health care programs, along with options affecting health-related taxes.) The options are grouped by program, but some are conceptually similar even though they concern different programs. For instance, several options would shift spending from the government to a program's participants or from the federal government to the states. Other options would redefine the population eligible for benefits or would reduce the payments that beneficiaries receive.

Six options in this chapter concern Social Security. Another five involve means-tested benefit programs (including nutrition assistance programs and the Supplemental Security Income program). The remaining options focus on programs that deal with education, veterans' benefits, federal pensions, agriculture, Fannie Mae and Freddie Mac, and natural resources. Each option's budgetary effect is estimated independently, with no consideration of how it might interact with other options.

Mandatory Spending—Option 1 Function 300

Change the Terms and Conditions for Oil and Gas Leasing on Federal Lands

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	0	0	*	-1.3	-0.2	-0.2	-0.8	-0.2	-0.2	-0.4	-1.6	-3.4

This option would take effect in October 2017.

* = between –$50 million and zero.

The federal government lets private businesses bid on leases to develop most of the onshore and offshore oil and natural gas resources on federal property. By the Congressional Budget Office's estimates, the federal government's gross proceeds from those leases will total $92 billion during the next decade, under current laws and policies; after paying a share of those receipts to states, the federal government is projected to collect net proceeds totaling $79 billion. Those net proceeds are counted in the budget as offsetting receipts—that is, as negative outlays.

This option would change the leasing programs in two ways. First, it would increase the acreage available for leasing by repealing the statutory prohibition on leasing in the Arctic National Wildlife Refuge (ANWR) and by directing the Department of the Interior to lease areas on the Outer Continental Shelf (OCS) that are unavailable under current administrative policies. Second, the option would change the terms of all new leases, imposing a fee that applied during years when oil or gas was not produced. (The latest available data indicate that such nonproducing leases accounted for about 75 percent of offshore leases at the end of fiscal year 2016 and about half of onshore leases at the end of fiscal year 2015.) The fee would be $6 per acre per year.

CBO estimates that those changes would reduce net federal outlays by $3 billion from 2018 through 2026. About three-quarters of that total would result from leasing in ANWR and the increase in leasing on the OCS, and the rest would result from the new fee on nonproducing leases.

One rationale for offering leases in ANWR and additional leases on the OCS is that increasing oil and gas production from federal lands and waters could boost employment and economic output. The leasing also could raise revenues for state and local governments; the amounts would depend on states' tax policies, the amount of oil and gas produced in each area, and the existing formulas for distributing some federal oil and gas proceeds to states. The primary argument against expanded leasing is that oil and gas production in environmentally sensitive areas, such as the coastal plain in ANWR and other coastal areas, could threaten wildlife, fisheries, and tourism. Moreover, increased development of resources in the near term would reduce the supply of oil and gas available for production in the future, when prices might be higher and households and businesses might value the products more highly.

One rationale for imposing a new fee on nonproducing oil and gas leases is that doing so could slightly increase the efficiency of oil and gas production: Firms would have an additional financial incentive to refrain from acquiring leases that they considered less likely to be worth exploring, and also to invest sooner in exploration and development of the leases that they did acquire. The incentive's effect would be small, however, because $6 per acre would usually be a small part of a parcel's potential value and a minor factor in a leaseholder's decisions about when to begin exploration and production.

An argument against the new fee is that it might lead businesses to reduce some of their bids on leases; furthermore, some parcels might go unleased entirely, generating no receipts for the government either from bids or from production royalties. However, CBO estimates that those effects on receipts would be smaller than the receipts from the new fee itself. The effect on bids would be small because a fee of $6 per acre would significantly affect bids for relatively few parcels—those that would generate low bids even without the fee because of uncertainty about the availability and production cost of oil and gas resources. Similarly, the effect on royalty payments would be small because the unleased parcels would be those with the lowest likelihood of successful development. Moreover, some parcels that went unleased under the option could be acquired later if their value increased; bids then would probably be higher, and royalty payments could be higher as well.

RELATED OPTION: Revenues, Option 28

RELATED CBO PUBLICATIONS: *Options for Increasing Federal Income From Crude Oil and Natural Gas on Federal Lands* (April 2016), www.cbo.gov/publication/51421; *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527; *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012

Mandatory Spending—Option 2 Function 300

Limit Enrollment in the Department of Agriculture's Conservation Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Phase out the Conservation Stewardship Program	0	*	-0.2	-0.4	-0.5	-0.7	-0.9	-1.0	-1.2	-1.5	-1.1	-6.4
Scale back the Conservation Reserve Program	0	*	*	*	-0.1	-0.1	-0.5	-0.6	-0.9	-1.0	-0.1	-3.3
Both alternatives above	0	*	-0.2	-0.4	-0.6	-0.8	-1.4	-1.7	-2.2	-2.4	-1.3	-9.7

This option would take effect in October 2017.

* = between –$50 million and zero.

Under the Conservation Stewardship Program (CSP), landowners enter into contracts with the Department of Agriculture (USDA) to undertake various conservation measures—including ones to conserve energy and improve air quality—in exchange for annual payments and technical help. Those contracts last five years and can be extended for another five years. For every acre enrolled in the CSP, a producer receives compensation for carrying out new conservation activities and for improving, maintaining, and managing existing conservation practices. Current law limits new enrollment in the CSP to 10 million acres per year, at an average cost of $18 per acre; in 2015, USDA spent $1 billion on the program.

Under the Conservation Reserve Program (CRP), landowners enter into contracts to stop farming on specified tracts of land, usually for 10 to 15 years, in exchange for annual payments and cost-sharing grants from USDA to establish conservation practices on that land. One type of tract used in the program is a "conservation buffer"—a narrow strip of land maintained with vegetation to intercept pollutants, reduce erosion, and provide other environmental benefits. Acreage may be added to the CRP through general enrollments, which are competitive and held periodically for larger tracts of land, or through continuous enrollments, which are available at any time during the year for smaller tracts of land. Current law caps total enrollment in the CRP at 24 million acres by 2017; in 2015, USDA spent $2 billion on the roughly 24 million acres enrolled.

Beginning in 2018, the first part of this option would prohibit new enrollment in the CSP. Land enrolled now—and therefore hosting new or existing conservation activities—would be eligible to continue in the program until the contract for that land expired. By the Congressional Budget Office's estimates, prohibiting new enrollment would reduce federal spending by $6 billion through 2026.

Beginning in 2018, the second part of this option would prohibit both new enrollment and reenrollment in the general enrollment portion of the CRP; continuous enrollment would remain in effect under the option. Prohibiting general enrollment would reduce spending by $3 billion through 2026, CBO estimates. The amount of land enrolled in the CRP would drop to about 10 million acres by 2026.

One argument for prohibiting new enrollment in the CSP and thus phasing out the program is that some provisions of the program limit its effectiveness. For example, paying farmers for conservation practices they have already adopted may not enhance the nation's conservation efforts. Moreover, USDA's criteria to determine payments for conservation practices are not clear, and payments may be higher than necessary to encourage farmers to adopt new conservation measures.

An argument against phasing out the CSP is that, unlike traditional crop-based subsidies, the CSP may offer a way to support farmers while also providing environmental benefits. Furthermore, conservation practices often impose significant up-front costs, which can reduce the net economic output of agricultural land, and CSP payments help offset those costs.

One argument for scaling back the CRP is that the land could become available for other uses that would provide greater environmental benefits. For example, reducing enrollment could free more land to produce crops and biomass for renewable energy products.

An argument against scaling back the CRP is that studies have indicated that the program yields high returns—in the form of enhanced wildlife habitat, improved water quality, and reduced soil erosion—for the money it spends. Furthermore, USDA is enrolling more acres targeting specific environmental and resource concerns, perhaps thereby improving the cost-effectiveness of protecting fragile tracts.

RELATED OPTIONS: Mandatory Spending, Options 3, 4, 5, 6

Mandatory Spending—Option 3 Function 350

Eliminate Title I Agriculture Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays	0	0	*	-0.3	-4.5	-4.1	-4.2	-4.0	-4.0	-4.3	-4.8	-25.4

This option would take effect in October 2018.

* = between zero and $50 million.

Since 1933, lawmakers have enacted and often modified various programs to support commodity prices and supplies, farm income, and producer liquidity. The Agricultural Act of 2014 (the 2014 farm bill) was the most recent comprehensive legislation addressing farm income and price support programs. Title I of that bill authorized those programs through 2018 for producers of major commodities (such as corn, soybeans, wheat, and cotton) and specialized programs for dairy and sugar.

Beginning with the 2019 marketing year—when most programs expire and after existing contracts end—this option would eliminate all Title I commodity support programs. (For example, that period begins on June 1, 2019, for wheat and September 1, 2019, for corn.) Under this option, the permanent agriculture legislation enacted in 1938 and 1949 also would be repealed. (That permanent legislation would offer producers price and income support at a relatively high level after the 2014 farm bill expired.)

Although authorization for the Title I programs expires in October 2018, the option would generate savings with respect to the Congressional Budget Office's baseline projections because, in its baseline, CBO is required by law to assume that those programs continue beyond their expiration date. Reductions in government spending with respect to CBO's baseline would begin in fiscal year 2020 and savings would rise sharply in fiscal year 2021, when most outlays for the 2019 marketing year appear in the baseline. CBO estimates that this option would reduce spending by $25 billion, with respect to that baseline, over the 2019–2026 period.

During the Great Depression of the 1930s, the 25 percent of the U.S. population who lived on farms had less than half the average household income of urban households; federal commodity programs came about to alleviate that income disparity. One argument for eliminating Title I commodity support programs is that the structure of U.S. farms has changed dramatically since then: The significant income disparity between farm and urban populations no longer exists. In 2014, about 97 percent of all farm households (which now constitute about 2 percent of the U.S. population) were wealthier than the median U.S. household. Farm income, excluding program payments, was 58 percent higher than median U.S. household income. Moreover, commodity payments today are concentrated among a relatively small portion of farms. Three-quarters of all farms received no farm-related government payments in 2014; most program payments, in total, went to mid- to large-scale farms (those with annual sales above $350,000).

Moreover, agricultural producers would continue to have access to other federal assistance programs, such as subsidized crop insurance and farm credit assistance. In addition, eliminating Title I programs would limit spending that may distort trade, thereby reducing the risk that the World Trade Organization might again challenge U.S. agricultural support (as it did with the U.S. cotton program).

An argument against eliminating commodity programs is that despite relatively high average income among farmers, the farm sector still faces significant challenges. Farm income fluctuates markedly and depends on the vagaries of the weather and international markets. Commodity programs try to stabilize crop revenues over time. Also, much of U.S. agricultural production is exported to markets where foreign governments subsidize their producers. Without support from commodity programs, U.S. producers may not be able to compete fairly in those export markets. Finally, many years of continual government payments from commodity programs have been capitalized into the fixed assets of farm operations (primarily land); abruptly removing that income stream would cause farmers' wealth to drop significantly.

RELATED OPTIONS: Mandatory Spending, Options 2, 4, 5, 6

Mandatory Spending—Option 4 **Function 350**

Reduce Subsidies in the Crop Insurance Program

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Reduce premium subsidies	0	-0.2	-2.3	-2.7	-2.8	-2.8	-2.8	-2.9	-2.9	-2.9	-8.0	-22.3
Limit administrative expenses and the rate of return	0	-0.1	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-1.7	-4.7
Both alternatives above	0	-0.3	-2.8	-3.3	-3.4	-3.4	-3.4	-3.5	-3.5	-3.5	-9.7	-27.0

This option would take effect in June 2017.

The Federal Crop Insurance Program protects farmers from losses caused by droughts, floods, pest infestations, other natural disasters, and low market prices. Farmers can choose various amounts and types of insurance protection—for example, they can insure against losses caused by poor crop yields, low crop prices, or both. The Department of Agriculture (USDA) sets rates for federal crop insurance so that the premiums equal the expected payments to farmers for crop losses. Of total premiums, the federal government pays about 60 percent, on average, and farmers pay about 40 percent. Private insurance companies—which the federal government reimburses for their administrative costs—sell and service insurance policies purchased through the program. The federal government reinsures those private insurance companies by agreeing to cover some of the losses when total payouts exceed total premiums.

Beginning in June 2017, this option would reduce the federal government's subsidy to 40 percent of the crop insurance premiums, on average. It also would limit the federal reimbursement to crop insurance companies for administrative expenses to 9.25 percent of estimated premiums and limit the rate of return on investment for those companies to 12 percent each year. Under current law, by the Congressional Budget Office's estimates, federal spending for crop insurance will total $88 billion from 2017 through 2026. Reducing the crop insurance subsidies as specified in this option would save $27 billion over that period, CBO estimates.

An argument in favor of this option is that cutting the federal subsidies for premiums would probably not substantially affect participation in the program. Private lenders increasingly view crop insurance as an important way to ensure that farmers can repay their loans, which encourages participation. In addition, the farmers who dropped out of the program would generally continue to receive significant support from other federal farm programs. However, if significantly fewer farmers participate, then some smaller crop insurance companies would probably go out of business.

Current reimbursements to crop insurance companies for administrative expenses (around $1.3 billion per year) were established in 2010, when premiums were relatively high. Recent reductions in the value of the crops insured (partly because of lower average commodity prices) have resulted in lower average premiums for crop insurance. However, administrative expenses have not shown a commensurate reduction. A cap of 9.25 percent, or about $915 million per year, is close to average reimbursements during the years before the run-up in commodity prices in 2010. Furthermore, according to a recent USDA study, the current rate of return on investment for crop insurance companies, 14 percent, was higher than that of other private companies, on average.

An argument against this option is that cutting the federal subsidies for premiums would probably cause farmers to buy less insurance. If the amount of insurance declined significantly, lawmakers might be more likely to enact significant difficulties, which would offset some of the savings from cutting the premium subsidy. (Such ad hoc disaster assistance programs for farmers cost an average of about $700 million annually in the early 2000s.) In addition, limiting reimbursements to companies for administrative expenses and reducing the targeted rate of return to companies could add to the financial stress of companies in years with significant payouts for covered losses.

RELATED OPTIONS: Mandatory Spending, Options 2, 3, 5, 6

Mandatory Spending—Option 5 Function 350

Eliminate ARC and PLC Payments on Generic Base Acres

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Outlays	0	0	-0.1	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-1.2	-4.2

This option would take effect in June 2018.

The Agricultural Act of 2014 replaced the existing agricultural support programs with the Agriculture Risk Coverage (ARC) and Price Loss Coverage (PLC) programs. The law also removed upland cotton from the list of commodities eligible for payments available to producers with base acres (those acres with a proven history of being planted with covered commodities established with the Department of Agriculture under statutory authority granted by previous farm bills).[1] Finally, the 2014 law assigned upland cotton base acres to a new category called generic base acres and allows for ARC and PLC payments on generic base acres if producers plant a covered commodity on those acres.[2]

Beginning in crop year 2018, this option would eliminate ARC and PLC payments on generic base acres.[3] Most savings from eliminating ARC and PLC payments on generic base acres would begin in fiscal year 2020, when ARC and PLC payments for the 2018 crop year would be made.[4] Because of its likely effects on peanut planted acres, the option also would, starting in 2019, lead to lower outlays for the government's peanut marketing loan program. The Congressional Budget Office estimates that savings under this option would be $4 billion through 2026.

Linking payments on generic base acres to current (rather than historical) planting decisions is a departure from previous farm support programs, which had sought to decouple support payments from planting decisions to limit subsidies that may distort agricultural markets.[5] Arguments in this option's favor relate to removing such potential distortions, particularly as they relate to peanuts. Motivated by a high peanut PLC support price, growers have disproportionately planted peanuts on generic base acres to collect larger payments. The number of acres planted with peanuts increased by 27 percent in 2014 and by 20 percent in 2015, and ending stocks (the quantity of peanuts remaining in storage at the end of the crop year) for 2016 are projected to be slightly less than the record-high peanut stocks at the end of 2005.

The increase in acres planted with peanuts has had a large negative effect on U.S. peanut prices paid to farmers because the market for the crop is relatively small and inelastic.[6] Peanut prices decreased by 12 percent during the 2014–2015 marketing year and by an additional 12 percent in 2015–2016. As a result of those price declines, per-acre payment rates in 2014 and 2015 were higher for peanuts than for any other covered commodity. At the same time, the income of peanut growers who do not have base acres (albeit a small segment of peanut growers) has been dampened. This option would cut the link between program payments and planting decisions. Planted acreage for peanuts would be expected to contract, increasing the market price for peanuts and the

1. Only farmers who have established base acres may participate in the ARC and PLC programs. The most recent opportunity was in 2002.
2. Covered commodities include wheat, oats, barley, corn, grain sorghum, long-grain rice, medium-grain rice, legumes, soybeans, other oilseeds, and peanuts.
3. ARC and PLC payments are set to expire beginning with the 2019 crop year. However, following the rules for developing baseline projections specified by the Balanced Budget and Emergency Deficit Control Act of 1985, the Congressional Budget Office's 10-year baseline incorporates the assumption that lawmakers will extend those programs after they expire.
4. A crop year (also called a marketing year) begins in the month that the crop is first harvested and ends 12 months later. For example, the corn marketing year begins September 1 and ends the following August 31.
5. The World Trade Organization Agreement on Agriculture imposes limits on agricultural subsidies linked to production.
6. Around 60 percent of U.S. peanuts are typically marketed to the domestic food market (for peanut butter, candy, and snack nuts). The price of peanuts is inelastic (meaning that a 1 percent change in price results in a less than 1 percent change in consumption).

share of peanut growers' income that is not accounted for by government spending.

In addition, this option might avert potential World Trade Organization (WTO) challenges to the U.S. peanut program. Government support has enabled domestic peanut sellers to sell more peanuts internationally than they otherwise might have. That increase has drawn the attention of peanut-exporting countries, who might argue that such an arrangement violates WTO rules.[7]

One argument against this option is that some producers of covered commodities would receive less federal support. Although peanut prices paid to farmers might rise without payments on generic base acres, many growers appear to favor the income stability fostered by the federal programs.

7. Brazil successfully challenged U.S. subsidies for upland cotton through the WTO in 2002. Under threat of retaliatory trade measures involving other U.S. industries, the U.S. government changed its upland cotton support program. Many of those changes were enacted in the 2014 farm bill, including removing upland cotton from the list of covered commodities.

RELATED OPTIONS: Mandatory Spending, Options 2, 3, 4, 6

Mandatory Spending—Option 6 Function 350

Limit ARC and PLC Payment Acres to 50 Percent of Base Acres

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays	0	0	0	-0.1	-1.9	-1.8	-1.9	-1.8	-1.8	-1.8	-2.0	-11.1

This option would take effect in June 2019.

The Agricultural Act of 2014 provides support to producers of covered commodities through the Agriculture Risk Coverage (ARC) and Price Loss Coverage (PLC) programs:[1]

- ARC guarantees revenue at either the county level (ARC-County, or ARC-CO—accounting for most coverage) or the individual farm level (ARC-Individual Coverage, or ARC-IC). The program pays farmers when actual crop revenue in a given crop year is below the revenue guarantee for that year.[2]
- PLC pays farmers when the national average market price for a covered commodity in a given crop year falls below a reference price specified in the law.

Eligibility under those programs is determined from a producer's planting history. Only producers who have established base acres (that is, a proven history of planting covered commodities on their farms) with the Department of Agriculture under statutory authority granted by previous farm bills may participate. In general, growers with base acres for covered commodities (corn base acres, for example) need not plant a crop to receive payments.[3]

When a payment for a crop is triggered, total payments are calculated by multiplying the payment rate (on a per-acre basis) by a producer's payment acres for that crop. For ARC-CO and PLC, the number of payment acres equals 85 percent of base acres; for ARC-IC, it is 65 percent of base acres.

Beginning with the 2019 crop year, this option would limit payment acres for ARC-CO and for PLC to 50 percent of base acres and would make a comparable cut to ARC-IC (to 42 percent of base acres).[4] Savings would largely begin in fiscal year 2021, when ARC and PLC payments for crop year 2019 would be made.[5] Total savings over the 2019–2026 period would be $11 billion, the Congressional Budget Office estimates.

One argument in favor of this option is that it would limit program payments to nonfarmer landowners and on land no longer used to grow crops. The economics literature suggests that nonfarmer landowners capture between 25 percent and 40 percent—and sometimes up to 60 percent—of program payments through increased land rents; to the extent that program payments raise land values, new farmers face higher costs to buy land. Also, the benefits of farm program payments tend to accrue to larger farms, which may speed consolidation and make it

1. Covered commodities include wheat, oats, barley, corn, grain sorghum, long-grain rice, medium-grain rice, legumes, soybeans, other oilseeds, and peanuts.
2. A crop year (also called a marketing year) begins in the month that the crop is first harvested and ends 12 months later. For example, the corn marketing year begins September 1 and ends the following August 31.
3. Exceptions include generic base acres and ARC-IC. For generic base acres (which are former upland cotton base acres), producers must plant a covered commodity on that acreage to receive payments. Also, producers participating in ARC-IC must plant the commodity to establish actual crop revenue.
4. Because producers entered into contracts with the Department of Agriculture to receive payments on 85 percent of base acres through the 2018 crop year, the Congressional Budget Office assumes that the limit to payment acres would begin in crop year 2019. Though ARC and PLC are set to expire beginning with the 2019 crop year, following the rules for developing baseline projections specified by the Balanced Budget and Emergency Deficit Control Act of 1985, CBO's 10-year baseline incorporates the assumption that lawmakers will extend those programs after they expire.
5. Because of the option's likely effects on peanut planted acres and the resulting domestic peanut supply, savings would include reduced outlays for the peanut marketing loan program, which would occur starting in 2020.

harder for new farmers to enter. Finally, because only covered commodities are eligible for ARC and PLC support, the availability of those payments tends to encourage farmers to plant crops they might not otherwise plant.

An argument against this option is that farming is an inherently risky enterprise. Many growers favor the income stability fostered by federal programs.

RELATED OPTIONS: Mandatory Spending, Options 2, 3, 4, 5

Mandatory Spending—Option 7 **Function 370**

Raise Fannie Mae's and Freddie Mac's Guarantee Fees and Decrease Their Eligible Loan Limits

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Outlays												
Increase guarantee fees	0	-0.8	-0.3	-0.1	-0.3	-0.5	-0.5	-0.7	-1.0	-1.4	-1.6	-5.6
Decrease loan limits	0	-0.1	-0.1	*	-0.1	-0.2	-0.2	-0.1	-0.2	-0.3	-0.3	-1.2
Both alternatives above[a]	0	-0.9	-0.4	-0.1	-0.4	-0.6	-0.6	-0.7	-1.0	-1.4	-1.8	-6.0

This option would take effect in October 2017.

* = between –$50 million and zero.

a. If both alternatives were enacted together, the total effect would be less than the sum of the effects of each alternative because of interactions between them.

Fannie Mae and Freddie Mac are government-sponsored enterprises (GSEs) that were federally chartered to help ensure a stable supply of financing for residential mortgages, including those for low- and moderate-income borrowers. Those GSEs carry out that mission through two activities in the secondary mortgage market (that is, the market for buying and selling mortgages after they have been issued): by issuing and guaranteeing mortgage-backed securities (MBSs) and by buying mortgages and MBSs to hold as investments. Under current law, the entities generally can guarantee and purchase mortgages up to $625,500 in areas with high housing costs and $417,000 in other areas, and regulators can alter those limits if house prices change. Those two GSEs provided credit guarantees for about half of all single-family mortgages that originated in 2015.

In September 2008—after falling house prices and rising mortgage delinquencies threatened the GSEs' solvency and impaired their ability to ensure a steady supply of financing to the mortgage market—the federal government took control of Fannie Mae and Freddie Mac in a conservatorship process. Because of that shift in control, the Congressional Budget Office concluded that the institutions had effectively become government entities whose operations should be reflected in the federal budget. By CBO's projections under current law, the mortgage guarantees that the GSEs issue from 2017 through 2026 will cost the federal government $12 billion. That estimate reflects the subsidies inherent in the guarantees at the time they are made—that is, the up-front payments that a private entity would need to receive (in an orderly market and allowing for the fees that borrowers pay) to assume the federal government's responsibility for those guarantees. CBO's estimates are constructed on a present-value basis. (A present value is a single number that expresses a flow of current and future payments in terms of an equivalent lump sum paid today; the present value of future cash flows depends on the discount rate that is used to translate them into current dollars.) By contrast, the Administration's projections focus on the cash flows between the enterprises and the Treasury. Those cash flows reflect a mix of existing and new business. Both CBO and the Administration expect the government to receive substantial net cash inflows from Fannie Mae and Freddie Mac over the 2017–2026 period.

This option includes two approaches to reduce the federal subsidies that Fannie Mae and Freddie Mac receive. In the first approach, the average guarantee fee that Fannie Mae and Freddie Mac assess on loans they include in their MBSs would increase by 10 basis points (100 basis points is equivalent to 1 percentage point), to more than 65 basis points, on average, beginning in October 2017. In addition, to keep guarantee fees constant after 2021—when an increase of 10 basis points that was put in place in 2011 is scheduled to expire—the average guarantee fee would be increased, with respect to the amount under current law, by 20 basis points after 2021. The increased collections of fees, which the GSEs would be required to pass through to the Treasury, would reduce net federal spending by $6 billion from 2017 through 2026, would cause new guarantees by Fannie Mae and Freddie Mac to fall by around 10 percent, and would change the mix of borrowers, CBO estimates. (The effect on spending is the sum of the present values of the decreases in subsidies for mortgages made in each of nine years after the option would take effect.)

In the second approach, the maximum size of a mortgage that Fannie Mae and Freddie Mac could include in their MBSs would be reduced, beginning with a drop to $417,000 in October 2017, followed by drops to $260,000 in 2021 and $175,000 in 2024. (Guarantee fees would remain as they are under current law.) That reduction in loan limits would save $1 billion from 2017 through 2026 because new guarantees would fall by about 20 percent, CBO estimates.

Taking both approaches together would lower federal subsidies for Fannie Mae and Freddie Mac by $6 billion from 2017 through 2026 and would result in a drop in new guarantees of about 25 percent, according to CBO's estimates. Because raising guarantee fees by 10 basis points would eliminate most of the federal subsidies for the GSEs, taking the additional step of lowering loan limits would have little effect on subsidies. For consistency, similar changes could be made to the limits on loans guaranteed by the Federal Housing Administration (FHA). The estimates presented here do not include the effects of lower limits on FHA loans, which would affect discretionary spending subject to appropriations.

Because some of the subsidies that Fannie Mae and Freddie Mac receive flow to mortgage borrowers in the form of lower rates, both approaches in this option would raise borrowing costs. The higher guarantee fees would probably pass directly through to borrowers in the form of higher mortgage rates. The lower loan limits would push some borrowers into the so-called jumbo mortgage market, where loans exceed the eligible size for guarantees by Fannie Mae and Freddie Mac and where rates might be slightly higher, on average.

The major advantage of those approaches to reduce federal subsidies for Fannie Mae and Freddie Mac is that they could restore a larger role for the private sector in the secondary mortgage market, which would reduce taxpayers' exposure to the risk of defaults. Lessening subsidies also would help address the current underpricing of mortgage credit risk, which encourages borrowers to take out bigger mortgages and buy more expensive homes. Consequently, the option could reduce overinvestment in housing and shift the allocation of some capital toward more productive activities.

A particular advantage of lowering loan limits, instead of raising fees, is that many moderate- and low-income borrowers would continue to benefit from the subsidies provided to the GSEs. More-affluent borrowers generally would lose that benefit, but they typically can more easily find other sources of financing. The $175,000 limit would allow for the purchase of a home for about $220,000 (with a 20 percent down payment), which was roughly the median price of an existing single-family residence in March 2016; thus, lowering loan limits as specified here would not affect most moderate- and low-income borrowers.

One disadvantage of reducing subsidies for the GSEs and thereby increasing the cost of mortgage borrowing is that doing so could weaken housing markets because new construction and new home sales have not completely recovered from their sharp drop several years ago. Moreover, mortgage delinquency rates remain elevated, and many borrowers are still "underwater" (that is, they owe more than their homes are worth). Posing another drawback, the slightly higher mortgage rates resulting from lower subsidies would limit some opportunities for refinancing—perhaps constraining spending by some consumers and thereby dampening the growth of private spending. Phasing in the specified changes more slowly could mitigate those concerns, although that approach would reduce the budgetary savings as well. Finally, by affecting the GSEs, this option would make FHA loans more attractive to some borrowers (without corresponding changes to the rules governing FHA loans), which could increase risks for taxpayers because FHA guarantees loans with lower down payments than do the GSEs.

RELATED OPTIONS: Discretionary Spending, Option 15; Revenues, Option 5

RELATED CBO PUBLICATIONS: *The Effects of Increasing Fannie Mae's and Freddie Mac's Capital* (October 2016), www.cbo.gov/publication/52089; *The Federal Role in the Financing of Multifamily Rental Properties* (December 2015), www.cbo.gov/publication/51006; *Transitioning to Alternative Structures for Housing Finance* (December 2014), www.cbo.gov/publication/49765; *Modifying Mortgages Involving Fannie Mae and Freddie Mac: Options for Principal Forgiveness* (May 2013), www.cbo.gov/publication/44115; *Fannie Mae, Freddie Mac, and the Federal Role in the Secondary Mortgage Market* (December 2010), www.cbo.gov/publication/21992; *CBO's Budgetary Treatment of Fannie Mae and Freddie Mac* (January 2010), www.cbo.gov/publication/41887

Mandatory Spending—Option 8 **Function 500**

Eliminate the Add-On to Pell Grants, Which Is Funded With Mandatory Spending

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	-1.6	-6.0	-6.2	-6.3	-6.4	-6.5	-6.6	-6.7	-6.8	-6.9	-26.5	-60.0

This option would take effect in July 2017.

The Federal Pell Grant Program is the largest source of federal grant aid to low-income students for undergraduate education. For the 2016–2017 academic year, the program will provide $28 billion in aid to 7.8 million students, the Congressional Budget Office estimates. A student's Pell grant eligibility is chiefly determined on the basis of his or her expected family contribution (EFC)—the amount that the federal government expects a family to pay toward the student's postsecondary education expenses. The EFC is based on factors such as the student's income and assets. For dependent students (in general, unmarried undergraduate students under the age of 24 who have no dependents of their own), the parents' income and assets, as well as the number of people (excluding parents) in the household who are attending postsecondary schools, are also taken into account. To be eligible for the maximum grant, which is $5,815 for the 2016–2017 academic year, a student must have an EFC of zero and be enrolled in school full time. For each dollar of EFC above zero, a student's eligible grant amount is reduced by a dollar. Students with an EFC exceeding 90 percent of the maximum grant (that is, an EFC of $5,234 for the 2016–2017 academic year) are ineligible for a grant. Part-time students are eligible for smaller grants than those received by full-time students with the same EFC.

Since 2008, funding for the Pell grant program has had both discretionary and mandatory components. The discretionary component, which is set in each fiscal year's appropriation act, specifies a maximum award of $4,860 per student for the 2016–2017 academic year. That award is bolstered by mandatory funding, which provides an "add-on." The add-on for the 2016–2017 academic year is $955, resulting in the total maximum award of $5,815. Under current law, the add-on is indexed to inflation through the 2017–2018 academic year and remains constant thereafter.

This option would eliminate the add-on to Pell grants, thereby reducing the maximum grant awarded to students with an EFC of zero to $4,860 for the 2016–2017 academic year. There would be two effects. First, about 3 percent of people who will be eligible for Pell grants under current law would lose that eligibility—because to be eligible, people would now need an EFC that was below 90 percent of the new, smaller maximum grant. Second, people who remained eligible would see their grant size reduced by the amount of the add-on. CBO estimates that this option would result in a reduction of $60 billion in mandatory spending over the 2017–2026 period.

A few studies suggest that some postsecondary institutions have responded to past increases in the size of Pell grants by raising tuition or shifting more of their own aid to students who did not qualify for Pell grants. A rationale for reducing the maximum Pell grant, therefore, is that institutions might become less likely to raise tuition and more likely to aid students who had lost eligibility for a Pell grant or who were receiving a smaller Pell grant. In addition, this option would spread the reductions in grants among all recipients, minimizing the impact on any individual recipient.

But an argument against this option is that even with the grant at its current amount, the cost of attending a public four-year college is greater for most recipients than their EFC plus all financial aid—and for many recipients attending private colleges, the gap is even larger. Reducing Pell grants (and eliminating them for some students) would further increase that financial burden and might cause some students to choose a less suitable institution, less postsecondary education, or none at all. Moreover, among students who remained eligible for Pell grants under this option, grant amounts would be reduced uniformly, regardless of the students' financial need. By contrast, targeted reductions in grants might be more effective in protecting one of the program's goals: boosting the educational attainment of students from the lowest-income families.

RELATED OPTIONS: Mandatory Spending, Option 10; Discretionary Spending, Option 21; Revenues, Option 17

RELATED CBO PUBLICATIONS: *The Pell Grant Program: Recent Growth and Policy Options* (September 2013), www.cbo.gov/publication/44448; *Options to Change Interest Rates and Other Terms on Student Loans* (June 2013), www.cbo.gov/publication/44318

Mandatory Spending—Option 9 Function 500

Limit Forgiveness of Graduate Student Loans

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Estimated Using the Method Established in the Federal Credit Reform Act												
Change in Outlays												
Limit amount forgiven under the PSLF program	-0.1	-0.3	-0.4	-0.5	-0.6	-0.7	-0.8	-1.0	-1.1	-1.2	-1.8	-6.7
Extend repayment period for IDR plans	-0.2	-0.4	-0.6	-0.8	-1.0	-1.2	-1.5	-1.7	-2.0	-2.1	-3.1	-11.6
Both alternatives above[a]	-0.3	-0.8	-1.1	-1.4	-1.7	-2.0	-2.4	-2.9	-3.2	-3.5	-5.2	-19.3
Estimated Using the Fair-Value Method												
Change in Outlays												
Limit amount forgiven under the PSLF program	-0.1	-0.2	-0.3	-0.3	-0.4	-0.5	-0.6	-0.7	-0.8	-0.8	-1.2	-4.6
Extend repayment period for IDR plans	-0.1	-0.3	-0.5	-0.6	-0.8	-0.9	-1.1	-1.3	-1.5	-1.6	-2.3	-8.7
Both alternatives above[a]	-0.2	-0.5	-0.8	-1.0	-1.2	-1.5	-1.8	-2.1	-2.4	-2.5	-3.7	-13.9

This option would take effect in July 2017.

By law, the costs of federal student loan programs are measured in the budget according to the method established in the Federal Credit Reform Act. The fair-value method is an alternative and is included in this table for informational purposes.

IDR = income-driven repayment; PSLF = Public Service Loan Forgiveness.

a. If both alternatives were enacted together, the total effect would be greater* than the sum of the effects of each alternative because of interactions between them. [*Text corrected after printing but before online release]

Various programs exist that forgive federal student loans. In one kind, called income-driven repayment (IDR) plans, after borrowers make monthly payments (which are calculated as a percentage of income) for a certain period, usually 20 years, the outstanding balance of their loans is forgiven. Another program is Public Service Loan Forgiveness (PSLF), which is for borrowers in an IDR plan who are employed full time in public service; that program provides debt forgiveness after only 10 years of monthly payments. Neither the IDR plans nor the PSLF program limits the amount that can be forgiven. The programs' biggest benefits go to people who borrow to attend graduate or professional school, because they tend to borrow larger amounts than people who borrow for undergraduate studies do.

This option includes two alternatives that would reduce loan forgiveness primarily for borrowers who took out federal student loans to pay for graduate school, starting with loans originated to new borrowers in July 2017. The first alternative would limit the amount that could be forgiven under the PSLF program to $57,500, shifting any remaining balance into an IDR plan with a longer repayment period. Because that limit is equal to the limit for federal student loans for undergraduate studies, and because there is no such maximum for graduate studies, the alternative would mostly affect students who borrow for graduate school. The second alternative would extend the repayment period—from 20 years to 25 years—for borrowers in an IDR plan who take out loans to finance graduate school. (The repayment period for borrowers with only undergraduate loans would continue to be 20 years.)

When estimating the budgetary effects of proposals to change federal loan programs, the Congressional Budget Office is required by law to use the method established in the Federal Credit Reform Act (FCRA). FCRA accounting, however, does not consider all the risks borne by the government. In particular, it does not consider market risk—the risk that taxpayers face because federal receipts from payments on student loans tend to be low when economic and financial conditions are poor and resources are therefore more valuable. Under an alternative method, the fair-value approach, estimates are based on market values—market prices when they are available, or approximations of market prices when they are not—which better account for the risk that the government takes on. As a result, the discount rates (or interest rates) used to calculate the present value of higher loan repayments under the option are higher for fair-value estimates than for FCRA estimates, and the savings from those higher repayments are correspondingly lower. (A present value is a single number that expresses a flow of current and future payments in terms of an equivalent lump sum paid today; the present value of future cash flows depends on the discount rate that is used to translate them into current dollars.)

Estimated according to the FCRA method, federal costs under the first alternative would be reduced by $7 billion from 2017 to 2026. According to the fair-value method, over the same period, federal costs would be reduced by $5 billion. Under the second alternative, CBO estimates, federal costs from 2017 to 2026 would be reduced by $12 billion according to the FCRA method and by $9 billion according to the fair-value method. If both alternatives were implemented, the total savings would be slightly greater than the sum of the savings if the alternatives were individually adopted because of interactions between the two alternatives.

An argument in favor of these alternatives is that reducing the amount of student debt that is forgiven—either by explicitly limiting the amount that would be forgiven or by extending the repayment period—would reduce students' incentive to borrow and encourage them to enroll in graduate programs whose benefits, in terms of improved opportunities for employment, justified the costs of the additional schooling. The first alternative would encourage prospective graduate students to limit their borrowing because their loans would no longer be forgiven without regard to the outstanding balance. The second alternative would increase by 25 percent the number of payments that affected borrowers made—and because income tends to increase with experience, it would probably boost the sums that they repaid by an even larger percentage.

A second argument in favor of these alternatives is that they focus on people who have borrowed for graduate studies, who often have relatively high income and are therefore more likely to be able to pay back their loans eventually. The PSLF program is especially generous to borrowers who, after 10 years of repayment, still have heavy debt but also have high income and do not have trouble making the monthly payments. Many borrowers in the PSLF program who have relatively high income and who, under the first alternative, would receive only a partial forgiveness of their debt after 10 years of repayment would probably be able to repay their remaining debt in full. Under the second alternative, all borrowers for graduate school in an IDR plan would eventually pay more than they would otherwise, and more of those borrowers would completely pay off their debt before the end of the repayment period. (Under either alternative, IDR plans would continue to not limit the amount that could be forgiven, so debt relief would be provided to borrowers who, despite making regular payments for 20 or 25 years, could not pay off their debt.)

An argument against the alternatives is that they would increase the risk that students would not be able to repay their loans. The increased risk might lead some students to choose less graduate education or to forgo it altogether. Furthermore, limiting forgiveness under the PSLF program could discourage borrowers with graduate debt from seeking employment in public service. And both alternatives would disproportionately affect prospective graduate students with fewer financial resources, such as those who come from low-income families. Such students would be less likely to attend graduate school and consequently would have lower future earnings; if they did choose to take out loans to attend graduate school, they would be likelier to have heavy student debt later in life.

RELATED OPTION: Mandatory Spending, Option 10

RELATED CBO PUBLICATION: *Options to Change Interest Rates and Other Terms on Student Loans* (June 2013), www.cbo.gov/publication/44318

Mandatory Spending—Option 10 Function 500

Reduce or Eliminate Subsidized Loans for Undergraduate Students

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
						Estimated Using the Method Established in the Federal Credit Reform Act						
Change in Outlays												
Restrict access to subsidized loans to students eligible for Pell grants	-0.3	-0.7	-0.8	-0.8	-0.9	-0.9	-0.9	-1.0	-1.0	-1.0	-3.5	-8.3
Eliminate subsidized loans altogether	-1.0	-2.2	-2.6	-2.7	-2.8	-2.9	-3.0	-3.1	-3.2	-3.3	-11.2	-26.8
						Estimated Using the Fair-Value Method						
Change in Outlays												
Restrict access to subsidized loans to students eligible for Pell grants	-0.3	-0.6	-0.7	-0.7	-0.8	-0.8	-0.8	-0.8	-0.9	-0.9	-3.0	-7.2
Eliminate subsidized loans altogether	-0.8	-1.8	-2.2	-2.3	-2.4	-2.5	-2.6	-2.7	-2.8	-2.9	-9.6	-23.1

This option would take effect in July 2017.

By law, the costs of federal student loan programs are measured in the budget according to the method established in the Federal Credit Reform Act. The fair-value method is an alternative and is included in this table for informational purposes.

The Federal Direct Student Loan Program lends money directly to students and their parents to help finance postsecondary education. Two types of loans are offered to undergraduates: subsidized loans, which are available only to undergraduates who demonstrate financial need, and unsubsidized loans, which are available to undergraduates regardless of need (and to graduate students as well).

For undergraduates, the interest rates on the two types of loans are the same, but the periods during which interest accrues are different. Subsidized loans do not accrue interest while students are enrolled at least half time, for six months after they leave school or drop below half-time status, and during certain other periods when they may defer making repayments. Unsubsidized loans accrue interest from the date of disbursement. The program's rules cap the amount—per year, and also for a lifetime—that students may borrow through subsidized and unsubsidized loans. By the Congressional Budget Office's estimates, subsidized and unsubsidized loans will each constitute about half of the dollar volume of federal loans to undergraduate students for the 2016–2017 academic year.

This option includes two possible changes to subsidized loans. In the first alternative, only students who were eligible for Pell grants would have access to subsidized loans. The Federal Pell Grant Program provides grants to help finance postsecondary undergraduate education; to be eligible for those grants, students and their families must demonstrate financial need. Under current law, only students with an expected family contribution (EFC)—the amount that the federal government expects a family to pay toward the student's postsecondary education expenses—of less than about $5,200 are eligible for a Pell grant, whereas recipients of subsidized loans may have a larger EFC, as long as it is less than their estimated tuition, room, board, and other costs of attendance not covered by other aid received. This change would therefore reduce the number of students who could take out subsidized loans. Specifically, CBO projects that about 30 percent of students who would borrow through subsidized loans under current law would lose their eligibility for those loans—and would instead borrow almost as much through unsubsidized loans. In the second alternative, subsidized loans would be eliminated altogether. CBO again expects that students would borrow almost as much through unsubsidized loans as they would have borrowed through subsidized loans.

Under either alternative, borrowers who lost access to subsidized loans would pay interest on unsubsidized loans from the date of loan disbursement, which would raise their costs. If a student who would have borrowed $23,000 (the lifetime limit) through subsidized loans, beginning in the 2017–2018 academic year, instead borrowed the same amount through unsubsidized loans, that student would leave school with additional debt of about $3,400. Over a typical 10-year repayment period, the student's monthly repayment would be $37 higher than if he or she had borrowed the same amount through subsidized loans.

When estimating the budgetary effects of proposals to change federal loan programs, CBO is required by law to use the method established in the Federal Credit Reform Act (FCRA). FCRA accounting, however, does not consider all the risks borne by the government. In particular, it does not consider market risk—the risk that taxpayers face because federal receipts from payments on student loans tend to be low when economic and financial conditions are poor and resources are therefore more valuable. Under an alternative method, the fair-value approach, estimates are based on market values—market prices when they are available, or approximations of market prices when they are not—which better account for the risk that the government takes on. As a result, the discount rates (or interest rates) used to calculate the present value of higher loan repayments under the option are higher for fair-value estimates than for FCRA estimates, and the savings from those higher repayments are correspondingly lower. (A present value is a single number that expresses a flow of current and future payments in terms of an equivalent lump sum paid today; the present value of future cash flows depends on the discount rate that is used to translate them into current dollars.)

Estimated according to the FCRA method, federal costs would be reduced by $8 billion under the first alternative and by $27 billion under the second alternative from 2017 to 2026. According to the fair-value method, over the same period, federal costs would be reduced by $7 billion under the first alternative and by $23 billion under the second.

An argument in favor of this option is that providing subsidies by not charging interest on loans for a period of time may unnecessarily and perhaps harmfully encourage borrowing; it may also make it hard for students to evaluate the cost of their education net of subsidies. Another argument in favor of the option is that some postsecondary institutions may increase tuition to benefit from some of the subsidies that the government gives students; reducing subsidies might therefore slow the growth of tuition. If institutions responded in that way, they would at least partially offset the effect of higher borrowing costs on students' pocketbooks. Also, the prospect of higher loan repayments upon graduation might encourage students to pay closer attention to the economic value to be obtained from a degree and to complete postsecondary programs more quickly. And for most college students, $37 a month in additional costs is small compared with the benefits that they obtain from a college degree.

An argument against this option is that students faced with a higher cost of borrowing might decide not to attend college, to leave college before completing a degree, or to apply to schools with lower tuition but educational opportunities not as well aligned with their interests and skills. Those decisions eventually could lead to lower earnings. Moreover, for any given amount borrowed, higher interest costs would require borrowers to devote more of their future income to interest repayments. That, in turn, could constrain their career choices or limit their ability to make other financial commitments, such as buying a home.

RELATED OPTIONS: Mandatory Spending, Options 8, 9; Discretionary Spending, Option 21; Revenues, Option 17

RELATED CBO PUBLICATIONS: *The Pell Grant Program: Recent Growth and Policy Options* (September 2013), www.cbo.gov/publication/44448; *Options to Change Interest Rates and Other Terms on Student Loans* (June 2013), www.cbo.gov/publication/44318

Mandatory Spending—Option 11 Function 600

Eliminate Concurrent Receipt of Retirement Pay and Disability Compensation for Disabled Veterans

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	0	-9	-13	-15	-15	-18	-17	-16	-18	-19	-52	-139

This option would take effect in January 2018.

Military service members who retire—either after at least 20 years of military service under the longevity-based retirement program or early because of a disability—are eligible for retirement annuities from the Department of Defense (DoD). In addition, veterans with medical conditions or injuries incurred or that worsened during active-duty military service may be eligible for disability compensation from the Department of Veterans Affairs (VA).

Until 2003, military retirees eligible for disability compensation could not receive both their full retirement annuity and their disability compensation. Instead, they had to choose between receiving their full retirement annuity from DoD or receiving their disability benefit from VA and forgoing an equal amount of their DoD retirement annuity; that reduction in the retirement annuity is typically referred to as the VA offset. Because the retirement annuity is generally taxable and disability compensation is not, most retirees chose the second alternative.

As a result of several laws, starting with the National Defense Authorization Act for 2003, two classes of retired military personnel who receive VA disability compensation (including those who retired before the enactment of those laws) can now receive payments that make up for part or all of the VA offset, benefiting from what is often called concurrent receipt. Specifically, retirees whose disabilities arose from combat are eligible for combat-related special compensation (CRSC), and veterans who retire with at least 20 years of military service and who receive a VA disability rating of at least 50 percent are eligible for what is termed concurrent retirement and disability pay (CRDP). CRSC is exempt from federal taxes, but CRDP is not; some veterans would qualify for both payments but must choose between them.

Beginning in 2018, this option would eliminate concurrent receipt of retirement pay and disability compensation: Military retirees now drawing CRSC or CRDP would no longer receive those payments, nor would future retirees. As a result, the option would reduce federal spending by $139 billion between 2018 and 2026, the Congressional Budget Office estimates.

In 2015, of the roughly 2 million military retirees, about 55 percent were subject to the VA offset; about 50 percent of that latter group—or 575,000 retirees—got concurrent receipt payments totaling $10 billion. Spending for concurrent receipt—just over $1 billion in 2005—has climbed sharply because of both an expansion in the program's parameters and an increase in the share of military retirees receiving disability compensation. In particular, the share of military retirees receiving a longevity-based retirement annuity who also receive disability compensation rose from 33 percent in 2005 to just over 50 percent in 2015.

One argument for this option is that disabled veterans would no longer be compensated twice for their service, reflecting the reasoning underlying the creation of the VA offset. However, military retirees who receive VA disability payments would still receive higher after-tax payments than would nondisabled retirees who have the same retirement annuity because VA disability benefits are not taxed.

An argument against this option is that DoD's retirement system and VA's disability program compensate for different characteristics of military service: rewarding longevity in the former case and remunerating for pain and suffering in the latter. In addition, if fewer retirees applied for VA disability compensation because concurrent receipt was no longer available—since some consider the application process onerous—some veterans might bypass other VA services such as health care or vocational training. Moreover, some retirees would find the loss of income financially difficult.

RELATED OPTIONS: Mandatory Spending, Options 24, 25

RELATED CBO PUBLICATIONS: *Veterans' Disability Compensation: Trends and Policy Options* (August 2014), www.cbo.gov/publication/45615; *Costs of Military Pay and Benefits in the Defense Budget* (November 2012), www.cbo.gov/publication/43574

Mandatory Spending—Option 12 Function 600

Reduce Pensions in the Federal Employees Retirement System

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Reduce the basic annuity	0	*	*	-0.1	-0.1	-0.2	-0.3	-0.4	-0.4	-0.5	-0.3	-2.1
Eliminate the SRS	0	-0.1	-0.2	-0.4	-0.5	-0.6	-0.7	-0.7	-0.8	-0.8	-1.1	-4.7
Total	0	-0.1	-0.3	-0.4	-0.6	-0.8	-1.0	-1.1	-1.2	-1.3	-1.4	-6.8

This option would take effect in January 2018.

SRS = Special Retirement Supplement; * = between –$50 million and zero.

In 2015, the federal government paid pension benefits, in the form of lifetime annuities, totaling about $82 billion to civilian retirees and their survivors. Roughly 14 percent of that amount was paid through the Federal Employees Retirement System (FERS), which covers about 30 percent of federal civilian retirees and over 90 percent of current civilian employees. (Most of the other retirees and workers are covered by pensions in the Civil Service Retirement System, which is not available to employees first hired after 1983.)

Annuities in FERS are based on the average of employees' earnings over the three consecutive years when they earned the most. Also, people who begin collecting that basic annuity when they are younger than 62 can receive the Special Retirement Supplement (SRS) until they turn 62, at which point they become eligible for Social Security benefits. The SRS is approximately equal to the Social Security benefits that the workers earned during their service under FERS. However, most employees do not receive the SRS, because most do not start collecting the basic annuity before they turn 62. To do so, employees in most occupations must have at least 30 years of service with the federal government and have reached age 56 or 57 (depending on the employee's year of birth), or have at least 20 years of service and have reached age 60. Federal employees in law enforcement, as well as a few other groups of employees, become eligible for the annuities regardless of their age once they complete 25 years of service.

This option includes two alternatives for reducing spending on FERS, both of which would apply only to federal workers who retire in January 2018 or later. In the first alternative, the basic annuity would be calculated on the basis of an employee's five consecutive years with the highest earnings. That change would save the federal government $2 billion over the 2018–2026 period, the Congressional Budget Office estimates. Annual savings would reach $500 million in 2026, and they would continue to grow, because an increasing fraction of retirees would be receiving benefits under the new, less generous formula as time went on. The second alternative would eliminate the SRS. That change would save the federal government $5 billion by 2026. If both alternatives were implemented, the total savings through 2026 would be $7 billion.

One argument for the option is that it would better align federal practices with practices in the private sector, where pensions are commonly based on a five-year average of earnings and supplements are rarely provided to workers who retire before they are eligible for Social Security. More broadly, the option would make the ratio of deferred compensation to current compensation in the federal government closer to the ratio in the private sector. A substantial number of private-sector employers no longer provide health insurance benefits for retirees and have shifted from lifetime annuities to defined contribution plans that require smaller contributions from employers; the federal government, by contrast, still offers many retirees health insurance, an annuity, and a defined contribution plan. As a result, federal employees receive a much larger portion of their compensation in retirement benefits than private-sector workers do, on average. Consequently, reducing pensions might be less harmful to the federal government's ability to compete with the private sector in attracting and retaining highly qualified personnel than a reduction in current compensation would be.

An argument against the option is that reducing retirement benefits would lessen the attractiveness of the overall compensation package provided by the federal government, hampering its ability to attract and retain a highly qualified workforce. Positions requiring professional and advanced degrees might become particularly difficult to fill, because federal workers with those qualifications already receive less compensation than their private-sector counterparts do, on average. Another argument against the option is that it would reduce the amount of income that federal workers receive in retirement. In 2018, for example, using a five-year average would reduce the FERS annuities of about 55,000 new retirees by an average of roughly 2 percent. The elimination of SRS would affect a much smaller portion of new retirees, because most federal employees do not retire until after reaching age 62. However, many of the workers who did retire before 62 would see a large reduction in their income until they reached that age. That period of reduced income could exceed 10 years for employees in law enforcement and the other groups of employees who can qualify for the annuities at an early age.

RELATED OPTION: Revenues, Option 43

RELATED CBO PUBLICATIONS: *Comparing the Compensation of Federal and Private-Sector Employees* (January 2012), www.cbo.gov/publication/42921; Justin Falk, *Comparing Benefits and Total Compensation in the Federal Government and the Private Sector*, Working Paper 2012-04 (January 2012), www.cbo.gov/publication/42923

Mandatory Spending—Option 13 Function 600

Convert Multiple Assistance Programs for Lower-Income People Into Smaller Block Grants to States

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
SNAP	0	-30	-28	-27	-26	-25	-24	-23	-22	-22	-111	-227
SSI	0	*	-4	-4	-5	-10	-6	-1	-7	-7	-13	-43
Child nutrition programs	0	-8	-8	-9	-10	-11	-11	-12	-13	-14	-35	-97
Total	0	-37	-41	-41	-40	-45	-40	-36	-42	-44	-160	-367
Change in Discretionary Spending for SSI	0	-5	-5	-5	-5	-6	-6	-6	-6	-6	-21	-50

This option would take effect in October 2017.

SNAP = Supplemental Nutrition Assistance Program; SSI = Supplemental Security Income; * = between zero and $500 million.

Several sizable federal programs assist people who have relatively low income. Such programs include the Supplemental Nutrition Assistance Program (SNAP; formerly the Food Stamp program), Supplemental Security Income (SSI), and a collection of child nutrition programs. Federal spending for SNAP, SSI, and child nutrition programs in 2016 was $156 billion, or roughly 4 percent of total federal spending.

SNAP provides benefits to help low-income households buy food. Federal outlays for the program were $73 billion in 2016. SSI provides cash assistance to elderly or disabled people who have low income and few assets; spending (most of it mandatory) for that program totaled $61 billion that year. Child nutrition programs subsidize meals provided to children at school, at child care centers, in after-school programs, and in other settings. In 2016, spending for those programs was $22 billion, most of it for the National School Lunch Program and the School Breakfast Program.

Beginning in October 2017, this option would convert SNAP, SSI, and the child nutrition programs to separate, smaller block grants to the states. Each of the three block grants would provide a set amount of funding to states each year, and states would be allowed to significantly change the structure of the programs. The annual funding provided would equal federal outlays for each program in 2007, increased to account for inflation for all urban consumers since then. (The 2007 starting amounts would include outlays for both benefits and administrative costs and, for child nutrition programs, would represent total spending for that set of programs. For SSI, the 2007 amount would be adjusted to account for 12 monthly benefit payments instead of 11.)

By the Congressional Budget Office's estimates, this option would reduce spending on SNAP by $227 billion from 2017 through 2026—or by 31 percent of the amount that would be spent under current law. For SSI, mandatory spending during that period would decline by $43 billion, or by 7 percent. For child nutrition programs, the reduction would be $97 billion, or 35 percent. In addition, funding to administer SSI is provided annually in discretionary appropriations; this option would eliminate those appropriations, resulting in $50 billion in discretionary savings during the 2017–2026 period, so long as appropriations were adjusted accordingly.

The budgetary effects of switching SNAP, SSI, and child nutrition programs to block grants would depend heavily on the formulas used to set the amounts of the grants. For this option, the inflation-adjusted value of the grants would remain at 2007 amounts. If, instead, the grants were fixed in nominal dollars (as is, for example, the block grant for Temporary Assistance for Needy Families), savings would be larger (and increasingly so) each year. By contrast, if the grants were indexed for both inflation and population growth—that is, if they were allowed to grow faster than specified—savings would be smaller (and increasingly so) each year. Savings also would be less if the starting values for the grants were based on larger amounts than the outlays in 2007—for example, the outlays for those programs in more recent years. And savings would be less if spending in 2018 and the following few years was adjusted downward from CBO's current-law projections more slowly instead of immediately reverting to the 2007 amounts adjusted for inflation.

Although the formula used to set the amount of each separate block grant in this option is the same, the effects on spending for the programs would differ. For SNAP, the effect on projected spending would be larger early on, whereas for the child nutrition programs and in general for SSI, the effects would be larger in the later years.

For SNAP, the estimated reduction in federal spending from converting to the specified block grant would decline, both in dollar terms and as a share of projected spending under current law. CBO projects that, under current law, spending on SNAP will decline over the 2017–2022 period and then slowly increase through 2026. The number of people receiving benefits will decline as the economy improves over the 10-year period, but the increase in per-person benefits in the later years will outweigh the effect of the decline in the number of participants. (SNAP benefits are adjusted annually for changes in food prices.) By contrast, under the option, spending on SNAP would increase over the 10-year period. Under current law, spending on SNAP will be $73 billion in 2018, CBO projects; this option would reduce that amount by an estimated $30 billion, or by 41 percent. In 2026, spending on SNAP under current law is projected to be $74 billion; the option would cut that figure by an estimated $22 billion, or by 30 percent.

For SSI, the estimated reduction in mandatory outlays from converting to the specified block grant would generally increase, both in dollar terms and as a share of projected spending under current law. (The reduction in spending would fluctuate in a few years because, as scheduled under current law, benefit payments in October shift to the previous fiscal year when the first day of the month falls on a weekend.) The option would result in greater reductions in the later years primarily because, by CBO's estimates under current law, participation in the program will increase. Under current law, mandatory spending on SSI will be $50 billion in 2018, CBO projects; this option would increase that spending by less than $500 million. In 2026, mandatory spending on SSI under current law is projected to be $69 billion; the option would cut that figure by an estimated $7 billion, or by 10 percent.

For child nutrition programs, the estimated reduction in federal spending from converting to the specified block grant would increase, both in dollar terms and as a share of projected spending under current law. In 2018, the estimated reduction in spending would be $8 billion, or about one-third; and in 2026, the estimated reduction would be $14 billion, or more than 40 percent. The savings would be greater in the later years of the period for two reasons: Most spending for the programs under current law is indexed to an inflator that adjusts benefits for changes in the price of food away from home—which CBO projects will be larger than the changes in prices to which the specified block grant is indexed. Also, by CBO's expectations under current law, participation in the programs will grow.

A rationale for this option is that block grants would make spending by the federal government more predictable. The programs that this option affects must, under current law, make payments to eligible people. Therefore, spending automatically increases or decreases without any legislative changes. For example, outlays for SNAP benefits more than doubled between 2007 and 2011, primarily because participation in the program increased mainly as a result of deteriorating labor market conditions. And even if the number of participants in a program does not change, the benefits paid per person can change if the income of participants changes.

Another rationale for the option is that state programs might better suit local needs and might be more innovative. States could define eligibility and administer benefits in ways that might better serve their populations. Moreover, allowing states to design their own programs would result in more experimentation, and some states could adopt approaches that had worked elsewhere.

A rationale against this option is that, from 2018 to 2026, it would cut mandatory federal spending for programs that support lower-income people by $367 billion (with an additional cut of $50 billion in discretionary spending, if appropriations were reduced as specified). Whom that cut in spending affected—and how—would depend on how states structured their programs and how state spending changed. But such a cut—amounting to 25 percent of the projected mandatory spending on SNAP, SSI, and child nutrition programs during those years—would almost certainly eliminate benefits for some people who would have otherwise received them, as well as significantly reduce the benefits of some people who remained in the programs.

Another rationale against this option is that block grants would be less responsive to economic conditions than the current federal programs. The automatic changes in spending on benefits under current law help stabilize the economy, reducing the depth of recessions during economic downturns. Those stabilizing effects would be lost under the option. Furthermore, if federal spending did not increase during a future economic downturn and more people qualified for benefits, states that could not increase their spending (probably at a time when their own revenues were declining) would have to reduce per-person benefits or tighten eligibility, perhaps adding to the hardship for families just when their need was greatest.

RELATED OPTIONS: Mandatory Spending, Options 14, 15, 17; Health, Option 2

RELATED CBO PUBLICATIONS: *Child Nutrition Programs: Spending and Policy Options* (September 2015), www.cbo.gov/publication/50737; *The Effects of Potential Cuts in SNAP Spending on Households With Different Amounts of Income* (March 2015), www.cbo.gov/publication/49978; *Supplemental Security Income: An Overview* (December 2012), www.cbo.gov/publication/43759; *The Supplemental Nutrition Assistance Program* (April 2012), www.cbo.gov/publication/43173

Mandatory Spending—Option 14 **Function 600**

Eliminate Subsidies for Certain Meals in the National School Lunch, School Breakfast, and Child and Adult Care Food Programs

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	-0.1	-0.7	-1.0	-1.1	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-4.0	-10.3

This option would take effect in July 2017.

The National School Lunch Program, the School Breakfast Program, and the Child and Adult Care Food Program provide funds that enable public schools, nonprofit private schools, child and adult care centers, and residential child care institutions to offer subsidized meals and snacks to participants.[1] In the 2016–2017 school year, federal subsidies are generally 59 cents for each lunch, 29 cents for each breakfast, and 7 cents for each snack for participants in households with income above 185 percent of the federal poverty guidelines (commonly known as the federal poverty level, or FPL). The programs provide larger subsidies for meals served to participants from households with income at or below 185 percent of the FPL and above 130 percent of the FPL, and still larger subsidies to participants from households with income at or below 130 percent of the FPL. As a result of the subsidies, participants from households with income at or below 130 percent of the FPL pay nothing for their meals.

Beginning in July 2017, this option would eliminate the subsidies for meals and snacks served to participants from households with income greater than 185 percent of the FPL. The Congressional Budget Office estimates that the option would reduce federal spending by $10 billion through 2026.

Under current law, federal subsidies for meals served to participants from households with income greater than 185 percent of the FPL can include base cash subsidies; certain commodities; and, for those schools participating in the National School Lunch Program that comply with federal nutrition guidelines, an additional cash subsidy. In the 2016–2017 school year, the base cash subsidies for meals served to participants from households with income greater than 185 percent of the FPL are 30 cents per lunch and 29 cents per breakfast; for after-school snacks provided to such participants, the amount is 7 cents. All participating schools and centers also receive commodities—food from the Department of Agriculture, such as fruit and meat—with a value of 23 cents per lunch. Schools whose meals that state authorities certify as complying with federal nutrition guidelines receive an additional cash subsidy of 6 cents per lunch in the 2016–2017 school year. (Additional subsidies are available for schools and centers in Alaska and Hawaii, schools in Puerto Rico, and participating schools that serve many meals to students from households with income at or below 185 percent of the FPL.)

The primary rationale for this option is that it would target federal subsidies to those most in need. Because the subsidies for meals served to participants from households with income greater than 185 percent of the FPL are small, the effect of the option on those participants and the members of their households would probably be minimal.

1. The Child and Adult Care Food Program provides funds for meals and snacks served in child and adult care centers as well as in day care homes. Reimbursement rates for meals served through participating child and adult care centers are equal to the reimbursement rates for meals served through the National School Lunch Program and the School Breakfast Program. Because reimbursement rates for meals served in day care homes are set differently, this option does not affect day care homes.

A rationale against this option is that schools and centers would probably offset part or all of the loss of the subsidies by charging participants from higher-income households higher prices for meals, and some of those participants might stop buying meals. In addition, schools and centers might leave the programs if they incur meal program costs that exceed the subsidies they receive for meals served to participants from households with income at or below 185 percent of the FPL.[2] Individuals at such institutions who would be eligible for free or reduced-price meals would no longer receive subsidized meals, and the meals served at those institutions would no longer have to meet any other requirements of the programs (including the nutrition guidelines).

2. About one-third of school food authorities surveyed claimed that expenses exceeded revenues in the 2012–2013 school year. See Food and Nutrition Service, *Special Nutrition Program Operations Study, School Year 2013–14*, Nutrition Assistance Program Report (October 2016), p. 173, http://go.usa.gov/xkSeh (PDF, 7.3 MB).

RELATED OPTIONS: Mandatory Spending, Options 13, 15

RELATED CBO PUBLICATION: *Child Nutrition Programs: Spending and Policy Options* (September 2015), www.cbo.gov/publication/50737

Mandatory Spending—Option 15 **Function 600**

Tighten Eligibility for the Supplemental Nutrition Assistance Program

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	0	-4.4	-10.5	-10.4	-10.4	-10.3	-10.3	-10.3	-10.4	-10.6	-35.7	-87.6

This option would take effect in October 2017.

The Supplemental Nutrition Assistance Program (SNAP; formerly the Food Stamp program) provides benefits to low-income households to help them purchase food. Eligibility is generally based on participation in other government assistance programs or on the income and assets of a household.

Most households that receive SNAP benefits—more than 90 percent in fiscal year 2014 (the most recent year for which such data are available)—are considered categorically eligible; that is, they automatically qualify for benefits because they participate in other federal or state programs. Most such households—three-quarters in 2014—qualify for benefits under what is termed broad-based categorical eligibility. Namely, all household members receive or are authorized to receive noncash benefits from the Temporary Assistance for Needy Families (TANF) program; such benefits could include child care, transportation assistance, or even a token benefit such as a pamphlet describing TANF. The remaining categorically eligible households—one-quarter in 2014—are ones in which all members receive cash assistance from TANF, Supplemental Security Income, or certain state programs that serve people with low income. Most households that qualify for SNAP because of categorical eligibility (including broad-based categorical eligibility) would also meet the federal income and asset requirements for eligibility.

Households that receive SNAP benefits but are not categorically eligible for the program—less than 10 percent of all participating households in 2014—qualify by meeting certain income and asset tests set by law that vary depending on households' characteristics. For households that do not include an elderly or disabled person, total income in the month of application must be less than or equal to 130 percent of the monthly federal poverty guidelines. (Those guidelines are commonly known as the federal poverty level, or FPL.) Also, their cash assets must be less than or equal to $2,250. For households that include an elderly or disabled person, different tests apply.

This option would reduce the monthly income limit for eligibility from 130 percent to 67 percent of the federal poverty guidelines and would eliminate broad-based categorical eligibility, reducing SNAP outlays by 15 percent in 2019—the first year in which the option would be fully implemented. Eligibility for households with elderly or disabled people or those receiving cash assistance from certain other programs (45 percent of households receiving SNAP in 2014, the Congressional Budget Office estimates) would be unchanged. CBO estimates that this approach would yield federal savings of $88 billion from 2018 to 2026. (Eliminating broad-based categorical eligibility while leaving the monthly income limit unchanged would yield federal savings of about $8 billion over the same period.)

A rationale for lowering the income limit for eligibility and eliminating broad-based categorical eligibility is that doing so would focus SNAP benefits on people most in need. Also, eliminating broad-based categorical eligibility would make the eligibility for and benefits from SNAP more consistent among states because states have different policies regarding other assistance programs.

An argument against this option is that it would eliminate benefits for many households in difficult financial situations, including some people below the federal poverty level. (Lowering the income limit for eligibility to 100 percent of the FPL would eliminate benefits for fewer households but would save less than lowering the limit to 67 percent of the FPL.) An additional argument against eliminating broad-based categorical eligibility is that doing so would increase the complexity and time involved in verifying information on SNAP applications, probably resulting in more errors. Adopting that approach would also increase the paperwork for applicants.

RELATED OPTIONS: Mandatory Spending, Options 13, 14

RELATED CBO PUBLICATIONS: *The Effects of Potential Cuts in SNAP Spending on Households With Different Amounts of Income* (March 2015), www.cbo.gov/publication/49978; *The Supplemental Nutrition Assistance Program* (April 2012), www.cbo.gov/publication/43173

Mandatory Spending—Option 16 **Function 600**

Reduce TANF's State Family Assistance Grant by 10 Percent

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Outlays	0	-1.0	-1.5	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-5.6	-13.8

This option would take effect in October 2017.

Temporary Assistance for Needy Families (TANF) provides cash assistance, work support (such as subsidized child care), and other services to some low-income families with children. Almost all of the federal government's TANF funding is provided through a block grant called the state family assistance grant (SFAG), which totals $16 billion annually. The states administer TANF and have considerable latitude in determining the mix of cash assistance, work support, and other services that the program provides. The states also determine the requirements for participation in work-related activities that some recipients must meet to avoid receiving less cash assistance through the program.

Beginning in October 2017, this option would decrease the SFAG by 10 percent. That change would reduce federal spending by $14 billion through 2026, the Congressional Budget Office estimates.

One rationale for this option is that it might prevent some families from becoming dependent on federal aid if states responded to the reduction in SFAG funding by making their work requirements more stringent to reduce their spending on cash assistance. The more stringent work requirements would probably result in some families' receiving cash assistance for shorter periods. And in some cases, families might find work more quickly, either to compensate for the loss of cash assistance or to comply with the work requirements. However, some states might respond to the reduction in funding by decreasing their spending on work support, which could make finding and keeping jobs harder.

A rationale against this option is that it would reduce the amount of assistance available to low-income families with children. Because federal spending on TANF has stayed about the same since 1998 (the program's first full year), the purchasing power of that funding has fallen by about 25 percent. As real (inflation-adjusted) spending on TANF has decreased, so has the number of families who get cash assistance from the program—from 3.2 million families in 1998 to 1.3 million in 2015. In comparison, roughly 6.9 million families had income below the poverty threshold in 2015, CBO estimates. Reducing real spending on the program by an additional 10 percent would further limit the number of families that it served or the amount of assistance that it provided.

RELATED CBO PUBLICATION: *Temporary Assistance for Needy Families: Spending and Policy Options* (January 2015), www.cbo.gov/publication/49887

Mandatory Spending—Option 17 Function 600

Eliminate Supplemental Security Income Benefits for Disabled Children

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Mandatory Outlays	0	-10	-11	-11	-11	-12	-12	-11	-13	-13	-42	-104
Change in Discretionary Spending	0	-1	-1	-1	-1	-1	-1	-1	-1	-1	-4	-9

This option would take effect in October 2017.

The Supplemental Security Income (SSI) program provides cash assistance to people who are disabled, aged, or both and who have low income and few assets. The Congressional Budget Office estimates that 15 percent of SSI recipients in 2016 will be disabled children under age 18, receiving an average monthly benefit of $664. Those children must have marked and severe functional limitations and usually must live in a household with low income and few assets.

This option would eliminate SSI benefits for disabled children. CBO estimates that making that change would reduce mandatory spending by $104 billion through 2026. Also, because annual discretionary appropriations cover SSI's administrative costs, this option would generate $9 billion in discretionary savings over the same period so long as total appropriations were adjusted accordingly.

One rationale for this option is that providing SSI benefits to children may discourage their parents from working. Unlike Temporary Assistance for Needy Families, a welfare program that aims to help families achieve self-sufficiency, SSI imposes no work requirements on parents and does not explicitly limit how long they may receive benefits as long as the child remains medically and financially eligible. Furthermore, SSI benefits decrease by 50 cents for each additional dollar parents earn above a certain threshold, depending on household size and other factors. (For example, in calendar year 2016, for a single parent with one child who is disabled and with no other income, SSI benefits are generally reduced after the parent earns more than $1,551 per month.) Those program traits create a disincentive for parents to increase work and thereby boost earnings.[1]

Another rationale for this option is that, rather than provide a cash benefit to parents without ensuring that they spend the money on their disabled children, policymakers could choose to support those children in other ways. For example, states could receive grants to make an integrated suite of educational, medical, and social services available to disabled children and their families. To the extent that funds that would have been used to provide SSI benefits for children were instead used for a new program or to increase the resources of other existing programs, federal savings from this option would be correspondingly reduced.

A rationale against this option is that this program serves a disadvantaged group. SSI is the only federal income support program geared toward families with disabled children, and SSI benefits reduce child poverty rates. Families with disabled children are typically more susceptible to economic hardship than other families because of

1. Research has not shown that parents significantly reduce work in anticipation of receiving SSI benefits for their child. However, in one study, parents who stopped receiving their child's SSI benefit significantly increased their work hours and fully offset the loss of the benefit. It remains unclear exactly how increased parental work affects the outcomes of disabled children. See Manasi Deshpande, "The Effect of Disability Payments on Household Earnings and Income: Evidence From the SSI Children's Program," *Review of Economics and Statistics*, vol. 98, no. 4 (October 2016), pp. 638–654, http://dx.doi.org/10.1162/REST_a_00609.

both direct and indirect costs associated with children's disabilities. (Direct costs can include additional out-of-pocket health care expenses, spending on adaptive equipment, and behavioral and educational services. Indirect costs for the parents of disabled children can include lost productivity and negative health effects.)

RELATED OPTION: Mandatory Spending, Option 13

RELATED CBO PUBLICATION: *Supplemental Security Income: An Overview* (December 2012), www.cbo.gov/publication/43759

Mandatory Spending—Option 18 Function 650

Link Initial Social Security Benefits to Average Prices Instead of Average Earnings

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays												
Pure price indexing	0	*	-1	-3	-6	-9	-14	-20	-26	-34	-11	-114
Progressive price indexing	0	*	-1	-2	-4	-6	-9	-12	-17	-22	-7	-72

This option would take effect in January 2018.

* = between –$500 million and zero.

Social Security benefits for retired and disabled workers are based on their average lifetime earnings. The Social Security Administration uses a statutory formula to compute a worker's initial benefits, and through a process known as wage indexing, the benefit calculation in each year accounts for economywide growth of wages. Average initial benefits for Social Security recipients therefore tend to grow at the same rate as do average wages, and such benefits replace a roughly constant portion of wages. (After people become eligible for benefits, their monthly benefits are adjusted annually to account for increases in the cost of living but not for further increases in average wages.)

One approach to constrain the growth of Social Security benefits would be to change the computation of initial benefits so that the real (inflation-adjusted) value of average initial benefits did not rise. That approach, often called "pure" price indexing, would allow increases in average real wages to result in higher real Social Security payroll taxes but not in higher real benefits. Beginning with participants who became eligible for benefits in 2018, pure price indexing would link the growth of initial benefits to the growth of prices (as measured by changes in the consumer price index for all urban consumers) rather than to the growth of average wages. (That link would operate through reducing three factors that determine the primary insurance amount. The factors would be reduced by the real wage growth in each year. Those three factors are now 90 percent, 32 percent, and 15 percent; the earnings amounts at which the factors change are called bend points. For example, with real wage growth of 1 percent, the three factors would be reduced by 1 percent, so in 2018 they would be 89.1 percent, 31.68 percent, and 14.85 percent, respectively.)

Pure price indexing would reduce federal outlays by $114 billion through 2026, the Congressional Budget Office estimates. By 2046, scheduled Social Security outlays would be reduced by 16 percent from what would occur under current law; when measured as a percentage of total economic output, the reduction would be 1 percentage point because outlays would decline from 6.3 percent to 5.3 percent of gross domestic product. People newly eligible for benefits in 2046, CBO estimates, would experience a reduction in benefits of about one-third from the benefits scheduled under current law.

Under pure price indexing, each cohort of beneficiaries would receive successively smaller benefit payments than those scheduled to be paid under current law; the growth of average real wages would determine the extent of the reduction. For example, if real wages grew by 1 percent annually, workers newly eligible for benefits in the first year the policy was in effect would receive 1 percent less than they would have received under the current rules; those becoming eligible in the second year would receive about 2 percent less; and so on. The actual incremental reduction would vary from year to year, depending on the growth of real earnings.

Another approach to constrain the growth of initial Social Security benefits, called progressive price indexing, would keep the current benefit formula for workers who had lower earnings and would reduce the growth of initial benefits for workers who had higher earnings. (That approach would be implemented by adding a new bend point and reducing the factors that determine the primary insurance amount above that bend point.) The present formula for calculating initial benefits is structured so that workers with higher earnings receive higher benefits, but the benefits paid to workers with lower earnings replace a larger share of their earnings.

Under progressive price indexing, initial benefits for the 30 percent of workers with the lowest lifetime earnings would increase with average wages, as they are scheduled to do under current law, whereas initial benefits for other workers would increase more slowly, at a rate that depended on their position in the distribution of earnings. For example, for workers whose earnings put them at the 31st percentile of the distribution, benefits would rise only slightly more slowly than average wages, whereas for the highest earners, benefits would rise with prices—as they would under pure price indexing. Thus, under progressive price indexing, initial benefits for most workers would increase more quickly than prices but more slowly than average wages. As a result, the benefit structure would gradually become flatter, and after about 70 years, all newly eligible workers in the top 70 percent of earners would receive the same monthly benefit.

Progressive price indexing would reduce scheduled Social Security outlays less than would pure price indexing, and beneficiaries with lower earnings would not be affected. Real annual average benefits would still increase for all but the highest-earning beneficiaries. Benefits would replace less of affected workers' earnings than under current law but would replace more than they would under pure price indexing.

A switch to progressive price indexing would reduce federal outlays by $72 billion through 2026, CBO estimates. By 2046, outlays for Social Security would be reduced by 9 percent; when measured as a percentage of total economic output, the reduction would be 0.6 percentage points because outlays would fall from 6.3 percent to 5.7 percent of gross domestic product.

Under both approaches, the reductions in benefits with respect to current law would be largest for beneficiaries in the distant future. Those beneficiaries, however, would have had higher real earnings during their working years and thus a greater ability to save for retirement on their own to offset those reductions.

An advantage of both approaches in this option is that average inflation-adjusted benefits in the program would not decline. If lawmakers adopted pure price indexing, future beneficiaries would generally receive the same real monthly benefit paid to current beneficiaries, and they would, as average longevity increased, receive larger total lifetime benefits.

But because benefits would not be as closely linked to average wages, a disadvantage of both approaches is that affected beneficiaries would not share in overall economic growth to the same extent. As a result, benefits would replace less of workers' earnings than they do today.

RELATED OPTIONS: Mandatory Spending, Options 19, 20, 21

RELATED CBO PUBLICATIONS: *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; letter to the Honorable Paul Ryan providing CBO's analysis of the Roadmap for America's Future Act of 2010 (January 27, 2010), www.cbo.gov/publication/41860; *Long-Term Analysis of S. 2427, the Sustainable Solvency First for Social Security Act of 2006* (attachment to a letter to the Honorable Robert F. Bennett, April 5, 2006), www.cbo.gov/publication/17701

Mandatory Spending—Option 19 **Function 650**

Make Social Security's Benefit Structure More Progressive

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Implement 90/32/5 PIA factors	0	*	*	-0.2	-0.3	-0.6	-0.8	-1.3	-1.9	-2.5	-0.5	-7.6
Implement 100/25/5 PIA factors	0	*	-0.3	-0.8	-1.5	-2.7	-4.2	-6.2	-8.6	-11.5	-2.6	-35.8

This option would take effect in January 2018.

PIA = primary insurance amount; * = between –$50 million and zero.

The amount of Social Security benefits paid to a disabled worker or to a retired worker who claims benefits at the full retirement age is called the primary insurance amount (PIA). The Social Security Administration calculates the PIA by applying a progressive benefit formula to a worker's average indexed monthly earnings (AIME), a measure of average taxable earnings over that worker's lifetime. That amount is separated into three brackets (or portions) by using two bend points. In calendar year 2016, the first bend point is $856 and the second bend point is $5,157. The PIA consists of any average indexed earnings in each of the three brackets multiplied by three corresponding PIA factors: 90 percent, 32 percent, and 15 percent. (Bend points grow each year with average wages, whereas PIA factors remain constant.)

For example, a worker with an AIME of $1,000 would have a PIA of $816 because the 90 percent rate would apply to the first $856, and the 32 percent rate would apply to the remaining $144. A worker with an AIME of $6,000 would have a PIA of $2,273 because the 90 percent rate would apply to the first $856, the 32 percent rate would apply to the next $4,301 ($5,157 minus $856), and the 15 percent rate would apply to the remaining $843 ($6,000 minus $5,157). Because the PIA formula is progressive, it replaces a larger share of lifetime earnings for the worker with a lower AIME than it does for the worker with a higher AIME. (For an AIME of $1,000, the PIA would be 82 percent of the worker's AIME; for $6,000, the PIA would be 38 percent.)

This option would make the Social Security benefit structure more progressive by cutting benefits for people with higher average earnings while either preserving or expanding benefits for people with lower earnings. Starting with people newly eligible in 2018, the first approach in this option would affect only beneficiaries with an AIME above the second bend point. That approach would reduce the 15 percent PIA factor by 1 percentage point per year until it reached 5 percent in 2027.

The more progressive second approach in this option would reduce benefits for a larger fraction of beneficiaries with relatively high lifetime earnings while increasing benefits for people with lower lifetime earnings. The second approach would lower both the 15 percent and 32 percent PIA factors and would increase the 90 percent factor. The factors would change gradually over 10 years until they reached 5 percent, 25 percent, and 100 percent, respectively. (The 15 percent and 90 percent factors would change by 1 percentage point per year, while the 32 percent factor would change by 0.7 percentage points per year.)

The first approach in this option would affect about 13 percent of all newly eligible beneficiaries, the Congressional Budget Office estimates, and would reduce total federal outlays for Social Security over the 10-year period by about $8 billion. The second approach would increase benefits for about 45 percent of new beneficiaries and reduce benefits for about 55 percent, achieving total federal savings of $36 billion over the 10-year period. In 2046, the first and second approaches would reduce Social Security outlays from what would occur under current law by 3 percent and 7 percent, respectively. When measured as a percentage of total economic output, the reduction in Social Security outlays under the two approaches would be 0.2 percentage points and 0.4 percentage points as the outlays would fall from 6.3 percent to 6.1 percent and to 5.8 percent of gross domestic product, respectively.

An argument in favor of this option is that it would protect or expand Social Security benefits for people with low average earnings while trimming payments to higher-income beneficiaries. This option would help make the Social Security system more progressive at a time when growing disparities in life expectancy by income level are making the system less progressive. (Beneficiaries with higher income typically live longer and experience larger improvements in their life expectancy than lower-income beneficiaries. As a result, higher-income groups receive benefits for more years than lower-income beneficiaries.) The second approach in this option would increase progressivity more than the first approach by boosting benefits to lower-income people.

A disadvantage of this option is that it would weaken the Social Security system's link between earnings and benefits. In addition, the second approach would reduce benefits for beneficiaries with an AIME above the 45th percentile. In particular, CBO projects that in 2018 the second approach would reduce benefits for people with an AIME higher than about $2,200, or approximately $26,000 in annual indexed earnings.

RELATED OPTIONS: Mandatory Spending, Options 18, 20, 21

RELATED CBO PUBLICATIONS: *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *CBO's 2015 Long-Term Projections for Social Security: Additional Information* (December 2015), www.cbo.gov/publication/51047

Mandatory Spending—Option 20 Function 650

Raise the Full Retirement Age for Social Security

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays	0	0	0	0	0	0	-0.2	-0.9	-2.2	-4.3	0	-7.6

This option would take effect in January 2023.

The age at which workers become eligible for full retirement benefits from Social Security—the full retirement age (FRA), also called the normal retirement age—depends on their year of birth. For workers born in 1937 or earlier, the FRA was 65. It increased in two-month increments for each successive birth year until it reached 66 for workers born in 1943. For workers born between 1944 and 1954, the FRA holds at 66, but it then increases again in two-month increments until it reaches age 67 for workers born in 1960 or later. As a result, workers who turn 62 in 2022 or later will be subject to an FRA of 67. The earliest age at which workers may start to receive reduced retirement benefits will remain 62; however, benefit reductions at that age will be larger for workers whose FRA is higher. For example, workers born in 1954 (whose FRA is 66) will receive a permanent 25 percent reduction in their monthly benefit amount if they claim benefits at age 62 rather than at the FRA, whereas workers born in 1960 (whose FRA is 67) will receive a 30 percent benefit reduction if they claim benefits at 62.

Under this option, the FRA would continue to increase from age 67 by two months per birth year, beginning with workers turning 62 in 2023, until it reaches age 70 for workers born in 1978 or later (who turn 62 beginning in 2040). As under current law, workers could still choose to begin receiving reduced benefits at age 62, but the reductions in their initial monthly benefit from the amounts received at the FRA would be larger, reaching 45 percent when the FRA is 70. This option would not reduce the benefits for workers who qualify for Social Security Disability Insurance (DI).

An increase in the FRA would reduce lifetime benefits for every affected Social Security recipient, regardless of the age at which a person claims benefits. A one-year increase in the FRA is equivalent to a reduction of about 6 percent to 8 percent in the monthly benefit, depending on the age at which a recipient chooses to claim benefits. Workers could maintain the same monthly benefit by claiming benefits at a later age, but then they would receive benefits for fewer years.

This option would shrink federal outlays by $8 billion through 2026, the Congressional Budget Office estimates. By 2046, the option would reduce Social Security outlays from what would occur under current law by 7 percent; when measured as a percentage of total economic output, the reduction would be 0.5 percentage points, because outlays would fall from 6.3 percent to 5.8 percent of gross domestic product.

Because many workers retire at the FRA, increasing that age is likely to result in beneficiaries' working longer and claiming Social Security benefits later than they would if a policy with identical benefit cuts at each age was implemented by adjusting the benefit formula. Any additional work would increase total output and boost federal revenues from income and payroll taxes. It also would result in higher future Social Security benefits, although the increase in benefits would be smaller than the increase in revenues. The estimates shown here for this option over the next decade do not include those effects of additional work.

A rationale for this option is that people who turn 65 today will, on average, live significantly longer and collect Social Security benefits for more years than retirees did in the past, increasing average lifetime Social Security benefits. In 1940, life expectancy at age 65 was 11.9 years for men and 13.4 years for women. Since that time, life expectancy has risen by more than six years for 65-year-olds, to 18.1 years for men and 20.6 years for women. Therefore, a commitment to provide retired workers with a certain monthly benefit beginning at age 65 today is significantly costlier than that same commitment made to recipients in 1940.

A disadvantage of this option is that it would increase the incentive for older workers nearing retirement to stop working and apply for DI benefits. Under current law, workers who retire at age 62 in 2046 will receive 70 percent of their primary insurance amount (what they would have received had they claimed benefits at their FRA); if they qualify for DI benefits, however, they will receive the full amount. Under this option, workers who retired at 62 in 2046 would receive only 55 percent of their primary insurance amount; they would still receive 100 percent if they qualified for DI benefits. (The estimates of how this option affects the budget account for the higher resulting applications and awards for the DI program.) To eliminate that added incentive to apply for disability benefits, policymakers could narrow the difference by also reducing scheduled disability payments.

Some proposals to raise the FRA also would increase the early eligibility age (EEA)—when participants may first claim retirement benefits—from 62. Increasing only the FRA would reduce monthly benefit amounts and would increase the risk of poverty at older ages for people who did not respond to the increase in the FRA by delaying the age at which they claimed benefits. Increasing the EEA along with the FRA would make many people wait longer to receive retirement benefits, so their average monthly payments would be higher than if only the FRA was increased; higher benefits would help people who lived a long time. However, for people who would depend on retirement benefits at age 62, increasing the EEA could cause financial hardship, even if the total lifetime value of benefits would be generally unchanged. Increasing the EEA together with the FRA would cause federal spending to be lower in the first few decades of the policy and higher in later decades than if only the FRA was increased.

RELATED OPTIONS: Mandatory Spending, Options 18, 19, 21, 23; Health, Option 9

RELATED CBO PUBLICATIONS: *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *Policy Options for the Social Security Disability Insurance Program* (July 2012), www.cbo.gov/publication/43421; *Raising the Ages of Eligibility for Medicare and Social Security* (January 2012), www.cbo.gov/publication/42683; "Raise the Earliest Eligibility Age for Social Security," in *Reducing the Deficit: Spending and Revenue Options* (March 2011), www.cbo.gov/publication/22043; Jae Song and Joyce Manchester, *Have People Delayed Claiming Retirement Benefits? Responses to Changes in Social Security Rules,* Working Paper 2008-04 (May 2008), www.cbo.gov/publication/19575

Mandatory Spending—Option 21 Function 650

Reduce Social Security Benefits for New Beneficiaries

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Reduce benefits by 5 percent	0	*	-2	-4	-7	-10	-14	-18	-23	-28	-12	-105
Reduce benefits by 15 percent	0	*	-2	-4	-8	-15	-23	-33	-45	-58	-15	-190

This option would take effect in January 2018.

* = between –$500 million and zero.

Social Security is the largest single program in the federal budget, providing a total of $905 billion in benefits in 2016 to retired and disabled workers, their eligible dependents, and survivors of deceased workers. The Congressional Budget Office estimates that the average monthly benefit is now $1,365 for retired workers and $1,178 for disabled workers. The benefits that people receive in the year they are first eligible for benefits—at age 62 for retired workers and five months after the onset of disability for disabled workers—are based on those workers' average lifetime earnings. The formula used to translate average earnings into benefits is progressive; that is, the ratio of benefits to earnings is higher for people with lower average earnings than for people with higher average earnings. One way to achieve budgetary savings would be to adjust that formula to reduce benefits for all new beneficiaries.

This option includes two ways to adjust the benefit formula to reduce Social Security benefits by two amounts, 5 percent and 15 percent. Both alternatives would phase in the reductions starting with people who would be newly eligible in 2018. Under the 5 percent reduction, benefits would be permanently lowered by 2.5 percent for newly eligible beneficiaries in 2018 and by 5 percent for newly eligible beneficiaries beginning in 2019. (Benefits for newly eligible beneficiaries in 2018 would remain 2.5 percent lower throughout their lifetime.) Under the 15 percent reduction, benefits would be permanently reduced by 2.5 percent for people newly eligible in 2018, 5 percent for people newly eligible in 2019, and so on, up to 15 percent for people newly eligible beginning in 2023.

Serving as a benchmark, this option shows that policymakers might achieve substantial savings by cutting benefits for new Social Security beneficiaries only. This option would not affect current beneficiaries or those who will become eligible before 2018. CBO estimates that, between 2018 and 2026, federal outlays would be reduced by $105 billion under the 5 percent alternative and by $190 billion under the 15 percent reduction. Federal savings from those changes in the formula would continue to grow in later years as more beneficiaries were subject to the lower benefits. By 2046, Social Security outlays would be about 4 percent lower under the 5 percent benefit reduction and 12 percent lower under the 15 percent alternative than under current law, CBO estimates. When measured as a percentage of total economic output, Social Security outlays would fall from 6.3 percent to 6.0 percent of gross domestic product under the 5 percent alternative and to 5.5 percent of gross domestic product under the 15 percent reduction.

An advantage of this option is its simplicity. The current benefit structure would be retained, and equal percentage reductions would be applied to all benefits, including those paid to survivors and dependents, which are based on the same formula used to compute workers' benefits.

One rationale against this option is that both reductions would be applied soon, leaving people approaching retirement little time to adjust to the change. A more moderate approach would reduce Social Security benefits only for people becoming eligible for benefits 5 or 10 years in the future. However, delaying the option's start date would reduce the resulting budgetary savings. For example, if the 15 percent benefit reduction was implemented starting in 5 years (in 2022), increasing by 3 percent each year, total savings between 2017 and 2026 would amount to $40 billion.

Because benefit reductions would apply to all new beneficiaries, another disadvantage of the two alternatives in this option is that people with lower benefits would generally experience a larger percentage reduction in total income. In particular, such people are less likely than others to have savings and sources of income outside Social Security, such as pensions, so a reduction in Social Security benefits would result in a larger reduction in total income for that group and a greater relative decline in their standard of living. A more progressive approach would reduce Social Security benefits by larger percentages for people with higher benefits.

If the goal instead was to achieve the level of 10-year savings attained by the 5 percent or 15 percent alternatives by cutting benefits for all current and future beneficiaries, the required reduction would be considerably smaller: All benefits would need to be lowered by about 1 percent or about 2 percent, respectively.

RELATED OPTIONS: Mandatory Spending, Options 18, 19, 20

RELATED CBO PUBLICATIONS: *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *CBO's 2015 Long-Term Projections for Social Security: Additional Information* (December 2015), www.cbo.gov/publication/51047

Mandatory Spending—Option 22 **Function 650**

Require Social Security Disability Insurance Applicants to Have Worked More in Recent Years

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays	0	-0.6	-1.6	-2.7	-3.8	-4.9	-6.0	-7.2	-8.3	-9.5	-8.6	-44.5

This option would take effect in January 2018.

To be eligible for benefits under Social Security Disability Insurance (DI), disabled workers must generally have worked 5 of the past 10 years. Specifically, workers over age 30 must have earned at least 20 quarters of coverage in the past 10 years (which is the time span used to evaluate that requirement, also known as the look-back period). In calendar year 2016, a worker receives one quarter of coverage for each $1,260 of earnings during the year, up to four quarters; the amount of earnings required for a quarter of coverage generally increases annually with average wages.

This option would raise the share of recent years that disabled workers must have worked while shortening the look-back period by requiring disabled workers older than 30 to have earned 16 quarters in the past 6 years—usually equivalent to working 4 of the past 6 years. That change in policy would apply to people seeking benefits in 2018 and later and would not affect blind applicants, who are exempt from the recency-of-work requirement. This option would reduce the number of workers who received DI benefits by 6 percent in 2026, the Congressional Budget Office estimates, and would lower federal outlays for Social Security by $45 billion from 2018 through 2026. In relation to current law, outlays for Social Security in 2046 would be lower by roughly 1 percent. (Those estimates do not include any effects of this option on spending for other federal programs—such as Medicare, Medicaid, and Supplemental Security Income, or SSI—as well as spending on subsidies for health insurance purchased through the marketplaces established under the Affordable Care Act. Over the 10-year period, those effects would roughly offset. On one hand, disabled workers who no longer qualify for DI under this option would lose their eligibility for Medicare until age 65, thus reducing spending for Medicare. On the other hand, some disabled workers who lose DI and Medicare benefits under this option would become eligible for SSI, Medicaid, or health insurance subsidies, increasing spending for those programs.)

An argument in favor of this option is that it would better target benefits toward people who cannot work because of a recent disability. To qualify for disability benefits, applicants must be judged to be unable to perform "substantial" work because of a disability—but knowing whether applicants would have worked if they were not disabled is impossible. Under current law, even people who have not been in the labor force for five years can qualify for disability benefits. By comparison, this option would allow people who were out of the labor force for only two years or less to qualify for benefits.

A reason to keep the existing work provision is that the option could penalize some people who would have been working were they not disabled. For example, some people might leave the workforce for more than two years to care for children or pursue additional education and then become disabled while out of the workforce or shortly after returning to work. Such people could qualify for disability benefits under current law but would not qualify under this option. Similarly, some people who were in the labor force but unable to find work for over two years before becoming disabled would become ineligible for benefits under the option. To lessen the penalty for those workers, an alternative approach could raise the number of recent years that disabled workers must have worked while lengthening the look-back period by requiring workers to have worked 8 of the past 12 years. That approach would result in similar budgetary savings.

RELATED OPTION: Mandatory Spending, Option 23

RELATED CBO PUBLICATIONS: *Social Security Disability Insurance: Participation and Spending* (June 2016), www.cbo.gov/publication/51443; *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *Policy Options for the Social Security Disability Insurance Program* (July 2012), www.cbo.gov/publication/43421

Mandatory Spending—Option 23 Function 650

Eliminate Eligibility for Starting Social Security Disability Benefits at Age 62 or Later

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	0	-0.1	-0.4	-0.8	-1.3	-1.8	-2.3	-2.9	-3.6	-4.3	-2.6	-17.4

This option would take effect in January 2018.

Under current law, people are eligible for Social Security Disability Insurance (DI) until they reach full retirement age—currently 66 years for workers who turn 62 in 2016. The full retirement age will rise gradually, starting at 66 and 2 months for workers born in 1955 (who will turn 62 in 2017) and eventually reaching 67 for people born in 1960 (who will turn 62 in 2022) or later. Workers who claim retirement benefits at age 62 rather than at their full retirement age receive lower benefits for as long as they live. By contrast, workers who claim DI benefits at age 62 are not subject to a reduction. Instead, they receive in each year approximately the same retirement benefits that they would have received had they claimed retired-worker benefits at their full retirement age.

That difference in benefits encourages some people between age 62 and their full retirement age to apply for DI at the same time that they apply for Social Security retirement benefits. If their DI application is approved, they receive higher benefits for the rest of their life than if they had applied only for retirement benefits. (Some people claim retirement benefits during the five-month waiting period that the DI program imposes on applicants. If they receive retirement benefits during the waiting period and then are approved for the DI program, their DI benefits and future retirement benefits are reduced a little. For example, if they receive retirement benefits for five months, their future DI and retirement benefits are generally reduced by 2 percent.)

Under this option, workers would not be allowed to apply for DI benefits after their 62nd birthday or to receive DI benefits for a qualifying disability beginning after that date, even if they applied before age 62. Under such a policy, individuals who would have become eligible for DI benefits at age 62 or later under current law would instead have to claim retirement benefits if they wanted to receive Social Security benefits based on their own earnings. Benefits for those people over their lifetime would be as much as 30 percent lower than the DI and retirement benefits they would receive under current law. (The actual reduction in lifetime benefits would depend on their year of birth and the age at which they claimed retirement benefits.)

In 2026, this option would affect about 700,000 people who would have received disability benefits under current law. The option would reduce federal outlays by $17 billion between 2018 and 2026, the Congressional Budget Office estimates. Those savings would be the net result of a $77 billion reduction in DI outlays and a $60 billion increase in Social Security retirement benefits as people shifted from the DI program to the retirement program. By 2046, Social Security outlays (including both DI and retirement benefits) would be reduced by about 1 percent from what they would be under current law. (Those estimates do not include any effects of this option on spending for other federal programs—such as Medicare, Medicaid, and Supplemental Security Income, or SSI—as well as spending on subsidies for health insurance purchased through the marketplaces established under the Affordable Care Act. Over the 10-year period, those effects would roughly offset. On one hand, disabled workers older than 62 would lose their eligibility for Medicare until age 65, thus reducing spending for Medicare. On the other hand, some disabled workers who lose DI and Medicare benefits under this option would become eligible for SSI, Medicaid, or health insurance subsidies, increasing spending for those programs.)

A rationale for this option is that it eliminates the incentive for people applying for retirement benefits to apply for disability benefits at the same time in hopes of securing a financial advantage. Moreover, workers who became disabled between age 62 and the full retirement age would still have access to Social Security retirement benefits, although those benefits would be less than the disability benefits available under current law.

An argument against this option is that it would substantially reduce the support available to older people who, under current law, would be judged too disabled to perform substantial work. Among the workers who began receiving disability benefits in 2014, about 8 percent were age 62 or older when they applied or became disabled. Those people would have received significantly lower benefits from Social Security if they had been ineligible for DI and had applied for retirement benefits instead. In addition, some people would have lost coverage through Medicare because that program's benefits are generally not available to people under age 65, whereas most recipients of DI become entitled to Medicare benefits 24 months after their DI benefits begin.

The option's net effect on older people's participation in the labor force is unclear. On one hand, the option would induce some people to work longer than they will under current law: Although DI benefits are available only to people judged unable to perform substantial work, some people could find employment that would accommodate their disabilities. If DI benefits were not available, those people would work longer than they would under current law. On the other hand, the option would induce some people planning to work until age 62 or later to leave the labor force at age 61 so that they could apply for DI benefits. (The estimates presented here do not include any effects of changes in labor supply.)

RELATED OPTIONS: Mandatory Spending, Options 20, 22

RELATED CBO PUBLICATIONS: *Social Security Disability Insurance: Participation and Spending* (June 2016), www.cbo.gov/publication/51443; *Supplemental Security Income: An Overview* (December 2012), www.cbo.gov/publication/43759; *Policy Options for the Social Security Disability Insurance Program* (July 2012), www.cbo.gov/publication/43421

Mandatory Spending—Option 24 Function 700

Narrow Eligibility for Veterans' Disability Compensation by Excluding Certain Disabilities Unrelated to Military Duties

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Outlays	0	-2.0	-2.9	-2.9	-2.9	-3.2	-3.0	-2.7	-3.0	-3.1	-10.7	-25.7

This option would take effect in January 2018.

Veterans may receive disability compensation from the Department of Veterans Affairs (VA) for medical conditions or injuries that occurred or worsened during active-duty military service. Such service-connected disabilities range widely in severity and type, from migraines and treatable hypertension to the loss of limbs. VA also provides dependency and indemnity compensation—payments to surviving spouses or children of a veteran who died from a service-related injury or disease. The Department of Defense (DoD) has a separate disability compensation system for service members who can no longer fulfill their military duties because of a disability.

Not all service-connected medical conditions and injuries are incurred or exacerbated in the performance of military duties. For example, a qualifying injury can occur when a service member was at home or on leave, and a qualifying medical condition, such as multiple sclerosis, can develop independently of a service member's military duties. In 2015, VA paid 716,000 veterans a total of $3.7 billion, the Congressional Budget Office estimates, to compensate for seven of the medical conditions that, according to the Government Accountability Office (GAO), military service is unlikely to cause or aggravate. Those conditions are arteriosclerotic heart disease, chronic obstructive pulmonary disease, Crohn's disease, hemorrhoids, multiple sclerosis, osteoarthritis, and uterine fibroids.

Beginning in January 2018, this option would cease veterans' disability compensation for those seven medical conditions GAO identified. Under the option, veterans now receiving compensation for those conditions would have their compensation reduced or eliminated, and veterans who applied for compensation for those conditions in the future would not be eligible for it. The option would not alter DoD's disability compensation system, which focuses on fitness for military duties rather than compensation for disabilities.

By CBO's estimates, this option would reduce outlays by $26 billion from 2018 to 2026. Most of the savings would result from curtailing payments to current recipients of disability compensation. A broader option could eliminate compensation for all disabilities unrelated to military duties, not just those conditions GAO identified. For arthritis, for instance, which may not result from military duties, VA could determine whether the condition was related to military activities. An option with that broader reach could generate significantly larger savings but could be harder to administer depending on how VA sets its eligibility criteria.

An argument in support of this option is that it would make the disability compensation system for military veterans more comparable to civilian systems. Few civilian employers offer long-term disability benefits, and among those that do, benefits do not typically compensate individuals for all medical problems that developed during employment.

An argument against this option is that military service is not like a civilian job; instead, it confers unique benefits to society and imposes extraordinary risks on service members. By that logic, the pay and benefits that service members receive should reflect the hardships of military life, including compensating veterans who become disabled in any way during their military service.

RELATED OPTIONS: Mandatory Spending, Options 11, 25

RELATED CBO PUBLICATION: *Veterans' Disability Compensation: Trends and Policy Options* (August 2014), www.cbo.gov/publication/45615

Mandatory Spending—Option 25 **Function 700**

Restrict VA's Individual Unemployability Benefits to Disabled Veterans Who Are Younger Than the Full Retirement Age for Social Security

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Outlays	0	-2.9	-4.0	-4.2	-4.3	-4.5	-4.7	-4.8	-5.0	-5.2	-15.4	-39.6

This option would take effect in January 2018.

In 2015, more than 4 million veterans with medical conditions or injuries that occurred or worsened during active-duty military service were receiving disability compensation from the Department of Veterans Affairs (VA). The amount of compensation they receive depends on the severity of their disabilities (which are generally rated between zero and 100 percent in increments of 10), their number of dependents, and other factors—but not on their income or civilian employment history.

In addition, VA may supplement the regular disability compensation payments for veterans whom it deems unable to engage in substantial work. To qualify for those supplemental benefits, termed individual unemployability (IU) payments, veterans must have low earnings and generally must be rated between 60 percent and 90 percent disabled. A veteran qualifying for the IU supplement receives a monthly disability payment equal to the amount that he or she would receive if rated 100 percent disabled. In 2015, for veterans who received the supplement, it boosted monthly VA disability payments by an average of about $1,250. In September 2015, about 350,000 veterans received IU payments.

VA's regulations require that IU benefits be based on a veteran's inability to maintain substantial employment because of the severity of a service-connected disability and not because of age, voluntary withdrawal from work, or other factors. More than 60 percent of veterans receiving the IU supplement were 65 or older in September 2015, up from about one-third in September 2010. That rise is attributed largely to the aging of Vietnam War veterans.

Under this option, beginning in January 2018, VA would stop making IU payments to veterans older than Social Security's full retirement age, which varies from 65 to 67 depending on beneficiaries' birth year. Therefore, at recipients' full retirement age, VA disability payments would revert to the amount associated with the rated disability. By the Congressional Budget Office's estimates, the savings from this option would be $40 billion between 2018 and 2026.

One rationale for this option is that most veterans older than Social Security's full retirement age would not be in the labor force because of their age, so a lack of earnings for those veterans would probably not be attributable to service-connected disabilities. In particular, in 2015, about 35 percent of men ages 65 to 69 were in the labor force; for men age 75 or older, that number dropped to 11 percent. In addition, most recipients of IU payments who are older than 65 would have other sources of income: They would continue to receive regular VA disability payments and might also collect Social Security benefits. (Recipients of the IU supplement typically begin collecting it in their 50s and probably have worked enough to earn Social Security benefits.)

An argument for retaining the current policy is that IU payments should be determined solely on the basis of a veteran's ability to work and that considering age would be unfair. In addition, replacing the income from the IU supplement would be hard or impossible for some disabled veterans. If they had been out of the workforce for a long time, their Social Security benefits might be small, and they might not have accumulated much in personal savings.

RELATED OPTIONS: Mandatory Spending, Options 11, 24

RELATED CBO PUBLICATION: *Veterans' Disability Compensation: Trends and Policy Options* (August 2014), www.cbo.gov/publication/45615

Mandatory Spending—Option 26 **Multiple Functions**

Use an Alternative Measure of Inflation to Index Social Security and Other Mandatory Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Outlays												
Social Security	0	-1.8	-4.4	-7.1	-10.1	-13.2	-16.4	-19.5	-22.8	-26.1	-23.4	-121.4
Other benefit programs with COLAs[a]	0	-0.5	-1.3	-2.0	-2.7	-3.8	-4.3	-4.8	-5.8	-6.6	-6.5	-31.8
Effects on SNAP from interactions with COLA programs[b]	0	*	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.5	2.3
Health programs	0	-0.3	-0.8	-1.5	-2.1	-3.0	-3.9	-4.7	-5.6	-6.2	-4.6	-27.9
Other federal spending[c]	0	*	-0.1	-0.2	-0.3	-0.3	-0.5	-0.6	-0.9	-0.8	-0.5	-3.6
Total	0	-2.6	-6.4	-10.6	-15.0	-20.0	-24.8	-29.2	-34.6	-39.3	-34.5	-182.4
Change in Revenues[d]	0	*	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.8
Decrease in the Deficit	0	-2.6	-6.3	-10.5	-14.9	-19.9	-24.7	-29.1	-34.5	-39.1	-34.3	-181.6

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

This estimate does not include the effects of using the chained consumer price index for parameters in the tax code.

COLA = cost-of-living adjustment; SNAP = Supplemental Nutrition Assistance Program; * = between –$50 million and $50 million.

a. Other benefit programs with COLAs include civil service retirement, military retirement, Supplemental Security Income, veterans' pensions and compensation, and other retirement programs whose COLAs are linked directly to those for Social Security or civil service retirement.

b. The policy change would reduce payments from other federal programs to people who also receive benefits from SNAP. Because SNAP benefits are based on a formula that considers such income, a decrease in those other payments would lead to an increase in SNAP benefits.

c. Other federal spending includes changes to benefits and various aspects (eligibility thresholds, funding levels, and payment rates, for instance) of other federal programs, such as those providing Pell grants and student loans, SNAP, child nutrition programs, and programs (other than health programs) linked to the federal poverty guidelines. (The changes in spending on SNAP included here are those besides the changes in benefits that result from interactions with COLA programs.)

d. The effects on revenues include changes in the revenue portion of refundable tax credits for health insurance purchased through the marketplaces established under the Affordable Care Act, as well as shifts in taxable compensation that would result from changes in the take-up of employment-based insurance.

Cost-of-living adjustments (COLAs) for Social Security and many other parameters of federal programs are indexed to increases in traditional measures of the consumer price index (CPI). The CPI measures overall inflation and is calculated by the Bureau of Labor Statistics (BLS). In addition to the traditional measures of the CPI, that agency computes another measure of inflation—the chained CPI—designed to account for changes in spending patterns and to eliminate several types of statistical biases that exist in the traditional CPI measures. (Nonetheless, the chained CPI does not resolve all statistical issues with traditional CPI measures.)

Beginning in 2018, this option would use the chained CPI for indexing COLAs for Social Security and parameters of other programs. The chained CPI has grown an average of about 0.25 percentage points more slowly per year over the past decade than the traditional CPI measures have, and the Congressional Budget Office expects that gap to persist. Therefore, the option would reduce federal spending, and savings would grow each year as the effects of the change compounded. Outlays would be reduced by $182 billion through 2026, CBO estimates, and the net effect on the deficit would be about the same. (This option would not change the measure of inflation used to index parameters of the tax code, as would be done in the related option cited below; the small revenue effects estimated here stem from changes in the revenue portion of refundable tax credits for health insurance purchased through the marketplaces established under the Affordable Care Act, as well as shifts in taxable compensation that would result from changes in the take-up of employment-based insurance.)

COLAs for Social Security and the pensions that the government pays to retired federal civilian employees and military personnel are linked to the CPI, as are outlays for veterans' pensions and veterans' disability compensation. In most of those programs, the policy change would not alter benefits when people are first eligible to receive them, either now or in the future, but it would reduce their benefits in later years because the annual COLAs would be smaller, on average. The effect would be greater the longer people received benefits (that is, the more years of the reduced COLAs they experienced). Therefore, the effect would ultimately be especially large for the oldest beneficiaries as well as for some disabled beneficiaries and military retirees, who generally become eligible for annuities before age 62 and thus can receive COLAs for a longer period.

Growth in the CPI also affects spending for Supplemental Security Income, Medicare, Medicaid, the health insurance marketplaces, Pell grants, student loans, the Supplemental Nutrition Assistance Program, child nutrition programs, and other programs. The index is used to calculate various eligibility thresholds, payment rates, and other factors that affect the number of people eligible for those programs and the benefits they receive. Therefore, switching to the chained CPI would reduce spending by both decreasing the number of people eligible for certain programs and reducing the average benefits that those people receive.

One argument for switching to the chained CPI in Social Security and other federal programs is that the chained CPI is generally viewed as a more accurate measure of overall inflation than the traditional CPI measures, for two main reasons. First, the chained CPI more fully accounts for how people tend to respond to price changes. Consumers often lessen the effect of inflation on their standard of living by buying fewer goods or services that have risen in price and by buying more goods or services that have not risen in price or have risen less. Measures of inflation that do not account for such substitution overstate growth in the cost of living—a problem known as substitution bias. BLS's procedures for calculating the traditional CPI measures account for some types of substitution, but the chained CPI more fully incorporates the effects of changing buying patterns.

A second reason to believe that the chained CPI is a better measure of inflation is that it is largely free of a problem known as small-sample bias. That bias, which is significant in the traditional CPI measures, occurs when certain statistical methods are applied to price data for only a limited number of items in the economy.

One argument against using the chained CPI, and thereby reducing COLAs in Social Security and other federal retirement programs, is that the chained CPI might not accurately measure the growth in prices that Social Security beneficiaries and other retirees face. The elderly tend to spend a larger percentage of their income on items whose prices can rise especially quickly, such as health care. (However, determining how rising health care prices affect the cost of living is problematic because accurately accounting for changes in the quality of health care is challenging.) The possibility that the cost of living may grow faster for the elderly than for the rest of the population is of particular concern because Social Security and pension benefits are the main source of income for many retirees.

Another potential drawback of this option is that a reduction in COLAs would ultimately have larger effects on the oldest beneficiaries and on disabled beneficiaries who received benefits for a longer period. For example, if benefits were adjusted every year by 0.25 percentage points less than the increase in the traditional CPI measures, Social Security beneficiaries who claimed benefits at age 62 would face a reduction in retirement benefits at age 75 of about 3 percent compared with what they would receive under current law, and a reduction at age 95 of about 8 percent. To protect vulnerable people, lawmakers might choose to reduce COLAs only for beneficiaries whose income or benefits were greater than specified amounts. Doing so, however, would reduce the budgetary savings from the option.

Finally, policymakers might prefer to maintain current law because they want benefits to grow faster than the cost of living so that beneficiaries would share in overall economic growth. An alternative option would be to link benefits to wages or gross domestic product. Because those measures generally grow faster than inflation, such a change would increase outlays.

RELATED OPTION: Revenues, Option 4

RELATED CBO PUBLICATIONS: Testimony of Jeffrey Kling, Associate Director for Economic Analysis, before the Subcommittee on Social Security, House Committee on Ways and Means, *Using the Chained CPI to Index Social Security, Other Federal Programs, and the Tax Code for Inflation* (April 18, 2013), www.cbo.gov/publication/44083; *Using a Different Measure of Inflation for Indexing Federal Programs and the Tax Code* (February 2010), www.cbo.gov/publication/21228; "Technical Appendix: Indexing With the Chained CPI-U for Tax Provisions and Federal Programs" (supplemental material for *Using a Different Measure of Inflation for Indexing Federal Programs and the Tax Code,* February 2010), www.cbo.gov/publication/21228

CHAPTER

3

Discretionary Spending Options

Discretionary spending—the part of federal spending that lawmakers control through annual appropriation acts—amounted to about $1.2 trillion, or 31 percent of total federal outlays, in 2016, the Congressional Budget Office estimates.[1] Just under half of that spending was for defense programs; the rest paid for an array of nondefense activities. Some fees and other charges that are triggered by appropriation action are classified in the budget as offsetting collections and credited against discretionary spending.

The discretionary budget authority (that is, the authority to incur financial obligations) provided in appropriation acts results in outlays when the money is spent. Some appropriations (such as those for employees' salaries) are spent quickly, but others (such as those for major construction projects) are disbursed over several years. Thus, in any given year, discretionary outlays include spending from new budget authority as well as spending from budget authority provided in earlier appropriations.[2]

Trends in Discretionary Spending

The share of federal spending that results from the annual appropriation process has diminished since the 1960s. From 1966 to 2016, discretionary spending fell from 67 percent of total federal spending to 31 percent. Measured as a percentage of gross domestic product (GDP), discretionary spending declined from 11.5 percent in 1966 to a low of 6.0 percent in 1999 before reaching 6.4 percent in 2016 (see Figure 3-1).

Most of that decline in discretionary spending relative to GDP stemmed from a decrease in spending for national defense measured as a share of GDP.[3] Discretionary spending for defense was 7.5 percent of GDP in 1966, and on the whole, it fell over the next several decades, reaching a low of 2.9 percent at the turn of the century. Such spending began climbing again shortly thereafter and averaged 4.6 percent of GDP from 2009 through 2011. (A large portion of the growth in defense spending over the 2001–2011 period resulted from spending on operations in Afghanistan and Iraq; in 2011, such spending amounted to 1.0 percent of GDP.) Since then, discretionary defense spending has declined in relation to the size of the economy, falling to 3.2 percent of GDP in 2016, CBO estimates.

The nondefense discretionary category comprises spending for an array of federal activities in areas such as education, transportation, veterans' health care, and homeland security. Over the past five decades, such spending has generally ranged from about 3 percent to 4 percent of GDP. One exception was the period from 1976 to 1981, when such spending averaged almost 5 percent of GDP. Another exception occurred from 2009 through 2011, when funding from the American Recovery and Reinvestment Act of 2009 helped push nondefense outlays above 4 percent of GDP. Nondefense discretionary outlays have declined in relation to the size of the economy since then, dropping to 3.3 percent of GDP in 2016, CBO estimates.

From 2012 through 2016, discretionary outlays measured as a percentage of GDP decreased largely because of constraints imposed by the Budget Control Act of 2011 and lower spending for military operations

1. In this volume, "spending" generally refers to outlays.

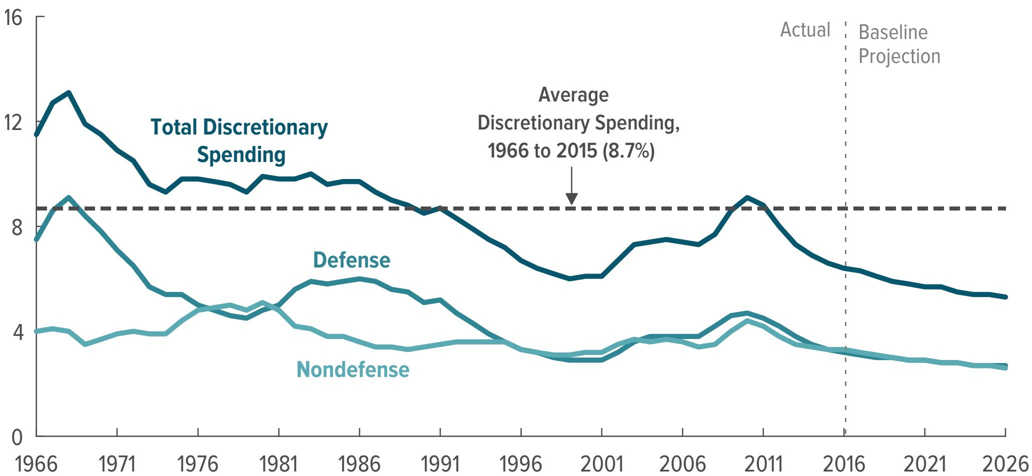
2. For some major transportation programs, budget authority is considered mandatory, but the outlays resulting from that authority are discretionary. Budget authority for those programs is provided in authorizing legislation rather than appropriation acts, but the amount of that budget authority that the Department of Transportation can obligate each year is limited by appropriation acts. Those obligation limitations are treated as a measure of discretionary budgetary resources. For more information, see Congressional Budget Office, *The Highway Trust Fund and the Treatment of Surface Transportation Programs in the Federal Budget* (June 2014), www.cbo.gov/publication/45416.

3. Most defense spending is funded through discretionary appropriations.

Figure 3-1.

Discretionary Spending

Percentage of Gross Domestic Product



If current statutory limits on discretionary spending remained in place through 2021 and grew with inflation thereafter, discretionary spending would decline as a percentage of gross domestic product over the next 10 years.

Source: Congressional Budget Office (as of August 2016).

in Afghanistan and Iraq. In CBO's baseline projections, discretionary spending further declines in relation to the size of the economy over the next 10 years, falling from about 6 percent of GDP in 2016—already below the 50-year average of 8.7 percent—to 5.3 percent in 2026. Two main factors account for that decline. First, the caps and automatic spending reductions put in place by the Budget Control Act, if adhered to, will constrain most discretionary appropriations through 2021; between 2016 and 2018, those caps decline by an average of 0.1 percent a year, but from 2018 through 2021 they grow by about 2 percent a year, on average, which is slower than GDP is projected to grow. Second, in CBO's baseline projections for 2022 through 2026, discretionary appropriations grow from the 2021 amount at the rate of inflation, which is also slower than GDP is projected to grow. By 2026, defense spending would equal 2.7 percent of GDP and nondefense spending 2.6 percent of GDP—the smallest share of the economy that either category (and discretionary spending as a whole) has accounted for since at least 1962, the first year for which comparable data are available.

Analytic Method Underlying the Estimates of Discretionary Spending

For the most part, the budgetary effects described in this chapter were calculated in relation to CBO's March 2016 baseline projections of discretionary spending over the next 10 years.[4] In accordance with section 257 of the Balanced Budget and Emergency Deficit Control Act of 1985, those projections reflect the assumption that current appropriations will continue in future years, with adjustments to keep pace with inflation. (Although CBO follows that law in constructing baseline projections for individual components of discretionary spending, its baseline projections of overall discretionary spending incorporate the caps and automatic spending reductions put in place by the Budget Control Act.) As specified in the law, CBO uses the following measures of inflation when constructing its baseline: the employment cost index for wages and salaries (applied to spending for federal personnel) and the GDP price index (applied to other spending).

The budgetary effects of the option involving military force structure (Option 1) and of the options related to the Department of Defense's (DoD's) operation and maintenance (Option 2) and acquisition (Options 5 through 10) were measured on a different basis. Because the baseline projections do not reflect programmatic details for force structure and acquisition (and maintenance) of specific weapon systems, the effects of those options are calculated in relation to DoD's planned spending as laid out in its 2017 Future Years Defense

4. Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

Program (FYDP). The FYDP provides details about DoD's intended funding requests for the 2017–2021 period—including the Administration's plans for the number of military and civilian personnel, the procurement and maintenance of weapon systems, and operational intensity—so measuring estimates of DoD's spending under a given option against that planned defense spending better captures the effects the option would have than comparing estimated spending under the option with CBO's baseline projections. Through 2021, the budgetary effects estimated for those eight options are based on DoD's estimates of the costs of its plans. From 2022 through 2026, they are based on DoD's estimates (such as those in the Navy's annual 30-year shipbuilding plan) when available and on CBO's projections of price and compensation trends for the overall economy when they are not. For an option that would cancel the planned acquisition of a weapon system, for example, the potential savings reported in this volume reflect DoD's estimates of the cost and purchasing schedule for that system; CBO often adjusts those savings to account for the costs to continue purchasing and operating existing systems instead of the system that would be canceled. In addition to budgetary costs, the text of each acquisition option discusses the effects of the option on DoD's ability to perform its missions, as well as any other consequences the option might have.

Because the costs of implementing the FYDP would exceed CBO's baseline projections for defense spending—in some cases, by significant amounts—the options involving military force structure, operation and maintenance, and acquisition would not necessarily reduce deficits below those projected in CBO's baseline. Rather, they are, at least in part, options for bringing DoD's planned funding closer to the amounts projected in the baseline, which accord with the current-law limits on such spending.

In many instances, CBO would have estimated higher costs for DoD's planned programs than the amounts budgeted either in DoD's FYDP or in CBO's extension of the FYDP, which relies primarily on DoD's cost estimates.[5] However, the savings from an option in relation to DoD's budget request are better represented by the program's costs in the FYDP and the extended FYDP than by CBO's independent cost estimates. If lawmakers enacted legislation to cancel a planned weapon system, for instance, DoD could delete the amounts budgeted for that system from its FYDP and increase the amounts for operating existing systems to come closer to the funding limits currently in place.

Options in This Chapter

The 28 options in this chapter encompass a broad range of discretionary programs. (They do not include options that would affect spending for health care programs, which are presented in Chapter 5 along with options that would affect taxes related to health.) Ten options in this chapter deal with defense programs and the rest with nondefense programs. Some include broad cuts—such as Option 1, which would reduce the size of the military to satisfy caps specified by the Budget Control Act, or Option 25, which would reduce federal civilian employment. Others focus on specific programs; for instance, Option 13 concerns the Department of Energy's programs for research and development in energy technologies. Some options would change the rules of eligibility for certain federal programs; Option 21, for example, would tighten eligibility criteria for Pell grants. Option 25 would impose fees to cover the cost of enforcing regulations and providing certain services.

To reduce deficits through changes in discretionary spending, lawmakers would need to lower the statutory funding caps below the amounts already established under current law or enact appropriations that were below those caps. The options in this chapter could be used to help accomplish either of those objectives. Alternatively, some of the options could be implemented to help comply with the existing caps on discretionary funding.

Under the constraints imposed by the Budget Control Act, total discretionary spending over the 2017–2026 period is projected to be $717 billion (or about 6 percent) lower than it would be if the funding provided for 2016 was continued in future years with increases for inflation. In other words, spending would have to be $717 billion lower than it is in the baseline projections for individual accounts just to comply with the discretionary caps (which are currently in place through 2021). CBO estimates that thereafter discretionary spending will grow from those lower levels at the rate of inflation. If all of the options presented in this chapter

5. For CBO's estimates of the cost of DoD's plans, see Congressional Budget Office, *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming).

other than those involving military force structure or acquisition were implemented, the savings generated would amount to roughly $820 billion—about 14 percent greater than the discretionary savings that result from the caps. (That estimate reflects the assumptions that there are no interactions between the options and that for those options with multiple alternatives, the one resulting in the highest savings is implemented.)

Discretionary Spending—Option 1 **Function 050**

Reduce the Size of the Military to Satisfy Caps Under the Budget Control Act

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Planned Defense Spending												
Budget authority	0	-18	-23	-23	-24	-36	-40	-35	-41	-41	-87	-281
Outlays	0	-11	-18	-20	-22	-31	-36	-35	-38	-39	-72	-251

This option would take effect in October 2017.

Estimates of changes in spending displayed in the table are based on the 2017 Future Years Defense Program—which projects costs that are higher than are permitted under the Budget Control Act—and CBO's extension of that plan. This option would not reduce spending and deficits below the amounts projected in CBO's baseline, which reflect the law's funding caps.

The cost of the plans described in the Department of Defense's (DoD's) most recent Future Years Defense Program (FYDP) greatly exceeds the funding allowed under the Budget Control Act of 2011 (BCA), as amended. For example, by DoD's estimate, implementing the FYDP would require funding of $557 billion in 2018, which is $35 billion, or 7 percent, higher than the limit of $521 billion implied by the BCA for that year (roughly 95 percent of the overall BCA cap of $549 billion in 2018 for the broader category of national defense). (The gap is even larger when the resource requirements are estimated using the Congressional Budget Office's projections of cost factors and growth rates that reflect DoD's experience in recent years.) Closing that gap to bring DoD's budget into compliance with the BCA would require a reduction in the size of the military (measured by the number of major combat units such as Marine regiments or Army brigade combat teams—BCTs); a decrease in the per-unit funding provided to man, equip, train, and operate forces; or a combination of both of those measures.

Under this option, the size of the military would be gradually reduced so that by 2020, DoD's budget would satisfy the BCA cap for that year and average funding per military unit would remain commensurate with 2016 amounts (including adjustments for anticipated cost growth in areas such as pay, military health care, and new weapon systems). The size of the military would remain unchanged thereafter. Using DoD's cost assumptions, CBO estimates that the force cuts would require $281 billion less in budget authority from 2018 through 2026 than DoD's current plans. As a result, CBO estimates that outlays would be reduced by $251 billion through 2026. The initial cuts would be phased in from 2018 through 2020 to provide time for an orderly drawdown and to avoid sudden changes in the size of the force. As a consequence, this option alone would not satisfy the BCA caps for the years 2018 and 2019.

If reductions were spread evenly across DoD's four military services and among all full-time (active) and part-time (reserve and National Guard) units, those reductions might, for example, eliminate the following forces by 2021: 6 Army brigade combat teams (out of a planned force of 56), an aircraft carrier and 11 other major warships (out of 238), 2 Marine battalions (out of 32), and 72 Air Force fighters (out of about 1,200 in combat squadrons). Proportional reductions would be made to most other types of units in each service and in support organizations across DoD, as well as in the acquisition of new weapons.

An advantage of this option is that it would reduce the mismatch between the cost of DoD's plans and the funding available through 2021, the final year that funding is constrained under the BCA. Also, unlike reductions that merely postpone costs, savings from the reductions in military force structure under this option would continue to accrue after 2021 for as long as forces were held at the smaller size. Consequently, it would eliminate pressure for a sudden, large increase in defense spending when the BCA lapses in 2022. Although keeping the current force structure and using short-term reductions in average funding per unit to stay within the BCA caps might be possible through 2021, such an approach would, over the long term, pose the risk of having a so-called hollow force—one that is large but that lacks the equipment or training necessary to be effective. Under this option, units would continue to receive funding equivalent to what they had in 2016 and would not require a large increase in 2022.

The disadvantage of this option is that the size and number of military operations that could be simultaneously conducted and the duration for which they could be sustained would be reduced if the size of the force was cut. Under Army policy, for example, three active BCTs (or five National Guard BCTs) are required to support the rotation of a single BCT in and out of a combat zone. Consequently, the number of BCTs that the Army could continuously deploy would decrease by one for every three active or five National Guard BCTs that were cut from the force structure.

RELATED OPTION: Discretionary Spending, Option 25

RELATED CBO PUBLICATIONS: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *The U.S. Military's Force Structure: A Primer* (July 2016), www.cbo.gov/publication/51535; *Approaches for Scaling Back the Defense Department's Budget Plans* (March 2013), www.cbo.gov/publication/43997

Discretionary Spending—Option 2 Function 050

Reduce DoD's Operation and Maintenance Appropriation, Excluding Funding for the Defense Health Program

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Freeze O&M Budget Authority for Five Years and Then Limit Its Growth to the Rate of Inflation												
Change in Planned Defense Spending												
Budget authority	0	-9	-13	-17	-20	-20	-21	-21	-21	-22	-59	-163
Outlays	0	-6	-11	-15	-18	-19	-20	-20	-21	-21	-49	-151
Limit the Growth of O&M Budget Authority to the Rate of Inflation												
Change in Planned Defense Spending												
Budget authority	0	-5	-7	-6	-5	-6	-6	-6	-6	-6	-24	-53
Outlays	0	-3	-6	-6	-6	-6	-6	-6	-6	-6	-21	-49

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

O&M = operation and maintenance.

The Department of Defense (DoD) uses funds from its operation and maintenance (O&M) account to pay the salaries and benefits of most of its civilian employees, to train its military personnel, and to purchase goods (ranging from paper clips to jet fuel) and services (including, for example, health care, the maintenance and repair of equipment, and information technology support). O&M accounts for about 40 percent of DoD's request for base-budget funding in 2017 (which does not include the additional funding that DoD requested for overseas contingency operations), making it the largest single appropriation title in DoD's budget. In real terms (that is, after the amounts have been adjusted to remove the effects of inflation as measured by growth in the price index for gross domestic product), DoD's base-budget costs for O&M grew by nearly 40 percent from 2000 to 2016, despite a slight decrease in the size of the military. Under DoD's current plans as laid out in its Future Years Defense Program (FYDP), O&M funding—measured in real dollars—would grow by 4 percent from 2016 through 2021, the last year in the most recent FYDP.

This option has two alternatives that would reduce the growth in DoD's O&M appropriation without affecting the portion of O&M funding slated for the Defense Health Program (DHP). (The Congressional Budget Office excluded funding for the DHP from this option because the causes of growth in that program are well-known and distinct from the factors that underlie growth in the rest of the O&M account; such funding is addressed by two health options in this volume, which are listed below.) Under the first alternative, DoD's O&M appropriation in the base budget (excluding funding for the DHP) for the years 2018 through 2021 would equal the amount that the department requested in its budget for 2017. That portion of the budget would grow with inflation from 2022 through 2026. Under the second alternative, DoD's O&M appropriation in the base budget (excluding funding for the DHP) would grow with inflation from the 2017 amount throughout the entire 10-year period.

The first alternative would reduce the discretionary budget authority needed for O&M by $163 billion over 10 years in relation to what would be needed under the FYDP and CBO's extension of it. Outlays would decrease by $151 billion over that period. With the compound effects of inflation, the effect of the first alternative would be to reduce the purchasing power of the O&M appropriation (excluding funding for the DHP) in 2022 by 10 percent. The second alternative would reduce discretionary budget authority by $53 billion and outlays by $49 billion. DoD's total purchasing power for O&M

would be 3 percent less than it would be under the department's current plan.

The option does not specify how the O&M reductions would be spread among the four military services and the defensewide agencies or how they would be implemented within each service or agency. Rather than stipulating across-the-board cuts, for example, the option would allow DoD to redistribute O&M funding among the services and agencies in its future budget requests as it sees fit and would leave it to the services and agencies to reallocate their funding in a manner that minimizes any losses of capability or readiness.

There are a number of methods that DoD could use to meet the O&M targets. Although those methods could be implemented individually, they might be more effective if they were applied as part of a DoD-wide effort to streamline its functions and business processes. One approach would be to gradually but significantly reduce the number of civilian personnel paid from the O&M account. If DoD used that approach, by 2022 it would, under the first alternative, employ roughly 220,000 (or 35 percent) fewer civilian personnel than it would under its current plan; under the second alternative, DoD would employ 60,000 (or 10 percent) fewer civilians. However, such cuts would generate the necessary savings only if the functions performed by the civilian personnel who were cut were not fulfilled by contractors (who would also be paid through the O&M account). The military services and DoD could continue to provide those functions if they found ways to operate more efficiently, or they could forgo the functions altogether. Using military personnel to replace civilians, contractors, or contracted services would not be an effective solution: Although that approach would lower O&M spending, it would transfer those costs to the military personnel account. Further, CBO has found that in many cases, substituting military personnel for civilians would have the net effect of increasing total costs.

Another method that could be used to meet the O&M targets would be to reduce the use of contractors and contracted services. DoD relies on contractors to perform a wide range of functions—from mowing lawns to maintaining complex weapon systems—that in the past were performed almost exclusively by military personnel and civilian employees. As with reducing the civilian workforce, cutting down on the use of contractors each year could save billions of dollars—but only if DoD forgoes the functions that contractors fulfill or finds more efficient ways of performing them.

The primary advantage of this option is that slowing the growth in O&M would make it easier for DoD to preserve force structure (the number of major combat units such as Army brigade combat teams or Marine regiments) and to modernize its weapon systems while still responding to pressures to constrain overall defense spending. Costs per uniformed service member generally increase every year because their pay and health care costs typically rise faster than inflation, and DoD's current plan calls for significant increases in spending to modernize many of its weapon systems. Slowing the growth in O&M spending would help offset those increases.

A disadvantage of this option is that it could negatively affect the capability of the military if care is not taken to ensure that personnel remain as well trained and equipment as well maintained as under DoD's current plan. If DoD was unable to afford that level of readiness under this option, it would have to reduce force structure to preserve readiness. Another disadvantage of the option is that it could discourage DoD's efforts to make changes that would allow it to provide essential functions more efficiently. For example, in 2012, DoD identified about 14,000 military positions in commercial activities that could be converted to positions filled by federal civilian employees or contractors (see Option 4). By reducing spending on military personnel, such conversions would probably reduce DoD's overall costs, but they would nevertheless increase the department's O&M spending. Policymakers and DoD would need to take precautions to prevent the option from forestalling such conversions.

RELATED OPTIONS: Discretionary Spending, Option 4; Health, Options 14, 15

RELATED CBO PUBLICATIONS: *Replacing Military Personnel in Support Positions With Civilian Employees* (December 2015), www.cbo.gov/publication/51012; *Growth in DoD's Budget from 2000 to 2014* (November 2014), www.cbo.gov/publication/49764

Discretionary Spending—Option 3 Function 050

Cap Increases in Basic Pay for Military Service Members

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Spending												
Budget authority	0	-0.3	-0.8	-1.2	-1.7	-2.3	-2.8	-3.4	-4.0	-4.7	-4.1	-21.3
Outlays	0	-0.3	-0.7	-1.2	-1.7	-2.2	-2.8	-3.4	-4.0	-4.7	-4.0	-21.1

This option would take effect in January 2018.

About 20 percent of the savings displayed in the table reflect intragovernmental transfers and thus would not reduce the deficit.

Basic pay is the largest component of military members' cash compensation, accounting for about 60 percent of the total. (Allowances for housing and for food, along with the tax advantage that arises because those allowances are not subject to federal taxes, make up the remainder of that compensation.) Between 2006 and 2015, real (inflation-adjusted) spending per capita on basic pay rose by 9 percent. Lawmakers typically use the percentage increase in the employment cost index (ECI) for private-sector workers' wages and salaries (for all occupations and industries) as a benchmark for setting the annual increase in basic pay. Under current law, the pay raise is, by default, set to equal the percentage change in the ECI. However, lawmakers have often overridden that stipulation by temporarily changing the law to specify a different pay raise for a single year through the annual defense authorization and appropriations acts while reverting to current law for future years. Although for each of the years from 2000 to 2013 lawmakers enacted pay raises equal to or higher than the increase in the ECI, in recent years they have approved pay raises that were smaller than the increase in the ECI.

This option would, starting in January 2018, cap basic pay raises at 0.5 percentage points below the increase in the ECI for five years and then return them to the ECI benchmark in 2023. The Congressional Budget Office estimates that this option would reduce the need for discretionary budget authority by $21 billion from 2018 through 2026 compared with what personnel costs would be if the raises were equal to the annual percentage increase in the ECI. Discretionary outlays would decrease by about the same amount.

Although the prospect of smaller basic pay raises could make it harder to retain personnel, CBO anticipates that the effect would be small and that the military services would not need to offer additional incentives to service members to encourage them to stay in the military. Anticipated reductions in force size would make it easier for the Department of Defense (DoD) to tolerate small declines in retention rates and still maintain the services' force structures. DoD has already implemented some reductions, decreasing the size of the Marine Corps and the Army beginning in 2010 and 2012, respectively. The Marine Corps has achieved its target for the number of active duty personnel, and the Army plans to reach its goal by 2018. For this estimate, CBO assumed that all four service branches will achieve their personnel goals as planned and that the numbers of military personnel in each service branch will remain at those levels—about 1.3 million active duty service members—for the rest of the 10-year estimation period.

One rationale for this option is that DoD has consistently exceeded its goal of ensuring that the average cash compensation for military personnel exceeds the wages and salaries received by 70 percent of civilians with comparable education and work experience. According to DoD's analysis in 2012, the average cash compensation for enlisted personnel is greater than the wages and salaries of 90 percent of their civilian counterparts; the corresponding value for officers is 83 percent. Furthermore, the annual increase in the ECI might not be the most appropriate benchmark for setting pay raises over the long run. The comparison group for the ECI includes a broad sample of civilian workers who are, on average, older than military personnel and more likely to have a post-secondary degree. Historically, pay raises for those workers have been larger than for younger or less educated workers, who more closely match the demographic profile of military personnel.

An argument against this option is that, over the next decade, military recruiting and retention could be compromised if basic pay raises did not keep pace with the ECI. Capping raises would also constrain the amount service members received in other benefits, such as the retirement annuities that are tied to a member's 36 highest months of basic pay over the course of a military career.

RELATED OPTION: Discretionary Spending, Option 24

RELATED CBO PUBLICATIONS: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *Costs of Military Pay and Benefits in the Defense Budget* (November 2012), www.cbo.gov/publication/43574; testimony of Carla Tighe Murray, Senior Analyst for Military Compensation and Health Care, before the Subcommittee on Personnel, Senate Committee on Armed Services, *Evaluating Military Compensation* (April 28, 2010), www.cbo.gov/publication/21430

Discretionary Spending—Option 4 Function 050

Replace Some Military Personnel With Civilian Employees

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Spending												
Budget authority	0	-0.2	-0.6	-1.1	-1.5	-1.9	-2.0	-2.1	-2.2	-2.3	-3.4	-13.8
Outlays	0	-0.1	-0.5	-0.9	-1.4	-1.7	-1.9	-2.0	-2.1	-2.2	-2.9	-12.9

This option would take effect in October 2017.

About 40 percent of the savings displayed in the table reflect intragovernmental transfers and thus would not reduce the deficit.

The workforce of the Department of Defense (DoD) consists of members of the active-duty and reserve military, federal civilian employees, and private contractors. According to data from DoD, thousands of members of the military work in support, or "commercial," jobs that could be performed by civilian employees or contractors. Many of those jobs do not involve functions that could raise concerns about personal safety or national security and are performed in military units that do not deploy overseas for combat.

Under this option, over four years DoD would replace 80,000 of the roughly 340,000 active-duty military personnel in commercial jobs with 64,000 civilian employees and, as a result, decrease active-duty end strength (the number of military personnel on the rolls on the final day of the fiscal year) by 80,000. By the Congressional Budget Office's estimate, those changes could reduce the need for appropriations by $14 billion and discretionary outlays by $13 billion from 2018 through 2026. The savings would occur primarily because fewer civilians would be needed to replace a given number of military personnel. (Civilians require less on-the-job training, do not have to devote part of the work year to general military training, and generally do not rotate among positions as rapidly as military personnel do.) Although not shown here, the long-term savings to the federal government as a whole, particularly beyond the next decade, would be larger than those amounts because, ultimately, some of the costs of military personnel are borne by other departments and because a smaller proportion of civilian pay than of military pay is exempt from federal income taxation.

Although there is precedent for such conversions (between 2004 and 2010, DoD converted about 48,000 military positions to 32,000 civilian jobs), only a small percentage of all military positions have been reviewed for that purpose. Moreover, the mix of military and civilian employees used to perform various commercial functions differs from branch to branch. For example, the Army fills 27 percent of its finance and accounting jobs with military personnel, whereas the Marine Corps staffs 64 percent of those jobs with military personnel. The Navy employs military personnel for 8 percent of its jobs in motor vehicle transportation services; the Air Force, 67 percent. If each service adopted the personnel mix with the lowest percentage of military personnel in commercial occupations, up to 100,000 jobs currently held by military personnel could be opened to civilians, CBO estimates. Under this option, 80,000 of those jobs would be filled with 64,000 civilian employees.

One argument for converting military to civilian positions is that civilians require, on average, less job-specific training over their careers because, unlike military personnel, they are not subject to frequent transfers. The military services can thus employ, on average, a smaller number of civilians than military personnel to provide the same quantity and quality of services. However, if DoD did not reduce military end strength but simply reassigned military personnel to other duties, total personnel costs would increase by an amount equal to the cost of the civilian replacements. In that case, this option would still free some military personnel to fulfill their primary mission of training for and, if necessary, engaging in combat.

An argument against this option is that even though many service members might spend part of their career in jobs that could be performed by civilians, most are trained fighters who could be deployed if needed.

Replacing such military personnel with civilians could reduce DoD's ability to surge quickly if called upon to do so. Moreover, despite the potential cost savings, the military services try to avoid converting certain types of positions because doing so could lead to reductions in effectiveness or morale and hinder their workforce management objectives. For example, the Navy must provide shore positions for sailors—so that they do not spend their entire careers at sea—even if some of those positions could be filled by civilians.

RELATED CBO PUBLICATION: *Replacing Military Personnel in Support Positions With Civilian Employees* (December 2015), www.cbo.gov/publication/51012

Discretionary Spending—Option 5 Function 050

Cancel Plans to Purchase Additional F-35 Joint Strike Fighters and Instead Purchase F-16s and F/A-18s

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Planned Defense Spending												
Budget authority	0	-4.1	-3.1	-3.2	-4.2	-5.0	-1.5	-1.6	-2.4	-3.9	-14.6	-29.0
Outlays	0	-0.4	-1.5	-2.5	-3.0	-3.5	-3.9	-3.3	-2.5	-2.4	-7.4	-23.0

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

The F-35 Joint Strike Fighter (JSF) program is the military's largest aircraft development program. The F-35 is a stealthy aircraft—one that is difficult for adversaries to detect by radar and other air defense sensors. The objective of the program is to produce three versions of that aircraft: the conventional takeoff F-35A for the Air Force, the short takeoff and vertical landing (STOVL) F-35B for the Marine Corps, and the carrier-based F-35C for the Navy. Through 2016, 285 F-35s had been purchased for the U.S. military: 178 F-35As, 71 F-35Bs, and 36 F-35Cs. Current plans call for purchasing 2,158 more F-35s through 2038. The Department of Defense (DoD) has estimated that the remaining cost of those purchases, including the cost to complete development, will amount to $265 billion (in nominal dollars). The Marine Corps and the Air Force declared their versions of the F-35 operational in 2015 and 2016, respectively. The Navy expects to declare its version operational by 2019.

Under this option, DoD would halt further production of the F-35 and instead purchase the most advanced versions of older, nonstealthy fighter aircraft that are still in production: the F-16 Fighting Falcon for the Air Force and the F/A-18 Super Hornet for the Navy and Marine Corps. The services would operate the F-35s that have already been purchased. By the Congressional Budget Office's estimates, the option would reduce the need for discretionary budget authority by $29 billion from 2018 through 2026 if the F-16s and F/A-18s were purchased on the same schedule as that currently in place for the F-35s. Outlays would decrease by $23 billion over that period. Additional savings would accrue from 2027 through 2038 if F-16s and F/A-18s were purchased instead of the F-35s that are scheduled to be purchased in those later years. However, the Navy and Air Force are both planning to develop entirely new aircraft with fighterlike capabilities to be fielded in the 2030s and might choose to replace some planned F-35s with those aircraft instead.

An advantage of this option is that it would reduce the cost of replacing DoD's older fighter aircraft while still providing new F-16s and F/A-18s with improved capabilities—including modern radar, precision weapons, and digital communications—that would be able to defeat most of the threats that the United States is likely to face in the coming years. The F-35s that have already been purchased would augment the stealthy B-2 bombers and F-22 fighters that are currently in the force, improving the services' ability to operate against adversaries equipped with advanced air defense systems. The military has successfully operated a mix of stealthy and nonstealthy aircraft since the advent of the F-117 stealth fighter in the 1980s.

A disadvantage of this option is that a force consisting of a mix of stealthy and nonstealthy aircraft would be less flexible against advanced enemy air defense systems. An inability to neutralize such defenses in the early stages of a conflict might preclude the use of F-16s and F/A-18s, effectively reducing the number of fighters that the United States would have at its disposal. Another disadvantage is that the services would have to continue to operate more types of aircraft instead of concentrating on a smaller number of types. For example, F-16s would remain in the Air Force's inventory longer than currently planned, and the Marine Corps might need to field new F/A-18s to augment its F-35Bs. Depending on how expensive it was to operate the F-35, the added costs of maintaining mixed fleets of fighters for a longer period could offset some of the savings under this option.

RELATED OPTION: Discretionary Spending, Option 10

RELATED CBO PUBLICATIONS: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *Strategies for Maintaining the Navy's and Marine Corps' Inventories of Fighter Aircraft* (May 2010), www.cbo.gov/publication/21251; *Alternatives for Modernizing U.S. Fighter Forces* (May 2009), www.cbo.gov/publication/41181

Discretionary Spending—Option 6 Function 050

Stop Building Ford Class Aircraft Carriers

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Planned Defense Spending												
Budget authority	0	-1.8	-1.7	-1.8	-3.1	-3.0	-3.1	-2.2	-2.1	-2.2	-8.4	-21.0
Outlays	0	-0.1	-0.6	-0.9	-1.3	-1.9	-2.3	-2.6	-2.5	-2.5	-2.9	-14.7

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

The Administration's 2017 budget calls for maintaining a fleet of 11 aircraft carriers and 9 active-duty naval air wings. (The number of active air wings is two less than the number of carriers because normally two of the Navy's carriers are having their nuclear reactors refueled or undergoing other major maintenance at any particular time.) Aircraft carriers are accompanied by a mix of surface combatants (typically cruisers and destroyers) and submarines to defend against enemy aircraft, ships, and submarines. The Navy calls such a force a carrier strike group.

Under this option, the Navy would stop building new aircraft carriers after completion of the second of its modern Ford class carriers, the *John F. Kennedy*, which lawmakers authorized in 2013 and which is expected to be completed in 2022. Thus, plans to start building the third Ford class carrier (the *Enterprise*) in 2018 would be canceled, as would the Navy's plans to purchase additional carriers in subsequent years. (Under its current shipbuilding plan, the Navy would purchase a new carrier every five years. Because those ships are expensive and take a long time to build, the Congress allows the Navy to spread the costs out over six years. Funding for the *Enterprise* began in 2016.)

Savings under this option would result exclusively from not buying new carriers; those savings would be offset somewhat by higher costs for nuclear-powered submarines and for refueling the Navy's existing carriers because the fixed overhead costs of the shipyard would be allocated to fewer programs. (The same commercial shipyard that builds and overhauls aircraft carriers also builds parts of submarines. Some of the overhead costs for that yard that are currently associated with building new carriers would instead be charged to submarine programs and to refueling carriers, increasing the total costs of those programs.) This option would reduce the need for discretionary budget authority by $21 billion from 2018 through 2026, the Congressional Budget Office estimates. Outlays would decrease by $15 billion over that period. Additional savings would be realized after 2026 because the Navy would no longer be purchasing new aircraft carriers and because it would need to buy fewer aircraft to put on its carrier fleet, which would slowly shrink as old ships retired from the fleet. Those additional savings would, however, be substantially offset if the Navy decided that it had to buy other weapon systems to replace the capability and capacity that it lost by not purchasing additional carriers.

One argument in favor of this option is that the existing fleet and the carriers under construction would maintain the current size of the carrier force for a long time because the ships are designed to operate for 50 years. Two Ford class carriers, including the *John F. Kennedy*, are currently under construction and will replace the first two Nimitz class carriers when they are retired in the 2020s, so as late as 2030, the Navy would still field 10 carriers under this option. The size of the carrier force would decline thereafter, however, falling to 7 ships by 2040. If national security interests made additional carriers necessary in the future, the Navy could once again start building new carriers. But doing so would be more expensive and complex than building new carriers is today, and it takes years to construct such large ships. Building new designs of small warships is a challenge; relearning how to build the largest warship ever produced would pose much greater challenges for the shipyard tasked with the job.

Another argument in favor of this option is that, as new technologies designed to threaten and destroy surface ships are developed and are acquired by an increasing number of countries, the large aircraft carrier may cease to be an effective weapon system for defending the United States' interests overseas. Among the technologies that might threaten the carrier in the future are long-range supersonic antiship cruise missiles, antiship ballistic missiles, very quiet submarines, and satellite and other tracking systems. The risk to the carrier force is not great today, but if the United States' defensive capabilities fail to keep pace with advances in antiship technologies, the Navy's large surface warships may face much greater risks in the future. If over the next 20 years the technologies to detect, track, and attack the Navy's aircraft carriers advanced to such an extent that it could not effectively defend against those weapons, then any large investment in new carriers that the Navy made today would ultimately not be cost-effective.

An argument against this option is that it could hamper the Navy's fighting ability. Since World War II, the aircraft carrier has been the centerpiece of the U.S. Navy. According to the Navy, each of its 10 older Nimitz class carriers can sustain 95 strike sorties per day and, with each aircraft carrying four 2,000-pound bombs, deliver three-quarters of a million pounds of bombs each day. That firepower far exceeds what any other surface ship can deliver. The new Ford class aircraft carriers will be able to generate an even larger number of sorties each day.

Another argument against this option is that carriers may prove adaptable to a future environment that includes more sophisticated threats to surface ships—perhaps through the development of new weapon systems on the carriers. Since World War II, carriers have transported many different types and generations of aircraft. The Navy is now developing long-range unmanned aircraft that would be capable of striking an enemy's shores while allowing the carrier to operate outside the range of air and missile threats. Equipping long-range unmanned aircraft with long-range precision, stealthy munitions could perhaps extend the life of the aircraft carrier as an effective weapon system for decades to come. Furthermore, the Navy is developing new technologies that may make the defense of large surface ships economically and tactically effective. Energy-based weapons designed to shoot down incoming missiles would probably be far more cost-effective than today's ship defenses, which rely primarily on missiles. In short, if either of those technological developments bears fruit, then the large aircraft carrier could remain a potent weapon system into the distant future.

RELATED OPTION: Discretionary Spending, Option 7

RELATED CBO PUBLICATIONS: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *An Analysis of the Navy's Fiscal Year 2017 Shipbuilding Plan* (forthcoming)

Discretionary Spending—Option 7 Function 050

Reduce Funding for Naval Ship Construction to Historical Levels

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Planned Defense Spending												
Budget authority	0	-3.8	-2.0	-3.8	-4.6	-5.0	-5.4	-5.9	-6.3	-6.7	-14.2	-43.5
Outlays	0	-0.2	-1.1	-1.5	-2.4	-3.1	-3.8	-4.4	-4.9	-5.4	-5.2	-26.8

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

The Navy's fiscal year 2017 shipbuilding plan calls for buying 254 new ships over the next 30 years at an average cost of $17 billion per year in 2016 dollars. Including the costs of all activities funded by the Navy's shipbuilding account, such as refueling nuclear-powered aircraft carriers and outfitting new ships, the average annual cost of implementing the plan is $18.8 billion. That amount is 18 percent more than the average of $15.9 billion per year (in 2016 dollars) that the Navy has spent on shipbuilding over the past 30 years.

This option would decrease spending on naval ship construction to the 30-year average. Specifically, the option would reduce the number of ships that the Navy is scheduled to purchase over the next 30 years from 254 to 180, cutting the number to be purchased between 2017 and 2026 from 86 to 75. The cuts would affect several types of ships in the Navy's fleet: surface combatants, attack submarines, amphibious ships, and combat logistics and support ships. The number of aircraft carriers, however, would remain unchanged to comply with the Congressional mandate that the Navy maintain a force of 11 such ships. The number of ballistic missile submarines also would not be affected by the cuts, because Navy officials consider those ships their highest acquisition priority. If funding for ship construction was reduced to the 30-year average, the need for discretionary budget authority would be reduced by $44 billion through 2026. Outlays would fall by a total of $27 billion over that period, the Congressional Budget Office estimates.

An argument in favor of this option is that the Navy would still have a powerful fleet in 2026 and beyond. Because ships take a long time to build and then serve in the fleet for 25 to 50 years, even with the cuts the size of the fleet would grow by nearly the same amount through 2026 under this option as it would under the 2017 plan. Today, the fleet numbers 272 ships. Under the Navy's 30-year plan, the fleet would grow to 309 ships by 2026 before dropping to 292 ships in 2046. Under this option, the fleet would grow to 308 ships in 2026, and then it would steadily decline to 231 ships in 2046.

An argument against this option is that it would further decrease the size of the fleet over the next 30 years when the fleet has already shrunk over the past 30 years. Since 1987, the number of ships in the fleet has fallen by more than 50 percent—from 568 to 272. With a smaller fleet, the Navy may not have the forces that it needs to implement its war plans if a conflict was to erupt. The Navy's shipbuilding plan is based on the 2014 update to its 2012 force structure assessment, which concluded that the fleet should comprise 308 ships. That is the minimum number of ships that the Navy has determined it needs in its fleet in order to deploy an adequate number of ships overseas in the event of a conflict. At any given time, some ships are undergoing long-term maintenance or are in the early stages of training and thus are unavailable to be immediately deployed, so the Navy must maintain more ships in the fleet than it would need to fight. Some observers, pointing to the increasing assertiveness with which Russia and China conduct foreign relations, have noted that the world appears to be entering an era of renewed competition between major powers. Decreasing funding for shipbuilding and substantially reducing the size of the fleet would, over the long run, result in the Navy's having fewer ships than it says it needs to protect the United States' interests overseas in the event of a conflict with another major power.

Another argument against this option is that it could lead the Navy to reduce its overseas presence. Today the Navy operates more than a third of its fleet—or about 100 ships—overseas. If the fleet was smaller, it is likely that fewer ships would be based overseas in peacetime. The Navy could, however, maintain the same level of presence with a smaller fleet by stationing more ships overseas, increasing the practice of crew rotation, or extending the length of deployments. But those measures would cost money and, in the case of longer deployments, place greater stress on the crews that operate the ships.

RELATED OPTION: Discretionary Spending, Option 6

RELATED CBO PUBLICATIONS: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *An Analysis of the Navy's Fiscal Year 2017 Shipbuilding Plan* (forthcoming); *Preserving the Navy's Forward Presence With a Smaller Fleet* (March 2015), www.cbo.gov/publication/49989

Discretionary Spending—Option 8 Function 050

Reduce the Size of the Nuclear Triad

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
	Retain a Nuclear Triad With 10 Submarines, 300 ICBMs, and 1,550 Warheads											
Change in Planned Defense Spending												
Budget authority	0	0.1	-0.2	-0.4	-0.7	-2.4	-0.2	-5.6	-1.5	-1.2	-1.2	-12.3
Outlays	0	-0.1	-0.2	-0.4	-0.6	-0.8	-1.2	-1.4	-2.4	-2.1	-1.3	-9.2
	Retain a Nuclear Triad With 8 Submarines, 150 ICBMs, and 1,000 Warheads											
Change in Planned Defense Spending												
Budget authority	0	-0.1	-0.3	-0.5	-0.7	-2.8	-0.8	-6.7	-2.8	-2.3	-1.6	-17.0
Outlays	0	-0.2	-0.3	-0.5	-0.7	-1.1	-1.7	-2.1	-3.3	-3.2	-1.7	-13.0

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

The United States' nuclear deterrence strategy, developed during the Cold War, is built around the strategic nuclear triad, which comprises intercontinental ballistic missiles (ICBMs), submarines that launch ballistic missiles (SSBNs), and long-range bombers. Each component of the triad plays a particular role that complements the other two. Bombers provide flexibility, and by changing the tempo of their operations, the United States can signal intent to an adversary. ICBMs provide the most rapid response, and their dispersed underground silos present several hundred targets that an adversary would need to destroy in order to disable the United States' nuclear forces. The ability of SSBNs to remain on alert while submerged and undetectable for long periods makes them the most difficult of the three components to destroy and ensures that the United States can retaliate against a nuclear attack. That ability to retaliate and assure the destruction of an adversary that launched a nuclear attack helps provide stability during a crisis by deterring adversaries from using nuclear weapons.

The most recent arms control treaty between the United States and Russia, New START, limits strategic forces to 700 deployed (800 total) delivery systems and 1,550 deployed warheads. To comply with those limits when they take effect in 2018, the United States plans to maintain a nuclear force consisting of the following: 12 deployed (14 total) Ohio class SSBNs that together carry up to 1,090 warheads on 240 missiles; 400 deployed (454 total) Minuteman III ICBMs, each carrying a single warhead; and 60 deployed (66 total) B-52H and B-2A bombers, each of which counts as a single warhead under New START rules.

Almost all components of the United States' nuclear forces are scheduled to be modernized (refurbished or replaced by new systems) over the next 20 years. Current plans call for developing and purchasing 12 new SSBNs, 642 new ICBMs (of which up to 450 would be fielded in existing silos after they were refurbished; the remainder would be spares and test stock), and 80 to 100 B-21 bombers, the next-generation long-range strategic bombers currently under development. Through the mid-2030s, modernization is expected to roughly double annual spending on nuclear forces (currently about $20 billion).

This option would reduce the cost of modernization by retiring some existing delivery systems early and by purchasing fewer of the new systems, but it would allow the United States to retain the strategic benefits provided by the complementary roles of the legs of the triad. The Congressional Budget Office examined two alternative approaches to reducing the size of the triad: The first would keep U.S. forces at the New START limit of 1,550 warheads, and the second would make deeper cuts and reduce the number of deployed warheads to 1,000. Neither alternative would change the size or composition of the planned bomber fleet because the number of bombers is determined largely by their conventional (that is, non-nuclear) mission.

Smaller Triad With 1,550 Warheads

The first alternative would reduce forces to 10 SSBNs and 300 ICBMs and would load more warheads on SSBNs or ICBMs. Under this alternative, the Navy would retire 4 Ohio class SSBNs at a rate of one per year starting in 2018; delay by one year the purchases of new SSBNs included in its current shipbuilding plan, starting with the second submarine, which is slated to be procured in 2024; and cancel orders for the last 2 SSBNs scheduled to be purchased under the current plan. In addition, the Department of Defense (DoD) would retire 150 ICBMs—50 each year for three years starting in 2018—and procure 482 new ICBMs instead of the 640 that are in the current plan. Over the next decade, this alternative would reduce the need for discretionary budget authority by $12 billion, CBO estimates. Outlays would decrease by $9 billion over that period. However, the majority of savings from this alternative would occur after the 10-year period, when DoD would purchase fewer new systems and operate fewer systems overall than it would under the current plan.

An argument in favor of this approach is that it would reduce the cost of nuclear modernization without sacrificing the complementary roles of the triad or reducing the size of the nuclear forces significantly below those permitted under New START. In addition, scaling back plans now may reduce the chances of problematic programs being canceled later and thus may prevent development funding for such programs from being wasted.

An argument against this alternative is that it would reduce the capabilities of the nuclear forces. In particular, with fewer boats the Navy may not be able to meet the current requirements for the number of SSBNs on patrol even though the number of warheads deployed with the submarine fleet could remain the same as under the current plan. In addition, cutting the number of ICBMs that were deployed by one-third would present fewer targets to an adversary, thereby increasing the likelihood that such an adversary could disable that leg of the United States' nuclear triad.

Smaller Triad With 1,000 Weapons

The second alternative under this option would make deeper cuts to forces but still retain a triad structure. Under this alternative, the Navy would field 8 SSBNs and the Air Force would deploy 150 ICBMs. That force level would be reached by retiring existing systems early, starting in 2018, and by purchasing fewer replacement systems. Over the coming decade, those steps would reduce the need for discretionary budget authority by an estimated $17 billion. Outlays would decrease by $13 billion. As with the first alternative, the majority of savings would occur after 10 years, when DoD would purchase and operate fewer modernized systems.

An argument in favor of this alternative is that a force with 1,000 warheads would comport with the *Nuclear Weapons Employment Strategy of the United States,* released in 2013, which states that the United States could maintain a "strong and credible" strategic nuclear deterrent with about one-third fewer weapons deployed than allowed under New START. Such a reduction would continue the trend started by earlier treaties, which have made the United States' current nuclear arsenal about 85 percent smaller than it was at its peak during the Cold War. Some analysts argue that further reduction would strengthen efforts at preventing nuclear proliferation by continuing the United States' compliance with the Nuclear Non-Proliferation Treaty, in which countries with nuclear weapons agreed to work toward reductions in and the eventual elimination of such weapons and, in exchange, countries without nuclear weapons agreed not to develop or acquire them.

An argument against this alternative is that unless a new arms control agreement was reached—which may not be possible in the current international atmosphere—the United States' decision to reduce its stockpile to 1,000 warheads would be unilateral and could be politically untenable domestically. Internationally, those allies that do not have their own nuclear weapons and rely on U.S. nuclear forces to deter attacks would probably oppose such cuts. If they determined that a reduction to 1,000 warheads signaled that the United States was less committed to protecting them than it has been in the past, they may choose to pursue their own nuclear weapons programs, which could provoke regional arms races. Furthermore, this approach would reduce the capabilities of U.S. nuclear forces even more than would the first alternative. The possibility of the Navy's encountering difficulties in meeting SSBN patrol requirements under this alternative would therefore be greater than under the first, and the smaller ICBM force would present even fewer targets to an adversary.

RELATED OPTION: Discretionary Spending, Option 9

RELATED CBO PUBLICATIONS: *Projected Costs of U.S. Nuclear Forces, 2015 to 2024* (January 2015), www.cbo.gov/publication/49870; *Projected Costs of U.S. Nuclear Forces, 2014 to 2023* (December 2013), www.cbo.gov/publication/44968

Discretionary Spending—Option 9 Function 050

Build Only One Type of Nuclear Weapon for Bombers

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
						Cancel the Long-Range Standoff Weapon						
Change in Planned Defense Spending												
Budget authority	0	-0.8	-1.1	-1.0	-1.1	-1.0	-1.0	-0.8	-0.9	-1.3	-4.1	-9.1
Outlays	0	-0.5	-0.9	-1.0	-1.1	-1.1	-1.0	-0.9	-0.9	-1.0	-3.5	-8.3
						Cancel the B61-12 Life Extension Program						
Change in Planned Defense Spending												
Budget authority	0	-1.0	-1.0	-0.8	-0.7	-0.7	-0.8	-0.7	-0.4	-0.3	-3.5	-6.4
Outlays	0	-0.6	-0.9	-0.9	-0.8	-0.7	-0.6	-0.6	-0.4	-0.3	-3.2	-5.9

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

Long-range bombers are the most visible of the three components of the strategic nuclear triad, which also includes intercontinental ballistic missiles and submarine-launched ballistic missiles. Since 1945, the United States has used nuclear-capable bombers to deter adversaries and assure allies during crises by raising the pace of their operations or deploying the aircraft to areas of potential conflict. For bomber weapons to be effective, they must be able to penetrate air defenses to reach their targets. To ensure that they are able to do so, the Air Force relies on hard-to-detect platforms, including cruise missiles that can deliver a warhead when launched from a bomber operating safely away from air defenses and stealthy manned bombers that can fly into defended airspace and deliver short-range gravity bombs from directly above targets. Currently, the Air Force fields two types of long-range bombers that can carry nuclear weapons, both of which can also perform conventional missions: the B-52H, which carries the Air-Launched Cruise Missile (ALCM), and the stealthy B-2A, which carries several varieties of nuclear gravity bombs.

The major pieces of the nuclear bomber force are slated for modernization over the coming decades through the combined efforts of the Department of Defense (DoD) and the Department of Energy (DOE). The most expensive program related to that modernization effort is the development of a new stealthy bomber, the B-21. Two other programs focus on the development of new weapons for that bomber. In one, the B61-12 life extension program (LEP), DOE is working to refurbish and combine several varieties of the B61 bomb into a single hybrid design. In the other, DoD is developing the Long-Range Standoff Weapon (LRSO), a new nuclear air-launched cruise missile that will carry a warhead that DOE will produce. Plans call for the B-21 to be capable of carrying both the B61-12 bomb and the LRSO.

This option would cancel one of the two new weapons and limit the United States' nuclear arsenal to a single type of weapon that could be carried by bombers in the future. The option includes two alternatives. The first would cancel the LRSO but retain the B61-12 LEP. After the nuclear cruise missiles that are currently in service reached the end of their operational lifetime, strategic bombers would no longer be equipped with such missiles. The second alternative would do the opposite—cancel the B61-12 LEP and retain the LRSO. Under that alternative, after the nuclear bombs that are currently in service reached the end of their operational lifetime, strategic bombers would cease to carry such bombs. Canceling the B61-12 program would also eliminate the option to deploy that weapon on tactical fighter aircraft based in Europe. Neither variant of this option would change the planned size of the strategic bomber fleet. Only one version of the option or the other could be implemented without eliminating the nuclear capability of the bomber component of the nuclear triad.

One argument in favor of this option is that by equipping bombers with a single type of nuclear weapon, the United States could reduce costs while still retaining the ability to deploy nuclear bombers. In addition, the timing of the option makes the savings particularly beneficial: The savings would occur when nearly all other components of the United States' nuclear forces are currently scheduled to be modernized. Over the next 20 years, the modernization efforts are expected to roughly double the total amount that the United States spends annually on nuclear forces (currently about $20 billion).

An argument against canceling the development of one type of bomber weapon is that doing so would reduce nuclear capabilities at a time when international tensions, particularly with Russia and China, might make reductions risky. The impact of the option on the United States' nuclear capabilities would depend on which alternative was pursued.

Cancel the Long-Range Standoff Weapon

Under the first alternative, the Air Force would stop equipping bombers with cruise missiles armed with nuclear warheads after the current ALCMs reached the end of their service life around 2030. Specifically, DoD would cancel development and production of the LRSO, and DOE would cancel the development and production of the associated warhead. That approach would reduce the need for discretionary budget authority by $9 billion over the next decade, the Congressional Budget Office estimates. Outlays would decrease by $8 billion. Additional savings would accrue after the 10-year projection period by eliminating both the cost of the additional LRSO missiles and warheads that are currently slated for purchase after 2026 and the expense of operating the new systems.

One argument for canceling the LRSO program is that the need for nuclear cruise missiles has been significantly reduced by the development of modern conventional cruise missiles, which can perform most of the same missions. In addition, to maintain the ability to conduct missions requiring nuclear weapons, some analysts argue, the LRSO program could be postponed until adversaries' air defenses advanced to the point that the B-21 could no longer penetrate them.

An argument against canceling the development of new air-launched cruise missiles is that doing so would somewhat diminish the capabilities of U.S. nuclear forces, particularly the forces' capacity to carry out limited nuclear strikes. Cruise missiles offer operational planners flexibility because they can travel for extended distances (the unclassified range for the current ALCM is more than 1,500 miles) along complicated flight paths, potentially allowing bombers to avoid dangerous or sensitive areas. Thus, removing air-launched cruise missiles would be more detrimental to the Air Force's strategic nuclear capabilities than eliminating nuclear bombs, which must be dropped in close proximity to a target.

Cancel the B61-12 Life Extension Program

Under the second alternative, the United States would cancel the B61-12 program and the associated program that is developing improved guidance kits for the bombs. Strategic bombers (and tactical fighters) would no longer be equipped with nuclear gravity bombs after current models reach the end of their service life. This version of the option would reduce the need for discretionary budget authority by about $6 billion over the next decade. The decrease in outlays would be slightly smaller.

One argument for canceling the B61-12 LEP is the potential that the costs of the program will grow: Early cost estimates varied widely, and the DOE's current estimates are substantially lower than an independent estimate from DoD, so the actual costs may exceed them. Furthermore, the planned guidance systems are considered by some analysts to be a significant improvement in performance and thus contradict the United States' publicly declared policy of not developing new nuclear military capabilities. Moreover, like those of the bombs that it will replace, the nuclear yield of the B61-12—that is, the amount of nuclear energy that it releases upon detonation—will be variable. Many analysts argue that the improvements in accuracy on the B61-12 would allow it to destroy a larger set of targets at a low-yield setting than current bombs can and that the availability of such advanced low-yield weapons might increase the likelihood that nuclear weapons would be used.

An argument against the second alternative is that, in addition to strategic nuclear bomber capability, it would also affect the United States' short-range nuclear capabilities. The B61-12 is slated to be carried not only by the long-range B-21 but also by shorter-range tactical aircraft; those shorter-range aircraft do not carry nuclear cruise missiles. The United States fields such nuclear-equipped tactical aircraft at bases in Europe, where it also has nuclear bombs that could be carried by those aircraft or by the tactical aircraft of its allies in the North Atlantic Treaty Organization (NATO). If the B61-12 LEP was canceled, U.S. policymakers might choose to eliminate that tactical nuclear mission. Such a choice, however, would probably be opposed by other NATO member nations given current tensions between NATO allies and Russia. If the United States chose to continue the tactical nuclear mission, it would need to overhaul the tactical varieties of the B61 when they reached the end of their lifetime or seek some other solution, such as adapting the LRSO for tactical missions. Any of those approaches to preserve the tactical nuclear mission would reduce—and, in some cases, perhaps even negate—savings from this alternative, but those effects may occur beyond CBO's 10-year projection period.

RELATED OPTION: Discretionary Spending, Option 8

RELATED CBO PUBLICATIONS: *Projected Costs of U.S. Nuclear Forces, 2015 to 2024* (January 2015), www.cbo.gov/publication/49870; *Projected Costs of U.S. Nuclear Forces, 2014 to 2023* (December 2013), www.cbo.gov/publication/44968

Discretionary Spending—Option 10 Function 050

Defer Development of the B-21 Bomber

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Planned Defense Spending												
Budget authority	0	-2.2	-2.6	-3.0	-3.0	-3.0	-5.5	-6.1	-7.0	-6.2	-10.8	-38.5
Outlays	0	-1.2	-2.1	-2.6	-2.8	-2.9	-3.3	-3.5	-3.7	-4.6	-8.8	-26.7

This option would take effect in October 2017.

Estimates of savings displayed in the table are based on the 2017 Future Years Defense Program and CBO's extension of that plan.

The Air Force operates a fleet of 158 long-range bombers: 76 B-52Hs built in the 1960s, 62 B-1Bs from the 1980s, and 20 B-2A stealth bombers from the 1990s. Although those aircraft should be able to continue flying through at least 2040, the Air Force is in the early stages of developing a new bomber—recently named the B-21—that it plans to field in the mid- to late-2020s. The goal of that program is to produce 100 aircraft that could augment and eventually replace today's bombers. The Air Force currently estimates that the total program (including development and procurement) will cost $80 billion (in 2016 dollars). Other specifics—including the aircraft's speed, payload, and stealth characteristics, as well as the production schedule—are classified.

Under this option, development of a new bomber would be deferred until after 2026, reducing the need for new budget authority by $39 billion (in nominal dollars) through that year. Those savings include $11 billion that the Air Force has budgeted for development for 2018 through 2021 in the most recent Future Years Defense Program, plus an estimated $28 billion for development and procurement for 2022 through 2026. The Congressional Budget Office based its estimate of savings for that latter period on its analysis of the Department of Defense's plans for bombers as described in the Annual Aviation Inventory and Funding Plan issued in 2016. Measured in terms of outlays, savings would total $27 billion from 2018 through 2026, CBO estimates.

An advantage of this option is that it would reduce acquisition costs at a time when the Air Force plans to modernize other parts of its fleet of aircraft. Funding would not have to be provided for full bomber production while the Air Force carried out its plan to purchase KC-46A tankers and F-35A fighters and to develop other aircraft, including two types of helicopter, advanced trainers, reconnaissance aircraft, and a replacement for Air Force One. Another advantage of this option is that a bomber program that begins later might be able to take advantage of any general advances in aerospace technology that are made in the coming years. Such advances might make possible an even more capable bomber or might lead to other types of weapons that would make a new bomber unnecessary or reduce the number of bombers needed. Taking advantage of future technological developments could be particularly valuable for weapon systems that are expected to be in use for several decades. Even with a 10-year delay, a new bomber would still be available before today's bombers reach the end of their service life.

A disadvantage of this option is that if some of today's bombers need to be retired sooner than expected, a new bomber would not be available. By 2035, the B-52Hs will be almost 75 years old, the B-1Bs about 50 years old, and the B-2As about 40 years old. Expecting those aircraft to perform reliably at such advanced ages may prove to be overly optimistic. Similarly, a gap in capability could arise if the new bomber was deferred and ended up taking significantly more time to field than expected (as was the case for the F-35 fighter program). Another disadvantage is that the Air Force's inventory of stealthy bombers that are able to fly in defended airspace would remain limited to the B-2A, which makes up only about 12 percent of today's bomber force. Larger numbers of stealthy bombers might be useful in operations against adversaries that employed advanced air defenses. A third disadvantage is that fewer bombers would be available to address the recent shift in strategic focus toward the western Pacific Ocean, where long distances and limited basing options would make long-range aircraft such as the B-21 particularly useful during a conflict.

RELATED OPTION: Discretionary Spending, Option 5

RELATED CBO PUBLICATION: *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming)

Discretionary Spending—Option 11 Function 150

Reduce Funding for International Affairs Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-14	-15	-15	-15	-16	-16	-16	-17	-17	-59	-141
Outlays	0	-6	-9	-12	-13	-14	-15	-15	-16	-16	-40	-117

This option would take effect in October 2017.

The budget for international affairs funds diplomatic and consular programs, global health initiatives, security assistance, and other programs. In 2016, those programs cost an estimated total of $51.6 billion, including $11.3 billion for international security assistance, $8.2 billion for diplomatic and consular programs, $9.0 billion for global health programs, and $1.2 billion for narcotics control and law enforcement programs. Most funding for international affairs is funneled through the Department of State or the Agency for International Development. Several other agencies, such as the Departments of Defense, Agriculture, and the Treasury, also receive funding for overseas assistance programs. Eliminating any single program would result in very modest savings, but a broad cut to the entire international affairs budget could yield significant savings.

This option would reduce the total international affairs budget by 25 percent. By doing so, the option would save $117 billion from 2018 through 2026, the Congressional Budget Office estimates.

An advantage of this option is that reducing federal spending on international affairs could encourage the private sector to take a larger role in providing foreign assistance. Private organizations already provide significant resources for various international initiatives, such as HIV/AIDS research and financial development assistance, and further diversifying funding sources for international initiatives could increase their overall success. In addition, some of the government's foreign assistance may be ineffective at promoting growth and reducing poverty. Although some projects and programs are generally considered successful, the Congressional Research Service concludes that "in most cases, clear evidence of the success or failure of U.S. assistance programs is lacking, both at the program level and in the aggregate." Another argument for this option is that a reduction in federal spending on international affairs would lead to greater savings than eliminating smaller foreign aid programs, such as cargo preference for international food assistance (which is projected to cost less than $500 million from 2018 through 2026).

The primary argument against this option is that reducing funding for international affairs programs could have far-reaching effects that might ultimately impede both the international and the domestic policy agendas of the United States. Such programs, which encompass many activities in addition to foreign aid, are central to establishing and maintaining positive relations with other countries. Those relationships contribute to increased economic opportunities at home, better international cooperation, and enhanced national security. Significant reductions in federal funding for international affairs programs could hinder humanitarian, environmental, public health, economic, and national security efforts.

Discretionary Spending—Option 12 Function 250

Eliminate Human Space Exploration Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-8.5	-8.7	-8.9	-9.1	-9.3	-9.5	-9.7	-9.9	-10.1	-35.2	-83.5
Outlays	0	-6.3	-8.5	-8.8	-9.0	-9.2	-9.4	-9.6	-9.8	-10.0	-32.6	-80.7

This option would take effect in October 2017.

The National Aeronautics and Space Administration's (NASA's) Human Exploration and Operations Mission Directorate oversees both the development of the systems and capabilities required to explore deep space and the agency's operations in low-Earth orbit. The directorate's human exploration programs fund the research and development of the next generation of systems for deep space exploration and provide technical and financial support to the commercial space industry. Complementing those efforts, the space operations programs carry out missions in low-Earth orbit, most notably using the International Space Station, and provide space communications capabilities.

This option would terminate NASA's programs for human space exploration and space operations, except for those necessary to meet space communications needs, such as communication with the Hubble Space Telescope. (The agency's science and aeronautics programs and robotic space missions would continue.) Eliminating those human space programs would save $81 billion between 2018 and 2026, the Congressional Budget Office estimates.

The main argument for this option is that increased capabilities in electronics and information technology have generally reduced the need for humans to fly space missions. The scientific instruments used to gather knowledge in space today rely much less (or not at all) on nearby humans to operate them. NASA and other federal agencies have increasingly used robots to perform potentially dangerous missions in order to avoid putting humans in harm's way. For example, NASA uses remotely piloted vehicles to track hurricanes over the Atlantic Ocean. Those vehicles are able to operate at much higher altitudes than conventional tracking aircraft without exposing pilots to the dangers presented by severe storms.

Eliminating humans from spaceflights would avoid risk to human life and would decrease the cost of space exploration by reducing the weight and complexity of the vehicles needed for the missions. (Unlike instruments, humans need water, air, food, space to move around in, and rest.) In addition, by replacing people with instruments, one-way missions would be possible, thus eliminating the cost and complexity of return and reentry into the Earth's atmosphere. Return trips would be necessary only when a particular mission required it, such as to collect samples for further analysis.

A major argument against this option is that eliminating human spaceflight from the orbits near Earth would end the technical progress necessary to prepare for human missions to Mars (though such missions are—at a minimum—decades away). Moreover, if robotic missions proved too limiting, then human space efforts would have to be restarted. Another argument against this option is that there may be some scientific advantage to having humans at the International Space Station to conduct experiments in microgravity that could not be carried out in other, less costly, ways. (However, the International Space Station is currently scheduled to be retired in 2024; its decommissioning was twice postponed, first from 2015 and then from 2020.)

Discretionary Spending—Option 13 Function 270

Reduce Department of Energy Funding for Energy Technology Development

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Reduce Funding for Fossil Energy Research, Development, and Demonstration												
Change in Spending												
Budget authority	0	-0.2	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.6	-1.5	-4.1
Outlays	0	*	-0.1	-0.2	-0.3	-0.4	-0.5	-0.5	-0.5	-0.5	-0.6	-3.0
Reduce Funding for Nuclear Energy Research, Development, and Demonstration												
Change in Spending												
Budget authority	0	-0.2	-0.4	-0.7	-0.7	-0.7	-0.7	-0.7	-0.8	-0.8	-2.1	-5.8
Outlays	0	-0.1	-0.3	-0.5	-0.6	-0.7	-0.7	-0.7	-0.8	-0.8	-1.5	-5.2
Reduce Funding for Energy Efficiency and Renewable Energy Research, Development, and Demonstration												
Change in Spending												
Budget authority	0	-0.4	-0.7	-1.1	-1.2	-1.2	-1.2	-1.2	-1.3	-1.3	-3.4	-9.6
Outlays	0	-0.1	-0.3	-0.5	-0.8	-1.0	-1.1	-1.2	-1.2	-1.2	-1.7	-7.5
Total												
Change in Spending												
Budget authority	0	-0.7	-1.5	-2.3	-2.4	-2.4	-2.5	-2.5	-2.6	-2.6	-6.9	-19.5
Outlays	0	-0.2	-0.6	-1.2	-1.8	-2.1	-2.3	-2.4	-2.5	-2.5	-3.8	-15.6

This option would take effect in October 2017.

* = between –$50 million and zero.

The Department of Energy's (DOE's) spending on the development of new technologies in the areas of fossil fuels, nuclear power, and energy efficiency and renewable energy has varied from year to year but has generally been lower in recent years than in the past. Measured in 2015 dollars, spending in those three areas has averaged $4.7 billion per year since 2010, whereas in the early 1990s, it averaged $7.6 billion per year. (A notable exception to the trend occurred in 2009 when substantial amounts of funding were provided by the American Recovery and Reinvestment Act.) Currently, DOE's programs support the various stages of the development process, from basic energy research through commercial demonstration projects. Roughly one-third of DOE's funding in 2015 went to basic energy sciences and the remaining two-thirds to applied energy research. About half of the applied research projects that received funding from DOE focused on energy efficiency and renewable energy.

This option would reduce spending for technology development in fossil fuel, nuclear power, energy efficiency, and renewable energy programs to roughly 25 percent of their 2016 amounts incrementally over three years. The Congressional Budget Office estimates that, in total, those reductions would lower discretionary outlays by $16 billion from 2018 through 2026. This option would eliminate DOE's efforts to support the later stages of technology development and the demonstration of commercial feasibility while leaving untouched DOE's support of basic and early applied research. (This option would not affect funding for technical assistance or financial assistance, such as that for weatherization services for low-income families; for an option that would affect such funding, see Option 28.)

An argument for this option is that federal funding is generally more cost-effective when it supports basic science and research aimed at the very early stages of developing new technologies than when it supports research that is focused on technologies that are closer to reaching the marketplace. That is because basic research done early in the technology development process is more likely to lead to knowledge that, although it may be valuable to society, results in benefits that cannot be fully captured by firms in the form of higher profits. In contrast, research done in the later stages of the technology development process is more likely to be profitable for firms to undertake.

Another argument for this option is that the private sector has an advantage in the development, demonstration, and deployment of new energy technologies. Generally, the direct feedback that the markets provide to private investors has proven more effective than the judgment of government managers in selecting which technologies will be commercially successful. The limits on the government's ability to promote the development of new energy technologies are illustrated by federal efforts to commercialize technology to capture and store carbon dioxide. For example, although DOE has offered financial incentives to firms to build that technology into new commercial power plants, it has found few firms willing to do so. Overall, DOE has long sought to introduce new energy technologies for coal through expensive technology demonstration plants that have often failed to deliver commercially useful knowledge or attract much private interest.

An argument against this option is that reducing federal support may result in too little spending on the development and use of products that reduce energy consumption or produce energy with minimal greenhouse gas emissions. Reducing emissions of greenhouse gases would diminish the potentially large long-run costs associated with climate change, but producers and consumers have little incentive to manufacture or purchase technologies that reduce those emissions. That lack of incentive results from the fact that the costs imposed by climate change are not reflected in current energy prices. Federal support can help compensate for the resulting underinvestment in greenhouse gas–reducing technologies.

RELATED CBO PUBLICATIONS: *Federal Support for the Development, Production, and Use of Fuels and Energy Technologies* (November 2015), www.cbo.gov/publication/50980; *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* (June 2012), www.cbo.gov/publication/43357; *Federal Climate Change Programs: Funding History and Policy Issues* (March 2010), www.cbo.gov/publication/21196

Discretionary Spending—Option 14 **Function 300**

Eliminate Certain Forest Service Programs

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-0.7	-2.5	-5.9
Outlays	0	-0.4	-0.5	-0.6	-0.6	-0.6	-0.7	-0.7	-0.7	-0.7	-2.2	-5.6

This option would take effect in October 2017.

The Department of Agriculture's Forest Service is responsible for more research and development (R&D) on forestry and forest-related resources than any other organization in the world. The Forest Service's R&D programs address environmental concerns and provide information and tools to assist businesses and other stakeholders in sustainably managing and using natural resources. Research in seven primary areas—which range from the systematic collection and analysis of data on the trees in a particular forest to the identification of best practices in resource management and use—supports a wide variety of projects. Among them are projects aimed at developing new biobased products (such as wood-based chemicals, biofuels, and products that can substitute for petroleum-based materials), identifying innovations in nanotechnology that allow wood fibers to be used to manufacture a variety of products (car body panels or textiles, for example), improving carbon sequestration, measuring how resilient resources are to changes in climate, and supporting the management of forest health (such as efforts to combat damaging insects, diseases, and invasive plants).

This option would eliminate two Forest Service programs: the Forest and Rangeland Research program and the State and Private Forestry program. Doing so would save $6 billion through 2026, the Congressional Budget Office estimates.

One argument in favor of eliminating federal R&D spending for forestry is that extending such support to the private sector distorts businesses' investment decisions. When businesses receive support for developing certain products—fuels and chemicals derived from plant materials or new durable composite materials and papers made from wood, for example—they do not have to weigh the full costs of developing those products against the potential gains. Similarly, in a well-functioning market, the domestic and international demand for forest and rangeland products and services would compensate resource managers for investing appropriately in the sustainable production of those goods and services.

One argument against this option is that the benefits of those programs are so widely dispersed that only the federal government has sufficient incentive to provide them. For example, it may be most efficient for the federal government to conduct research and disseminate information on the resiliency of forest resources to changes in climate. Also, markets do not fully account for the benefits that forests and rangelands provide in terms of improved air quality, water quality, and habitat. If those benefits are to be preserved, it may be necessary for the federal government to continue to address forest health.

Discretionary Spending—Option 15 Function 370

Convert the Home Equity Conversion Mortgage Program From a Guarantee Program to a Direct Loan Program

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
					Estimated Using the Method Established in the Federal Credit Reform Act							
Change in Discretionary Spending												
Budget authority	0	-2.1	-2.2	-2.3	-2.4	-2.5	-2.6	-2.7	-2.8	-3.0	-9.1	-22.8
Outlays	0	-2.1	-2.2	-2.3	-2.4	-2.5	-2.6	-2.7	-2.8	-3.0	-9.1	-22.8
Change in Mandatory Outlays	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.7
					Estimated Using the Fair-Value Method							
Change in Discretionary Spending												
Budget authority	0	-1.4	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-1.9	-2.0	-6.2	-15.5
Outlays	0	-1.4	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-1.9	-2.0	-6.2	-15.5
Change in Mandatory Outlays	0	*	*	*	*	*	*	*	*	*	*	*

This option would take effect in October 2017.

* = between –$50 million and zero.

Under current law, the Federal Housing Administration (FHA) of the Department of Housing and Urban Development is permitted to guarantee private home equity conversion mortgages (HECMs) for elderly homeowners. Such loans, which are also called reverse mortgages, enable homeowners who are at least 62 years old to withdraw some of the equity in their home in the form of monthly payments, a lump sum, or a line of credit. As long as they reside in the property, borrowers are not required to repay their loan. But when the home is no longer the borrower's primary residence, the outstanding balance (which includes payments made to the homeowner and any interest accrued on those payments) must be repaid. The borrower or the borrower's estate may either retain the home by repaying the loan in full or sell the home and repay the loan with the proceeds from that sale. If the proceeds are not sufficient to repay the outstanding balance of the loan, FHA will fulfill the terms of its HECM guarantee by reimbursing the private lender. In addition to the cost of the risk associated with that guarantee, FHA bears the cost of servicing some loans. Although private lenders initially bear the servicing costs of the loans they originate under the program, when the outstanding balance of a loan reaches 98 percent of the guarantee amount, it is assigned to FHA, and the agency takes on those costs.

This option would replace the HECM guarantee program with a direct loan reverse mortgage program. Instead of guaranteeing loans that private lenders originate, FHA would make loan disbursements directly to the borrower. The cost of the risk borne by FHA under a direct loan program would be largely the same as that associated with its guarantee on reverse mortgages under current law. The agency's servicing costs would increase because it would be responsible for the cost of servicing all loans from the time they were originated. However, FHA's interest income would also increase because the agency would collect all repayments of principal and interest from the borrower or the borrower's estate.

The savings that this option generates stem from the fact that, in the Congressional Budget Office's estimation, private lenders are charging rates on reverse mortgages that are higher than is necessary to cover their financing costs. Some of that surplus is used to cover their marketing and other nonfinancing costs, but some of it may result from lenders' ability to charge borrowers more than they would be able to in a more competitive market simply because the number of lenders originating reverse mortgages is limited. If the legislation that created the direct loan program required FHA to charge borrowers an interest rate that was comparable to those charged by private lenders on reverse mortgages, the option would generate savings for the federal government. Although FHA would incur the costs of financing and servicing loans that are currently borne by private lenders, by charging an interest rate comparable to the rates projected to be charged under the current program structure, the agency would be able to retain the surplus built into that rate.

CBO estimates that if FHA implemented the direct loan program in 2018, it would originate approximately 550,000 reverse mortgages by 2026. (The number of new loans originated each year is estimated to rise from 60,000 in 2018 to nearly 63,000 in 2026). On the basis of that estimate and in accordance with the budgetary procedures prescribed by the Federal Credit Reform Act of 1990 (FCRA), CBO projects that if FHA charged borrowers an interest rate comparable to those charged by private lenders, the option would result in discretionary savings with a net present value of $23 billion from 2018 to 2026. (A present value is a single number that expresses a flow of current and future payments in terms of an equivalent lump sum paid today; the present value of future cash flows depends on the rate of interest, or discount rate, that is used to translate them into current dollars.)

The option would, under the FCRA approach, increase mandatory spending. Replacing HECMs with direct loan reverse mortgages would eliminate savings for the federal government generated by the securitization of HECMs by the Government National Mortgage Association, or Ginnie Mae. By eliminating the Ginnie Mae securitization program, the option would increase mandatory spending over the period by $0.7 billion, estimated on a FCRA basis.

Under an alternative method, the fair-value approach, estimates are based on market values—market prices when they are available, or approximations of market prices when they are not—which better account for the risk that the government takes on. As a result, the discount rates used to calculate the present value of projected loan repayments under the option are higher for fair-value estimates than for FCRA estimates, and the savings from those projected repayments are correspondingly lower. On a fair-value basis, net discretionary savings are projected to amount to approximately $16 billion over the period. Mandatory savings associated with eliminating the Ginnie Mae securitization program would be very close to zero.

The primary advantage of converting FHA's HECM guarantees to direct loans is that the government—instead of private lenders—would earn the interest margin on reverse mortgages without incurring significant additional risk because, in its role as guarantor, FHA already bears much of the risk associated with reverse mortgage loans. In addition, the complexity of reverse mortgages has limited both demand for them and the number of lenders that originate them, so having FHA serve as the single originator of reverse mortgages might provide consistency and transparency and make them more attractive to borrowers. Finally, FHA could potentially reduce the cost of reverse mortgages for borrowers by lowering the interest rate or fees charged on such loans, but doing so would eliminate some of the savings from this option.

An argument against this option is that it would increase federal debt (but not debt net of financial assets) because FHA would need to fund the principal balances of the reverse mortgages that are currently funded by private lenders. The option would also reduce the private sector's involvement in the reverse mortgage market, which may limit innovations in product features and servicing techniques designed to tailor those loans for elderly homeowners.

Discretionary Spending—Option 16 Function 370

Eliminate the International Trade Administration's Trade Promotion Activities

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Spending												
Budget authority	0	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5	-1.5	-3.6
Outlays	0	-0.3	-0.3	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-1.4	-3.4

This option would take effect in October 2017.

The International Trade Administration (ITA) is an agency within the Department of Commerce that provides support to U.S. businesses that sell their goods and services abroad. The agency assists domestic companies that either are new to the exporting process or are seeking to increase their exports. Under its authority to provide assistance for trade development, ITA assesses the competitiveness of specific U.S. industries in foreign markets and develops trade and investment policies to promote U.S. exports. In addition, ITA supports U.S. exporters in their pursuit of receiving fair market value for their goods, monitors compliance with trade agreements, and enforces U.S. trade law. ITA is one of several federal agencies that engage in trade development and promotion. The Congressional Budget Office estimates that ITA's 2016 appropriation for those purposes was $334 million—about 70 percent of the agency's budget.

This option would eliminate ITA's trade promotion activities. By doing so, the option would reduce discretionary outlays by $3 billion from 2018 through 2026, CBO estimates.

One rationale for this option is that the cost to taxpayers of providing trade promotion services at the federal level probably exceeds the benefit to U.S. businesses. Because those costs are not reflected in the prices of the goods and services sold abroad, a portion of the benefits are passed on to consumers and firms in other countries in the form of lower prices for U.S. exports. In addition, trade promotion activities developed by the private sector would probably be more efficient than those developed by government agencies because the private sector can better tailor policies to meet the particular needs of the businesses involved. Several private-sector entities already provide trade promotion services that target particular industries or regions. For example, TradePort, a joint venture of the Bay Area Council Economic Institute and the Los Angeles Area Chamber of Commerce, is a repository of free information and resources for businesses seeking to increase international trade to and from California.

An argument against eliminating ITA's trade promotion activities is that those activities may be subject to economies of scale. It might therefore be more effective to have a single entity (the federal government) develop the expertise to counsel exporters about foreign legal and other requirements, disseminate information about foreign markets, and promote U.S. products abroad than to have several entities involved in those activities. In addition, eliminating the ITA's trade promotion programs could curtail efforts that are currently under way to increase U.S. exports, including, for example, the National Export Initiative, which relies in part on those programs for support.

Discretionary Spending—Option 17 Function 400

Eliminate Funding for Amtrak and the Essential Air Service Program

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Amtrak												
Change in Discretionary Spending												
Budget authority	0	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-5.9	-14.0
Outlays	0	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-5.9	-14.0
Payments to Air Carriers (Under the Essential Air Service program)												
Change in Discretionary Spending												
Budget authority	0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.7	-1.8
Outlays	0	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.6	-1.7
Essential Air Service Program												
Change in Mandatory Outlays	0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.4	-1.0

This option would take effect in October 2017.

The federal government subsidizes intercity travel in various ways. For example, the National Railroad Passenger Corporation—or Amtrak—received appropriations of about $1.4 billion in both 2015 and 2016 to subsidize intercity passenger rail services, including $1.1 billion in grants for capital expenses and debt service and about $0.3 billion in grants for operating subsidies. The 2015 grants represented close to 90 percent of Amtrak's capital spending and 7 percent of its operating expenses (excluding depreciation costs). Another form of federal subsidy for intercity travel is the Essential Air Service (EAS) program, which received $175 million in discretionary budget authority and an estimated $103 million in mandatory budget authority in 2016; the latter came from fees charged to foreign aircraft that fly through U.S. airspace without landing. The EAS program—created by the Airline Deregulation Act of 1978 to maintain airline service in communities that had been covered by federally mandated service—subsidized air service in 61 communities in Alaska, 2 in Hawaii, and 111 in the continental United States (CONUS) as of November 2016. Based on EAS data available for those CONUS communities, the federal subsidy per airline passenger in 2015 ranged from $8 in Joplin, Missouri, to $985 in Thief River Falls, Minnesota.

This option would eliminate funding for Amtrak and discontinue the EAS program. It would yield savings of about $16 billion in discretionary spending from 2018 through 2026, the Congressional Budget Office estimates. That amount consists of $14 billion in savings from eliminating funding for Amtrak and $2 billion in savings from eliminating the discretionary component of the EAS program (identified separately in the budget as Payments to Air Carriers). Discontinuing the EAS program would also yield savings in mandatory spending totaling $1 billion over that same period, CBO estimates.

One argument in favor of the option is that when the Amtrak and EAS subsidies were first authorized in the 1970s, both were viewed as temporary measures. They were intended to help Amtrak become self-supporting and to aid communities and airlines as they adjusted to deregulation.

A second argument for the option is that both subsidies support transportation services that are of some value to particular groups of users but that are not commercially viable and provide little if any benefit to the general public. According to that argument, states or localities that highly value the subsidized rail or air services should provide the subsidies. States are already required to provide support for Amtrak service on rail lines less than 750 miles long in amounts determined by a cost-allocation method that Amtrak developed in consultation with the states to ensure that those lines cover their operating costs. Some analysts have called for the federal government to extend that requirement to Amtrak lines longer than 750 miles. The EAS program also has cost-sharing requirements, although they affect only the three communities in the program that are less than 40 miles from the nearest small hub airport: Those communities must now negotiate a local cost share before their participation in the program will be renewed. Communities not in the EAS program have used various methods to develop or maintain air service, including guaranteeing airlines a minimum amount of revenues (in some cases, using federal grants to back the guarantees), waiving fees, and taking over ground-handling operations.

The main argument against eliminating either Amtrak or EAS funding is that rail or air transportation service to some smaller communities would be curtailed without the federal subsidies. Amtrak's long rail lines could be particularly vulnerable because reaching agreement among all of the affected states on how to replace the federal subsidies could be difficult. Eliminating service on existing lines could cause hardship for passengers who currently rely on them and might undermine the economies of affected communities.

Another argument against eliminating support for Amtrak is that the amount of such support needs to be analyzed in relation to federal subsidies for travel by highways and air. Rail travel has certain advantages over those alternatives for society, including a better safety record and lower emissions of air pollutants and greenhouse gases. Those advantages could be lost under the option: Eliminating funding for Amtrak's capital investment, which currently relies almost entirely on federal support, could undermine the future viability of passenger rail service in the United States.

An additional argument against discontinuing EAS is that not enough time has elapsed to assess the effects of recent efforts to control the program's cost. In 2014, the Department of Transportation (DOT) announced that beginning in 2016 (using data from 2015), it would resume enforcing a $200 per-passenger subsidy cap for CONUS communities within 210 driving miles of a medium or large hub airport. (DOT suspended enforcement of that cap between 2007 and 2014, when disruptive conditions in the airline industry made compliance with the cap very difficult for some communities.) In August 2016, DOT determined that 30 communities had subsidy costs that exceeded the $200 cap; 12 of the 30 also failed to meet a requirement established by lawmakers in 2012 that CONUS communities within 175 miles of a medium or large hub airport have a daily average of at least 10 passengers boarding planes. The department used its authority to grant temporary waivers to 8 of the 30 communities on the grounds that they had experienced significant disruptions in their air service; the other 22 communities could apply for waivers as well. An additional cap enacted by lawmakers in 2011 limits the subsidy per passenger to $1,000 for all CONUS communities, regardless of their distance from a hub airport; 3 communities with subsidy costs above that limit lost their eligibility in 2016.

RELATED CBO PUBLICATION: *The Past and Future of U.S. Passenger Rail Service* (September 2003), www.cbo.gov/publication/14769

Discretionary Spending—Option 18 Function T400

Limit Highway Funding to Expected Highway Revenues

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Discretionary Spending												
Budget authority (Obligation limitations)	0	0	0	0	-6.4	-7.6	-8.9	-10.2	-11.6	-13.0	-6.4	-57.7
Outlays	0	0	0	0	-1.6	-4.5	-6.3	-7.7	-9.1	-10.4	-1.6	-39.6

This option would take effect in October 2020.

Most of the outlays for the highway program are controlled by limitations on obligations set in annual appropriation acts rather than by contract authority (a mandatory form of budget authority) set in authorizing law. By CBO's estimate, $739 million in contract authority is exempt from the limitations each year; spending stemming from that authority would not be affected by this option.

The Federal-Aid Highway program provides grants to states for highway and other surface transportation projects. The last reauthorization for the highway program—the Fixing America's Surface Transportation Act, or FAST Act—provided highway funding for 2016 through 2020 in the form of contract authority, a type of mandatory budget authority. However, most spending from the program is controlled by annual limitations on obligations set in appropriation acts.

Historically, most of the funding for highway programs has come from the Highway Trust Fund, an accounting mechanism in the federal budget that has two separate accounts—one for highways and another for mass transit. Both accounts are credited with revenues generated by the federal taxes on gasoline and diesel fuels, and the highway account is credited with other federal taxes related to highway transportation as well. Since 2001, the revenues credited to the highway account each year have consistently fallen short of outlays from that account; in 2016, for example, $45 billion was spent from the account and $36 billion in revenues and interest was credited to it. Since 2008, lawmakers have addressed the funding shortfall by supplementing revenues dedicated to the trust fund with several transfers, primarily from the Treasury's general fund. The FAST Act authorized the latest such transfer: $52 billion to the highway account and $18 billion to the mass transit account in 2016. The Congressional Budget Office estimates that those transfers, along with the revenues and interest credited to the fund, will permit the highway account to meet all obligations presented to the account through 2021. For later years, in accordance with the Balanced Budget and Emergency Deficit Control Act of 1985, CBO's baseline for highway spending incorporates the assumption that obligations incurred by the Highway Trust Fund will be paid in full.

This option would reduce federal funding for the highway system, starting in fiscal year 2021, by lowering the obligation limitations for the Federal-Aid Highway program to the amount of revenues projected to go to the highway account of the Highway Trust Fund. The federal taxes that directly fund the Highway Trust Fund would not change. CBO estimates that from 2021 through 2026, this option would reduce resources provided for the highway program by $58 billion, relative to the obligation limitations in CBO's baseline projections. Outlays would decrease by $40 billion over those years, CBO estimates.

One rationale for this option is that funding federal spending on highways with revenues obtained from the current taxes on highway users, rather than from general taxes paid by all taxpayers, is fairer (because those who benefit from the highways pay the costs of the program) and tends to promote a more efficient allocation of resources (because the taxes give users some incentive to limit their travel and because as use increases, more revenue becomes available). That argument suggests that if current revenues are too low to fund a desired level of federal support for highways, an increase in the taxes that are credited to the Highway Trust Fund is appropriate.

A related argument is that it is fairer and more efficient to have local or state tax revenues pay for highway projects that primarily benefit people in a particular area and to reserve federal revenues for projects that have true interstate significance. Another rationale for this option is that it would reduce the extent to which differing amounts of federal support distort the spending choices states make between highways and other priorities, as well as those they make among competing highway projects, which is beneficial because such distortion could lead states to pursue projects that do not yield the greatest net benefits. Also, some of the reduction in federal spending under this option could be offset by greater spending by state and local governments. (The Government Accountability Office reported in 2004 that the existence of federal highway grants has encouraged state and local governments to reduce their own spending on highways and to use those funds for other purposes.)

A general argument against reducing federal spending on highways is that doing so could increase the economic and social costs associated with aging roads and bridges and with increased traffic. In addition, the road network as a whole supports interstate commerce and thus strengthens the national economy.

A specific argument against the option is that using general revenues to support federal spending on highways is reasonable because a portion of the money from the highway account of the Highway Trust Fund is spent on nonhighway projects and purposes, such as public transit, sidewalks, bike paths, recreational trails, scenic beautification, and preservation of historic transportation structures. In addition, the efficiency benefits of the current federal taxes on highway users are limited because they give motorists only weak incentives to avoid contributing to the main social costs of road use—traffic congestion and pavement damage by heavy trucks.

RELATED CBO PUBLICATIONS: "Baseline Projections for Selected Programs: Highway Trust Fund Accounts" (March 2016), www.cbo.gov/publication/51300; *Approaches to Making Federal Highway Spending More Productive* (February 2016), www.cbo.gov/publication/50150; cost estimate for the conference agreement on H.R. 22, the FAST Act, as posted on the website of the House Committee on Rules on December 1, 2015 (December 2, 2015), www.cbo.gov/publication/51051; testimony of Joseph Kile, Assistant Director for Microeconomic Studies, before the Senate Committee on Finance, *The Status of the Highway Trust Fund and Options for Paying for Highway Spending* (June 18, 2015), www.cbo.gov/publication/50297

Discretionary Spending—Option 19 **Function 500**

Eliminate Federal Funding for National Community Service

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-1.1	-1.1	-1.2	-1.2	-1.2	-1.3	-1.3	-1.3	-1.3	-4.6	-11.0
Outlays	0	-0.2	-0.7	-0.9	-1.0	-1.0	-1.1	-1.2	-1.2	-1.2	-2.8	-8.5

This option would take effect in October 2017.

National community service programs provide financial and in-kind assistance to students, senior citizens, and others who volunteer in their communities in areas such as education, public safety, the environment, and health care. In 2016, funding for the programs of the Corporation for National and Community Service (CNCS), which include AmeriCorps and the Senior Corps, totaled $1.1 billion. Participants in those national community service programs receive one or more of the following types of compensation: wages, stipends for living expenses, training, and subsidies for health insurance and child care. In addition, upon completing their service, participants of certain CNCS programs can earn education awards, paid from the National Service Trust, in amounts tied to the maximum value of the Pell grant ($5,815 for the 2016–2017 academic year). In 2015, roughly 75,000 people participated in AmeriCorps and 270,000 people in the Senior Corps.

This option would eliminate federal funding for CNCS, reducing outlays by $9 billion from 2018 through 2026, the Congressional Budget Office estimates. (That estimate includes the savings in administrative costs associated with terminating the programs.)

An argument in favor of this option is that funding community service programs at the local level might be more efficient than funding them at the federal level because the benefits of such programs accrue more to the local community than to the nation as a whole. According to that argument, the local government, community, or organization that would receive the benefits of a given service project is better positioned than the federal government to decide whether that project is valuable enough to fund and to determine which service projects should receive the highest priority. Another rationale for eliminating student-focused national service programs and the education benefits associated with them is that unlike most other federal programs that provide financial aid to students, CNCS's education benefits are not targeted at low-income students. Participants in AmeriCorps are selected without regard to their family income or assets, so funds do not necessarily go to the students with the greatest financial need.

An argument against eliminating CNCS is that the programs provide opportunities for participants of all socioeconomic backgrounds to engage in public service and develop skills that are valuable in the labor market. In addition, if other community service programs do not take CNCS's place, this option could have adverse effects on the communities in which CNCS currently operates.

Discretionary Spending—Option 20 Function 500

Eliminate Head Start

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-9.5	-9.7	-9.9	-10.1	-10.3	-10.5	-10.7	-11.0	-11.2	-39.2	-92.9
Outlays	0	-3.6	-9.1	-9.6	-9.8	-10.0	-10.2	-10.4	-10.6	-10.8	-32.1	-84.0

This option would take effect in October 2017.

The Department of Health and Human Service's Head Start programs provide comprehensive development services, including pre-kindergarten education, for children in low-income families. The Head Start program serves primarily 3- and 4-year-old preschoolers, and the Early Head Start program provides services to pregnant women and child care to children under age 3. (In this analysis, "Head Start" refers to both programs collectively.) Head Start is administered by the Department of Health and Human Services, but services are provided by state or local governments or by private nonprofit or for-profit institutions. Children in foster care, homeless children, and children from families that receive public assistance (such as Temporary Assistance for Needy Families or Supplemental Security Income) are eligible for Head Start services, regardless of income. In 2015, roughly 1 million children were enrolled in Head Start.

This option would eliminate Head Start, resulting in savings of $84 billion between 2018 and 2026, the Congressional Budget Office estimates.

The main argument for this option is that many of the children expected to be enrolled in Head Start in the future would be enrolled in an alternative preschool or child care programs if Head Start was eliminated. Those alternative programs include private as well as public programs. For example, several states have instituted a universal pre-K program with the goal of enrolling all 4-year-olds in pre-K. If Head Start was eliminated, most of the children currently enrolled in Head Start in such states would be enrolled in the state-sponsored programs, and their families would likely pay no or only partial tuition. Children in states where such a program was not available could be enrolled in private preschools, although the tuition costs for such programs would most likely be higher than those for public programs.

The main argument against this option is that some children from low-income families would not be enrolled in any preschool program if Head Start was eliminated. Young children who did not attend any program would enter kindergarten less prepared than those who did attend such programs, and research suggests that they might do less well in school and earn less as adults than they would if they had attended preschool. Consequently, economic growth could be lower in the future if Head Start was eliminated. In addition, eliminating federal subsidies for child care would place an additional burden on the resources of low-income families.

Discretionary Spending—Option 21 Function 500

Restrict Pell Grants to the Neediest Students

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
	Restrict Pell Grants to Students With an EFC Less Than or Equal to 65 Percent of the Maximum Pell Grant Award											
Change in Discretionary Spending												
Budget authority	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-2.1	-4.5
Outlays	-0.1	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5	-0.5	-0.5	-0.5	-1.8	-4.1
Change in Mandatory Outlays	*	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.3	-0.7
	Restrict Pell Grants to Students With an EFC of Zero											
Change in Discretionary Spending												
Budget authority	-6.5	-6.7	-6.9	-7.0	-7.0	-7.3	-7.3	-7.3	-7.3	-8.0	-34.0	-71.2
Outlays	-1.7	-6.5	-6.8	-6.9	-7.0	-7.1	-7.3	-7.3	-7.3	-7.5	-28.8	-65.3
Change in Mandatory Outlays	-0.7	-2.4	-2.5	-2.6	-2.6	-2.6	-2.7	-2.8	-2.8	-2.9	-10.7	-24.5

This option would take effect in July 2017.

EFC = expected family contribution; * = between –$50 million and zero.

The Federal Pell Grant Program is the largest source of federal grant aid to low-income students for undergraduate education. Grant recipients enroll at a variety of educational institutions, including four-year colleges and universities, for-profit schools, two-year community colleges, and institutions that specialize in occupational training. (Pell grants are not available to students pursuing graduate or professional degrees.) For the 2016–2017 academic year, the program will provide $28 billion in aid to 7.8 million students, the Congressional Budget Office estimates.

A student's Pell grant eligibility is chiefly determined on the basis of his or her expected family contribution (EFC)—the amount, calculated using a formula established under federal law, that the government expects a family to contribute toward the cost of their student's postsecondary education. The EFC is based on factors such as the student's income and assets. For dependent students (in general, unmarried undergraduate students under the age of 24 who have no dependents of their own), the parents' income and assets, as well as the number of other people (excluding parents) in the household attending postsecondary schools, are also taken into account. Families with a high EFC generally have less financial need than those with a low EFC and thus are expected to contribute more to their child's education.

Since 2008, funding for the Pell grant program has had discretionary and mandatory components. The discretionary component is the maximum award amount set in each fiscal year's appropriation act. The maximum award for the 2016–2017 academic year is $4,860 per student. One mandatory component is the funding stemming from the Higher Education Act that is dedicated to supporting the discretionary program. The other mandatory component supports the "add-on" to the maximum award set in appropriation acts. The add-on for the 2016–2017 award year is $955, resulting in a total maximum award of $5,815. Under current law, the add-on is indexed to inflation through the 2017–2018 academic year and remains constant thereafter.

This option would tighten eligibility criteria to generate savings in the program. Under current law, students with an EFC exceeding 90 percent of the total maximum Pell grant award (that is, an EFC of $5,234 or greater for the 2016–2017 academic year) are ineligible for a grant. One version of this option would lower that threshold and make students with an EFC exceeding 65 percent of the total maximum Pell grant award ineligible for a Pell grant. Under that approach, the least needy Pell grant recipients as determined by the EFC formula—about 6 percent of recipients in recent years—would lose eligibility. Assuming that in future years the maximum discretionary award amount remained at the $4,860 amount specified in the most recent appropriation act, CBO estimates that this option would yield discretionary savings of $4 billion and mandatory savings of $1 billion from 2017 through 2026.

A stricter version of this option would limit eligibility to those students whose EFC is zero. Under that version, about 34 percent of Pell grant recipients in the 2014–2015 award year would have lost eligibility. That approach would yield discretionary savings of $65 billion and mandatory savings of $25 billion through 2026, CBO estimates.

A rationale for this option, applicable to both versions, is that it would focus federal aid on students who, on the basis of the federally calculated EFC, have the greatest need. Students who lost eligibility under the first version of the option would probably still be able to afford a public two-year college: Tuition and fees at public two-year colleges for the 2014–2015 academic year averaged about $2,955, which is below the EFC of students who would lose eligibility under that version of the option. In addition, most students whose EFC was in the affected range under either approach would be eligible for $3,500 or more in federal loans that are interest-free while they are in school. Furthermore, a few studies suggest that institutions responded to past increases in the size of Pell grants by raising tuition and shifting more of their own aid to students who did not qualify for those grants, which suggests that they may respond to the tightening of eligibility criteria for Pell grants by shifting some of their own aid to those students who lose eligibility.

An argument against the option is that many Pell grant recipients with an EFC above zero have educational expenses that are significantly greater than the family's expected contribution and are not covered by aid (grants, loans, and work-study programs) from federal, state, institutional, or other sources. In the 2011–2012 academic year, for example, 63 percent of students with an EFC above 65 percent of the maximum grant at the time and 76 percent of students with an EFC between zero and 65 percent of the maximum grant incurred educational expenses that were not covered by those sources. Denying Pell grants to those students would further increase the financial burden of obtaining an undergraduate education and might cause some of them to pursue less postsecondary education or to forgo it altogether. The amount of postsecondary education received is an important determinant of future wages. In 2015, for example, the median wage for workers between the ages of 16 and 64 who had a bachelor's degree was about 76 percent higher than the median wage for those who had only a high school diploma or GED certification.

RELATED OPTIONS: Mandatory Spending, Options 8, 10; Revenues, Option 17

RELATED CBO PUBLICATIONS: *The Pell Grant Program: Recent Growth and Policy Options* (September 2013), www.cbo.gov/publication/44448; *Options to Change Interest Rates and Other Terms on Student Loans* (June 2013), www.cbo.gov/publication/44318; *Changes in the Distribution of Workers' Hourly Wages Between 1979 and 2009* (February 2011), www.cbo.gov/publication/22010

Discretionary Spending—Option 22 Function 600

Increase Payments by Tenants in Federally Assisted Housing

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Spending												
Budget authority	0	-0.5	-1.0	-1.6	-2.1	-2.7	-2.8	-2.9	-3.0	-3.0	-5.2	-19.7
Outlays	0	-0.3	-0.8	-1.3	-1.9	-2.5	-2.8	-2.9	-2.9	-3.0	-4.2	-18.3

This option would take effect in October 2017.

The federal government provides housing assistance directly to low-income tenants through the Housing Choice Voucher program (sometimes called Section 8), public housing, and project-based rental assistance. Those three types of assistance are funded by the Department of Housing and Urban Development (HUD) and generally require tenants to pay 30 percent of their household income (after certain adjustments) toward housing expenses; the federal government covers the balance of the tenants' rent, up to established limits. In 2015, by the Congressional Budget Office's estimate, expenditures for all three programs came to roughly $7,800 per recipient household. That amount includes rent subsidies as well as payments to the local public housing agencies and contractors that administer the programs.

Under this option, tenants' rental contribution would, starting in 2018, gradually increase from 30 percent of adjusted household income to 35 percent in 2022 and then remain at that higher rate. Those higher rent contributions would reduce outlays by a total of $18 billion from 2018 through 2026 ($9 billion for the Housing Choice Voucher program, $5 billion for public housing, and $4 billion for project-based rental assistance), CBO estimates.

One argument for this option is that renters who are eligible for housing assistance but who do not currently receive it usually spend more than 30 percent of their income on rent. That is the case for at least four-fifths of such unassisted renters—a population that outnumbers assisted renters 3 to 1. Thus, even if the required contribution for assisted renters was increased to 35 percent of their income, it may still be less than the percentage of income that most unassisted renters pay toward rent. Furthermore, whereas unassisted renters are vulnerable to increases in housing costs relative to income, households that receive assistance would continue to benefit from paying a fixed percentage of their income toward housing under this option.

An argument against implementing this option is that assisted renters would have fewer resources to purchase other necessary goods and services, such as food, health care, and transportation. In addition, by increasing the proportion of income that tenants are required to pay in rent, the option would reduce the incentive for some participants to boost their income.

RELATED OPTIONS: Discretionary Spending, Option 23; Revenues, Option 32

RELATED CBO PUBLICATIONS: *Federal Housing Assistance for Low-Income Households* (September 2015), www.cbo.gov/publication/50782; *Growth in Means-Tested Programs and Tax Credits for Low-Income Households* (February 2013), www.cbo.gov/publication/43934; *An Overview of Federal Support for Housing* (November 2009), www.cbo.gov/publication/41219

Discretionary Spending—Option 23 Function 600

Reduce the Number of Housing Choice Vouchers or Eliminate the Program

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Reduce the Number of Housing Choice Vouchers												
Change in Spending												
Budget authority	0	-2	-2	-2	-2	-2	-2	-2	-2	-2	-7	-17
Outlays	0	-1	-2	-2	-2	-2	-2	-2	-2	-2	-6	-16
Eliminate the Housing Choice Voucher Program												
Change in Spending												
Budget authority	0	-2	-5	-7	-10	-12	-15	-18	-21	-24	-23	-113
Outlays	0	-3	-4	-7	-9	-12	-15	-17	-20	-23	-23	-111

This option would take effect in October 2017.

The Housing Choice Voucher program (sometimes called Section 8) provides federally funded vouchers that recipients can use to help pay the rent on units that they find in the private housing market. (Property owners choose whether to participate in the program.) To receive assistance, a household must have income that is below a specified level, and it must wait for a voucher to become available. (Although roughly 20 million households qualify for federal rental assistance on the basis of their income, only about one-quarter of those households receive such assistance because funding for the three discretionary spending programs that provide it is limited.)

Recipients usually pay 30 percent of their household income, after certain deductions, toward their rent. The value of the voucher is the difference between the household's rental payment and the limit on rent for the area that is determined annually by the Department of Housing and Urban Development. That limit is based on the benchmark rent charged for standard rental housing in the area. In some areas, the benchmark rent is set at the 40th percentile (meaning that it is less than 60 percent of rents in the area), and in others, at the 50th percentile. Recipients can continue to use their vouchers when they move; nonetheless, each year households leave the program for a variety of reasons—some because of the dissolution of their family, others because of a violation of program rules, and still others because changing circumstances make it so that they are better off without a voucher. The vouchers that had been used by those households are reissued, to the extent that funding is available, to eligible households on waiting lists for federal housing subsidies.

This option includes two approaches for reducing the number of vouchers. Lawmakers could retire 10 percent of all outstanding vouchers, principally by not reissuing them when households currently enrolled in the program leave it. Alternatively, lawmakers could gradually eliminate the program from 2018 to 2026. Retiring 10 percent of all outstanding vouchers in 2018 would reduce federal spending by $16 billion from 2018 through 2026, and eliminating the program altogether would reduce spending by an estimated $111 billion over that period, the Congressional Budget Office estimates.

An argument in support of retiring 10 percent of outstanding vouchers is that a onetime reduction of that magnitude—about 190,000 vouchers—is roughly equal to the number of households that would be expected to leave the program in a given year, so no one would lose assistance as a direct result of such a reduction. For example, in 2013 about 300,000 voucher-subsidized households (or about 13 percent) left the program.

One rationale in support of eliminating the voucher program entirely is that providing assistance to some households through the program is unfair to other households that are eligible for federally assisted rental housing (through the voucher program and other similar programs) but do not receive assistance. That population is three times as large as the population of households that receive assistance from those programs. Unassisted households must pay their own rent, and at least four-fifths of those households spend more than 30 percent of their income on rent.

An argument against reducing the number of vouchers available is that doing so would increase the amount of time that eligible but unassisted households would have to wait to receive assistance. The households that were added to the voucher program from the waiting lists in 2013 had been waiting for assistance for an average of 23 months. That number probably understates the amount of time that households have to wait for assistance because many waiting lists are periodically closed to new applicants.

An argument against eliminating the voucher program entirely is that doing so would probably increase overcrowding and homelessness because about 2 million households that would receive vouchers in 2026 under current law would no longer receive housing assistance.

RELATED OPTIONS: Discretionary Spending, Option 22; Revenues, Option 32

RELATED CBO PUBLICATIONS: *Federal Housing Assistance for Low-Income Households* (September 2015), www.cbo.gov/publication/50782; *Growth in Means-Tested Programs and Tax Credits for Low-Income Households* (February 2013), www.cbo.gov/publication/43934; *An Overview of Federal Support for Housing* (November 2009), www.cbo.gov/publication/41219

Discretionary Spending—Option 24 Multiple Functions

Reduce the Annual Across-the-Board Adjustment for Federal Civilian Employees' Pay

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Spending												
Budget authority	0	-0.8	-2.0	-3.2	-4.5	-5.9	-7.4	-8.9	-10.5	-12.3	-10.6	-55.6
Outlays	0	-0.8	-1.9	-3.2	-4.5	-5.9	-7.3	-8.9	-10.5	-12.2	-10.4	-55.1

This option would take effect in January 2018.

About 20 percent of the savings displayed in the table reflect intragovernmental transfers and thus would not reduce the deficit.

Under the Federal Employees Pay Comparability Act of 1990 (FEPCA), most federal civilian employees receive a pay adjustment each January. As specified by that law, the size of the adjustment is set at the annual rate of increase of the employment cost index (ECI) for private industry wages and salaries minus 0.5 percentage points. The across-the-board increase as spelled out in FEPCA does not, however, always occur. The President can limit the size of the increase if he determines that a national emergency exists or that serious economic conditions call for such action. Similarly, the Congress can authorize an adjustment that differs from the one sought by the President. Each year since 2011, policymakers have either lowered the annual across-the-board adjustment for federal employees below the percentage specified in FEPCA or canceled it altogether.

This option would reduce the annual across-the-board adjustment specified in FEPCA by 0.5 percentage points each year from 2018 through 2026, meaning that for those years, the adjustment would equal the ECI growth rate minus one percentage point. Federal outlays would be reduced by $55 billion from 2018 through 2026, the Congressional Budget Office estimates.

One rationale for this option is that because compensation for federal civilian employees is a large share of discretionary spending (about 18 percent), reducing the annual across-the-board adjustment is a relatively straightforward way to substantially cut spending across agencies. In addition, those cuts may not significantly affect the agencies' ability to retain employees in jobs that do not require a bachelor's degree because those employees would probably still receive more compensation than similar workers in the private sector, on average. Another rationale for this option is that it would signal that the federal government and its workers were sharing in the sacrifices that many beneficiaries of federal programs have made or will have to make to help reduce the deficit.

An argument against this option is that it could make it more difficult for the federal government to recruit qualified employees, and that effect might be more pronounced for federal agencies that require workers with advanced degrees and professional skills. Recent research suggests that federal workers with professional and advanced degrees are paid less than their private-sector counterparts. Thus, smaller across-the-board increases in federal pay would widen the gap between federal and private-sector workers in jobs that require more education. For federal employees who are eligible to retire but have not done so, lowering the across-the-board increases could also reduce the incentive to continue working. If a significant number of those workers decided to retire as a result of smaller increases in pay, the increased retirement costs could offset some of the payroll savings produced by the policy change. (Because retirement costs fall under mandatory spending, the effects of increases in such costs are not included in the estimates shown here.)

RELATED OPTION: Discretionary Spending, Option 3

RELATED CBO PUBLICATIONS: *Comparing the Compensation of Federal and Private-Sector Employees* (January 2012), www.cbo.gov/publication/42921; *Analysis of Federal Civilian and Military Compensation* (January 2011), www.cbo.gov/publication/22002

Discretionary Spending—Option 25 **Multiple Functions**

Reduce the Size of the Federal Workforce Through Attrition

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Spending												
Budget authority	0	-1.2	-3.6	-5.3	-6.0	-6.4	-6.6	-6.8	-6.9	-7.1	-16.1	-50.0
Outlays	0	-1.2	-3.5	-5.2	-6.0	-6.4	-6.6	-6.8	-6.9	-7.1	-15.9	-49.7

This option would take effect in October 2017.

About 20 percent of the savings reflect intragovernmental transfers and thus would not reduce the deficit.

In 2015, the federal government employed about 2.2 million civilian workers, excluding Postal Service employees. About 45 percent worked in the Department of Defense or Department of Homeland Security, and roughly 15 percent were employed by the Department of Veterans Affairs. The rest of the civilian workforce worked in agencies that provide a variety of public services—regulating businesses, investigating crimes, collecting taxes, and administering programs for the elderly, poor, and disabled, for example. The largest costs that the federal government incurred for those employees were for salaries, future retirement benefits, and health insurance.

This option would reduce the number of federal civilian employees at certain agencies by 10 percent by prohibiting those agencies from hiring more than one employee for every three workers who left. The President would be allowed to exempt an agency from the requirement under certain conditions—because of a national security concern or an extraordinary emergency, for instance, or if the performance of a critical mission required doing so. On the basis of the portion of employees that continued working during the two most recent government shutdowns, the Congressional Budget Office estimates that about two-thirds of the federal civilian workforce would be exempt. Thus, given recent rates of employee separation, CBO estimates that under this option, the workforce would be reduced by about 70,000 employees by 2021. Agencies would be limited in their ability to replace those employees with contractors because appropriations would be reduced accordingly. Discretionary outlays would be reduced by $50 billion from 2018 through 2026, CBO estimates.

An argument for this option is that some agencies could continue to provide crucial services with a smaller workforce by working more efficiently and by eliminating services that are not cost-effective. The number of management and supervisory positions has increased in many agencies as the workforce has aged, and research suggests that, in some cases, the additional layers of management hamper performance. This option could encourage agencies to reduce the number of managers and supervisors through attrition as people in those positions retired over the next few years. Research also suggests that federal workers earn more in occupations that do not require a college degree than do their counterparts in the private sector. If private-sector compensation is indicative of the value of those positions, then the savings generated by trimming that part of the workforce would exceed the value of the services that those jobs produce.

An argument against this option is that trends in federal employment suggest that the federal workforce may already be under strain from cost-cutting measures and that further reductions could impair the government's ability to fulfill parts of its mission. The federal civilian workforce is about the same size as it was 20 years ago, although both the number of people the government serves (as measured by the population of the United States) and federal spending per capita have grown substantially since that time. After declining throughout most of the 1990s, federal employment has increased moderately over the past 15 years. That growth largely reflects the establishment of the Department of Homeland Security and the increase in the volume of service that the Department of Veterans Affairs provides to veterans. Workforce reductions at those or other agencies would probably reduce the quality and quantity of some of the services provided and could have other negative effects, such as increasing the amount of fraud and abuse in some government programs. Moreover, because this option would be phased in as workers left their positions, federal agencies would have little control over the timing of the workforce reduction.

RELATED OPTION: Discretionary Spending, Option 1

RELATED CBO PUBLICATION: *Comparing the Compensation of Federal and Private-Sector Employees* (January 2012), www.cbo.gov/publication/42921

Discretionary Spending—Option 26 Multiple Functions

Impose Fees to Cover the Cost of Government Regulations and Charge for Services Provided to the Private Sector

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Spending												
Budget authority	0	-1.6	-2.0	-2.3	-2.5	-2.8	-3.0	-3.1	-3.1	-3.2	-8.5	-23.7
Outlays	0	-1.6	-2.0	-2.3	-2.5	-2.8	-3.0	-3.1	-3.1	-3.2	-8.5	-23.7

This option would take effect in October 2017.

Fees collected under this option could be recorded in the budget as offsetting collections (discretionary), offsetting receipts (usually mandatory), or revenues, depending on the specific legislative language used to establish them.

The federal government imposes regulations on individuals and businesses to ensure the health and safety of the public and to facilitate commerce. It also provides the private sector with a wide array of services and allows the use of public assets that have economic value, such as navigable waterways and grazing land. To cover the cost of enforcing those regulations and to ensure that it receives compensation for the services that it provides, the government could impose a number of fees or taxes. Those fees could be collected by several federal agencies and through a variety of programs.

This option would increase some existing fees and impose a number of new ones. The option is illustrative and includes several fees and taxes that could be implemented individually or as a group. If all of them were put in place, they would increase income to the government by $24 billion from 2018 through 2026. Specifically, under this option the government would make the following policy changes:

- Increase fees for permits issued by the Army Corps of Engineers ($0.6 billion),
- Set grazing fees for federal lands on the basis of the state-determined formulas used to set grazing fees for state-owned lands ($0.1 billion),
- Impose fees on users of the St. Lawrence Seaway ($0.3 billion),
- Increase fees for the use of the inland waterway system ($5.6 billion),
- Impose fees to recover the costs of registering pesticides and new chemicals ($1.3 billion),
- Charge fees to offset the cost of federal rail safety activities ($2.1 billion),
- Charge transaction fees to fund the Commodity Futures Trading Commission ($2.7 billion),
- Assess new fees to cover the costs of the Food and Drug Administration's reviews of advertising and promotional materials for prescription drugs and biological products ($0.1 billion), and
- Collect new fees for activities of the Food Safety and Inspection Service ($10.8 billion).

Whether the fees included in this option were recorded as revenues or as collections that are subtracted from discretionary or mandatory spending would depend on the nature of the fees and the terms of the legislation that imposed them. Several of the specific fees listed in this option would typically be classified as revenues, in accordance with the guidance provided by the 1967 President's Commission on Budget Concepts. That guidance indicates that receipts from a fee that is imposed under the federal government's sovereign power to assess charges for government activities should generally be recorded as revenues. If that treatment was applied to any of the specific fees included in this option, the amounts shown in the table would be reduced to account for the fact that the fees would shrink the tax base for income and payroll taxes and thus reduce revenues from those sources. However, lawmakers sometimes make the collection of fees subject to appropriation action. In those cases, the fees would be recorded as offsets to spending rather than as revenues.

A rationale for implementing user fees is that private businesses would cover more of the costs of doing business, including the costs of ensuring the safety of their activities and products. Some of those costs—the Federal Railroad Administration's costs for rail safety activities (such as safety inspections of tracks and equipment as well as accident investigations) and the Environmental Protection Agency's costs to register pesticides and new chemicals, for example—are currently borne by the federal government. Another argument in favor of this option is that the private sector would compensate the government for a greater share of the market value of services that benefit businesses (such as the dredging of the inland waterway system) and for using or acquiring resources on public lands (such as grasslands for grazing). If consumers highly value the products and services that businesses provide, those businesses should be able to charge prices that cover all of their costs.

An argument against setting fees to cover the cost of regulation and recover the value of public services and resources is that some of the products and services provided by private businesses are beneficial to people who neither produce nor consume those products and services. Thus, it is both fair and efficient for taxpayers to subsidize the provision of those benefits. For example, by lowering the cost of rail transportation, taxpayers' support for rail safety activities reduces highway congestion and emissions of greenhouse gases. Similarly, support for the registration of new chemicals reduces the use of older chemicals that may be more damaging to public health or the environment.

Discretionary Spending—Option 27 Multiple Functions

Repeal the Davis-Bacon Act

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Discretionary Spending												
Spending authority	0	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.9	-1.9	-6.6	-15.7
Budget authority	0	-0.8	-0.8	-0.8	-0.9	-0.9	-0.9	-0.9	-0.9	-1.0	-3.3	-8.0
Outlays	0	-0.4	-1.0	-1.3	-1.4	-1.6	-1.6	-1.7	-1.7	-1.8	-4.1	-12.5
Change in Mandatory Outlays	0	*	*	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.5

This option would take effect in October 2017.

Spending authority includes budget authority as well as obligation limitations (such as those for certain transportation programs).

* = between –$50 million and zero.

Since 1935, the Davis-Bacon Act has required that workers on all federally funded or federally assisted construction projects whose contracts total more than $2,000 be paid no less than the "prevailing wages" in the area in which the project is located. (A federally assisted construction project is paid for in whole or in part with funds provided by the federal government or borrowed on the credit of the federal government.) The Department of Labor determines the prevailing wages on the basis of the wages and benefits earned by at least 50 percent of the workers in a particular type of job or on the basis of the average wages and benefits paid to workers for that type of job.

This option would repeal the Davis-Bacon Act and reduce appropriations, as well as the government's authority to enter into obligations for certain transportation programs, accordingly. If this policy change was implemented, the federal government would spend less on construction, saving $13 billion in discretionary outlays from 2018 through 2026, the Congressional Budget Office estimates. The option would also result in reductions in mandatory spending of less than $1 billion from 2018 to 2026. Savings would accrue to federal agencies that engage in construction projects. In 2016, about half of all federal or federally financed construction was funded through the Department of Transportation, although a significant portion of federal construction projects were funded through the Department of Defense, the Department of Housing and Urban Development, and the Department of Veterans Affairs, among others.

A rationale for repealing the Davis-Bacon Act is that, since the 1930s, other policies (including a federal minimum wage) have been put in place that ensure minimum wages for workers employed in federal or federally financed construction. Moreover, when prevailing wages (including fringe benefits) are higher than the wages and benefits that would be paid in the absence of the Davis-Bacon Act, the act distorts the market for construction workers. In that situation, federally funded or federally assisted construction projects are likely to use more capital and less labor than they otherwise would, thus reducing the employment of construction workers. Additional arguments for repealing the Davis-Bacon Act are that the paperwork associated with the act effectively discriminates against small firms and that the act is difficult for the federal government to administer effectively.

One argument against repealing the Davis-Bacon Act is that doing so would lower the earnings of some construction workers. Another argument against such a change is that it might jeopardize the quality of construction at federally funded or federally assisted projects. When possible, managers of some construction projects would reduce costs by paying a lower wage than is permitted under the Davis-Bacon Act. As a result, they might attract workers who are less skilled and do lower-quality work. Also, if one of the objectives of federal projects is to increase earnings for the local population, repealing the Davis-Bacon Act might undermine that aim. The act prevents out-of-town firms from coming into a locality, using lower-paid workers from other areas of the country to compete with local contractors for federal work, and then leaving the area upon completion of the work.

Discretionary Spending—Option 28 Multiple Functions

Eliminate or Reduce Funding for Certain Grants to State and Local Governments

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Eliminate Department of Energy Grants for Energy Conservation and Weatherization												
Change in Spending												
Budget authority	0	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-1.1	-2.7
Outlays	0	-0.1	-0.1	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.7	-2.2
Phase Out Environmental Protection Agency Grants for Wastewater and Drinking Water Infrastructure												
Change in Spending												
Budget authority	0	-0.6	-1.2	-2.4	-2.4	-2.5	-2.5	-2.6	-2.6	-2.7	-6.6	-19.5
Outlays	0	*	-0.2	-0.5	-1.1	-1.6	-2.0	-2.2	-2.3	-2.4	-1.8	-12.3
Eliminate New Funding for Community Development Block Grants												
Change in Spending												
Budget authority	0	-3.2	-3.2	-3.3	-3.4	-3.4	-3.5	-3.6	-3.6	-3.7	-13.0	-30.8
Outlays	0	*	-0.7	-2.3	-3.0	-3.2	-3.3	-3.4	-3.5	-3.5	-6.1	-23.0
Eliminate Certain Department of Education Grants												
Change in Spending												
Budget authority	0	-1.5	-1.6	-1.7	-1.8	-2.0	-2.2	-2.5	-3.0	-3.6	-6.5	-19.8
Outlays	0	*	-0.9	-1.4	-1.6	-1.7	-1.9	-2.1	-2.4	-2.8	-3.9	-14.9
Decrease Funding for Certain Department of Justice Grants												
Change in Spending												
Budget authority	0	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-2.2	-5.2
Outlays	0	-0.1	-0.3	-0.4	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-1.2	-4.2
Total												
Change in Spending												
Budget authority	0	-6.0	-6.8	-8.2	-8.4	-8.8	-9.1	-9.6	-10.2	-10.9	-29.4	-78.0
Outlays	0	-0.2	-2.2	-4.8	-6.4	-7.4	-8.1	-8.6	-9.1	-9.6	-13.7	-56.5

This option would take effect in October 2017.

* = between –$50 million and zero.

The federal government provided $624 billion in grants to state and local governments in 2015. Those grants redistribute resources among communities around the country, finance local projects that may have national benefits, encourage policy experimentation by state and local governments, and promote national priorities. Although federal grants to state and local governments fund a wide variety of programs, spending is concentrated in the areas of health care, income security, education, and transportation. The conditions that accompany those federal funds vary substantially: Some grant programs give state and local governments broad flexibility in spending federal funds, whereas others impose more stringent conditions.

This option would reduce or eliminate funding for a group of grants. Specifically, it would make the following changes:

- Eliminate new funding for the Department of Energy's grants for energy conservation and weatherization, saving $2 billion between 2018 and 2026;

- Phase out grants from the Environmental Protection Agency for wastewater and drinking water infrastructure over three years, reducing outlays by $12 billion between 2018 and 2026;

- Eliminate new funding for the Community Development Block Grant program, saving $23 billion from 2018 to 2026;

- Eliminate Department of Education grants that fund nonacademic programs that address the physical, emotional, and social well-being of students, reducing federal outlays by $15 billion between 2018 and 2026; and

- Decrease funding for certain Department of Justice grants to nonprofit community organizations and state and local law enforcement agencies by 25 percent in relation to such funding in the Congressional Budget Office's baseline, reducing spending by $4 billion from 2018 through 2026. (Those grants fund various activities, including the purchase of equipment for law enforcement officers, the improvement of forensic activities, substance abuse treatment for prisoners, Boys and Girls Clubs, and research and data collection for justice programs and the judiciary.)

If all of those reductions were put in place, federal spending would be reduced by $57 billion from 2018 through 2026. (More details on the individual grant programs appear in similar options presented in CBO's March 2011 version of this volume.)

The main argument for this option is that the concerns that those grant programs address are primarily local, so leaving it to state and local governments to decide whether to continue to pay for the programs would lead to a more efficient allocation of resources. According to that reasoning, if state and local governments had to bear the full costs of those activities, they might be more careful in weighing those costs against potential benefits when making spending decisions. In addition, federal funding may not always provide a net increase in spending for those activities because state and local governments may reduce their own funding of such programs in response to the availability of federal funds.

One argument against this option is that those grants support programs that the federal government prioritizes but that state and local governments may lack the incentive or funding to promote to the extent desirable from a national perspective. In fact, many state and local governments face fiscal constraints that might make it difficult for them to compensate for the loss of federal funds. In addition, reducing funding for grants that redistribute resources across jurisdictions could lead to more persistent inequities among communities or individuals. Less federal support could also limit the federal government's ability to encourage experimentation and innovation at the state and local level and to learn from the different approaches taken to address a given policy issue.

RELATED CBO PUBLICATIONS: *Federal Grants to State and Local Governments* (March 2013), www.cbo.gov/publication/43967; *Reducing the Deficit: Spending and Revenue Options* (March 2011), www.cbo.gov/publication/22043

CHAPTER

4

Revenue Options

In fiscal year 2016, the federal government collected $3.3 trillion in revenues, equal to 17.8 percent of the nation's gross domestic product (GDP). Individual income taxes were the largest source of revenues, accounting for more than 47 percent of the total (see Figure 4-1). Payroll taxes (which primarily fund Social Security and Medicare's Hospital Insurance program) accounted for 34 percent. About 9 percent of the total was from corporate income taxes. Other receipts—from excise taxes, estate and gift taxes, earnings of the Federal Reserve System, customs duties, and miscellaneous fees and fines—made up the remaining 9 percent.

Revenues would be greater if not for the more than 200 tax expenditures—so called because they resemble federal spending to the extent that they provide financial assistance for specific activities, entities, or groups of people—in the individual and corporate income tax system. Those tax expenditures include exclusions, deferrals, deductions, exemptions, preferential tax rates, and credits in the individual and corporate income tax system that cause revenues to be lower than they would be otherwise for any given schedule of tax rates.[1]

Trends in Revenues

Over the past 50 years, total federal revenues have averaged 17.4 percent of GDP—ranging from a high of 19.9 percent of GDP in 2000 to a low of 14.6 percent in 2009 and 2010 (see Figure 4-2). That variation over time in total revenues as a share of GDP is primarily the result of fluctuations in receipts of individual income tax payments and, to a lesser extent, fluctuations in collections of corporate income taxes.

From 2017 through 2026, total revenues are projected to gradually increase from 17.9 percent to 18.5 percent of GDP, if current tax laws generally remain unchanged. That growth in revenues as a share of GDP mainly reflects an increase in individual income tax receipts as a share of GDP.

Individual and Corporate Income Taxes

Over the 1966–2016 period, revenues from individual income taxes have ranged from slightly more than 6 percent of GDP (in 2010) to slightly less than 10 percent of GDP (in 2000). Since the 1960s, corporate income taxes have fluctuated between about 1 percent and about 4 percent of GDP.

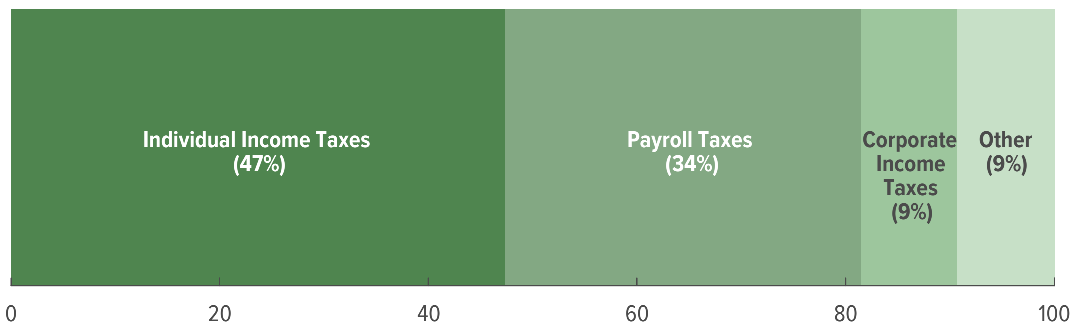
The variation in revenues generated by individual and corporate income taxes has stemmed in part from changes in economic conditions and from the way those changes interact with the tax code. For example, in the absence of legislated tax reductions, receipts from individual income taxes tend to grow relative to GDP because of a phenomenon known as real bracket creep, which occurs when income rises faster than prices,

1. The staff of the Joint Committee on Taxation (JCT) publishes estimates of tax expenditures each year. Tax expenditures, as defined under the Congressional Budget and Impoundment Control Act of 1974, are revenue losses attributable to provisions of federal tax laws that allow a special exclusion, exemption, or deduction from gross income or that provide a special credit, a preferential rate of tax, or a deferral of tax liability. Further, JCT designates as a tax expenditure any deviation from the normal individual or corporate income tax that results from a special provision reducing the tax liability of particular taxpayers. A normal individual income tax is considered to include the following major components: a personal exemption for each taxpayer and each dependent, the standard deduction, the existing tax rate structure, and deductions for investment and employee business expenses. For a more thorough discussion of tax expenditures, see Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2015–2019*, JCX-141R-15 (December 2015), http://go.usa.gov/cVM89; and Congressional Budget Office, *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768.

Figure 4-1.

Composition of Revenues, by Source, 2016

Percentage of Total Revenues



Individual income tax receipts were the largest component of revenues in 2016, accounting for almost half of the total.

Source: Congressional Budget Office.

Other sources of revenues include excise taxes, estate and gift taxes, earnings of the Federal Reserve System, customs duties, and miscellaneous fees and fines.

pushing an ever-larger share of income into higher tax brackets. Although certain parameters of the tax code—including tax brackets—are adjusted to include the effects of inflation, income can still be subject to higher tax rates if it grows faster than prices. In addition, because some parameters of the tax system are not indexed at all, income can be pushed into higher tax brackets even if it is not rising faster than prices.[2] During economic downturns, corporate profits generally fall as a share of GDP, causing corporate tax revenues to shrink; and losses in households' income tend to push a greater share of total income into lower tax brackets, resulting in lower revenues from individual income taxes. Thus, total income tax revenues automatically rise in relation to GDP when the economy is strong and decline in relation to GDP when the economy is weak.

Payroll Taxes

Payroll taxes, by contrast, have been a relatively stable source of federal revenues. Receipts from those taxes increased as a share of GDP from the 1960s through the 1980s because of rising tax rates, increases in the number of people paying those taxes, and growth in the share of wages subject to the taxes. For most of the past three decades, legislation has not had a substantial effect on payroll taxes, and the primary base for those taxes—wages and salaries—has varied less as a share of GDP than have other sources of income. In 2011 and 2012, however, the temporary reduction in the Social Security tax rate caused receipts from payroll taxes to drop. When that provision expired at the end of 2012, payroll receipts as a share of GDP returned to their historical level—close to 6 percent of GDP.

Other Revenue Sources

Revenues from other taxes and fees declined in relation to the size of the economy over the 1966–2016 period mainly because receipts from excise taxes—which are levied on goods and services such as gasoline, alcohol, tobacco, and air travel—have decreased as a share of GDP over time. That decline is chiefly attributable to the fact that those taxes are usually levied on the quantity of goods sold rather than on their cost, and the rates and fees have generally not kept up with inflation.

Tax Expenditures

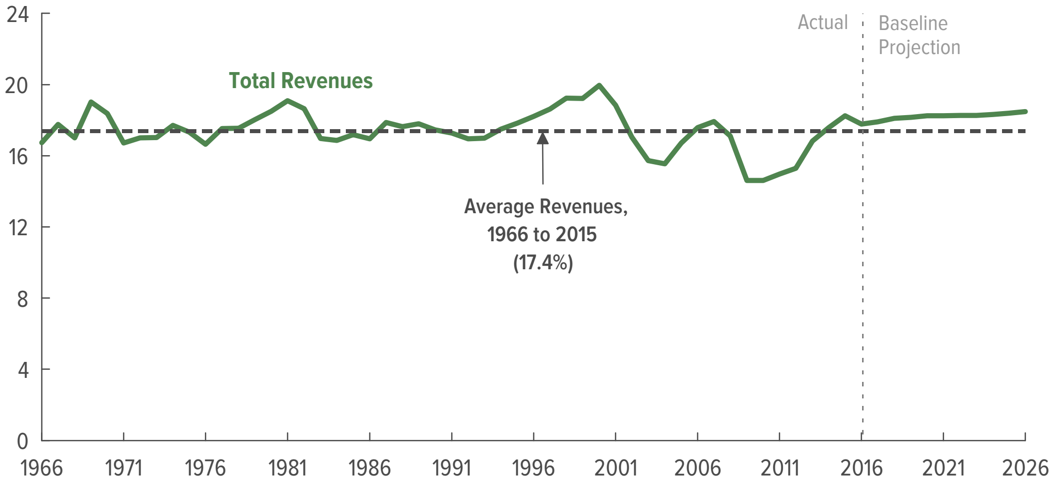
Unlike discretionary spending programs (and some mandatory programs), most tax expenditures are not subject to periodic reauthorization or annual appropriations. (However, a number of tax expenditures are enacted on a temporary basis. For a discussion of those tax provisions, see Box 4-1.) As is the case for mandatory programs, any person or entity that meets the provision's eligibility requirements can receive benefits. Because of the way tax expenditures are treated in the budget, however, they are

2. That effect was more pronounced before 1985, when the parameters of the individual income tax began to be indexed to include the effects of inflation.

Figure 4-2.

Total Revenues

Percentage of Gross Domestic Product



If current laws generally remained unchanged, revenues would gradually rise over the next decade—increasing from 17.9 percent of gross domestic product in 2017 to 18.5 percent by 2026.

Source: Congressional Budget Office.

much less transparent than is spending on mandatory programs.

Types of Tax Expenditures

There are five major categories of tax expenditures.

- *Tax exclusions* reduce the amount of income that filers must report on tax returns. Examples are the exclusions from taxable income of employment-based health insurance, net pension contributions and earnings, capital gains on assets transferred at death, and a portion of Social Security and Railroad Retirement benefits.

- In some situations, taxpayers can *defer* a portion of the taxes owed from one year to another. Some companies, for example, can defer taxes on income earned abroad from the operations of their foreign subsidiaries until that income is remitted (or "repatriated") to the U.S. parent company.

- *Tax deductions* are expenses that are subtracted from reported income in the calculation of taxable income. Examples are itemized deductions for certain taxes paid to state and local governments, mortgage interest payments, and charitable contributions.

- Some types of income are taxed at *preferential tax rates.* An example is the lower rates applied to realizations of many forms of capital gains and qualifying dividends.

- *Tax credits* reduce a taxpayer's tax liability. Credits can either be nonrefundable (the credit can only offset a taxpayer's tax liability) or refundable (the taxpayer receives a payment from the government if the credit exceeds the taxpayer's tax liability). An example of a nonrefundable tax credit is the foreign tax credit. Examples of refundable tax credits are the earned income tax credit and the additional child tax credit.

Major Tax Expenditures

Estimates of tax expenditures measure the difference between a taxpayer's liability under current law and the tax liability without the benefit of a given tax expenditure. The estimates incorporate the assumption that if a tax expenditure was repealed, taxpayers would change how they file their taxes (for example, by claiming an alternative credit or deduction) to minimize their total tax liability, but all other taxpayer behavior would remain unchanged. Because the most recent estimates of tax expenditures were released by the staff of the Joint Committee on Taxation (JCT) in late 2015, they do not reflect provisions of the Consolidated Appropriations Act, 2016.[3] That law, which was enacted in December 2015, reinstated or extended a number of temporary tax expenditures. The Congressional Budget Office

3. See Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2015–2019*, JCX-141R-15 (December 2015), http://go.usa.gov/cVM89.

Box 4-1.

Temporary Tax Provisions

Although most provisions in the tax code are permanent, a number of them are scheduled to expire at the end of calendar year 2016. Enacting provisions on a temporary rather than a permanent basis allows policymakers to address short-term conditions, to regularly review the provisions' effectiveness, and to reduce their initial budgetary cost. Such tax provisions include various income tax credits for individuals and corporations, deductions or exclusions from income, and preferential tax rates. Currently, about 60 provisions in the tax code are scheduled to expire by the end of calendar year 2025. Most of those provisions are set to expire at the end of calendar year 2016.[1] However, some of those temporary provisions have been extended repeatedly and consequently resemble permanent provisions.

Use of Temporary Provisions

Policymakers may enact provisions on a temporary basis for several reasons. Some provisions are used to deliver assistance in response to temporary hardships, such as economic downturns or natural disasters. Additionally, temporary tax provisions provide policymakers with an opportunity to evaluate the effectiveness of those provisions periodically and make changes. In recent years, however, expiring provisions have been extended largely as a group. Furthermore, some tax provisions have been reinstated retroactively after they have expired, creating uncertainty and causing many taxpayers to no longer respond to the incentive provided by the provision. A final reason to enact provisions on a temporary basis is that a temporary tax cut has a smaller budgetary cost than a permanent one. The Congressional Budget Office's revenue projections are based on the assumption that current laws remain unchanged and that temporary provisions expire as scheduled. As a result, those revenue projections are higher than would be the case if the tax cuts were permanent.

In practice, temporary provisions can resemble permanent features of the tax code. Many temporary provisions have been extended multiple times, often for one to two years at a time, and are referred to as tax extenders. The Work Opportunity Tax Credit, for example, has been extended 10 times since it was enacted in 1996 (see the table). Other tax provisions that were originally enacted on a temporary basis have been made permanent. At the end of calendar year 2015, more than 20 temporary tax provisions were made permanent, including the research and experimentation tax credit.

Revenue Effects of Permanently Extending Temporary Provisions

The expiration of temporary provisions boosts revenue projections, even though many of those provisions are likely to be extended in the future. Their effect on projected revenues can be assessed by considering the revenue reductions that would occur if the provisions were extended. For example, the permanent extension of the largest of the temporary provisions, partial expensing of equipment property (known as bonus depreciation), would reduce revenues by $240 billion between 2017 and 2026 if it was extended at a 50 percent rate, according to the staff of the Joint Committee on Taxation (JCT) and CBO (see the table).[2] JCT and CBO estimate that permanently extending all of the other provisions scheduled to expire by the end of calendar year 2025 would reduce revenues by $173 billion between 2017 and 2026. Other temporary provisions that would result in large declines in revenues if they were made permanent include tax credits for biodiesel and renewable diesel, the lower floor for medical expense deductions for taxpayers age 65 or older, and the exclusion of mortgage debt forgiveness from gross income. Because those estimates compare permanent extension to a scenario in which the provision expires as scheduled, extending provisions with a later expiration date would cause a revenue reduction over a shorter period than extending provisions that expire in 2016.

1. For a complete list of temporary tax provisions, see Congressional Budget Office, "Budget Data: Detailed Revenue Projections" (supplemental material for *An Update to the Budget and Economic Outlook: 2016 to 2026*, August 2016), www.cbo.gov/publication/51908; and Joint Committee on Taxation, *List of Expiring Federal Tax Provisions 2016–2025* (January 2016), http://go.usa.gov/x8XW5.

2. Under current law, businesses can expense 50 percent of their investment in equipment and certain other property in 2017. The portion that can be expensed drops to 40 percent in 2018 and 30 percent in 2019, after which the provision expires. Alternatively, if bonus depreciation phases down to 30 percent as scheduled and was permanently extended at that rate beyond 2019, that extension would reduce revenues by $140 billion between 2017 and 2026.

Continued

Box 4-1. Continued

Temporary Tax Provisions

Expiring Tax Provisions With the Largest Revenue Effects From Permanent Extension

Provision	Revenue Effects From Permanent Extension, 2017–2026 (Billions of dollars)	Year Provision Went Into Effect	Number of Extensions
Expiring in Calendar Year 2016			
Biodiesel and renewable diesel credits	-23	2005	5
Exclusion of mortgage debt forgiveness	-23	2007	4
Deduction floor for itemized medical expenses for taxpayers 65 or older	-18	2013	0
Deductible premiums for mortgage insurance	-13	2007	5
Credit for residential energy-efficient property	-9	2006	1
Credit for certain nonbusiness energy property	-7	2006	5
Expiring Between Calendar Years 2017 and 2025			
Extend partial expensing of equipment property at a 50 percent rate (Bonus depreciation)[a]	-240	2008 [b]	4
Payments between related controlled foreign corporations	-17	2006	5
Work Opportunity Tax Credit	-11	1996	10
Credit for business energy property, beginning construction date	-7	2006	2

Sources: Staff of the Joint Committee on Taxation; Congressional Budget Office.

a. The estimate includes provisions that allow businesses to accelerate alternative minimum tax credits instead of the partial-expensing provisions.

b. Bonus depreciation at a 50 percent rate was also in effect from calendar years 2003 to 2005.

estimates that, excluding the effects of recently enacted legislation, the 10 largest tax expenditures would account for almost three-quarters of the total budgetary effects (including payroll tax effects) of all tax expenditures in fiscal year 2016 and would total 6.2 percent of GDP over the period from 2017 to 2026—more than the government spends on Social Security benefits (see Figure 4-3). The exclusion of employers' health insurance contributions and the exclusion of pension contributions and earnings are the two largest tax expenditures.

Analytic Method Underlying the Estimates of Revenues

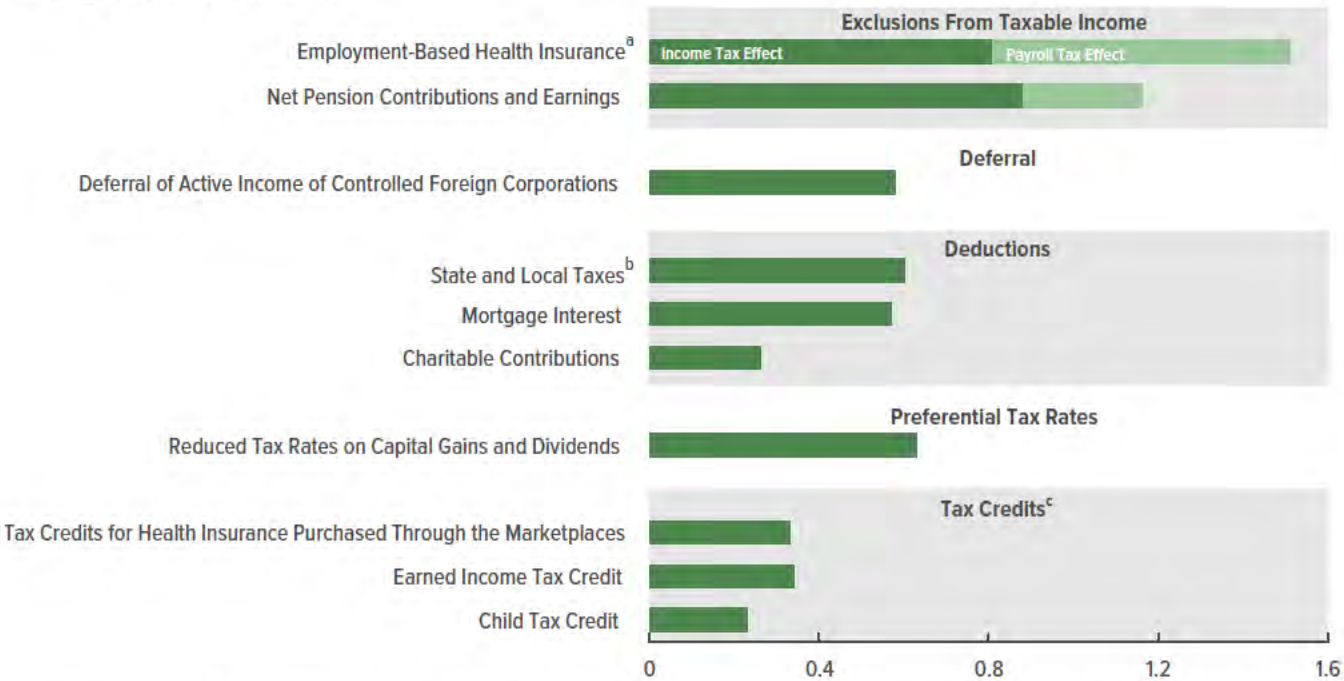
Although CBO prepared or contributed to the revenue estimates of a few options in this chapter, nearly all of the revenue estimates were prepared by JCT, which provides CBO with revenue estimates for legislation dealing with income, estate and gift, excise, or payroll taxes when such legislation is being considered by the Congress. JCT and CBO estimate the budgetary savings relative to the baseline used for budget enforcement purposes, which reflects the general assumption that current laws remain in effect—specifically, that scheduled changes in provisions of the tax code take effect and no additional changes to those provisions are enacted.[4] If combined, the options might interact with one another in ways that could alter their revenue effects and their impact on households and the economy.

4. For more information on JCT's revenue estimating methodology see Joint Committee on Taxation, *Summary of Economic Models and Estimating Practices of the Staff of the Joint Committee on Taxation* (September 2011), http://go.usa.gov/xkMyd. As specified in the Balanced Budget and Emergency Deficit Control Act of 1985, CBO's baseline reflects the assumption that expiring excise taxes dedicated to trust funds will be extended (unlike other expiring tax provisions, which are assumed to follow the schedules set forth in current law). For more information on CBO's baseline, see Congressional Budget Office, *The Budget and Economic Outlook: 2016 to 2026* (January 2016), www.cbo.gov/publication/51129, and *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

Figure 4-3.

Budgetary Effects of the Largest Tax Expenditures From 2017 to 2026

Percentage of Gross Domestic Product



Source: Congressional Budget Office, using estimates by the staff of the Joint Committee on Taxation, which were prepared before the enactment of the Consolidated Appropriations Act, 2016, and do not include the effects of that law.

These effects are calculated as the sum of the tax expenditures over the 2017–2026 period divided by the sum of gross domestic product over the same 10 years. Because estimates of tax expenditures are based on people's behavior with the tax expenditures in place, the estimates do not reflect the amount of revenue that would be raised if those provisions of the tax code were eliminated and taxpayers adjusted their activities in response to the changes.

a. Includes employers' contributions for health care, health insurance premiums, and long-term-care insurance premiums.

b. Consists of nonbusiness income, sales, real estate, and personal property taxes paid to state and local governments.

c. Includes effects on outlays.

Accounting for Changes in Behavior

The revenue estimates in this chapter generally reflect changes in the behavior of people and firms, except for behavioral changes that would affect total output in the economy. An impending increase in the tax rate applicable to capital gains in the following year, for example, would spur some investors to sell assets before the rate increase took effect. Or, when Social Security tax rates increased, employers would pay their employees less in salaries and benefits to offset the businesses' share of higher payroll taxes. Revenue estimates for those options would incorporate such behavioral responses: In the first example, the acceleration of capital gains realizations would cause a temporary hike in taxable realizations in the year before the increase was implemented; and in the second example, the change in compensation would cause individual income tax receipts to fall at the same time that payroll tax revenues rise. Revenue estimates for options presented here do not, however, incorporate macroeconomic effects such as changes in labor supply or private investment resulting from changes in fiscal policy.[5]

Accounting for Outlays

Some revenue options would affect outlays as well as receipts. For example, options that would change eligibility for, or the amount of, refundable tax credits would

5. Under some circumstances, cost estimates for legislation would take such effects into account. See Chapter 1 of this report.

generally cause a change in outlays because the amount of such credits that exceeds a person's income tax liability (before the tax credit is taken into account) is usually paid to that person and recorded in the budget as an outlay. In addition, changes in other tax provisions could affect the allocation of refundable credits between outlays and receipts. For instance, when tax rates are increased (with no changes in the amounts of refundable tax credits or eligibility requirements), the portion of the refundable credits that offsets tax liabilities increases (because the tax liabilities that can be offset are greater) and the outlay portion of the credits falls correspondingly; the total cost of the credit remains the same. For simplicity in presentation, the revenue estimates for options that affect refundable tax credits represent the net effects on revenues and outlays combined.

Options that would expand the base for Social Security taxes would affect outlays as well. When options would require some or all workers to contribute more to the Social Security system, those workers would receive larger benefits when they retired or became disabled. For nearly all such options in this report, CBO anticipates that a change in Social Security benefit payments would be small over the period from 2017 through 2026, and thus the estimates for those options do not include those effects on outlays. One exception, however, is Option 20, which would increase the amount of earnings subject to Social Security tax. In that case, the effects on Social Security outlays over the 10-year projection period would be more sizable; they are shown separately in the table for that option.

Options in This Chapter

This chapter presents 43 options that are grouped into several categories according to the part of the tax system they would target: individual income tax rates, the individual income tax base, individual income tax credits, payroll taxes, taxation of income from businesses and other entities, taxation of income from worldwide business activity, excise taxes, and other taxes and fees.

Options for Raising Revenues

The options presented in this chapter would increase revenues by raising tax rates; imposing a new tax on income, consumption, or certain activities; or broadening the tax base for an existing tax. The tax base is broadened when a tax is extended to more people or applied to additional types or amounts of income. That is generally achieved by either eliminating or limiting exclusions, deductions, or credits. Some of the options presented in this chapter would eliminate current exclusions or deductions. Others would address the limits on such tax expenditures. There are three main types of limits on tax expenditures:

- A *ceiling*—or an upper bound—on the amount that can be deducted or excluded, such as the limit on contributions to certain types of retirement funds.
- A *floor*, wherein tax expenditures are provided only for expenses above a threshold—for example, taxpayers can claim medical and dental expenses that exceed 10 percent of their adjusted gross income, or AGI. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.)
- A *limit* on the set of filers who can receive the full benefit from tax expenditures. For example, taxpayers with income above a specified threshold cannot reduce their taxable income by the full amount of their itemized deductions. The total value of certain itemized deductions is reduced by 3 percent of the amount by which a taxpayer's AGI exceeds a specified threshold, up to a maximum reduction of 80 percent of total itemized deductions. That limit is often called the Pease limitation (after Congressman Donald Pease, who originally proposed it).

Some of the options presented in this chapter would create new limits on tax expenditures. Others would tighten existing limits on tax expenditures by, for example, lowering an existing ceiling or further limiting the set of filers who can receive any benefit from the tax expenditure.

For each option presented, there is a discussion of the advantages and disadvantages of increasing revenues through that approach. Although some advantages and disadvantages are specific to a given option, others apply more broadly to options that would increase revenues in the same manner. For example, a general advantage of increasing existing tax rates is that the change would be simpler to implement than most other changes to the tax code. Changes that would broaden the tax base through standardizing the treatment of similar activities generally increase economic efficiency because taxpayers' decisions would be less influenced by tax considerations.

Some general disadvantages also apply to options that would raise revenues in the same manner. For example, options that would increase individual income tax rates or payroll tax rates would reduce the returns from working (that is, after-tax wages), which would increase the return from other activities relative to working. Similarly, options that would increase taxes on business income would reduce the returns from business investment and thus result in decreased investment.

Distinctions Between the Options and Tax Reform Proposals

Some comprehensive approaches to changing tax policy—each with the potential to increase revenues substantially—that have received attention lately are not included in this report. One approach would eliminate or reduce the value of a broad array of tax expenditures. Another approach would fundamentally change the tax treatment of businesses, especially multinational corporations. Each approach would have significant consequences for the economy and for the federal budget:

- Limiting or eliminating a broad array of tax expenditures would influence many taxpayers' decisions to engage in certain activities or to purchase favored goods.
- Changing the tax treatment of multinational corporations would, to some extent, affect businesses' choices about how and where to invest. Those changes also would affect incentives for engaging in various strategies that allow a business to avoid paying U.S. taxes on some income.

Although this chapter includes options that contain elements of various tax reform plans, none of the options is as comprehensive as those approaches. One reason the report does not contain options that entail comprehensive changes to the tax code is that such proposals often are combined with those that would reduce individual and corporate income tax rates, and therefore their effects are best assessed in the context of such broader packages. Moreover, the estimates would vary greatly depending on the particular proposal's specifications. Hence, the amount—and even the direction—of the budgetary impact of broad approaches to changing tax policy is uncertain.

Revenues—Option 1

Increase Individual Income Tax Rates

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Raise all tax rates on ordinary income by 1 percentage point	43.4	64.1	67.1	70.2	73.2	76.3	79.7	83.3	86.9	90.0	318.0	734.2
Raise ordinary income tax rates in the following brackets by 1 percentage point: 28 percent and over	8.6	12.7	13.4	14.3	15.0	15.7	16.5	17.4	18.3	18.9	64.0	150.8
Raise ordinary income tax rates in the following brackets by 1 percentage point: 35 percent and over	5.3	7.9	8.3	8.8	9.3	9.7	10.1	10.6	11.2	11.6	39.6	92.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates include the effects on outlays resulting from changes in refundable tax credits.

Under current law, taxable ordinary income earned by most individuals is subject to the following seven statutory rates: 10 percent, 15 percent, 25 percent, 28 percent, 33 percent, 35 percent, and 39.6 percent. (Taxable ordinary income is all income subject to the individual income tax other than most long-term capital gains and dividends minus allowable adjustments, exemptions, and deductions.)

As specified by the tax code, different statutory tax rates apply to different portions of people's taxable ordinary income. Tax brackets—the income ranges to which the different rates apply—vary depending on taxpayers' filing status (see the table on the next page). In 2016, for example, a person filing singly with taxable income of $40,000 would pay a tax rate of 10 percent on the first $9,275 of taxable income, 15 percent on the next $28,375, and 25 percent on the remaining $2,350 of taxable income. The starting points for those income ranges are adjusted, or indexed, each year to include the effects of inflation.

Most income in the form of long-term capital gains and dividends is taxed under a separate rate schedule, with a maximum statutory rate of 20 percent. Income from both short-term and long-term capital gains and dividends, along with other investment income received by higher-income taxpayers, is also subject to an additional tax of 3.8 percent.

Taxpayers who are subject to the alternative minimum tax (AMT) face statutory rates of 26 percent and 28 percent. (The AMT is a parallel income tax system with fewer exemptions, deductions, credits, and rates than the regular income tax. Households must calculate the amount they owe under both the AMT and the regular income tax and pay the larger of the two amounts.) However, the AMT does not affect most of the highest-income taxpayers because the highest statutory rate under the AMT is only 28 percent, and many deductions allowed under the regular income tax are still allowed under the AMT.

Starting Points for Tax Brackets (2016 dollars)		Statutory Tax Rate on Ordinary Taxable Income (Percent)
Single Filers	Joint Filers	2016
0	0	10
9,275	18,550	15
37,650	75,300	25
91,150	151,900	28
190,150	231,450	33
413,350	413,350	35
415,050	466,950	39.6

This option includes three alternative approaches for increasing statutory rates under the individual income tax. Those approaches are as follows:

- Raise all tax rates on ordinary income (income subject to the regular rate schedule) by 1 percentage point.
- Raise all tax rates on ordinary income in the top four brackets (28 percent and over) by 1 percentage point.
- Raise all tax rates on ordinary income in the top two brackets (35 percent and over) by 1 percentage point.

If implemented, the first approach—*raising all statutory tax rates on ordinary income by 1 percentage point*—would increase revenues by a total of $734 billion from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation (JCT). Under this alternative, for example, the top rate of 39.6 percent would increase to 40.6 percent. Because the AMT would remain the same as under current law, some taxpayers would not face higher taxes under the option.

The second two approaches would target specific individual income tax rates. Because these approaches would affect smaller groups of taxpayers, they would raise significantly less revenue. For example, *boosting rates only on ordinary income in the top four brackets (28 percent and over) by 1 percentage point* would raise revenues by $151 billion over the 10-year period, according to JCT—much less than the first alternative. *Boosting rates only on ordinary income in the top two brackets (35 percent and over) by 1 percentage point* would raise even less revenue—$93 billion over the 10-year period, according to JCT. Because most people who are subject to the top rate in the regular income tax are not subject to the alternative minimum tax, the AMT would not significantly limit the effect of that increase in regular tax rates.

As a way to boost revenues, an increase in tax rates would offer some administrative advantages over other types of tax increases because it would require only minor changes to the current tax system. Furthermore, by boosting rates only on income in higher tax brackets, both the second and third alternative approaches presented here would increase the progressivity of the tax system. Those approaches would impose, on average, a larger burden on people with more significant financial resources than on people with fewer resources.

Rate increases also would have drawbacks, however. Higher tax rates would reduce people's incentive to work and save. In addition, higher rates would encourage taxpayers to shift income from taxable to nontaxable forms (by substituting tax-exempt bonds for other investments, for example, or opting for more tax-exempt fringe benefits instead of cash compensation) and to increase spending on tax-deductible items relative to other items (by paying more in home mortgage interest, for example, and less for other things). In those ways, higher tax rates would cause economic resources to be allocated less efficiently than they would be under current law.

The estimates shown here incorporate the effect of taxpayers' shifting their income from taxable forms to nontaxable or tax-deferred forms. However, the estimates do not incorporate changes in how much people would work or save in response to higher tax rates. Such changes would depend in part on whether the federal government used the added tax revenues to reduce deficits or to finance increases in spending or cuts in other taxes.

RELATED OPTIONS: Revenues, Options 2, 3

RELATED CBO PUBLICATIONS: *The Distribution of Household Income and Federal Taxes, 2013* (June 2016), www.cbo.gov/publication/51361; *Average Federal Tax Rates in 2007* (June 2010), www.cbo.gov/publication/42870; *The Individual Alternative Minimum Tax* (January 2010), www.cbo.gov/publication/41810; *Analyzing the Economic and Budgetary Effects of a 10 Percent Cut in Income Tax Rates* (December 2005), www.cbo.gov/publication/17507

Revenues—Option 2

Implement a New Minimum Tax on Adjusted Gross Income

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	18.1	-11.6	6.2	6.5	6.8	7.3	7.6	8.0	8.4	8.9	26.0	66.2

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Under current law, individual taxpayers are subject to statutory tax rates on ordinary income (all income subject to the individual income tax other than most long-term capital gains and dividends) of up to 39.6 percent. Higher-income taxpayers are also subject to an additional tax of 3.8 percent on investment earnings. However, people in the highest tax brackets generally may pay a smaller share of their income in income taxes than those brackets might suggest, for at least two reasons. First, income realized from capital gains and received in dividends—which represents a substantial share of income for many people in the highest brackets—is generally subject to income tax rates of 20 percent or less (before the application of the 3.8 percent additional tax). Second, taxpayers can claim exemptions and deductions (both subject to limits) to reduce their taxable income, and they can further lower their tax liability by using credits.

Taxpayers may also be liable for an alternative minimum tax (AMT), which was intended to impose taxes on higher-income individuals who use tax preferences to greatly reduce or even eliminate their liability under the regular income tax. The AMT allows fewer exemptions, deductions, and tax credits than are allowed under the regular income tax, and taxpayers are required to pay the higher of their regular tax liability or their AMT liability. However, the AMT does not affect most of the highest-income taxpayers because the highest statutory rate under the AMT is only 28 percent, and many deductions allowed under the regular income tax are still allowed under the AMT.

In addition to the individual income tax, taxpayers are subject to payroll tax rates of up to 7.65 percent on their earnings: 6.2 percent for Social Security (Old-Age, Survivors and Disability Insurance) and 1.45 percent for Medicare Part A (Hospital Insurance). Employers also pay 7.65 percent of their employees' earnings to help finance those benefits. Higher-earning taxpayers are also subject to an additional tax of 0.9 percent on all earnings above $200,000 for single taxpayers and $250,000 for joint filers. However, the majority of those payroll taxes—specifically, those that fund Social Security benefits—are levied only on the first $118,500 of a worker's earned income. Therefore, as a share of income, payroll taxes have a smaller effect on higher-income taxpayers than on many lower-income taxpayers.

This option would impose a new minimum tax equal to 30 percent of a taxpayer's adjusted gross income, or AGI. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.) The new minimum tax would take effect beginning in 2017. It would not apply to taxpayers with AGI of less than $1 million and would fully apply to taxpayers with AGI of more than $2 million. Between those thresholds, the tax would gradually increase. The thresholds for its application would be adjusted, or indexed, to include the effects of inflation thereafter.

To reduce the liability associated with the new minimum tax, taxpayers could use just one credit equal to 28 percent of their charitable contributions. Taxpayers would pay whichever was higher: the new minimum tax or the sum of individual income taxes owed by the taxpayer and the portion of payroll taxes he or she paid as an employee. (When calculating individual income taxes, the taxpayer would include the 3.8 percent surtax on investment income and any liability under the current AMT.) If implemented, the option would raise $66 billion from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation.

One argument in favor of this option is that it would enhance the progressivity of the tax system. The various exclusions, deductions, credits, and preferential tax rates on certain investment income under the individual income tax—combined with the cap on earnings that are taxed for Social Security—allow some higher-income taxpayers, especially those whose income is primarily in the form of capital gains and dividends, to pay a smaller share of their income in taxes than many lower-income taxpayers, especially those whose income is primarily in the form of wages or salaries. By creating a new minimum tax with no deductions and just one tax credit, the option would increase the share of income paid in taxes by some higher-income taxpayers.

One argument against this option is that, by effectively imposing a second AMT, it would increase the complexity of the tax code—reducing the transparency of the tax system and making tax planning more difficult. Raising taxes on higher-income people through the existing tax system (for example, by increasing the top statutory rates or by limiting or eliminating certain tax deductions or exclusions) would be simpler to implement.

Furthermore, the option would alter the affected taxpayers' incentives to undertake certain activities. Under current law, for example, the tax subsidy rate for charitable contributions can be as high as 39.6 percent. For taxpayers subject to the minimum tax, this option would cap the subsidy rate at 28 percent of contributions. That reduction in the tax subsidy for charitable contributions would reduce donations to charities.

The option would also raise the marginal tax rates that some taxpayers face. (The marginal tax rate is the percentage of an additional dollar of income from labor or capital that is paid in taxes.) For example, the option would impose a minimum tax rate of 30 percent on most income realized from capital gains or received in dividends. In contrast, the highest tax rate on most capital gains and dividends is 23.8 percent under current law. Raising the marginal tax rate on capital gains and dividends would reduce taxpayers' incentives to save. In addition, the higher marginal tax rates on earnings that some higher-income taxpayers face would lessen their incentive to work.

RELATED OPTIONS: Revenues, Options 1, 3, 6

RELATED CBO PUBLICATION: *The Individual Alternative Minimum Tax* (January 2010), www.cbo.gov/publication/41810

Revenues—Option 3

Raise the Tax Rates on Long-Term Capital Gains and Qualified Dividends by 2 Percentage Points

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	6.7	-2.8	6.0	6.1	6.4	6.5	6.7	6.9	7.1	7.5	22.4	57.1

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

When individuals sell an asset for more than the price at which they obtained it, they generally realize a capital gain that is subject to taxation. Most taxable capital gains are realized from the sale of corporate stocks, other financial assets, real estate, and unincorporated businesses. Since the adoption of the individual income tax in 1913, long-term gains (those realized on assets held for more than a year) have usually been taxed at lower rates than other sources of income, such as wages and interest. Since 2003, qualified dividends, which include most dividends, have been taxed at the same rates as long-term capital gains. Generally, qualified dividends are paid by domestic corporations or certain foreign corporations (including, for example, foreign corporations whose stock is traded in one of the major securities markets in the United States).

The current tax rates on long-term capital gains and qualified dividends depend on several features of the tax code:

- The statutory tax rates on long-term capital gains and qualified dividends depend on the statutory tax rates that would apply if they were considered to be ordinary income—that is, all income subject to the individual income tax from sources other than long-term capital gains and qualified dividends. A taxpayer does not pay any taxes on long-term capital gains and qualified dividends that otherwise would be taxed at a rate of 10 percent or 15 percent if those earnings were treated as ordinary income. Long-term capital gains and qualified dividends become taxable when they would be taxed at a rate that ranged from 25 percent through 35 percent if they were treated as ordinary income; those gains and dividends are taxed, instead, at a rate of 15 percent. All other long-term capital gains and qualified dividends are subject to a tax rate of 20 percent—nearly 20 percentage points lower than the rate that would apply if they were considered ordinary income.
- Certain long-term capital gains and qualified dividends are included in net investment income, which is subject to the Net Investment Income Tax (NIIT) of 3.8 percent. Taxpayers are subject to the NIIT if their modified adjusted gross income is greater than $200,000 for unmarried filers and $250,000 for married couples filing joint tax returns. (Adjusted gross income, or AGI, includes income from all sources not specifically excluded by the tax code, minus certain deductions. Modified AGI includes foreign income that is normally excluded from AGI.) The additional tax is applied to the smaller of two amounts: net investment income or the amount by which modified AGI exceeds the thresholds. Therefore, for taxpayers subject to the NIIT, the marginal tax rate (that is, the percentage of an additional dollar of income that is paid in taxes) on long-term capital gains and qualified dividends effectively increases from 20 percent to 23.8 percent.
- Other provisions of the tax code—such as those that limit or phase out other tax preferences—may further increase the tax rate on long-term capital gains and dividends. For example, for each dollar by which taxpayers' AGI exceeds certain high thresholds, the total value of certain itemized deductions is reduced by 3 cents. As a result, the amount of income that is taxable will increase: For example, for taxpayers in the 39.6 percent tax bracket for ordinary income, taxable income will effectively rise by $1.03 for each additional dollar of long-term capital gains. That increase in taxable income will cause their marginal tax rate to rise by more than 1 percentage point (0.396 times 3 percent).

With all of those provisions taken into account, the tax rate on long-term capital gains and dividends is nearly 25 percent for most people in the top income tax bracket. Although that bracket applies to less than 1 percent of all taxpayers, the income of those taxpayers accounts for roughly two-thirds of income from dividends and realized long-term capital gains.

This option would raise the statutory tax rates on long-term capital gains and dividends by 2 percentage points. Those rates would then be 2 percent for taxpayers in the 10 percent and 15 percent brackets for ordinary income, 17 percent for taxpayers in the brackets ranging from 25 percent through 35 percent, and 22 percent for taxpayers in the top bracket. The option would not change other provisions of the tax code that also affect taxes on capital gains and dividends. The staff of the Joint Committee on Taxation estimates that this option would raise federal revenues by $57 billion over the 2017–2026 period.

One advantage of raising tax rates on long-term capital gains and dividends, rather than raising tax rates on ordinary income, is that it would reduce the incentive for taxpayers to try to mischaracterize labor compensation and profits as capital gains. Such strategizing occurs under current law even though the tax code and regulations governing taxes contain numerous provisions that attempt to limit it. Reducing the incentive to mischaracterize compensation and profits as capital gains would reduce the resources devoted to circumventing the rules.

Another rationale for raising revenue through this option is that it would be progressive with respect to people's wealth and income. Most capital gains are received by people with significant wealth and income, although some are received by retirees who have greater wealth but less income than some younger people who are still working. Overall, raising tax rates on long-term capital gains would impose, on average, a larger burden on people with significant financial resources than on people with fewer resources.

A disadvantage of the option is that raising tax rates on long-term capital gains and dividends would influence investment decisions by increasing the tax burden on investment income. By lowering the after-tax return on investments, the increased tax rates would reduce the incentive to invest in businesses. Another disadvantage is that the option would exacerbate an existing bias that favors debt-financed investment by businesses over equity-financed investment. That bias is greatest for investors in firms that pay the corporate income tax because corporate profits are taxed once under the corporate income tax and a second time when those profits are paid out as dividends or reinvested and taxed later as capital gains on the sale of corporate stock. In contrast, profits of unincorporated businesses, rents, and interest are taxed only once. That difference distorts investment decisions by discouraging investment funded through new issues of corporate stock and encouraging, instead, either borrowing to fund corporate investments or the formation and expansion of noncorporate businesses. The bias against equity funding of corporate investments would not expand if the option exempted dividends and capital gains on corporate stock—limiting the tax increase to capital gains on those assets that are not taxed under both the corporate and the individual income taxes. That modification, however, would also reduce the revenue gains from the option.

Another argument against implementing the option is related to the fact that taxation of capital gains encourages people to defer the sale of their capital assets, sometimes even leading them to never sell some of the assets during their lifetime. In the former case, the taxation of capital gains is postponed; in the latter case, it is avoided altogether because if an individual sells an inherited asset, the capital gain is the difference between the sale price and the fair-market value as of the date of the previous owner's death. By raising tax rates on long-term capital gains and dividends, this option could further encourage people to hold on to their investments only for tax reasons, which could reduce economic efficiency by preventing some of those assets from being put to more productive uses.

RELATED OPTIONS: Revenues, Options 1, 2, 9, 12, 41

RELATED CBO PUBLICATIONS: *The Distribution of Asset Holdings and Capital Gains* (August 2016), www.cbo.gov/publication/51831; *The Distribution of Household Income and Federal Taxes, 2013* (June 2016), www.cbo.gov/publication/51361; *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817; *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768; Tim Dowd, Robert McClelland, and Athiphat Muthitacharoen, *New Evidence on the Tax Elasticity of Capital Gains*, Working Paper 2012-09 (June 2012), www.cbo.gov/publication/43334

Revenues—Option 4

Use an Alternative Measure of Inflation to Index Some Parameters of the Tax Code

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	2.9	4.0	5.5	7.6	13.3	17.6	20.3	24.0	29.2	32.2	33.3	156.7

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates include the effects on outlays resulting from changes in refundable tax credits.

Each year, the Internal Revenue Service (IRS) adjusts some parameters of the tax code on the basis of changes in the prices of goods and services, which generally increase over time, using the consumer price index for all urban consumers (CPI-U). The CPI-U, which is produced by the Bureau of Labor Statistics (BLS), is a monthly price index that is based on average prices for a broad basket of goods and services (including food and energy). It is designed to approximate a cost-of-living index. Adjusting, or indexing, certain tax parameters every year by the percentage change in the CPI-U is intended to keep their values relatively stable in real (inflation-adjusted) terms. (Inflation—an increase in the average price level—is a significant component in changes in the cost of living.) Among the tax parameters adjusted are the amounts of the personal and dependent exemptions; the size of the standard deductions; the income thresholds that divide the rate brackets for the individual income tax; the amount of annual gifts exempt from the gift tax; and the income thresholds and phase-out boundaries for the earned income tax credit and several other credits. Parameters for the individual alternative minimum tax (AMT) are also adjusted, including the exemption amounts, the income thresholds at which those exemptions phase out, and the income threshold at which the second AMT rate bracket begins.[1]

Indexing is accomplished by adjusting a tax parameter's value in a base year by the percentage change in the CPI-U between that base year and the most recent year for which the CPI-U is available. The annual period used for the calculation is not a calendar year but the 12 months that elapse from September to August. The value of the CPI-U in August becomes available in September, which allows the IRS enough time to index the tax parameters and prepare the necessary forms for the coming tax year. Adjustments in parameters of the tax code are calculated as follows: In the base year of 1987, for example, the standard deduction for a single tax filer was $3,000. Between 1987 and 2015, the CPI-U increased by 111.4 percent; correspondingly, the standard deduction (rounded to the lowest $50 increment) increased to $6,300 for 2016.

The CPI-U, however, overstates changes in the cost of living by not fully accounting for the extent to which households substitute one product for another when the relative prices of products change. To address that "substitution bias," BLS created another measure of changes in consumer prices—the chained CPI-U. Whereas the standard CPI-U uses a basket of products reflecting consumption patterns that are as much as two years old, the chained CPI-U incorporates adjustments that people make in the types of products they buy from one month to the next (thus "chaining" the months together). In addition, the standard CPI-U overstates increases in the cost of living because of a statistical bias related to the limited amount of price data that BLS can collect, which is known as "small-sample bias." The chained CPI-U does not have the same statistical bias. However, even though the chained CPI-U corrects for the substitution bias in the standard CPI-U and does not suffer from small-sample bias, neither the chained nor the standard CPI-U perfectly captures changes in the cost of living because neither fully accounts for increases in the quality of existing products, the value of new products entering consumers' baskets, or changes in where consumers make their purchases.

1. The AMT is a parallel income tax system with fewer exemptions, deductions, credits, and rates than the regular income tax. Taxpayers must calculate the amount they owe under both the AMT and the regular income tax and pay the larger of the two amounts.

Under this option, the chained CPI-U would be used instead of the standard CPI-U to adjust various parameters of the tax code. The Congressional Budget Office estimates that the chained CPI-U is likely to grow at an average annual rate that is 0.25 percentage points less than the standard CPI-U over the next decade. Therefore, using the chained CPI-U to index tax parameters would increase the amount of income subject to taxation and result in higher tax revenues. Furthermore, the effects of instituting such a policy would grow over time. The net revenue increase would be about $3 billion in 2017 but would reach $32 billion in 2026, the staff of the Joint Committee on Taxation estimates. Net additional revenues would total about $157 billion from 2017 through 2026.

An argument in favor of using the chained CPI-U to adjust tax parameters is that this approach would more accurately reflect changes in the cost of living and modify each taxpayer's liability accordingly. The chained CPI-U provides a better measure of changes in the cost of living in two ways: by more quickly capturing the extent to which households adjust their consumption in response to changes in relative prices and by using a formula that essentially eliminates the statistical bias that can occur when estimates of aggregate price changes are calculated on the basis of relatively small samples of prices.

An argument against implementing this option is that only an initial estimate of the chained CPI-U is available on a monthly basis; a final and more accurate estimate is delayed because it is more complicated and time-consuming to compute than the standard CPI-U. (Details of that approach are available in a web-only technical appendix that CBO released with its February 2010 issue brief *Using a Different Measure of Inflation for Indexing Federal Programs and the Tax Code*.) At the start of every year, all of the initial estimates for the prior year are revised, and one year later those interim estimates are further revised and made final. Because of those delays, the initial and interim estimates of the chained CPI-U, which typically contain errors, would need to be used to index the parameters in the tax code. Since the chained CPI-U was first published in 2002, however, the changes between the initial and final values have been relatively small. If the adjustment for each year was based on the index value from an earlier base year, those small errors would not accumulate beyond the current year. Furthermore, because the initial and interim estimates of the chained CPI-U have been closer to the final version of the chained CPI-U than the standard CPI-U has been, those estimates still reflect the basic improvement attributable to the chained CPI-U.

RELATED OPTION: Mandatory Spending, Option 26

RELATED CBO PUBLICATIONS: Testimony of Jeffrey Kling, Associate Director for Economic Analysis, before the Subcommittee on Social Security of the House Committee on Ways and Means, *Using the Chained CPI to Index Social Security, Other Federal Programs, and the Tax Code for Inflation* (April 18, 2013), www.cbo.gov/publication/44083; *Using a Different Measure of Inflation for Indexing Federal Programs and the Tax Code* (February 2010), www.cbo.gov/publication/21228

Revenues—Option 5

Convert the Mortgage Interest Deduction to a 15 Percent Tax Credit

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	0.1	0.7	1.7	4.0	5.5	9.4	19.0	20.3	21.5	22.8	12.0	105.0

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates include the effects on outlays resulting from changes in refundable tax credits.

The tax code treats investments in owner-occupied housing more favorably than it does other types of investments. For example, landlords can deduct certain expenses—such as mortgage interest, property taxes, depreciation, and maintenance—from their income, but they have to pay taxes on rental income, net of those expenses, and on any capital gain realized when their property is sold. In contrast, homeowners can deduct mortgage interest and property taxes if they itemize deductions, even though they do not pay tax on the net rental value of their home. (Other housing-related expenses, however, cannot be deducted from homeowners' income.) In addition, in most circumstances, homeowners can exclude from taxation capital gains of up to $250,000 ($500,000 for married couples who file joint tax returns) when they sell their primary residence.

Under current law, the deduction for mortgage interest is restricted in two ways. First, the amount of mortgage debt that can be included when calculating the interest deduction is limited to $1.1 million: $1 million for debt that a homeowner incurs to buy, build, or improve a first or second home; and $100,000 for debt for which the borrower's personal residence serves as security (such as a home-equity loan), regardless of the purpose of that loan. Second, the total value of certain itemized deductions—including the deduction for mortgage interest—is reduced if the taxpayer's adjusted gross income is above specified thresholds. (Adjusted gross income includes income from all sources not specifically excluded by the tax code, minus certain deductions.) Those thresholds are adjusted, or indexed, every year to include the effects of inflation. For 2016, the thresholds were set at $259,400 for taxpayers filing as single and $311,300 for married couples who file jointly.

This option would gradually convert the tax deduction for mortgage interest to a 15 percent nonrefundable tax credit. The option would be phased in over six years, beginning in 2017. From 2017 through 2021, the deduction would still be available, but the maximum amount of the mortgage deduction would be reduced by $100,000 each year—to $1 million in 2017, $900,000 in 2018, and so on, until it reached $600,000 in 2021. In 2022 and later years, the deduction would be replaced by a 15 percent credit; the maximum amount of mortgage debt that could be included in the credit calculation would be $500,000; and the credit could be applied only to interest on debt incurred to buy, build, or improve a first home. (Other types of loans, such as home-equity lines of credit and mortgages for second homes, would be excluded.) Because the credit would be nonrefundable, people with no income tax liability before the credit was taken into account would not receive any credit, and people whose precredit income tax liability was less than the full amount of the credit would receive only the portion of the credit that offset the amount of taxes they otherwise would owe. The option would raise $105 billion in revenues from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation.

One argument in favor of the option is that it would make the tax system more progressive by distributing the mortgage interest subsidy more evenly across households with different amounts of income. Relative to other taxpayers, lower-income people receive the least benefit from the current itemized deduction, for three reasons. First, lower-income people are less likely than higher-income people to have sufficient deductions to make itemizing worthwhile; for taxpayers with only small amounts of deductions that can be itemized, the standard deduction, which is a flat dollar amount, provides a larger tax benefit. Second, the value of itemized deductions is greater for people in higher income tax brackets. And third, the value of the mortgage interest deduction is greater for people who have larger mortgages. Unlike the current mortgage interest deduction, a credit would be available to taxpayers who do not itemize and would provide the same subsidy rate to all recipients, regardless of income. However, taxpayers with larger mortgages—up to the $500,000 limit specified in this option—would still receive a greater benefit from the credit than would households with smaller mortgages. Altogether, many higher-income people would receive a smaller tax benefit for housing than under current law, and many lower- and middle-income people would receive a larger tax benefit. (The credit could be made available to more households by making it refundable, although doing so would significantly reduce the revenue gain.)

Another argument in favor of the option is that it would increase the tax incentive for home ownership for lower- and middle-income taxpayers who might otherwise rent. Research indicates that when people own rather than rent their homes, they maintain their properties better and participate more in civic affairs. However, because people are unlikely to consider those benefits to the community when deciding whether to buy or rent a personal residence, a subsidy that encourages home ownership can help align their choices with the community's interest. Increased home ownership can also put people in a better position for retirement because they can tap into their home equity for any unexpected expenses. In addition, expenses associated with home ownership remain relatively stable, which matches well with retirees' typically fixed income.

A further rationale for such a change is that it probably would improve the overall allocation of resources in the economy. With its higher subsidy rates for taxpayers in higher tax brackets and its high $1.1 million limit on loans, the current mortgage interest deduction encourages higher-income taxpayers who would buy houses anyway to purchase more expensive dwellings than they otherwise might. That reduces the savings available for productive investment in businesses. Reducing the tax subsidy for owner-occupied housing would probably redirect some capital, which would moderate that effect. In principle, this option could induce low- and middle-income taxpayers to spend more on housing, which could create an offsetting reduction in business investment. However, on net, the option probably would increase investment in businesses for two reasons. First, the total mortgage interest subsidy would be lower under the option, which would most likely result in lower aggregate spending on housing. Second, a larger fraction of increases in spending on housing by low- and middle-income taxpayers would probably be financed by a reduction in other expenditures rather than by a reduction in business investment. Because investment in owner-occupied housing is boosted by the current tax subsidy, and investment in many businesses is held down by taxes on their profits, the before-tax return on the additional business investment that would occur under this option would generally be higher than the forgone return from housing, indicating a better allocation of resources.

One disadvantage of the option is that, by providing a larger tax benefit to lower- and middle-income people than they receive under current law and thereby encouraging more of them to buy houses and to buy more expensive houses than they otherwise would, the option would increase the risk that some people assume. Principal residences tend to be the largest asset that people own and the source of their largest debt. When housing prices rise, homeowners' wealth can rise significantly. However, when prices drop, people can lose their homes and much of their wealth, especially if their income falls at the same time and they cannot keep up with their mortgage payments. The collapse of the housing market during the late 2000s demonstrated that risk vividly.

Another disadvantage of the option is that it would adversely affect the housing industry and people who currently own their own homes—especially in the short term. Many homeowners have taken out long-term mortgages under the assumption that they would be able to deduct the interest on their loans. Many financial institutions have been willing to lend homebuyers higher amounts than they otherwise might have under the assumption that the mortgage interest deduction would help those buyers repay their loans. Reducing the tax subsidy for housing would make it more difficult for some homeowners to meet their mortgage obligations. Such a change would also reduce the amount that new homebuyers would be willing to pay, which would lower the prices of homes, on average. Lower housing prices would create further stress on the finances of existing owners and lead to reduced new construction. Over time, as the supply of housing declined, prices would rise again, but probably not to the levels they would reach under current law. Most of those hardships could be eased by phasing in restrictions on the mortgage interest deduction. Because of the lengthy terms of mortgages, however, and the slowness with which the stock of housing changes, substantial adjustment costs would still occur even with a six-year phase-in period.

RELATED OPTIONS: Revenues, Options 7, 8; Mandatory Spending, Option 7

RELATED CBO PUBLICATIONS: *Federal Housing Assistance for Low-Income Households* (September 2015), www.cbo.gov/publication/50782; *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817; *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768; Larry Ozanne, *Taxation of Owner-Occupied and Rental Housing*, Working Paper 2012-14 (November 2012), www.cbo.gov/publication/43691; *An Overview of Federal Support for Housing* (November 2009), www.cbo.gov/publication/41219

Revenues—Option 6

Curtail the Deduction for Charitable Giving

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	4.2	21.2	22.2	23.1	24.1	25.0	25.9	26.9	27.9	28.9	94.8	229.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Current law allows taxpayers who itemize to deduct the value of their contributions to qualifying charitable organizations. By lowering the after-tax cost of donating to charities, the deduction provides an added incentive to donate. In calendar year 2014 (the most recent year for which data are available), taxpayers claimed $211 billion in charitable contributions on 36 million tax returns.

The deduction is restricted in two ways. First, charitable contributions may not exceed 50 percent of a taxpayer's adjusted gross income (AGI) in any one year. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.) Second, the total value of certain itemized deductions—including the deduction for charitable donations—is reduced if the taxpayer's AGI is above $259,400 for taxpayers filing as single or $311,300 for taxpayers filing jointly in 2016. The thresholds are adjusted, or indexed, to include the effects of inflation.

This option would further curtail the deduction for charitable donations while preserving a tax incentive for donating. Only contributions in excess of 2 percent of AGI would be deductible for taxpayers who itemize. That amount would still be subject to the additional reduction described above for higher-income taxpayers. Limiting the deduction to contributions in excess of 2 percent of AGI would match the treatment that now applies to unreimbursed employee expenses, such as job-related travel costs and union dues. Such a policy change would increase revenues by $229 billion from 2017 through 2026, the staff of the Joint Committee on Taxation (JCT) estimates.

An argument in favor of this option is that, even without a deduction, a significant share of charitable donations would probably still be made. Therefore, allowing taxpayers to deduct contributions is economically inefficient because it results in a large loss of federal revenue for a very small increase in charitable giving. For taxpayers who contribute more than 2 percent of their AGI to charity, this option would maintain the current incentive to donate but at much less cost to the federal government. People who make large donations often are more responsive to that tax incentive than people who make small contributions. Moreover, deductions of smaller contributions are more likely to be fraudulent because donations that are less than $250 do not require the same degree of documentation as those that are larger.

A potential disadvantage of this option is that total charitable giving would decline, albeit by only a small amount, JCT and the Congressional Budget Office estimate. People who contribute less than 2 percent of their AGI would no longer have a tax incentive to donate, and many of them could reduce their contributions. Although people who make larger donations would still have an incentive to give, they would have slightly lower after-tax income because of the smaller deduction and thus might reduce their contributions as well (although by a lesser percentage than people making smaller donations). Another effect of creating the 2 percent floor is that it would encourage taxpayers who had planned to make gifts over several years to combine donations into a single tax year to qualify for the deduction. As a result, some taxpayers would devote more resources to tax planning than they otherwise would have in an effort to best time their contributions and thereby minimize the amount of taxes they owe over a multiyear period.

RELATED OPTION: Revenues, Option 8

RELATED CBO PUBLICATIONS: *Options for Changing the Tax Treatment of Charitable Giving* (May 2011), www.cbo.gov/publication/41452; *The Estate Tax and Charitable Giving* (July 2004), www.cbo.gov/publication/15823; *Effects of Allowing Nonitemizers to Deduct Charitable Contributions* (December 2002), www.cbo.gov/publication/14230

Revenues—Option 7

Limit the Deduction for State and Local Taxes

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	44.1	86.6	87.1	91.2	95.5	99.7	104.5	110.0	115.7	121.0	404.5	955.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

In determining their taxable income, taxpayers may choose the standard deduction when they file their tax returns, or they may itemize and deduct certain expenses (including state and local taxes on income, real estate, and personal property) from their adjusted gross income, or AGI. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.) Under current law, taxpayers who itemize may also choose to deduct state and local sales taxes instead of state and local income taxes. The total value of certain itemized deductions—including the deduction for state and local taxes—is reduced if the taxpayer's AGI is above $259,400 for taxpayers filing as single or $311,300 for married taxpayers filing jointly in 2016. The thresholds are adjusted, or indexed, to include the effects of inflation.

This option would limit the deductibility of state and local tax payments by capping the deduction at 2 percent of AGI. That change would increase federal revenues by $955 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

The deduction for state and local taxes is effectively a federal subsidy to state and local governments; that means the federal government essentially pays a share of people's state and local taxes. Therefore, the deduction indirectly finances spending by those governments when federal revenues could be used to fund the activities of the federal government. It also creates an incentive for state and local governments to raise taxes and increase spending—although some research indicates that total spending by state and local governments is not sensitive to that incentive.

An argument in favor of capping the deduction is that the federal government should not provide a tax deduction that subsidizes the spending of state and local governments because revenues from state and local taxes are largely paid in return for services provided to the public. When used to pay for public services, such taxes are analogous to spending on other types of consumption that are nondeductible. Another argument is that the deduction largely benefits wealthier localities, where many taxpayers itemize, are in the upper income tax brackets, and enjoy more abundant state and local government services. Because the value of an additional dollar of itemized deductions increases with the marginal tax rate (the percentage of an additional dollar of income from labor or capital that is paid in federal taxes), the deductions are worth more to taxpayers in higher income tax brackets than they are to those in lower income brackets. Additionally, the unlimited deductibility of taxes could deter states and localities from financing some services with nondeductible fees, which could be more efficient.

An argument against capping the current deduction involves the equity of the tax system as a whole. A person who must pay relatively high state and local taxes has less money with which to pay federal taxes than does someone with the same total income and smaller state and local tax bills. The validity of that argument, however, depends at least in part on whether people who pay higher state and local taxes also benefit more from goods and services provided by states and localities.

RELATED OPTIONS: Revenues, Options 8, 10

RELATED CBO PUBLICATIONS: Testimony of Frank Sammartino, Assistant Director for Tax Analysis, before the Senate Committee on Finance, *Federal Support for State and Local Governments Through the Tax Code* (April 25, 2012), www.cbo.gov/publication/43047; *The Deductibility of State and Local Taxes* (February 2008), www.cbo.gov/publication/41647

Revenues—Option 8

Limit the Value of Itemized Deductions

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Limit the tax benefits of itemized deductions to 28 percent of their total value	7.2	14.9	15.8	16.6	17.4	18.2	19.0	19.9	20.7	21.6	71.9	171.5
Limit the tax value of itemized deductions to 6 percent of AGI	5.2	10.6	11.2	11.6	11.9	12.5	13.2	13.8	14.3	14.9	50.5	119.2
Eliminate all itemized deductions	93.2	193.8	206.4	216.7	227.0	237.0	247.5	258.7	270.4	281.1	937.1	2,231.8

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

AGI = adjusted gross income.

When preparing their income tax returns, taxpayers may either choose the standard deduction—which is a flat dollar amount—or choose to itemize and deduct certain expenses, such as state and local taxes, mortgage interest, charitable contributions, and some medical expenses. Taxpayers benefit from itemizing when the value of their deductions exceeds the amount of the standard deduction. The fact that those expenses are deductible reduces the cost of incurring them; so, in effect, the itemized deductions serve as subsidies for undertaking deductible activities. The tax savings from itemized deductions, and thus the amount of the subsidies, generally depend on a taxpayer's marginal tax rate (the percentage of an additional dollar of income that is paid in taxes). For instance, $10,000 in deductions reduces tax liability by $1,500 for someone in the 15 percent tax bracket and by $2,800 for someone in the 28 percent tax bracket. Most of those tax savings constitute a "tax expenditure" by the federal government. (Tax expenditures resemble federal spending in that they provide financial assistance for specific activities, entities, or groups of people.)

The tax code imposes some limits on the amount of itemized deductions that taxpayers can claim. For some types of expenses (such as medical expenses), only the amount that exceeds a certain percentage of the taxpayer's adjusted gross income (AGI) can be deducted. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.) Moreover, taxpayers cannot deduct home mortgage interest on loan amounts in excess of $1.1 million. In addition, the total value of certain itemized deductions is reduced by 3 percent of the amount by which a taxpayer's AGI exceeds a specified threshold. That reduction can reduce a taxpayer's itemized deductions by up to 80 percent (that is, taxpayers retain no less than 20 percent of their deductions). That limit, originally proposed by Congressman Donald Pease, is often called the Pease limitation.

This option considers three alternative approaches to broadly restrict the total amount of itemized deductions that taxpayers can take:

- The first alternative would limit the tax benefits of itemized deductions to 28 percent of the deductions' total value while removing the Pease limitation. As a result, taxpayers in tax brackets with statutory rates above 28 percent would receive less benefit from itemized deductions than under current law, whereas taxpayers in tax brackets with statutory rates that are equal to or less than 28 percent would be unaffected by the change. The staff of the Joint Committee on Taxation (JCT) estimates that this approach would increase revenues by $172 billion from 2017 through 2026.

- The second alternative would limit the tax benefits of itemized deductions to 6 percent of a taxpayer's AGI while removing the Pease limitation. As a result, taxpayers whose savings from itemized deductions exceeded 6 percent of their AGI would receive less benefit from itemized deductions than under current law, whereas taxpayers whose savings from itemized deductions were 6 percent or less of their AGI would be unaffected by the change. This approach would raise revenues by $119 billion from 2017 through 2026, according to JCT's estimates.

- The third alternative would eliminate all itemized deductions. As a result, all taxpayers who currently itemize deductions would have to claim the standard deduction, which generally would be of less value to them. Taxpayers who would have claimed the standard deduction under current law would be unaffected by the change. JCT estimates that this approach would raise revenues by $2.2 trillion from 2017 through 2026.

A major argument for reducing or eliminating itemized deductions is that their availability encourages taxpayers to spend more on deductible activities in order to receive the tax benefits those activities provide; that tendency can lead to an inefficient allocation of economic resources. For example, the mortgage interest deduction distorts the housing market, prompting people to take out larger mortgages and buy more expensive houses, and pushing up home prices. People therefore invest less in other assets than they would if all investments were treated equally. Reducing the tax benefits of itemized deductions would diminish taxpayers' incentive to spend more on specified goods or activities than they would under current law. That would improve the allocation of resources because taxpayers would make spending decisions based on the benefit they derive from the specified goods or activities, rather than based on tax considerations. Doing less of some activities for which expenses can be deducted under current law—in particular, activities that primarily benefit the taxpayers undertaking the activities—would improve the allocation of resources. However, doing less of other activities for which expenses can be deducted—in particular, those activities that offer widespread benefits—could worsen the allocation of resources. An oft-cited example of tax-deductible spending in the latter category is contributions to charitable organizations.

Each of the three alternatives in this option would reduce the incentives for taxpayers to spend on tax-deductible items in different ways and to different degrees. Limiting the tax benefit of deductions to 28 percent of their total value would reduce the incentives created by the existing system only for taxpayers in rate brackets above 28 percent, who would see their subsidy rate fall from as high as 39.6 percent to 28 percent. Those taxpayers would continue to receive a tax benefit for each additional dollar they spent on tax-preferred items, but the amount of that benefit would be less than under current law. Other taxpayers would not experience any change in their incentives to spend money on tax-deductible items. In contrast, limiting the tax value of itemized deductions to 6 percent of AGI would eliminate the tax incentives for some taxpayers to spend more on tax-preferred items because taxpayers would not receive any tax benefit for each additional dollar spent above that threshold. Eliminating every itemized deduction would remove the tax incentives for all taxpayers to spend more on deductible items. Among all itemizers, limiting the tax subsidy to 28 percent would have the smallest effect on incentives to spend on tax-deductible items. Eliminating itemized deductions would have the largest effect on incentives.

If policymakers wanted to maintain the current tax subsidy for certain activities while reducing the tax subsidy for others, they could adopt one of the approaches described in this option but exempt certain deductions entirely from the restrictions or limit certain deductions in a less constraining way. For example, policymakers could limit most itemized deductions in one of the ways offered above but allow taxpayers to fully deduct at their marginal tax rates any charitable contributions that are *greater* than some specified percentage of AGI (see Option 6). Imposing a floor on the amount of charitable contributions that could be deducted would reduce the tax expenditure for such contributions while continuing to encourage additional contributions by taxpayers who would give charities the threshold amount anyway.

Another argument for reducing or eliminating itemized deductions is that higher-income taxpayers benefit more from those deductions than do taxpayers with lower income because people with higher income typically have more deductions and because the per-dollar tax benefit of those deductions depends on a taxpayer's marginal tax rate, which rises with income. In calendar year 2013, CBO estimates, more than 80 percent of the tax expenditures resulting from the three largest itemized deductions—for state and local taxes, mortgage interest, and charitable contributions—accrued to households with income in the highest quintile (or one-fifth) of the population (with 30 percent going to households in the top 1 percent of the population). In 2013, the tax benefit of those three deductions equaled less than 0.05 percent of after-tax income for households in the lowest income quintile, 0.4 percent for the middle quintile, 2.5 percent for the highest quintile, and 3.9 percent for the top percentile. Hence, reducing or eliminating them would increase the progressivity of the tax code. Capping the tax value of deductions at 28 percent would increase taxes primarily on taxpayers in the top 10 percent of the before-tax household-income distribution. In contrast, limiting the tax value of deductions to 6 percent of AGI or eliminating itemized deductions altogether would, to some extent, increase taxes on taxpayers throughout the top half of the income distribution because even some taxpayers in the middle quintile have deductions that are a large share of their income.

The three variants would affect the complexity of the tax code in different ways. Eliminating itemized deductions would simplify the tax code. Taxpayers would no longer have to keep records of their deductible expenses or enumerate them on the tax form. In contrast, the other two alternatives would increase the complexity of the tax code to some extent. Capping the tax benefit of itemized deductions—either at 28 percent of itemized deductions or at 6 percent of AGI—would require taxpayers to do more complicated calculations to determine their tax liability. They would essentially have to compute their taxes twice—once with their itemized deductions and once without those deductions—to determine whether the tax benefits of their itemized deductions exceeded the relevant threshold.

An argument against any of the alternatives described in this option is that some deductions are intended to yield a measure of taxable income that more accurately reflects a person's ability to pay taxes. For example, the deductions for payments of investment interest and unreimbursed employee business expenses allow people to subtract the costs of earning the income that is being taxed. And taxpayers with high medical expenses, casualty and theft losses, or state and local taxes have fewer resources than taxpayers with the same amount of income and smaller expenses or losses (all else being equal). Under this option, taxpayers subject to the limitations on deductions would not be able to fully subtract those expenses from their taxable income.

Another argument against these alternatives is that reducing the value of itemized deductions would disrupt many existing financial arrangements, especially in the housing market. Many homeowners have purchased homes under the assumption that they would be able to deduct the interest on their mortgages and their property taxes. Reducing the value of those deductions would make it more difficult for some homeowners to meet their obligations. And such a change would also reduce the amount new homebuyers would be willing to pay, which would lower the prices of homes, on average. Lower housing prices would create further stress on the finances of existing owners.

Each of these approaches could be expanded by subjecting more tax provisions to the limits or by tightening the limits on itemized deductions described above. For example, the President's budget for 2017 proposed that a 28 percent limit be applied not only to itemized deductions but also to a broader set of tax provisions, including the exclusion for interest earned on tax-exempt state and local bonds, employment-based health insurance paid for by employers or with before-tax employee dollars, and employee contributions to defined contribution retirement plans and individual retirement plans. That proposal, which also retains the Pease limitation, would increase revenues by $542 billion from 2017 to 2026, according to JCT's estimates.

RELATED OPTIONS: Revenues, Options 5, 6, 7

RELATED CBO PUBLICATIONS: *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768; Larry Ozanne, *Taxation of Owner-Occupied and Rental Housing,* Working Paper 2012-14 (November 2012), www.cbo.gov/publication/43691; *Options for Changing the Tax Treatment of Charitable Giving* (May 2011), www.cbo.gov/publication/41452; *The Deductibility of State and Local Taxes* (February 2008), www.cbo.gov/publication/41647

Revenues—Option 9

Change the Tax Treatment of Capital Gains From Sales of Inherited Assets

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	0.6	4.2	5.2	6.0	6.8	7.5	8.2	8.9	9.8	10.9	22.8	68.0

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

When people sell an asset for more than the price at which they obtained it, they realize a net capital gain. That net gain is generally calculated as the sales price minus the asset's adjusted basis. The adjusted basis is generally the price of the asset at the time it was initially acquired plus the cost of any subsequent improvements and minus any deductions for depreciation. Net capital gains are included in taxable income in the year in which the sale occurs.

The tax treatment of capital gains resulting from the sale of inherited assets is different. Taxpayers who inherit assets generally use the asset's fair-market value at the time of the owner's death to determine their basis—often referred to as stepped-up basis—instead of the adjusted basis derived from the time the decedent initially acquired the asset. As a result, when the heir sells the asset, capital gains taxes are assessed only on the change in the asset's value that accrued after the owner's death. Any appreciation in value that occurred while the decedent owned the asset is not included in taxable income and therefore is not subject to capital gains taxation. (However, the estate may be subject to the estate tax.)

Under this option, taxpayers would generally adopt the adjusted basis of the decedent—known as carryover basis—on assets they inherit. As a result, the decedent's unrealized capital gains would be taxed at the heirs' tax rate when they eventually sell the assets. (For bequeathed assets that would be subject to both the estate tax and capital gains tax, this option would adjust the basis of some of those assets to minimize the extent to which both taxes would apply to the appreciation in value.) If implemented, this option would increase revenues by $68 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

Under the option, most gains accrued between the date a person initially acquired the asset and the date of that person's death would eventually be taxed. As a result, the tax treatment of capital gains realized on the sale of inherited assets would be more similar to the tax treatment of capital gains from the sale of other assets.

One advantage of this approach is that it would encourage people to shift investments to more productive uses during their lifetimes, rather than retaining them so that their heirs could benefit from the tax advantages offered by the stepped-up basis. The option, however, would not completely eliminate the incentive to delay the sale of assets solely for the tax advantages. For an asset that rose in value before the owner's death, replacing stepped-up basis with carryover basis would increase the total amount of taxable capital gains realized when the asset is sold by the heir (unless the asset's value dropped after the owner's death by an amount equal to or greater than the appreciation that occurred while the owner was alive). As a result, heirs might choose to delay sales to defer capital gains taxes (as they might for assets they purchased themselves). An alternative approach would be to treat transfers of assets through bequest as a sale at the time of the transfer, making the capital gains taxable in that year. However, that method might force the owner to sell some portion of the assets at an inopportune time to pay the tax and could be particularly problematic for nonliquid assets.

Another advantage is that using carryover basis to determine capital gains would decrease the incentive for people to devote resources to tax planning rather than to more productive activities. For example, it would lessen the advantages of using certain tax shelters that allow people to borrow against their assets for current consumption and for the loan to be repaid after their death by using the proceeds from the sale of their assets.

A disadvantage of this option is that heirs would find it difficult to determine the original value of the asset when the decedent had not adequately documented the basis of the asset. Additional provisions could be enacted to make it easier to value an asset. For example, heirs could have the choice of using carryover basis or setting the basis of an inherited asset at a specified percentage of the asset's value at the time they inherit it. Alternatively, appreciated assets in estates that are valued below a certain threshold could be exempt from the carryover basis treatment to minimize the costs of recordkeeping.

RELATED OPTION: Revenues, Option 3

RELATED CBO PUBLICATIONS: *The Distribution of Asset Holdings and Capital Gains* (August 2016), www.cbo.gov/publication/51831; *Federal Estate and Gift Taxes* (December 2009), www.cbo.gov/publication/41851

Revenues—Option 10

Eliminate the Tax Exemption for New Qualified Private Activity Bonds

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	*	0.4	0.8	1.4	2.1	2.9	3.7	4.6	5.4	6.2	4.7	27.5

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

* = between zero and $50 million.

The U.S. tax code permits state and local governments to finance certain projects by issuing bonds whose interest payments are exempt from federal income taxes. As a result, those bonds pay lower rates of interest than they would if the interest payments were taxable. For the most part, proceeds from tax-exempt bonds finance public projects, such as the construction of highways and schools. In some cases, however, state and local governments issue tax-exempt bonds to finance private-sector projects. The issuance of such bonds—which are known as qualified private activity bonds—is authorized by the tax code to fund private projects that provide at least some public benefits. Eligible projects include the construction or repair of infrastructure and certain activities, such as building schools and hospitals, undertaken by nonprofit organizations. (Those organizations are sometimes called 501(c)(3)s after the section of the tax code that authorizes them.)

This option would eliminate the tax exemption for new qualified private activity bonds beginning in 2017. The option would increase revenues by $28 billion through 2026, according to estimates by the staff of the Joint Committee on Taxation.

One rationale for this option is that eliminating the tax exemption for new qualified private activity bonds would improve economic efficiency in some cases. For example, the owners of some of the infrastructure facilities that benefit from the tax exemption can capture—through fees and other charges—much of the value of the services they provide. Therefore, such investments probably would take place without a subsidy. In those instances, providing a tax exemption for such investments would be inefficient because the tax exemption would shift resources from taxpayers to private investors without generating any additional public benefits. As another example, in cases in which the public benefits from a private-sector facility would be small relative to the existing tax exemption, the subsidy sometimes would lead to investment in projects whose total value (counting private as well as public benefits) was less than their costs.

Another argument in favor of this option is that it would encourage nonprofit organizations to be more selective when choosing projects and, in general, to operate more efficiently. Nonprofit organizations do not pay federal income tax on their investment income. Many nonprofit universities, hospitals, and other institutions use tax-exempt debt to finance projects that they could fund by selling their own assets. By holding on to those assets, they can earn an untaxed return that is higher than the interest they pay on their tax-exempt debt. Eliminating the tax exemption for the debt-financed projects of nonprofit organizations would put those projects on an even footing with the projects financed by selling assets. Further, the tightening of nonprofit organizations' financial constraints that would result from eliminating the tax exemption would encourage those organizations to operate more cost-effectively, although some nonprofits with small asset bases, or endowments, could be forced to cut back or even cease operations.

A disadvantage of this option is that some projects that would not be undertaken without a tax exemption would provide sufficient public benefits to warrant a subsidy. For example, some roads can have broad social benefits (because they are part of a larger transportation network) and, at the same time, be appealing to private owners (because those owners and operators could collect tolls from users). State and local governments are increasingly looking to the private sector to undertake projects of that sort, and supporters of qualified private activity bonds argue that eliminating the tax exemption would remove an important source of funding for them.

If lawmakers wished to continue to support infrastructure investment and other projects undertaken by the private sector, they could do so more efficiently by subsidizing them directly rather than doing so through the tax system. Tax-exempt financing is inefficient for two reasons: First, the reduction in borrowing costs for issuers of those bonds is less than the federal revenues forgone through the tax exemption. (The interest rate on tax-exempt debt is determined by the market-clearing tax-exempt bond buyer, who will typically be in a lower marginal income tax bracket—and hence be willing to accept a lower tax-free rate of return—than the average tax-exempt bond buyer, who determines the amount of federal revenue forgone as a result of the tax exemption.) Second, the amount of the subsidy delivered is determined by the tax code and so does not vary across projects according to federal priorities. Lawmakers could, instead, provide a direct subsidy for certain projects by guaranteeing loans or making loans available to the private sector at below-market rates of interest. By offering a direct subsidy rather than one provided through the tax system, the federal government would be better able both to select the types of projects receiving support and to determine the amount of the subsidy.

RELATED OPTION: Revenues, Option 7

RELATED CBO PUBLICATIONS: Testimony of Joseph Kile, Assistant Director for Microeconomic Studies, before the Senate Committee on Finance, *The Status of the Highway Trust Fund and Options for Paying for Highway Spending* (June 18, 2015), www.cbo.gov/publication/50297; Testimony of Joseph Kile, Assistant Director for Microeconomic Studies, before the Panel on Public-Private Partnerships, House Committee on Transportation and Infrastructure, *Public-Private Partnerships for Highway Projects* (March 5, 2014), www.cbo.gov/publication/45157; *Federal Grants to State and Local Governments* (March 2013), www.cbo.gov/publication/43967; Testimony of Frank Sammartino, Assistant Director for Tax Analysis, before the Senate Committee on Finance, *Federal Support for State and Local Governments Through the Tax Code* (April 25, 2012), www.cbo.gov/publication/43047; *Using Public-Private Partnerships to Carry Out Highway Projects* (January 2012), www.cbo.gov/publication/42685; *Tax Arbitrage by Colleges and Universities* (April 2010), www.cbo.gov/publication/21198; *Subsidizing Infrastructure Investment With Tax-Preferred Bonds*, A Joint CBO/JCT Study (October 2009), www.cbo.gov/publication/41359; *Nonprofit Hospitals and Tax Arbitrage* (attachment to a letter to the Honorable William "Bill" M. Thomas, December 6, 2006), www.cbo.gov/publication/18257

Revenues—Option 11

Expand the Base of the Net Investment Income Tax to Include the Income of Active Participants in S Corporations and Limited Partnerships

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	8.3	12.8	13.9	15.3	16.1	16.8	17.7	18.7	19.8	20.6	66.4	160.0

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The Affordable Care Act of 2010 (ACA) includes two new taxes on income above specified thresholds. One of those—the "Additional Medicare Tax" of 0.9 percent—applies to wages and self-employment income in excess of $250,000 for married taxpayers who file joint returns, $125,000 for married taxpayers who file separate returns, and $200,000 for people whose filing status is "single" or "head of household." In combination with the Hospital Insurance (HI) tax of 2.9 percent, which predates the ACA and applies to all wages and self-employment income, high-income employees and self-employed individuals are now subject to a total Medicare-related payroll tax of 3.8 percent. The other new tax—the Net Investment Income Tax (NIIT) of 3.8 percent—applies to investment income such as interest, dividends, capital gains, rents, royalties, and other passive business income of taxpayers whose modified adjusted gross income (MAGI) exceeds $250,000 for married taxpayers who file joint returns, $125,000 for married taxpayers who file separate returns, and $200,000 for everybody else.[1] If qualifying investment income is greater than the amount by which MAGI exceeds the applicable threshold, then the tax applies only to the excess MAGI.

In combination, the Additional Medicare Tax and the NIIT cover virtually all labor and capital income derived from the activities of sole proprietorships, general partnerships, and C corporations (those businesses subject to the corporate income tax). Net profits received by sole proprietors and general partners are considered earnings and are subject to the HI tax and the Additional Medicare Tax; and the interest, dividends, and capital gains paid by C corporations to their bondholders or shareholders are subject to the NIIT. Income generated by other forms of businesses, however, can escape both taxes under certain circumstances. In particular, income earned by people actively involved in limited partnerships (wherein certain partners are not liable for the debts of the business in excess of their initial investment) or in S corporations (which are not subject to the corporate income tax if they meet certain criteria defined in subchapter S of the tax code) falls into that category. If a taxpayer is a passive investor (not actively participating in the operations of such businesses), his or her share of the firm's net profits is subject to the NIIT. Most limited partners are passive investors and thus potentially liable for the NIIT. But if a taxpayer is actively involved in running such a business (as many owners of S corporations are), the taxpayer's share of the firm's net profits is not subject to either the Additional Medicare Tax or the NIIT. (If the taxpayer receives a salary from the firm, however, that income would be subject to the Additional Medicare Tax.)

This option would impose the NIIT on all income derived from business activity that is subject to the individual income tax but not to the Additional Medicare Tax, regardless of the business's organizational form or the taxpayer's level of activity. If implemented, the staff of the Joint Committee on Taxation estimates, the option would increase revenues by $160 billion between 2017 and 2026.

An advantage of this option is that, for tax purposes, it would treat businesses with different organizational structures in a more uniform way. Entrepreneurs would be more likely to select the form of organization that best suits the business rather than the form that minimizes their tax liability. The option would also reduce the incentive for high-income owners of S corporations to reduce their HI tax and Additional Medicare Tax by accepting a salary that is less than the value of the labor

1. For purposes of the NIIT, AGI is modified by adding back any excluded foreign earned income.

they contribute. Finally, decisions about actively participating in running an S corporation or limited partnership would be based on whether such participation would strengthen the business, not on whether it would avoid an additional tax liability.

A disadvantage of the option is that it would probably reduce total investment by businesses. Some investments may be attractive only if the organization is structured in a way that allows owners to avoid the NIIT. For example, two identical businesses—one organized as a general partnership and the other as an S corporation—could consider an expansion that would result in the same before-tax rate of return for each company. Under current law, the general partners whose income exceeds the specified thresholds must pay the Additional Medicare Tax, as well as the HI tax, on their profits. If that tax lowered the rate of return on an investment to less than it would have been if the partners had invested in 10-year Treasury bonds, the partners would buy bonds instead of expanding the business. Because the owners of the S corporation are not subject to the HI tax, the Additional Medicare Tax, or the NIIT, their after-tax income—after expansion—would be higher than the general partners would have received if they had also chosen to expand their business. However, if the owners of the S corporation were subject to the NIIT, the after-tax return they could realize by expanding the company would be the same as that the general partners would get with a comparable expansion, and the S corporation would also forgo expansion. That argument implies that the NIIT should apply to fewer (or no) sources of income, not more.

An alternative approach would subject net business income that is currently not subject to either the Additional Medicare Tax or the NIIT to the Self-Employment Contributions Act tax (of which the HI tax is a part) and the Additional Medicare Tax. In other words, the owners of all businesses except C corporations would be deemed self-employed and would be taxed in the same manner. If that approach was enacted, the goal of this option would be accomplished and there would be no reason to subject that income to the NIIT. (See Option 23.)

RELATED OPTION: Revenues, Option 23

RELATED CBO PUBLICATION: *Taxing Businesses Through the Individual Income Tax* (December 2012), www.cbo.gov/publication/43750

Revenues—Option 12

Tax Carried Interest as Ordinary Income

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	1.6	2.1	2.0	2.1	2.0	2.0	2.0	2.0	2.0	2.0	9.8	19.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Investment funds—such as private equity, real estate, and hedge funds—are often organized as partnerships. Those partnerships typically have two types of partners: general partners and limited partners. General partners determine investment strategy; solicit capital contributions; acquire, manage, and sell assets; arrange loans; and provide administrative support for all of those activities. Limited partners contribute capital to the partnership but do not participate in the fund's management. General partners can invest their own capital in the partnership as well, but such investments usually represent a small share (between 1 percent and 5 percent) of the total capital invested.

General partners typically receive two types of compensation for managing a fund: a fee tied to some percentage of the fund's assets; and a profit share, or "carried interest," tied to some percentage of the profits generated by the fund. In a common compensation agreement, general partners receive a management fee equal to 2 percent of the invested assets plus a 20 percent share in profits as carried interest. The fee, less the fund's expenses, is subject to ordinary income tax rates and the self-employment tax. (All income that is subject to the individual income tax, other than most long-term capital gains and dividends, is taxed at ordinary income tax rates.) In contrast, the carried interest that general partners receive is taxed in the same way as the investment income received by the limited partners. For example, if that investment income consists solely of capital gains, the carried interest is taxed only when those gains are realized and at the lower capital gains rate. Aside from the capital contributions general partners make to the fund, they typically are not exposed to fund losses.

This option would treat the carried interest that general partners receive for performing investment management services as labor income, taxable at ordinary income tax rates and subject to the self-employment tax. Income those partners received as a return on their own capital contribution would not be affected. If implemented, the change would produce an estimated $20 billion in revenues from 2017 through 2026, according to the staff of the Joint Committee on Taxation.[1]

An argument in favor of this option is that carried interest could be considered performance-based compensation for management services rather than a return on the capital invested by the general partner. By taxing carried interest as ordinary income, this option would make the treatment of carried interest consistent with that of many other forms of performance-based compensation, such as bonuses and most stock options. In particular, this option would equalize the tax treatment of income that general partners receive for performing investment management services and the income earned by corporate executives who do similar work. (For example, many corporate executives direct investment, arrange financing, purchase other companies, or spin off components of their enterprises, yet profits from those investment activities are not counted as individual capital gains for those executives and are therefore not taxed at preferential rates.)

An argument against the option is that a general partner's investment decisions could be considered more analogous to those of an entrepreneur than to those of a corporate executive. This option, however, would treat the income of general partners who manage investment funds differently from income earned by entrepreneurs when they sell their businesses. (Profits from such sales generally are taxed as capital gains, even though some portion of those profits represents a return on labor services provided by the entrepreneur.) Another argument against such a

1. Essentially all of the additional labor income would be above the maximum amount subject to the Social Security portion of the self-employment tax; therefore, the estimates shown here do not include any effects on social security taxes or future outlays.

policy change is that it would reduce a general partner's expected after-tax return on his or her investments. That reduced incentive, in turn, could possibly diminish innovation and make private equity markets—and consequently businesses—less efficient. It is not clear, however, to what extent the lower tax rate on capital gains promotes innovation and market efficiency or whether promoting risky investment offers greater benefits than costs.

Some partnerships would probably respond to such a policy change by restructuring their compensation agreements so that the general partner's share of profits—often 20 percent—continues to be taxed at the preferential tax rates. For example, to make an investment requiring $100 million, limited partners could contribute $80 million to the fund and advance $20 million to the general partner as an interest-free, nonrecourse loan with the requirement that the borrowed capital be invested in the fund. If the assets of the investment fund were eventually sold for a profit, the gains realized by the general partner on the $20 million loan would equal 20 percent of the fund's total gains. The general partner would then claim that income as a capital gain subject to lower tax rates, which is similar to the way carried interest is treated under current law. If the investment was sold for a loss and the general partner could not repay the loan in full, he or she would not be liable for the unpaid loan: Under the terms of a nonrecourse loan, a borrower is not liable for any amount beyond the pledged collateral, which in this case would be the underlying assets in the investment fund originally purchased with the loan. However, even if the compensation agreement between limited partners and the general partner was restructured in that manner, federal receipts would still rise, although by less than they would if restructuring was not feasible. That is because, under current law, the general partner is required to treat the forgone interest on the nonrecourse loan as income and pay tax on it at the higher ordinary rate. The revenue estimates shown above reflect the likelihood and consequences of such restructuring.

RELATED OPTION: Revenues, Option 3

RELATED CBO PUBLICATION: Testimony of Peter R. Orszag, Director, before the House Committee on Ways and Means, *The Taxation of Carried Interest* (September 6, 2007), www.cbo.gov/publication/19113

Revenues—Option 13

Include Disability Payments From the Department of Veterans Affairs in Taxable Income

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Include all disability payments	0.8	8.3	8.3	9.2	9.9	10.5	11.7	11.7	11.3	12.2	36.5	93.8
Include disability payments only for veterans with a disability rating of 20 percent or less	0.3	3.4	3.4	3.7	4.0	4.3	4.8	4.8	4.6	5.0	14.8	38.3

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The goal of the Department of Veterans Affairs' (VA) disability system is to compensate veterans for earnings lost as a result of their service-connected disabilities. According to statute, the amount of lost earnings is meant to be equal to the average reduction of earnings capacity experienced by civilian workers with similar medical conditions or injuries.

Compensable service-connected disabilities are medical problems incurred or aggravated during active duty, although not necessarily during the performance of military duties. Conditions range widely in severity and type, including scars, hypertension, and the loss of one or more limbs. The amount of a veteran's base payment is linked to his or her composite disability rating, which is expressed from zero to 100 percent in increments of 10 percentage points. Lower VA ratings generally reflect that a disability is less severe; in 2015 about one in three recipients of disability compensation had a rating of 20 percent or less. Veterans do not have to demonstrate that their condition has reduced their earnings or interferes with daily functioning. Disability compensation is not means-tested, and payments are exempt from federal and state income taxes. Veterans who have a job are eligible for benefits, and most working-age veterans who receive disability benefits are employed. Payments are in the form of monthly annuities and typically continue until death. Because disability benefits are based on VA's calculation of average earnings lost as a result of specific conditions, payments do not reflect disparities in earnings that are attributable to differences in veterans' education, training, occupation, or motivation to work.

This option considers two alternative approaches to taxing VA disability benefits under the individual income tax. The first alternative would include all such disability payments in taxable income. The staff of the Joint Committee on Taxation (JCT) estimates that, if implemented, this alternative would increase federal revenues by $94 billion from 2017 through 2026. The second alternative would include disability payments in taxable income only for veterans with a disability rating of 20 percent or less. That alternative would raise federal revenues by a smaller amount—$38 billion over the 2017–2026 period—according to JCT's estimates.

An argument in favor of the option is that including disability payments in taxable income would increase the equity of the tax system. Taxing disability payments would lead to taxpayers with comparable combined income—that is, from disability payments, earnings, and other sources—incurring similar tax liabilities. Eliminating income exclusions in the tax system moves the system toward one in which people in similar financial and family circumstances face similar tax rates. Furthermore, because higher-income taxpayers face higher tax rates than lower-income taxpayers, this option would result in taxpayers with higher combined income paying a larger share of their income in taxes than taxpayers with less income.

An argument against this option is that VA disability payments are connected to military service, which is not like civilian employment; instead, it confers unique benefits to society and imposes extraordinary risks on service members. By that logic, the pay and benefits that service members receive—such as the current exclusion of disability compensation from taxation—should reflect the hardships of military life. Veterans, however, are entitled to disability payments even for non-work-related medical conditions, as long as those conditions were incurred during the period when the individuals were serving on active duty. In contrast, disability benefits received by civilian workers for non-work-related injuries are taxable if the employer paid the premiums.

RELATED OPTIONS: Revenues, Option 14; Mandatory Spending, Option 24

RELATED CBO PUBLICATION: *Veterans' Disability Compensation: Trends and Policy Options* (August 2014), www.cbo.gov/publication/45615

Revenues—Option 14

Include Employer-Paid Premiums for Income Replacement Insurance in Employees' Taxable Income

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	19.2	36.1	35.6	34.6	33.2	33.7	34.4	35.3	36.3	37.5	158.7	335.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

To the extent that the option would affect Social Security payroll taxes, a portion of the revenues would be off-budget. In addition, the option would increase outlays for Social Security by a small amount. The estimates do not include those effects on outlays.

Benefits that replace income for the unemployed, injured, or disabled are currently subject to different tax treatments. Whereas unemployment benefits are fully taxable, benefits paid under workers' compensation programs (for work-related injuries or illnesses) are tax-exempt. Disability benefits (for non-work-related injuries) may be taxable, depending on who paid the premiums for the disability insurance. If the employer paid the premiums, the benefits are taxable (although the recipient's tax liability can be offset partly by special income tax credits for the elderly or disabled). If the employee paid the premiums out of after-tax income, the benefits are generally not taxed.

This option would gradually eliminate any tax on income replacement benefits over a five-year period but would immediately include in employees' taxable income the value of several taxes, insurance premiums, and other contributions paid by employers. Specifically, all of the following would be subject to the individual income tax and the payroll taxes for Social Security and Medicare: the taxes that employers pay under the Federal Unemployment Tax Act and to various state unemployment programs; 50 percent of the premiums that employers pay for workers' compensation (excluding the portion covering medical expenses); and the portion of insurance premiums or contributions to pension plans that employers pay to fund disability benefits. Together, those changes would increase revenues by $336 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates. Over the long term, the gain in revenues would result almost entirely from adding workers' compensation premiums to taxable income. Including those various items in employees' taxable earnings, and thus in the wage base from which Social Security benefits are calculated, also would increase federal spending for Social Security. Between 2017 and 2026, the option would increase federal spending very slightly, but the effect on spending would continue to increase after 2026 as more people whose premiums were taxed retired and began collecting Social Security benefits. The estimates shown above do not include any such effects on outlays.

An advantage of this option is that it would treat different kinds of income replacement insurance similarly and thereby eliminate many of the somewhat arbitrary disparities that currently exist. For example, people who are unable to work because of an injury would not be taxed differently on the basis of whether their injury was related to a previous job. Another advantage of the option is that it would spread the tax burden among all workers covered by such insurance rather than placing the burden solely on beneficiaries, as is now the case with unemployment insurance and employer-paid disability insurance. The effect on covered workers would be relatively small: Their after-tax earnings would fall, on average, by less than one-half of one percent. However, the effect would be greatest among low-wage workers, some of whom would be less likely to seek work as a result.

A disadvantage of the option is that it would discourage unemployed individuals from accepting available work because, with unemployment benefits no longer taxable, their disposable income would be higher while they were unemployed than is the case under current law. Research shows that higher after-tax unemployment benefits tend to lengthen periods of unemployment, particularly among those who have no savings and cannot obtain loans after they lose their job. (However, the increase in disposable income would also allow unemployed people more time to find a job that best matches their skill set.)

Another argument against the option is that it would not eliminate all disparities in the way income replacement benefits are treated. For example, the income replacement portion of adjudicated awards and out-of-court settlements for injuries not related to work and not covered by insurance would remain entirely exempt from taxation. Likewise, extended unemployment benefits that the federal government sometimes provides during economic downturns would never be taxed because no amount corresponding to an employer's contribution would ever have been included in the recipients' taxable income.

RELATED OPTIONS: Revenues, Options 13, 24

RELATED CBO PUBLICATION: *Unemployment Insurance in the Wake of the Recent Recession* (November 2012), www.cbo.gov/publication/43734

Revenues—Option 15

Further Limit Annual Contributions to Retirement Plans

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	5.4	7.8	7.8	8.2	8.4	9.4	10.2	10.7	11.2	12.7	37.6	91.7

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

To the extent that the option would affect Social Security payroll taxes, a portion of the revenues would be off-budget. In addition, the option would increase outlays for Social Security by a small amount. The estimates do not include those effects on outlays.

Current law allows taxpayers to make contributions to certain types of tax-preferred retirement plans up to a maximum annual amount that varies depending on the type of plan and the age of the taxpayer. The most common such vehicles are defined contribution plans (any plan that does not guarantee a particular benefit amount upon retirement) and individual retirement accounts (IRAs). Defined contribution plans are sponsored by employers. Some—most commonly, 401(k) plans—accept contributions by employees; others are funded entirely by the employer. IRAs are established by the participants themselves.

Most of the tax savings associated with retirement plans arise because the investment income that accrues in the account is either explicitly or effectively exempt from taxation. That is clearest in the case of Roth retirement plans—both IRAs and 401(k)s. Contributions to such plans cannot be excluded from taxable income; instead, the participant benefits by not paying tax on the investment income, either as it accrues or when it is withdrawn. More traditional types of tax-preferred retirement plans allow participants to exclude contributions from their taxable income and defer the payment of taxes until they withdraw funds. If the taxpayer is subject to the same tax rate that applied when contributions were made, the value of the deduction is offset by the tax on withdrawals. The actual tax benefit is equivalent to that provided by Roth plans—effectively exempting investment income from taxation. (In the traditional structure, however, the tax benefit can be higher or lower than under a Roth plan, depending on the difference between the participant's tax bracket at the time contributions are made and when withdrawals are made.)

The value of the tax exemption for investment earnings increases with the participant's income tax rate. Thus, a worker in the 15 percent tax bracket saves 15 cents on each dollar of investment income accrued in his or her retirement plan; however, an employee in the 35 percent tax bracket avoids taxes equal to 35 cents per dollar of investment income. (For some forms of investment income such as capital gains, lower tax rates apply in each tax bracket, and the savings are smaller.)

People under the age of 50 may contribute up to $18,000 to 401(k) and similar employment-based plans in 2016; participants ages 50 and above are also allowed to make "catch-up" contributions of up to $6,000, enabling them to make as much as $24,000 in total contributions in 2016. In general, the limits on a person's contributions apply to all defined contribution plans combined. However, contributions to 457(b) plans, available primarily to employees of state and local governments, are subject to a separate limit. As a result, employees enrolled in both 401(k) and 457(b) plans can contribute the maximum amount to both plans, thereby allowing some people to make tax-preferred contributions of as much as $48,000 in a single year. Employers may also contribute to their workers' defined contribution plans, up to a maximum of $53,000 per person in 2016, less any contributions made by the employee.

In 2016, combined contributions to Roth and traditional IRAs are limited to $5,500 for taxpayers under the age of 50 and $6,500 for those ages 50 and above. The tax deduction for contributions to a traditional IRA is phased out above certain income thresholds if either the taxpayer or the taxpayer's spouse is covered by an employment-based plan (but nondeductible contributions—which still enable a taxpayer to defer taxes on investment gains until they are withdrawn—are allowable at any income level). Allowable contributions to Roth IRAs are phased out above certain income levels, and no contributions are permitted at incomes above $194,000 for married taxpayers filing joint returns, $10,000 for married taxpayers filing separate returns, and $132,000 for unmarried taxpayers. However, that limit can be circumvented by making a nondeductible contribution to a traditional IRA and then converting the traditional IRA to a Roth IRA before any investment income can accrue.[1] Annual contribution limits for all types of plans are adjusted, or indexed, to include the effects of inflation but only in $500 increments ($1,000 increments in the case of the overall limit on contributions to defined contribution plans).

Under this option, a participant's maximum allowable contributions would be reduced to $16,000 per year for 401(k)–type plans and $5,000 per year for IRAs, regardless of the person's age. The option would also require that all contributions to employment-based plans—including 457(b) plans—be subject to a single combined limit. Total allowable employer and employee contributions to a defined contribution plan would be reduced from $53,000 per year to $47,000. Finally, conversions of traditional IRAs to Roth IRAs would not be permitted for taxpayers whose income is above the top threshold for making Roth contributions.

The lower limits on contribution amounts would increase revenues by $96 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates. The constraints on Roth conversions would reduce revenues by $4 billion over that period, for a combined total of $92 billion.

The revenue reduction associated with constraining Roth conversions largely reflects the loss of tax payments that would otherwise be due at the time of conversion. But the longer-term effects on revenues of that aspect of the option would probably be different. The loss of Roth benefits for those above the threshold would result in the taxation of more investment income—whether the nondeductible contributions remained in the traditional IRA or were diverted to a taxable account. Because balances can be converted only once, the tax consequences of disallowing some conversions would begin to decline as the demand for conversions was gradually satisfied. Over the longer term, revenues gained by taxing more investment income would probably outweigh those lost from disallowing conversions.

The option would also affect federal outlays, but by much smaller sums. Reducing the amount that employers are allowed to contribute would lead to an increase in taxable wages, the base from which Social Security benefits are calculated, and thus would increase spending for Social Security by a small amount. (The estimates shown here do not include any effects on such outlays.) The changes in contributions by employees would not affect the wage base for Social Security.

One argument in favor of this option centers on fairness. The option would reduce the disparity in tax benefits that exists between higher- and lower-income taxpayers in two ways. First, those directly affected by the option would make fewer contributions and accrue less tax-preferred investment income, so the greater benefit of the exemption to those in higher tax brackets would be reduced. Second, the option would affect more higher-income taxpayers than lower-income taxpayers. The limits on 401(k) contributions affect few taxpayers—only 9 percent of participants in calendar year 2010 (the most recent year for which such data are available)—but of those affected, 42 percent had income in excess of $200,000 that year. The option also would level the playing field between those who currently benefit from higher contribution limits (people ages 50 and over and employees of state and local governments) and those subject to lower limits.

In addition to enhancing fairness, the contribution limits imposed under the option would improve economic efficiency. A goal of tax-preferred retirement plans is to increase private saving (although at the cost of some public saving). However, the higher-income taxpayers who are constrained by the current limits on contributions are most likely to be those who can fund the tax-preferred accounts by using money they have already saved or would save anyway; in that case, the tax preference provides benefits to the people involved without boosting aggregate saving. Thus, the option would increase public saving—by reducing the deficit—at the cost of very little private saving.

1. Note that the first use of such a conversion would create a tax liability on amounts already in the traditional IRA. Once those preexisting amounts were taxed, however, subsequent nondeductible contributions and immediate conversions would be tax-free.

Finally, the option's constraints on Roth conversions would reduce the complexity and improve the transparency of the tax system, making it easier for participants and nonparticipants alike to understand the tax ramifications of Roth accounts. Furthermore, the financial institutions managing the accounts would incur, and pass on to participants, fewer administrative costs. (Even greater transparency could be realized by eliminating the income thresholds and allowing everybody to contribute directly to a Roth IRA, but that would reduce revenue over the long term.)

The main argument against this option is that it would reduce the retirement saving of some lower- and moderate-income people. Eliminating the extra allowance for catch-up contributions in particular would adversely affect those ages 50 and over who might have failed to save enough for a comfortable retirement while raising their families. The amount that they could contribute to tax-preferred retirement accounts would be cut at precisely the time when reduced family obligations and impending retirement make them more likely to respond to tax incentives to save more.

Finally, further limiting total contributions to a defined contribution plan would create an incentive for some small businesses to terminate their plans if the tax benefits to the owners of providing such plans were outweighed by the cost of administering them. To the extent that such plans were terminated, employees would then have to rely on IRAs, which would lead some to save less because of the lower contribution limits.

RELATED OPTION: Revenues, Option 16

RELATED CBO PUBLICATION: *Use of Tax Incentives for Retirement Saving in 2006* (October 2011), www.cbo.gov/publication/42731

Revenues—Option 16

Tax Social Security and Railroad Retirement Benefits in the Same Way That Distributions From Defined Benefit Pensions Are Taxed

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	17.9	36.7	38.5	40.5	42.6	44.7	46.9	49.3	51.7	54.2	176.2	423.1

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Under current law, less than 30 percent of the benefits paid by the Social Security and Railroad Retirement programs are subject to the federal income tax. Recipients with income below a specified threshold pay no taxes on those benefits. Most recipients fall into that category, which constitutes the first tier of a three-tiered tax structure. If the sum of their adjusted gross income, their nontaxable interest income, and one-half of their Social Security and Tier I Railroad Retirement benefits exceeds $25,000 (for single taxpayers) or $32,000 (for couples who file jointly), up to 50 percent of the benefits are taxed. Above a higher threshold—$34,000 for single filers and $44,000 for joint filers—as much as 85 percent of the benefits are taxed.

By contrast, distributions from defined benefit plans are taxable except for the portion that represents the recovery of an employee's "basis"—that is, his or her after-tax contributions to the plan. In the year that distributions begin, the recipient determines the percentage of each year's payment that is considered to be the nontaxable recovery of previous after-tax contributions, based on the cumulative amount of those contributions and projections of his or her life expectancy. Once the recipient has recovered his or her entire basis tax-free, all subsequent pension distributions are fully taxed. (Distributions from traditional defined contribution plans and from individual retirement accounts, to the extent that they are funded by after-tax contributions, are also taxed on amounts exceeding the basis.)

This option would treat the Social Security and Railroad Retirement programs in the same way that defined benefit pensions are treated—by defining a basis and taxing only those benefits that exceed that amount. For employed individuals, the basis would be the payroll taxes they paid out of after-tax income to support those programs (but not the equal amount that employers paid on their workers' behalf). For self-employed people, the basis would be the portion (50 percent) of their self-employment taxes that is not deductible from their taxable income. Under this option, revenues would increase by $423 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

An argument in favor of this option concerns equity. Taxing benefits from the Social Security and Railroad Retirement programs in the same way as those from defined benefit pensions would make the tax system more equitable in at least two ways. First, it would eliminate the preferential treatment given to Social Security benefits but not to pension benefits. For low- and middle-income taxpayers especially, that preference can cause elderly people with similar income to face very different tax liabilities depending on the mixture of retirement benefits they receive. Second, it would treat elderly and nonelderly taxpayers with comparable income the same way. For people who pay taxes on Social Security benefits under current law, the option could also simplify the preparation of tax returns. Instead of taxpayers' calculating the taxable portion themselves, the Social Security Administration—which would have information on their lifetime contributions and life expectancy—could compute the taxable amount of benefits and provide that information to beneficiaries each year.

This option also has drawbacks. It would have the greatest impact on people with the lowest income: People with income below $44,000, including some who depend solely on Social Security or Railroad Retirement for their support, would see their taxes increase by the greatest percentage. In addition, raising taxes on Social Security and Railroad Retirement benefits would be equivalent to reducing those benefits and could be construed as violating the implicit promises of those programs, especially because the option would provide little or no opportunity for current retirees and people nearing retirement to adjust their saving or retirement strategies to mitigate the impact. Finally, more elderly people would have to file tax returns than do so now, and calculating the percentage of each recipient's benefits that would be excluded from taxation would impose an additional burden on the Social Security Administration.

RELATED OPTION: Revenues, Option 15

RELATED CBO PUBLICATION: *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011

Revenues—Option 17

Eliminate Certain Tax Preferences for Education Expenses

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	4.0	20.1	20.2	20.5	20.8	21.0	21.4	21.8	22.3	22.9	85.6	195.0

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates include the effects on outlays resulting from changes in refundable tax credits.

Federal support for higher education takes many forms, including grants, subsidized loans, and tax preferences. Those tax preferences include several types of tax-advantaged accounts that allow families to save for their child's postsecondary education as well as education-related credits and deductions. The major credits and deductions in effect in 2016 are the following:

- The American Opportunity Tax Credit (AOTC) replaced and expanded the Hope tax credit starting in 2009. Although it was scheduled to expire at the end of 2017, the AOTC was permanently extended by the Consolidated Appropriations Act, 2016. Unlike the Hope tax credit, which was nonrefundable, the AOTC is partially refundable—that is, families whose income tax liability (before the credit is applied) is less than the total amount of the credit may receive all or a portion of the credit as a payment. The AOTC is available to cover qualifying educational expenses for up to four years of postsecondary education. In 2016, the AOTC can total as much as $2,500 (100 percent of the first $2,000 in qualifying expenses and then 25 percent of the next $2,000). Up to 40 percent of the credit (or $1,000) is refundable. The amount of the AOTC gradually declines (is "phased out") for higher-income tax filers. In 2016, the AOTC is reduced for married couples who file jointly and have modified adjusted gross income (MAGI) between $160,000 and $180,000 and for single filers with MAGI between $80,000 and $90,000.[1] Neither the credit amount nor the income thresholds are adjusted, or indexed, to include the effects of inflation.

- The nonrefundable Lifetime Learning tax credit provides up to $2,000 for qualifying tuition and fees. (The credit equals 20 percent of each dollar of qualifying expenses up to a maximum of $10,000.) Only one Lifetime Learning credit may be claimed per tax return per year, but the expenses of more than one family member (a taxpayer, spouse, or dependent) may be included in the calculation. The Lifetime Learning credit can be used beyond the first four years of postsecondary education and by students who attend school less than half-time. Taxpayers may not claim the Lifetime Learning credit and the AOTC for the same student in the same year. In 2016, the Lifetime Learning tax credit is gradually reduced for joint filers whose MAGI is between $111,000 and $131,000 and for single filers whose MAGI is between $55,000 and $65,000. Those income thresholds are indexed.

- Tax filers may deduct from their taxable income up to $2,500 per year for interest payments on student loans. That deduction is available regardless of whether a tax filer itemizes deductions. In 2016, the interest deduction for student loans phases out for joint filers with MAGI between $130,000 and $160,000 and for single filers with MAGI between $65,000 and $80,000. Although the maximum deduction amount is not indexed to change with price levels, the income thresholds for the phaseout ranges are indexed.

- Taxpayers (regardless of whether they claim the standard deduction or itemize their deductions) can deduct up to $4,000 from their taxable income for

1. Certain foreign income and foreign housing allowances that are excluded from taxable income are added to adjusted gross income (AGI) to calculate the modified AGI measure used to determine eligibility for education-related tax credits. (AGI includes income from all sources not specifically excluded by the tax code, minus certain deductions.)

qualifying tuition and fees instead of taking a credit. The deduction is gradually reduced for joint filers whose MAGI is between $130,000 and $160,000 and for single filers whose MAGI is between $65,000 and $85,000. Those income thresholds are indexed. That deduction is scheduled to expire at the end of 2016.

This option would eliminate the AOTC and the Lifetime Learning tax credit beginning in 2017. (The $4,000 deduction for qualifying tuition and fees described above would have already expired by 2017.) The option would also gradually eliminate the deductibility of interest expenses for student loans. Because students would have borrowed money with the expectation that a portion of the interest would be deductible over the life of the loan, the interest deduction for student loans would be phased out in annual increments of $250 over a 10-year period. If implemented, the option would raise revenues by $195 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates.

An argument in favor of the option is that the current tax benefits are not targeted to those who need assistance the most. Many low-income families do not have sufficient income tax liability to claim all—or in some cases, any—of the education-related tax benefits. However, the cost of higher education may impose a greater burden on those families as a proportion of their income. Further, some research indicates that lower-income individuals and families may be more sensitive to the cost of higher education than those with higher income and thus more likely to enroll in higher education programs if tuition and fees are subsidized.

A second rationale in favor of the option concerns the administration of education benefits through the income tax system. Education benefits administered through the tax system are poorly timed because families must pay tuition and fees before they can claim the benefits on their tax returns. In contrast, federal spending programs such as the Pell grant program are designed to provide assistance when the money is needed—at the time of enrollment. Further, providing education assistance through various credits and deductions, each with slightly different eligibility rules and benefit amounts, makes it difficult for families to determine which tax preferences provide the most assistance. As a result, some families may not choose the most advantageous educational benefits for their particular economic circumstances.

A drawback of this option is that some households would not receive as much assistance for educational expenses unless federal outlays for education assistance were increased. The option would increase the financial burden on families with postsecondary students—particularly middle-income families who do not qualify for current federal spending programs. Another drawback is that despite the current system's complexity—which creates overlapping tax benefits—some families may find it easier to claim benefits on their tax returns (on which they already provide information about their family structure and income) than to fill out additional forms for assistance through other federal programs.

RELATED OPTIONS: Mandatory Spending, Options 8, 10; Discretionary Spending, Option 21

RELATED CBO PUBLICATIONS: *Options to Change Interest Rates and Other Terms on Student Loans* (June 2013), www.cbo.gov/publication/44318; *Refundable Tax Credits* (January 2013), www.cbo.gov/publication/43767; *Costs and Policy Options for Federal Student Loan Programs* (March 2010), www.cbo.gov/publication/21018; *Private and Public Contributions to Financing College Education* (January 2004), www.cbo.gov/publication/15178

Revenues—Option 18

Lower the Investment Income Limit for the Earned Income Tax Credit and Extend That Limit to the Refundable Portion of the Child Tax Credit

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	*	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.7	2.9	6.5

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates represent the change in the overall budget balance that would result from the sum of changes to revenues and outlays.

* = between zero and $50 million.

Low- and moderate-income people are eligible for certain refundable tax credits under the individual income tax if they meet the specified criteria. Refundable tax credits differ from other tax preferences, such as deductions, in that their value may exceed the amount of income taxes that the person owes. Refundable tax credits thus can result in net payments from the government to a taxpayer: If the amount of a refundable tax credit exceeds a taxpayer's tax liability before that credit is applied, the government pays the excess to that person. Two refundable tax credits are available only to workers: the earned income tax credit (EITC) and the refundable portion of the child tax credit (referred to in the tax code as the additional child tax credit).

To qualify for the EITC and the refundable portion of the child tax credit, people must meet several income tests. First, they must have income from wages, salaries, or self-employment. Second, their adjusted gross income cannot exceed thresholds that vary with family characteristics.[1] (Adjusted gross income includes income from all sources not specifically excluded by the tax code, minus certain deductions.) For the EITC, the income thresholds for 2016 range from $14,880 for an unmarried worker who does not live with a child to $53,505 for a married couple that files jointly and has three or more children. For the child tax credit, the income thresholds for 2016 are $95,000 for an unmarried person with one child and $130,000 for joint filers with one child; the income thresholds increase with the number of children in the family. Finally, eligibility for the EITC is restricted to filers with investment income that is $3,400 or less in 2016. Investment income includes interest (counting tax-exempt interest), dividends, capital gains, royalties and rents from personal property, and returns from passive activities (business pursuits in which the person is not actively involved). For the EITC, the limitations on adjusted gross income and investment income are adjusted, or indexed, to include the effects of inflation. The income cutoff for the child tax credit, however, is not indexed.

This option would lower the threshold for the EITC investment income test from $3,400 to $1,700. As under current law, that threshold would be indexed to include the effects of inflation. Moreover, the option would extend that requirement to the refundable portion of the child tax credit. If implemented, the option would raise $7 billion from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation.

The main rationale for the option is that it would better target the credits to people without substantial means by denying the credits to people who have low earnings but have other resources to draw upon. Asset tests—requirements that recipients do not have savings in bank accounts, stocks, and other types of investments whose value is above a specified threshold—serve a similar role in some spending programs that provide benefits to lower-income populations. However, asset tests would be very difficult for the Internal Revenue Service (IRS) to administer because the agency does not collect information on the amount of assets held by individuals. By contrast, the IRS does have extensive information on the income from most of those investments, and much of

1. A special rule applies to the EITC when filers' earnings are higher than their adjusted gross income (because of business or investment losses). In that instance, eligibility for the EITC is denied if the filers' *earnings* exceed the specified thresholds.

that information is accurate because it is reported independently to the agency by financial institutions as well as by taxpayers on their returns.

An argument against the option is that it would reduce the incentive to save, especially among people whose income from investments is near the threshold amount and who could become (or remain) eligible for the credits under the option by making small reductions in their assets. However, some people would not respond to the lower thresholds by reducing their saving but instead by shifting their investments to less liquid forms (such as cars) that are not subject to the investment test or by changing the timing of the return from their investments (for example, by retaining stocks for longer periods in order to avoid realizing capital gains). For people with very low income, the investment test would probably have little effect because they have little means to save and invest.

RELATED OPTION: Revenues, Option 19

RELATED CBO PUBLICATIONS: *Effective Marginal Tax Rates for Low- and Moderate-Income Workers in 2016* (November 2015), www.cbo.gov/publication/50923; *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768; *Growth in Means-Tested Programs and Tax Credits for Low-Income Households* (February 2013), www.cbo.gov/publication/43934; *Refundable Tax Credits* (January 2013), www.cbo.gov/publication/43767

Revenues—Option 19

Require Earned Income Tax Credit and Child Tax Credit Claimants to Have a Social Security Number That Is Valid for Employment

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	0.2	4.7	4.4	4.3	4.2	4.1	4.0	3.9	3.7	3.7	17.8	37.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The estimates represent the change in the overall budget balance that would result from the sum of changes to revenues and outlays.

The earned income tax credit (EITC) and the child tax credit provide assistance to low- and moderate-income workers. Both credits are refundable: If the amount of the credit is greater than the amount of income taxes owed by the taxpayer before the credit is applied, the government pays the excess to that person. Eligibility for the EITC and the refundable portion of the child tax credit is limited to people with income from wages, salaries, or self-employment.

Eligibility requirements for the two credits differ for noncitizens, however—especially the rules governing the provision of Social Security numbers. For purposes of determining eligibility for the EITC, a noncitizen's Social Security number is considered invalid if it was issued by the Social Security Administration (SSA) solely to allow that individual to obtain benefits from a program entirely or partly financed by the federal government. In contrast, noncitizens can claim the child tax credit if they and their children have either Social Security numbers (including those issued to individuals for the sole purpose of receiving government benefits) or individual taxpayer identification numbers (ITINs), which are issued by the Internal Revenue Service (IRS) to anyone (including unauthorized residents) who is required to file a tax return but cannot obtain a Social Security number.

Some people who are not authorized to work in the United States can receive the EITC under current law. Those individuals were issued Social Security numbers before 2003 because they needed them to obtain drivers' licenses and to open bank accounts. SSA no longer issues Social Security numbers for such purposes, but the agency was not able to rescind the numbers obtained before the ban. Because those numbers were provided to people who were not applying for federal benefits, their Social Security numbers are considered valid for purposes of receiving the EITC.

Under this option, people who are not authorized to work in the United States would not be entitled to either the EITC or the child tax credit. The option would change the definition of a valid Social Security number for the EITC and extend that requirement to the child tax credit. For both credits, taxpayers, spouses, and qualifying children would be required to have Social Security numbers issued to U.S. citizens and noncitizens authorized to work in the United States. If enacted, the option would raise $37 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

Under current law, the IRS can use a procedure known as "mathematical and clerical error" authority (often referred to simply as math error authority) to deny the EITC when neither the taxpayer nor qualifying children have valid Social Security numbers. With math error authority, the IRS can prevent the credit from being paid to the taxpayer without initiating the audit process. This option would extend that authority to the child tax credit when the taxpayer and children do not have valid Social Security numbers.

The main advantage of this option is that it would eliminate some of the disparity that currently exists in the credits' eligibility rules, making them less confusing and easier to administer. Under the option, the requirements related to the possession of a valid Social Security number would be the same for both credits: Only taxpayers (and their children) who are authorized to work in the United States—U.S. citizens, lawful permanent residents, or people in the United States on temporary work visas—would be eligible for the EITC and child tax credit. The IRS would be able to verify those requirements using the data it already receives from SSA and immediately matches to tax returns, allowing the agency to prevent payment of the credits to ineligible noncitizens.

A disadvantage of the option is the additional burden it would impose on some individuals. Many noncitizens initially obtained Social Security numbers to receive federal benefits at a time when they were not authorized to work in the United States. If they subsequently became permanent residents or U.S. citizens, they may not have notified SSA of the change in their status. Under this option, those individuals would have to take the additional step of updating their work authorization status with SSA to receive the EITC or child tax credit. Those actions would also increase SSA's workload. Many immigrants, however, already have an incentive to inform SSA of changes in their immigration status, so that their new employers can use E-Verify (a system administered by the Department of Homeland Security) to determine whether they are authorized to work in the United States.

The option could be modified in several ways that would either limit or extend its application. As specified, the option would prevent some noncitizens with permanent work authorization from receiving the child tax credit and the EITC because other members of their family are not lawful permanent residents or do not have visas allowing them to work in the United States. For example, one parent may be a lawful permanent resident, but his or her spouse is not authorized to work in the United States. An alternative approach would allow the credits to be paid if only one spouse provides a valid Social Security number. Another effect of the option is that it would allow noncitizens who were issued Social Security numbers when they had temporary work visas to continue receiving the credits when those visas expired. The option could be modified to limit eligibility for the credits to U.S. citizens and lawful permanent residents. However, that restriction would be difficult to administer because Social Security records, which the IRS currently relies upon to verify the identity of taxpayers and which could also be used to determine work status, do not distinguish between noncitizens with temporary work visas and lawful permanent residents.

RELATED OPTION: Revenues, Option 18

RELATED CBO PUBLICATIONS: *How Changes in Immigration Policy Might Affect the Federal Budget* (January 2015), www.cbo.gov/publication/49868; *Growth in Means-Tested Programs and Tax Credits for Low-Income Households* (February 2013), www.cbo.gov/publication/43934; *Refundable Tax Credits* (January 2013), www.cbo.gov/publication/43767

Revenues—Option 20

Increase the Maximum Taxable Earnings for the Social Security Payroll Tax

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Raise Taxable Share to 90 Percent												
Change in outlays	0.1	0.2	0.5	0.7	1.1	1.5	1.9	2.5	3.1	3.8	2.6	15.4
Change in revenues	18.6	60.1	62.5	64.7	67.3	70.1	72.4	75.0	77.7	80.2	273.1	648.4
Decrease in the Deficit	-18.5	-59.9	-62.0	-64.0	-66.2	-68.6	-70.5	-72.5	-74.6	-76.4	-270.5	-633.0
Subject Earnings Greater Than $250,000 to Payroll Tax												
Change in revenues	27.2	85.6	90.1	95.2	101.2	107.6	113.7	121.0	129.1	137.1	399.3	1,007.8

Sources: Staff of the Joint Committee on Taxation; Congressional Budget Office.

This option would take effect in January 2017.

The change in revenues would consist of an increase in receipts from Social Security payroll taxes (which would be off-budget), offset in part by a reduction in individual income tax revenues (which would be on-budget). The change in outlays would be for additional payments of Social Security benefits and would be classified as off-budget.

Social Security—which consists of Old-Age and Survivors Insurance and Disability Insurance—is financed primarily by payroll taxes on employers, employees, and the self-employed. Only earnings up to a maximum, which is $118,500 in calendar year 2016, are subject to the tax. That maximum usually increases each year at the same rate as average wages in the economy. The Social Security tax rate is 12.4 percent of earnings: 6.2 percent is deducted from employees' paychecks, and 6.2 percent is paid by employers. Self-employed individuals generally pay 12.4 percent of their net self-employment income.

When payroll taxes for Social Security were first collected in 1937, about 92 percent of earnings from jobs covered by the program were below the maximum taxable amount. During most of the program's history, the maximum was increased only periodically, so the percentage varied greatly. It fell to 71 percent in 1965 and by 1977 had risen to 85 percent. Amendments to the Social Security Act in 1977 boosted the amount of covered taxable earnings, which reached 90 percent in 1983. That law also specified that the taxable maximum be adjusted, or indexed, annually to match the growth in average wages. Despite those changes, the percentage of earnings that is taxable has slipped in the past decade because earnings for the highest-paid workers have grown faster than average earnings. Thus, in 2016, about 82 percent of earnings from employment covered by Social Security fell below the maximum taxable amount.

This option considers two alternative approaches that would increase the share of earnings subject to payroll taxes.

- The first alternative would increase the taxable share of earnings from jobs covered by Social Security to 90 percent by raising the maximum taxable amount to $245,000 in calendar year 2017. (In later years, the maximum would grow at the same rate as average wages, as it would under current law.) Implementing such a policy change would increase revenues by an estimated $648 billion over the 2017–2026 period, according to the staff of the Joint Committee on Taxation (JCT). (The estimates include the reduction in individual income tax revenues that would result from employers' shifting some labor compensation from a taxable to a nontaxable form.)

  Because Social Security benefits are tied to the amount of earnings on which taxes are paid, however, some of the increase in revenues from this alternative would be offset by the additional benefits paid to people with earnings above the maximum taxable amount under current law. On net, this alternative would reduce federal budget deficits by an estimated $633 billion over the 10-year period.

- The second alternative would apply the 12.4 percent payroll tax to earnings over $250,000 in addition to earnings below the level specified by the current-law taxable maximum. The taxable maximum would continue to grow with average wages, but the $250,000 threshold would remain at that level, so the gap between the two would shrink. CBO projects that the taxable maximum would exceed $250,000 in calendar year 2037; after that, all earnings would be subjected to the payroll tax. The current-law taxable maximum would still be used for calculating benefits, so scheduled benefits would not change. This alternative would raise $1.0 trillion over the 2017–2026 period, according to JCT.

An advantage of either approach is that it would provide more revenue to the Social Security program, which, according to the Congressional Budget Office's projections, will not have sufficient income to finance the benefits that are due to beneficiaries under current law. If current law remained in place, spending for Social Security would rise from 4.9 percent of gross domestic product (GDP) in 2016 to 6.3 percent by 2041, CBO projects. But Social Security tax revenues, which already are less than spending for the program, would grow more slowly. In CBO's extended baseline, the combined Old-Age and Survivors Insurance and Disability Insurance trust funds are projected to be exhausted in calendar year 2029. The first alternative, which increases the taxable share of earnings from jobs covered by Social Security to 90 percent, would delay the exhaustion of the combined trust funds by 4 years, to calendar year 2033. The second alternative, which would apply the 12.4 percent payroll tax to earnings over $250,000, would delay the exhaustion of the combined trust funds by 12 years, to calendar year 2041.

In addition, either alternative would make the payroll tax less regressive. People with earnings above the ceiling now pay a smaller percentage of their total earnings in payroll taxes than do people whose total earnings are below the maximum. Making more earnings taxable would increase payroll taxes for those high earners. (That change would also lead to higher benefit payments for affected workers under the first alternative, but the tax increase would be much larger than the increase in benefits.) The second alternative would be more progressive than raising the taxable maximum because it would affect only those with earnings above $250,000.

A disadvantage of both alternatives is that raising the earnings cap would weaken the link between the taxes that workers pay into the system and the benefits they receive. That link has been an important aspect of Social Security since its inception. Under the first alternative, the increase in benefits would be modest relative to the increase in taxes, and under the second alternative, workers with higher earnings would pay additional taxes that would not increase their benefits.

Another drawback is that some people—those with earnings between the existing taxable limits and the higher thresholds under the first alternative, or those with earnings above the $250,000 threshold under the second alternative—would earn less after taxes for each additional hour worked. Increases in statutory tax rates have two opposing effects among people already working. First, people tend to work fewer hours because other uses of their time become relatively more attractive (the substitution effect). However, people also tend to work more hours because having less after-tax income requires additional work to maintain the same standard of living (the income effect). In CBO's estimation, the first effect would, on balance, be greater than the second effect. The first approach would thus reduce the incentive to work and also encourage taxpayers to substitute tax-exempt fringe benefits for taxable wages. In contrast, people with earnings well above the limit established by the first alternative would not see any reduction in the return on their additional work, but they would have less income after taxes, which would encourage them to work more.

RELATED OPTIONS: Revenues, Options 21, 23

RELATED CBO PUBLICATIONS: *CBO's 2015 Long-Term Projections for Social Security: Additional Information* (December 2015), www.cbo.gov/publication/51047; *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *The 2015 Long-Term Budget Outlook* (June 2015), www.cbo.gov/publication/50250

Revenues—Option 21

Expand Social Security Coverage to Include Newly Hired State and Local Government Employees

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	0.7	2.2	3.8	5.3	6.8	8.4	10.1	11.9	13.8	15.7	18.8	78.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The change in revenues would consist of an increase in receipts from Social Security payroll taxes (which would be off-budget), offset in part by a reduction in individual tax revenues (which would be on-budget). In addition, the option would increase outlays for Social Security by a small amount. The estimates do not include those effects on outlays.

Nearly all private-sector workers and federal employees are covered by Social Security, but a quarter of workers employed by state and local governments are not. Under federal law, state and local governments can opt to enroll their employees in the Social Security program, or they can opt out if they provide a separate retirement plan for those workers instead. (State and local governments may also have their employees participate in both Social Security and a separate retirement plan.) By contrast, all federal employees hired after December 31, 1983, are covered by Social Security and pay the associated payroll taxes. Furthermore, all state and local government employees hired after March 31, 1986, and all federal government employees pay payroll taxes for Hospital Insurance (Medicare Part A).

Under this option, Social Security coverage would be expanded to include all state and local government employees hired after December 31, 2016. Consequently, all newly hired state and local government employees would pay the Social Security payroll tax. That 12.4 percent tax on earnings, half of which is deducted from employees' paychecks and half of which is paid by employers, funds the Old-Age, Survivors, and Disability Insurance programs. If implemented, this option would increase revenues by a total of $78 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates. (The estimate includes the reduction in individual income tax revenues that would result from shifting some labor compensation from a taxable to a nontaxable form.)

Paying the Social Security payroll tax for 10 years generally qualifies workers (and certain family members) to receive Social Security retirement benefits; employees must meet different work requirements to qualify for disability benefits or, in the event of their death, for certain family members to qualify for survivors' benefits. Although extending such coverage to all newly hired state and local employees would eventually increase the number of Social Security beneficiaries, that increase would have little impact on the federal government's spending for Social Security in the short term. Over the 2017–2026 period, outlays would increase by only a small amount because most people hired by state and local governments during that period would not begin receiving Social Security benefits for many years, but the effects on outlays would grow in coming decades. (The above estimate does not include any effects on outlays.)

One rationale for implementing this option is that it would slightly enhance the long-term viability of the Social Security program. The Congressional Budget Office projects that, under current law, income dedicated to the program will be insufficient to cover benefits specified in law. Under the option, the additional benefit payments for the expanded pool of beneficiaries would be less, in the long term, than the size of the additional revenues generated by newly covered employees. That is largely because, under current law, most of the newly hired workers would receive Social Security benefits anyway for one of two possible reasons: They might have held other covered jobs, or they might be covered by a spouse's employment.

Another rationale for implementing the option concerns fairness. Social Security benefits are intended to replace only a percentage of a worker's preretirement earnings. That percentage (referred to as the replacement rate) is higher for workers with low career earnings than for workers with higher earnings. But the standard formula for calculating Social Security benefits does not distinguish between people whose career earnings are low and those who just appear to have low career earnings because they spent a portion of their career in jobs that were not covered by Social Security. To make the replacement rate more comparable for workers with similar earnings histories, current law reduces the standard benefits for retired government employees who have spent a substantial portion of their career in employment not covered by Social Security. However, that adjustment is imperfect and can affect various public employees differently. This option would eliminate those inequities.

Finally, implementing this option would provide better retirement and disability benefits for many workers who move between government jobs and other types of employment. By facilitating job mobility, the option would enable some workers—who would otherwise stay in state and local jobs solely to maintain their public-employee retirement benefits—to move to jobs in which they could be more productive. Many state and local employees are reluctant to leave their jobs because pensions are structured to reward people who spend their entire careers in the same pension system. If their government service was covered by Social Security, they would be less reluctant to change jobs because they would remain in the Social Security system. State and local governments, however, might respond to greater turnover by reducing their investment in workers (by cutting training programs, for example), causing the productivity of state and local employees to fall.

The main argument against the option is the impact it would have on the pension funds of affected state and local governments. That impact would depend on the current structure of state and local pension plans and the way they would be restructured in response to this option. One possibility is that a state or local government would add Social Security on top of its existing pension plan. Alternatively, state and local pension plans for new employees could be reduced or eliminated in response to the expansion of Social Security coverage: New employees would contribute less (or nothing) during their tenure, and they would receive smaller (or no) pension benefits when they retire. Implementing those changes would not be particularly difficult for fully funded pension plans, which could pay benefits for existing employers out of current assets. However, many state and local government pension plans are underfunded, and such plans would probably need future contributions to fund the benefits received by current retirees or by those about to retire under the existing pension system. Any reduction in future contributions to such plans would increase financial pressures on them.

RELATED OPTION: Revenues, Option 20

RELATED CBO PUBLICATIONS: *CBO's 2015 Long-Term Projections for Social Security: Additional Information* (December 2015), www.cbo.gov/publication/51047; *Social Security Policy Options, 2015* (December 2015), www.cbo.gov/publication/51011; *The 2015 Long-Term Budget Outlook* (June 2015), www.cbo.gov/publication/50250

Revenues—Option 22

Increase the Payroll Tax Rate for Medicare Hospital Insurance by 1 Percentage Point

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	47.1	73.7	76.6	79.5	82.5	85.6	89.0	92.6	96.3	100.5	359.4	823.2

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The primary source of financing for Hospital Insurance (HI) benefits provided under Medicare Part A is the HI payroll tax. The basic HI tax is 2.9 percent of earnings: 1.45 percent is deducted from employees' paychecks, and 1.45 percent is paid by employers. Self-employed individuals generally pay 2.9 percent of their net self-employment income in HI taxes. Unlike the payroll tax for Social Security, which applies to earnings up to an annual maximum ($118,500 in 2016), the 2.9 percent HI tax is levied on total earnings.

Workers with higher earnings are also subject to a surtax on all earnings above a certain threshold: $200,000 for unmarried taxpayers and $250,000 for married couples who file jointly. At those thresholds, the portion of the HI tax that employees pay increases by 0.9 percentage points, to a total of 2.35 percent. The surtax does not apply to the portion of the HI tax paid by employers, which remains 1.45 percent of earnings, regardless of how much the worker earns.

In recent years, spending for the HI program has grown at a much faster pace than revenues derived from the payroll tax. Since 2008, expenditures for HI have exceeded the program's total income—including interest credited to the Hospital Insurance Trust Fund—so balances in the trust fund have declined. The Congressional Budget Office projects that the balances will generally continue to fall until the HI trust fund is exhausted in 2026.

This option would increase the basic HI tax on total earnings by 1.0 percentage point. The basic rate for both employers and employees would increase by 0.5 percentage points, to 1.95 percent, resulting in a combined rate of 3.9 percent. The rate paid by self-employed people would also rise to 3.9 percent. For taxpayers with earnings above $200,000 ($250,000 for married couples who file jointly), the HI tax on earnings that exceed the surtax threshold would increase from 3.8 percent to 4.8 percent; employees would pay 2.85 percent, and employers would pay the remaining 1.95 percent.

If implemented, the option would increase revenues by $823 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates. (The estimate includes the reduction in individual income tax revenues that would result as some labor compensation shifted from a taxable to a nontaxable form.)

The main argument in favor of the option is that receipts from the HI payroll tax are currently not sufficient to cover the cost of the program, and increasing that tax would shrink the gap between the program's costs and the revenues that finance it. Another argument in support of the option is that an increase in the tax rate would be simpler to administer than most other types of tax increases because it would require relatively minor changes to the current tax system.

A drawback of the option is that it would encourage people to reduce the hours they work or to shift their compensation away from taxable earnings to nontaxable forms of compensation. When employees reduce the hours they work or change the composition of their earnings, economic resources are allocated less efficiently than they would be in the absence of the higher tax rate.

Another disadvantage of the option is that it would increase the tax burden of lower-income workers relative to that of workers with higher income. That is because a larger share of the income of lower-income families is, on average, from earnings that are subject to the HI tax. As a result, a percentage-point increase in the HI tax would represent a greater proportion of the income of lower-income taxpayers than would be the case for higher-income taxpayers. Moreover, because the option would not make any changes to the Medicare program, the increase in the tax burden would not be offset by greater Medicare benefits when people reached the age of 65.

RELATED OPTION: Revenues, Option 23

Revenues—Option 23

Tax All Pass-Through Business Owners Under SECA and Impose a Material Participation Standard

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	5.8	10.4	11.6	13.1	14.2	14.9	15.6	16.5	17.3	18.1	55.1	137.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Most of the revenues would be off-budget. In addition, the option would increase outlays for Social Security by a small amount. The estimates do not include those effects on outlays.

Under current law, workers with earnings from businesses owned by other people contribute to Social Security and Medicare Part A through the Federal Insurance Contributions Act (FICA) tax. The tax rate for Social Security is 12.4 percent of the tax base up to $118,500, and that threshold increases each year with average wages. For Medicare Part A, the tax rate is 2.9 percent, and there is no ceiling on that base.[1] The tax bases for both programs are limited to labor income (specifically, wages and salaries), and the taxes are split equally between the employer and the employee.

In contrast, people with earnings from businesses they own themselves are taxed either through FICA or through the Self-Employment Contributions Act (SECA), depending on whether the business is incorporated. Owners of unincorporated businesses are subject to the SECA tax, and their tax base is self-employment income (which, unlike the FICA base, generally includes some capital income.) The definition of self-employment income depends on whether one is classified as a sole proprietor, a general partner (that is, a partner who is fully liable for the debts of the firm), or a limited partner (a partner whose liability for the firm's debts is limited to the amount he or she invests). Sole proprietors pay SECA taxes on their net business income (that is, receipts minus expenses). General partners pay SECA taxes on their "guaranteed payments" (payments they are due regardless of the firm's profits) and on their share of the firm's net income. Limited partners pay SECA tax solely on any guaranteed payments they receive, and then only if those payments represent compensation for labor services.

The definition of limited partners is determined at the state level and, as a result, varies among states. Since the enactment of federal laws distinguishing between the treatment of general and limited partners under SECA, state laws have expanded eligibility for limited-partner status from strictly passive investors to certain partners who are actively engaged in the operation of businesses. Furthermore, state laws have recognized new types of entities, such as the limited liability company (LLC), whose owners do not fit neatly into either of the two partnership categories.

Unlike owners of unincorporated businesses, owners of privately held corporations pay FICA taxes as if they were employees. That treatment includes owners of S corporations—which are certain privately held corporations whose profits, like those of partnerships, are "passed through" to their owners—making them subject to the individual income tax rather than the corporate income tax. Owners of privately held corporations are required to report their "reasonable compensation" for any services they provide and pay FICA tax on that amount. The net income of the firm, after deducting that compensation, is subject to neither the FICA nor the SECA tax.

This option would require owners of all pass-through businesses to pay the SECA tax on their share of net income. In the case of S corporations, owners would no longer pay the FICA tax on their reasonable compensation. In addition, the option would change the definition of self-employment income so that it would no longer depend on whether a taxpayer was classified as a general partner or a limited partner. That distinction would be replaced with a "material participation" standard in which the primary test would be whether the individual engaged

1. If wages exceed certain thresholds—$250,000 for married taxpayers who file joint returns, $125,000 for married taxpayers who file separate returns, and $200,000 for people whose filing status is "single" or "head of household"—an additional 0.9 percent tax, the Additional Medicare Tax, is levied on the amount above the threshold.

in the operation of the business for more than 500 hours during a given year. Partners, LLC members, and S corporation owners categorized as material participants would pay SECA tax on both their guaranteed payments and their share of the firm's net income. Those not deemed to be material participants would pay SECA tax on their reasonable compensation. All sole proprietors would be considered material participants.

The option would increase taxes on owners of S corporations and on limited partners who are material participants by subjecting their entire share of the firm's net income to the SECA tax instead of just their reasonable compensation or guaranteed payments.[2] However, the option would lower taxes for general partners who are not material participants by excluding from SECA taxation their share of the firm's net income that is in excess of their reasonable compensation. On balance, federal revenues would increase by an estimated $137 billion over the period from 2017 through 2026, according to the staff of the Joint Committee on Taxation. By increasing, on net, the earnings base from which Social Security benefits are calculated, the option also would increase federal spending for Social Security over the long term. (The estimates do not include that effect on outlays.)

An advantage of this option is that it would eliminate the ambiguity created by the emergence of new types of business entities that were not anticipated when the laws governing Social Security were last amended. The treatment of partners and LLC members under the SECA tax would be defined entirely by federal law and would ensure that owners who are actively engaged in the operation of a business could not legally exclude a portion of their labor compensation from the tax base.

Moreover, because all firms not subject to the corporate income tax would be treated the same, businesses would be more likely to choose their form of organization on the basis of what allowed them to operate most efficiently rather than what minimized their tax liability.

Other arguments in favor of the option are that it would improve compliance with the tax code and reduce complexity for some firms. Under current law, the owners of S corporations have a strong incentive to underreport reasonable compensation so as to minimize their FICA tax liability. By subjecting S corporation owners to the SECA tax, the option would eliminate the ability of material participants to reduce their tax liability by underreporting their reasonable compensation. In addition, the option would simplify recordkeeping for S corporations whose owners are all material participants because they would no longer have to estimate the reasonable compensation of those owners.

A disadvantage of the option is that additional income from capital would be subject to the SECA tax, making the tax less like FICA, which taxes virtually no income from capital. That could deter some people from starting a business and paying the SECA tax on the profits (leading them instead to work for somebody else and pay the FICA tax on their wages). The option could also result in new efforts to recharacterize business income as either rental income or interest income, neither of which is subject to the FICA or the SECA tax. In addition, it could lead to the use of C corporations (businesses that are subject to the corporate income tax) as a tax shelter. For example, faced with a 15.3 percent SECA tax rate on top of the individual income tax, the owners of an S corporation might choose to pay the corporate income tax instead (even though profit distributions would be taxed again under the individual income tax). If the corporate income tax rate was lowered in the future, that incentive would be magnified. Finally, the option would place an additional administrative burden on many partnerships and LLCs: Those entities would be required to determine reasonable compensation for any members considered to be nonmaterial participants.

2. Unlike this option, Option 11 would add such income to the base of the Net Investment Income Tax (NIIT), which imposes a 3.8 percent tax on virtually all other forms of investment income when total income exceeds a certain threshold. The intent of that option is to ensure that all types of labor and capital income of higher-income taxpayers are subject to either the NIIT or the Additional Medicare Tax. If this option was implemented, that objective would be accomplished and Option 11 would be unnecessary.

RELATED OPTIONS: Revenues, Options 11, 20, 22

RELATED CBO PUBLICATION: *The Taxation of Capital and Labor Through the Self-Employment Tax* (September 2012), www.cbo.gov/publication/43644

Revenues—Option 24

Increase Taxes That Finance the Federal Share of the Unemployment Insurance System

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Increase the net FUTA rate to 0.8 percent	1.1	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	7.1	14.9
Increase the FUTA wage base to $40,000, index the base to future wage growth, and decrease the net FUTA rate to 0.167 percent	14.9	11.9	3.9	-0.1	-2.2	-2.2	-2.6	-3.5	-3.4	-3.7	28.4	13.1

This option would take effect in January 2017.

FUTA = Federal Unemployment Tax Act.

The unemployment insurance (UI) system is a partnership between the federal government and state governments that provides a temporary weekly benefit—consisting of a regular benefit and, often during economic downturns, emergency and extended benefits—to qualified workers who lose their job through no fault of their own. Funding for the state and federal portions of the UI system is drawn from payroll taxes imposed on employers under the State Unemployment Tax Act (SUTA) and the Federal Unemployment Tax Act (FUTA), respectively.

The states administer the UI system, establishing eligibility rules, setting regular benefit amounts, and paying those benefits to eligible people. State payroll taxes vary; each state sets a tax rate schedule and a maximum wage amount subject to taxation. Revenues from SUTA taxes are deposited into dedicated state accounts that are included in the federal budget.

The federal government sets broad guidelines for the UI system, pays a portion of the administrative costs that state governments incur, and makes advances to states that lack the money to pay UI benefits. In addition, during periods of high unemployment, the federal government has often funded, either fully or partially, temporary emergency benefits, supplemental benefits provided through the extended benefits program, or both.

Under FUTA, employers pay taxes on each worker's wages up to $7,000; the revenues are deposited into several federal accounts. The amount of wages subject to the FUTA tax (the taxable wage base) is not adjusted, or indexed, to increase with inflation and has remained unchanged since 1983. The FUTA tax rate, which is 6.0 percent, is reduced by a credit of 5.4 percent for state unemployment taxes paid, for a net tax rate of 0.6 percent—or $42 for each employee earning at least $7,000 annually. On January 1, 1976, a surtax of 0.2 percent went into effect, raising the total FUTA tax rate, net of the state tax credit, to 0.8 percent—for a maximum of $56 per employee. That surtax expired on July 1, 2011.

During and after the last recession, funds in the designated federal accounts were insufficient to pay the emergency and extended benefits enacted by the Congress, to pay the higher administrative costs that states incurred because of the greater number of people receiving benefits, or to make advances to several states that did not have sufficient funds to pay regular benefits. That shortfall necessitated that advances be made from the general fund of the U.S. Treasury to the federal accounts. Some of those advances must be repaid by the states, a process that the Congressional Budget Office expects will take several more years under current law.

This option includes two alternative approaches that would increase revenues from unemployment insurance taxes by roughly the same amount over the 2017–2026 period. The first approach would leave the FUTA taxable wage base unchanged but would raise the net FUTA tax rate by reinstating and permanently extending the 0.2 percent FUTA surtax. CBO estimates that this approach would generate a steady flow of additional revenues in each year between 2017 and 2026, for a total increase of $15 billion.

The second approach would expand the FUTA taxable wage base but decrease the tax rate. Specifically, the approach would raise the amount of wages subject to the FUTA tax from $7,000 to $40,000 in 2017 (and then index that threshold to the growth in future wages). It would also reduce the net FUTA tax rate, after accounting for the 5.4 percent state tax credit, from 0.6 percent under current law to 0.167 percent. Expanding the FUTA taxable wage base would also increase SUTA taxes, which are counted as part of the federal budget. Because federal law requires that each state's SUTA taxes be levied on a taxable wage base that is at least as large as that under FUTA, nearly all states would have to increase their tax base to $40,000 if this approach was adopted.[1] CBO estimates that this approach would raise revenues by $13 billion over the 2017–2026 period.

Under this second alternative, revenues would rise initially but fall in later years. They would rise substantially at first primarily because of the added proceeds from SUTA taxes. However, CBO expects that, in the years after 2017, many states would respond by reducing their UI tax rates but leave those rates high enough to generate some additional revenues, on net, over the 2017–2026 period. (States with low UI account balances would be especially likely to allow the increase in the taxable wage base to generate additional revenues.) The extra revenue generated during the first years would also leave the states with larger trust fund balances. That would reduce the need for states to raise revenues to improve their trust fund balances in later years.

The main advantage of both approaches is that they would improve the financial condition of the federal portion of the UI system. By expanding the taxable wage base, the second approach would also improve the financial condition of state UI tax systems. The additional revenues resulting from either approach would allow federal UI accounts to more rapidly repay the outstanding advances from the general fund and would better position those accounts to finance benefits during future recessions. By reducing reliance on advances from the general fund, both approaches would decrease what are effectively loans from all taxpayers (including nonworkers) to workers who benefit from having insurance against unemployment.

Either approach would generally be simpler to implement—especially for employers—than many other proposed changes to the federal tax code. However, expanding the taxable wage base would impose some burden on state governments, requiring them to ensure that their tax bases conformed to the indexed federal tax base.

An argument against both approaches is that employers would generally pass on the additional FUTA taxes to workers in the form of reduced earnings. By reducing workers' after-tax pay, the tax might induce some people to drop out of, or choose not to enter, the workforce. For some people in the workforce, both approaches would increase marginal tax rates by a small amount. (The marginal tax rate is the percentage of an additional dollar of income from labor or capital that is paid in taxes.) On balance, CBO estimates that increasing marginal tax rates reduces the amount that people work relative to what would have occurred otherwise.[2] Given the small size of the tax changes and corresponding changes in after-tax pay that would result from either approach, the effects on employment would probably be quite small under this option.

The combination of a single tax rate and low thresholds on the amount of earnings subject to the tax makes the FUTA tax regressive—that is, FUTA taxes measured as a share of earnings decrease as earnings rise. Even so, because workers with lower earnings receive, on average, UI benefits that are a higher fraction of their prior earnings than do workers with higher earnings, those benefits are progressive. If taxes and benefits are considered together, the unemployment insurance system is generally thought to be roughly proportional—neither progressive

1. In 2016, only Hawaii and Washington have taxable wages bases above $40,000.

2. That increase would have two possible effects. On the one hand, the higher marginal tax rates would reduce the share of the returns from additional work that people would keep, reducing their incentive to work. On the other hand, because higher marginal tax rates reduce after-tax income, they make it more difficult for people to attain their desired standard of living with a given amount of work, thus causing some people to work more.

nor regressive—under current law. Neither approach described in this option would affect UI benefits. However, the approaches would have different effects on the distribution of tax burdens: Reinstating the surtax would increase FUTA taxes proportionately for all income groups, whereas expanding the wage base and lowering the FUTA rate would reduce the regressivity of the FUTA tax.

RELATED OPTION: Revenues, Option 14

RELATED CBO PUBLICATION: *Unemployment Insurance in the Wake of the Recent Recession* (November 2012), www.cbo.gov/publication/43734

Revenues—Option 25

Increase Corporate Income Tax Rates by 1 Percentage Point

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	6.4	8.1	8.9	9.8	10.3	10.6	10.9	11.3	11.7	12.3	43.5	100.3

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Most corporations that are subject to the corporate income tax calculate their tax liability according to a progressive rate schedule. The first $50,000 of taxable corporate income is taxed at a rate of 15 percent; income of $50,000 to $75,000 is taxed at a 25 percent rate; income of $75,000 to $10 million is taxed at a 34 percent rate; and income above $10 million is generally taxed at a rate of 35 percent.[1]

Although most corporate income falls within the 35 percent tax bracket, the average tax rate on corporate income (corporate taxes divided by corporate income) is lower than 35 percent because of allowable deductions, exclusions, tax credits, and the lower tax rates that apply to the first $10 million of income. For example, corporations can deduct business expenses, including interest paid to the firm's bondholders, from gross income to compute taxable income. (Dividends paid to shareholders, however, are not deductible.) Most income earned by the foreign subsidiaries of U.S. corporations is not subject to U.S. taxation until it is repatriated in the form of dividends paid to the parent corporation. To prevent income earned abroad from being subject to both foreign and U.S. taxation, the tax code gives U.S. corporations a credit that reduces their domestic tax liability on that income by the amount of income and withholding taxes they have paid to foreign governments. The foreign tax credit is subject to limits that are designed to ensure that the dollar value of the credits taken does not exceed the amount of U.S. tax that otherwise would have been due.

This option would increase all corporate income tax rates by 1 percentage point. For example, the corporate income tax rate would increase to 36 percent for taxable income above $10 million. The option would increase revenues by $100 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates.

The major argument in favor of the option is its simplicity. As a way to raise revenue, increasing corporate income tax rates would be easier to implement than most other types of business tax increases because it would require only minor changes to the current tax collection system.

The option would also increase the progressivity of the tax system to the extent that the burden of the corporate income tax is largely borne by owners of capital, who tend to have higher income than other taxpayers. (Because the tax reduces capital investment in the United States, it reduces workers' productivity and wages relative to what they otherwise would be, meaning that at least some portion of the economic burden of the tax over the longer term falls on workers—making an increase in corporate tax rates less progressive than it would be if that burden was fully borne by the owners of capital.)

An argument against the option is that it would further reduce economic efficiency. The current corporate income tax system already distorts firms' choices about how to structure the business (for example, whether to operate as a C corporation, an S corporation, a partnership, or a sole proprietorship) and whether to finance investment by issuing debt or by issuing equity. Increasing corporate income tax rates would make it even more advantageous for firms to organize in a manner that

1. Under current law, surtaxes are imposed on some amounts of corporate income. Income between $100,000 and $335,000 is subject to a surtax of 5 percent, and an additional 3 percent tax is levied on income between $15 million and $18.3 million. Those surtaxes effectively phase out the benefit of the three lower tax rates for corporations with income above certain amounts. As a result, a company that reports more than $18.3 million in taxable income effectively faces a statutory rate equal to 35 percent of its total corporate taxable income.

allows them to be treated as an S corporation or partnership solely as a way to reduce their tax liabilities. That is because net income from C corporations—those that are subject to the corporate income tax—is first taxed at the business level and then again at the individual level after it is distributed to shareholders or investors. By contrast, income from S corporations and partnerships is generally free from taxation at the business level but is taxed under the individual income tax, even if the income is reinvested in the firm. Raising corporate tax rates would also encourage companies to increase their reliance on debt financing because interest payments, unlike dividend payments to shareholders, can be deducted. Carrying more debt might increase some companies' risk of default. Moreover, the option would discourage businesses from investing, hindering the growth of the economy. An alternative to this option that would reduce such incentives would be to lower the tax rate while broadening the tax base by, for example, reducing or eliminating some exclusions or deductions.

Another concern that might be raised about the option is that it would increase the tax rate that corporations—those based in the United States and those based in foreign countries—face when they earn income in the United States. Under current law, when the federal corporate tax is combined with state and local corporate taxes (which have a top rate averaging 4 percent), the U.S. tax rate on income in the highest bracket averages 39 percent—already higher than that in any of the other 33 member countries of the Organisation for Economic Co-operation and Development. (The top statutory rates, however, do not reflect the differences in various countries' tax bases and rate structures and therefore do not represent the true average tax rates that multinational firms face.) Those higher rates in the United States influence businesses' choices about how and where to invest; to the extent that firms respond by shifting investment to countries with low taxes as a way to reduce their tax liability at home, economic efficiency declines because firms are not allocating resources to their most productive use. The current U.S. system also creates incentives to shift reported income to low-tax countries without changing actual investment decisions. Such profit shifting erodes the corporate tax base and requires tax planning that wastes resources. Increasing the top corporate rate to 36 percent (40 percent when combined with state and local corporate taxes) would further accentuate those incentives to shift investment and reported income abroad. However, other factors, such as the skill level of a country's workforce and its capital stock, also affect corporations' decisions about where to incorporate and invest.

RELATED OPTIONS: Revenues, Options 33, 34, 35

RELATED CBO PUBLICATIONS: *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817; *Options for Taxing U.S. Multinational Corporations* (January 2013), www.cbo.gov/publication/43764; *Taxing Businesses Through the Individual Income Tax* (December 2012), www.cbo.gov/publication/43750; Jennifer C. Gravelle, *Corporate Tax Incidence: Review of General Equilibrium Estimates and Analysis,* Working Paper 2010-03 (May 2010), www.cbo.gov/publication/21486; William C. Randolph, *International Burdens of the Corporate Income Tax*, Working Paper 2006-09 (August 2006), www.cbo.gov/publication/18067; *Corporate Income Tax Rates: International Comparisons* (November 2005), www.cbo.gov/publication/17501

Revenues—Option 26

Capitalize Research and Experimentation Costs and Amortize Them Over Five Years

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	31.3	42.6	33.6	24.4	14.8	8.4	6.9	7.2	7.6	8.0	146.7	184.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Under current tax law, companies can deduct the costs of research and experimentation from their income in the year those costs are incurred. (Other cost-recovery methods are allowed but rarely used.) By allowing an immediate deduction, the tax code treats costs associated with research and experimentation as current expenses (the same way that wages of production workers are treated, for instance) rather than as an investment (which is how the purchase of a machine or a building is characterized, for example). Doing so is consistent with the way research and development expenses are treated under the generally accepted accounting principles used in the United States by corporations to report income and assets to shareholders in their financial statements.[1] Companies can also claim a tax credit for certain research costs in excess of a base amount that represents the company's historical level of such spending.

In recent years, some organizations have challenged the characterization of research and development costs as current expenses instead of investment. In 2013, the Bureau of Economic Analysis began treating research and development costs in the national income and product accounts as investments. Under the new approach, an investment in research and development creates an asset (generally referred to as intangible to distinguish it from tangible assets such as equipment and structures) that declines in value over time. That approach has been partially adopted by the International Financial Reporting Standards Board (which established the accounting standards used outside the United States). Under those standards, qualifying development costs—but not research costs—are capitalized (that is, added to the value of assets) and amortized (that is, deducted from both the value of assets and from current income) in equal annual amounts over the useful life of the asset.

This option would require the costs of both research and experimentation to be capitalized for tax purposes and amortized over five years. In other words, costs would be deducted in equal amounts over five years instead of all at once in the year the expenses were incurred. The existing credit for research and experimentation expenses would remain in place. The staff of the Joint Committee on Taxation estimates that, if implemented, the option would increase revenues by $185 billion between 2017 and 2026.

One argument in favor of the option is that it would treat investments in different types of assets more alike. The rationale is that investments in research projects that have a high probability of success and short development periods are comparable to investments in equipment and structures. Because the tax code is more favorable to those types of research and experimentation projects than it is to investments in equipment and structures, companies have an incentive to direct more of their resources toward such research and experimentation. Unless such research and experimentation generates benefits for people other than the company's investors (such as customers who benefit from an upgraded email application, for example), that favorable tax treatment results in a misallocation of resources that leads to lower output. However, high risk of failure and lengthy development periods more frequently characterize investments in intangible assets than investments in tangible assets, offsetting to some degree the favorable tax treatment of research and experimentation.

Another rationale is that the option would reduce an advantage that established companies, especially larger ones, have over newer businesses. Under current law, newer companies often do not have any income from

1. Experimentation expenses for tax purposes are a subset of development expenses for financial-reporting purposes. Most corporations use the development expenses from their financial reports as the basis for computing deductible experimentation expenses.

which to deduct their research and experimentation costs and therefore must effectively defer their deduction—for up to 20 years—until they have income from which to subtract their deductible costs. That delay lowers the value of the deduction. Large, established firms, in contrast, generally have income from other projects, allowing them to immediately claim the deduction and thus realize its full value. Under this option, however, the deductions of the large, established companies would be spread out over time, and the realized value of those deductions would more closely match the realized value for newer companies.

An argument against the option is that it would reduce the incentive to conduct research and experimentation that generates benefits for people outside of the firm that incurs the costs. By reducing the incentive to engage in research and experimentation, this option would, to some extent, discourage those activities and thus curtail those external benefits. For example, if the costs arising from the option were to deter the development of a drug that would improve public welfare, the public would never realize that improvement in welfare. The disincentive is magnified in cases involving a high risk of failure or a long development period.

Another argument against the option is that it would increase companies' recordkeeping burden. Because the option diverges from generally accepted accounting principles, businesses would have to maintain separate tax records for their research and development operations in addition to their records for financial-reporting purposes.

RELATED OPTION: Revenues, Option 27

RELATED CBO PUBLICATION: *Federal Policies and Innovation* (November 2014), www.cbo.gov/publication/49487

Revenues—Option 27

Extend the Period for Depreciating the Cost of Certain Investments

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	4.5	13.9	21.3	26.4	32.0	35.2	33.7	30.7	27.9	25.6	98.1	251.2

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

When calculating their taxable income, businesses can deduct the expenses they incurred when producing tangible goods or providing services for sale. One of those deductions is for depreciation—the drop in the value of a productive asset over time as a result of wear and tear or obsolescence. The tax code sets the number of years, or recovery period, over which the value of different types of investments can be deducted from taxable income and specifies what percentage of the cost can be deducted in each year of the period.

Equipment and structures are the two main types of tangible assets for which businesses take depreciation deductions. The tax code generally specifies recovery periods for equipment of between 3 and 20 years (with 5 years being the most common) and permits firms to accelerate the associated depreciation deductions so that those claimed early in the period are larger than those claimed later.[1] Most structures have recovery periods longer than 20 years (with 39 years being the most common). The cost of structures with recovery periods in excess of 20 years must be recovered by deducting equal amounts in each year over that period.[2]

The ability to accelerate depreciation deductions reduces the effective tax rate on income from investment in equipment relative to that on income from investment in structures. (Effective tax rates measure the impact of statutory tax rates and other features of the tax code in the form of a single tax rate that applies over the life of an investment.) The Congressional Budget Office estimates that businesses subject to the corporate income tax face an effective tax rate for equipment of 23.4 percent—9.6 percentage points less than the rate would be if deductions were limited to the actual decline in value (that is, economic depreciation). The corresponding effective tax rate for structures is 29.5 percent, which is 3.8 percentage points lower than if deductions were limited to economic depreciation.

This option would extend the recovery periods of assets placed into service after December 31, 2016, if those assets currently have recovery periods of 20 years or less. Specifically, where the tax code currently stipulates recovery periods of 3, 5, 7, 10, 15, or 20 years for a given type of asset, this option would increase those recovery periods to 4, 7, 9, 13, 20, or 25 years, respectively. If the current recovery period is greater than 20 years, it would not change under the option. Furthermore, the recovery periods for intangible assets, including computer software, would remain the same as under current law. Any asset that currently qualifies for accelerated depreciation would continue to qualify. If implemented, the option would increase revenues by $251 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates. (Because of the temporary expensing provisions that continue through 2019, the revenue gains would be smaller in the earlier years and greater in the later years than they would be in the absence of expensing.)

An argument in favor of this option is that it would make tax depreciation for equipment align more closely with economic depreciation. That, in turn, would make the effective tax rates on the income generated by different

1. In addition to accelerated depreciation, firms have been allowed, in every year since 2008, to "expense"—that is, deduct from taxable income during the year of purchase—50 percent (and, during one 15-month period, 100 percent) of the costs of purchases of equipment. The percentage that can be expensed declines to 40 percent for equipment acquired during 2018 and to 30 percent for equipment acquired during 2019. After 2019, the tax law will revert to the rules in effect before 2008, which allowed accelerated depreciation but no expensing (except in limited cases).

2. Accelerated depreciation is allowed for structures with recovery periods of 20 years or less, including (but not limited to) electric power plants, oil rigs, railroad tracks, and barns.

types of investment more equal. Under this option, the effective tax rates for businesses subject to the corporate income tax would be 28.2 percent for equipment and 29.9 percent for structures—reducing the gap between equipment and structures from 6.2 percentage points to 1.7 percentage points. That narrowing of the gap would mitigate the incentive that exists in the tax code for companies to invest more in equipment and less in structures than they might if investment decisions were based solely on economic returns.

An argument against this option is that its higher effective tax rates on income generated by capital would discourage investment. From that perspective, effective tax rates might best be equalized by easing taxation on less favored forms of capital rather than by raising the effective tax rate on a type of capital that is now favored. For example, the economic efficiencies gained by bringing the effective tax rates of equipment and structures closer together could be achieved by shortening the recovery periods of structures instead of by lengthening the recovery periods of equipment. However, that approach would reduce revenues. Another argument against this option is that by raising effective tax rates on business investment, this option would exacerbate the current tax bias in favor of owner-occupied housing relative to business investment.

RELATED OPTIONS: Revenues, Options 26, 28

RELATED CBO PUBLICATION: *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817

Revenues—Option 28

Repeal Certain Tax Preferences for Energy and Natural Resource–Based Industries

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Repeal the expensing of exploration and development costs	0.9	1.4	1.4	1.4	1.5	1.4	1.0	0.7	0.6	0.5	6.6	10.7
Disallow the use of the percentage depletion allowance	0.7	1.1	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.6	5.5	12.8
Both alternatives above	1.6	2.5	2.6	2.6	2.8	2.8	2.4	2.2	2.2	2.1	12.1	23.5

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

When calculating their taxable income, firms in most industrial sectors in the United States are generally allowed to deduct a portion of the investment costs they incurred that year and in previous years. The portion of those costs that is deductible depends on prescribed rates of depreciation or, for certain natural resources, depletion.[1] Costs are deducted over a number of years to reflect an asset's rate of depreciation or depletion.

In contrast, the U.S. tax code treats the energy industry and industries that are heavily based on natural resources more favorably. Tax preferences are provided through a mix of temporary and permanent provisions in the tax code. Tax preferences for the renewable-energy sector are provided largely through temporary provisions, whereas tax preferences for extractive industries that produce oil, natural gas, coal, and hard minerals are provided largely through permanent provisions. Two permanent tax preferences in particular give extractive industries an advantage over other industries:

- One preference allows producers of oil, gas, coal, and minerals to "expense" some of the costs associated with exploration and development. Expensing allows companies to fully deduct such costs as they are incurred rather than waiting for those activities to generate income. For extractive companies, the costs that can be expensed include, in some cases, those related to excavating mines, drilling wells, and prospecting for hard minerals. Specifically, under current law, integrated oil and gas producers (that is, companies with substantial retailing or refining activity) and corporate coal and mineral producers can expense 70 percent of their costs; those companies are then able to deduct the remaining 30 percent over a period of 60 months. Independent oil and gas producers (companies without substantial retailing or refining activity) and noncorporate coal and mineral producers can fully expense their costs.

- A second preference allows extractive industries to elect to use a percentage depletion allowance rather than the amount prescribed by the cost depletion method, which is a method that allows for the recovery of investment costs as income is earned from those investments. Through the percentage depletion allowance, certain extractive companies can deduct from their taxable income between 5 percent and 22 percent of the dollar value of material extracted during the year, depending on the type of resource and up to certain limits. (For example, oil and gas companies' eligibility for the percentage depletion allowance is limited to independent producers who operate domestically; for those firms, only the first 1,000 barrels of oil—or, for natural gas, oil-equivalent—per well, per day, qualify, and the allowance is limited to 65 percent of overall taxable income.) For each property they own, firms take a deduction for the greater of the percentage depletion allowance or the amount prescribed by the cost depletion system. The amount of deductions allowed under cost depletion is limited to the

1. One exception to this general rule allows firms with relatively small amounts of qualifying capital investments (primarily equipment) to fully deduct the costs of those items in the year in which they are incurred. That exception is generally referred to as section 179 expensing, after the section of the tax code that authorizes it.

value of the land and improvements. As a result, the percentage depletion allowance can be more generous than the cost depletion method because it is not limited to the cost of the property.

This option includes two different approaches to limiting tax preferences for extractive industries. The first approach would replace the expensing of exploration and development costs for oil, gas, coal, and hard minerals with the rules for deducting costs that apply in other industries.[2] That approach would increase revenues by $11 billion over the 2017–2026 period, according to estimates by the staff of the Joint Committee on Taxation (JCT). The second approach would eliminate the percentage depletion allowance, forcing all companies to use the cost depletion system rather than choose the more generous of the two methods. That approach would raise $13 billion over that 10-year period, according to JCT. If the two approaches were combined, revenues would increase by $24 billion over the 2017–2026 period.

The principal argument in favor of this option is that the two tax preferences for extractive industries distort the allocation of society's resources in several ways. First, for the economy as a whole, the preferences influence the allocation of resources between the extractive industries and other industries in a manner that does not reflect market outcomes. Those incentives encourage some investments in drilling and mining that produce output with a smaller market value than such investments would produce elsewhere because, when making investment decisions, companies take into account not only the market value of the output but also the tax advantage that expensing and percentage depletion provide. Second, for the same reason, the preferences also lead to an allocation of resources that does not reflect market outcomes within the extractive industries. Third, the preferences encourage producers to extract more resources in a shorter amount of time. In the case of oil, for example, that additional drilling makes the United States less dependent on imported oil in the short run, but it accelerates the depletion of the nation's store of oil and could cause greater reliance on foreign producers in the long run.

An argument against this option is that it treats expenses that might be viewed as similar in different ways. In particular, exploration and development costs for extractive industries can be seen as analogous to research and development costs, which can be expensed by all businesses. Another argument against this option is that encouraging producers to continue exploring and developing domestic energy resources may enhance the ability of U.S. households and businesses to accommodate disruptions in the supply of energy from other countries.

Another argument against this option is that it would alter permanent tax preferences for extractive industries but would not make any changes to temporary tax preferences for the renewable-energy sector. This report, however, does not include options to eliminate or curtail temporary tax preferences. Under current law, temporary tax preferences for the renewable-energy sector are scheduled to expire over the next several years; consequently, eliminating those preferences would not have a significant effect on deficits over the decade. Nonetheless, some temporary tax preferences are frequently extended and so resemble permanent tax preferences. For example, the tax credit for renewable-energy production is classified as temporary but has been in effect since 1992. In 2015, JCT estimated that if policymakers extended that credit so that it remained in place from 2015 to 2024, federal revenues would be reduced by $23 billion over that period. Limiting temporary tax preferences for renewable-energy sources would further reduce the distortions in the way resources are allocated between the energy sector and other industries, as well as within the energy sector. However, producing energy from renewable sources may yield wider benefits to society that a producer does not take into account, such as limiting pollution or reducing dependence on foreign governments as domestic reserves are depleted; in that case, preferential tax treatment could improve the allocation of resources.

2. The option would still allow other costs that are unique to extractive industries, such as those associated with unproductive wells and mines, to be expensed.

RELATED OPTIONS: Mandatory Spending, Option 1; Revenues, Options 27, 31

RELATED CBO PUBLICATIONS: *Federal Support for the Development, Production, and Use of Fuels and Energy Technologies* (November 2015), www.cbo.gov/publication/50980; *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012

Revenues—Option 29

Repeal the Deduction for Domestic Production Activities

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	9.6	17.8	18.0	18.2	18.2	18.1	18.3	18.3	18.5	18.8	81.8	173.7

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Most businesses can deduct from their taxable income 9 percent of what they earn from qualified domestic production activities.[1] The design of the deduction makes it comparable to a 3 percentage-point reduction in the tax rate on income earned from U.S.-based manufacturing. Various activities qualify for the deduction if they occur largely in the United States:

- Lease, rental, sale, exchange, or other disposition of tangible personal property, computer software, or sound recordings;
- Production of films (other than those that are sexually explicit);
- Production of electricity, natural gas, or potable water;
- Construction or renovation of real property; and
- Performance of engineering or architectural services.

The list of qualified activities specifically excludes the sale of food or beverages prepared at retail establishments; the transmission or distribution of electricity, natural gas, or potable water; and many activities that would otherwise qualify except that the proceeds come from sales to a related business.

This option would repeal the deduction for domestic production activities. Doing so would increase revenues by $174 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

1. The deduction is 6 percent for oil-related qualified production activities.

One argument in favor of this option is that it would reduce economic distortions. Although the deduction is targeted toward investments in domestic production activities, it does not apply to all domestic production. Thus, the deduction gives businesses an incentive to invest in a particular set of domestic production activities and to forgo other, perhaps more economically beneficial, investments in domestic production activities that do not qualify.

In addition, to comply with the law, businesses must satisfy a complex and evolving set of statutory and regulatory rules for allocating gross receipts and business expenses to the qualified activities. Companies that want to take full advantage of the deduction may incur large tax-planning costs (for example, fees to tax advisers). Moreover, the complexity of the rules can cause conflict between businesses and the Internal Revenue Service regarding which activities qualify under the provision.

An argument against implementing this option is that simply repealing the deduction for domestic production activities would increase the cost of domestic business investment and could reduce the amount of such investment. Alternatively, the deduction could be replaced with a revenue-neutral reduction in the top corporate tax rate (a cut that would reduce revenues by the same amount that eliminating the deduction would increase them). That alternative would end the current distortions between activities that qualify for the deduction and those that do not. It also would reduce the extent to which the corporate tax favors noncorporate investments over investments in the corporate sector and foreign activities over domestic business activities.

RELATED OPTION: Revenues, Option 25

RELATED CBO PUBLICATION: *Taxing Capital Income: Effective Marginal Tax Rates Under 2014 Law and Selected Policy Options* (December 2014), www.cbo.gov/publication/49817

Revenues—Option 30

Repeal the "LIFO" and "Lower of Cost or Market" Inventory Accounting Methods

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	11.4	22.8	22.8	22.9	12.4	1.8	1.9	1.9	2.0	2.0	92.3	101.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

To compute its taxable income, a business must first deduct from its receipts the cost of purchasing or producing the goods it sold during the year. Determining those costs requires that the business identify and attach a value to its inventory. Most companies calculate the cost of the goods they sell in a year by adding the value of the inventory at the beginning of the year to the cost of goods purchased or produced during the year and then subtracting from that total the value of the inventory at the end of the year.

The tax code allows firms to choose from among several approaches for identifying and determining the value of the goods included in their inventory. For itemizing and valuing goods in stock, firms can use the "specific identification" method. That approach, however, requires a very detailed physical accounting in which each item in inventory is matched to its actual cost (that is, the cost to purchase or produce the item). An alternative approach—"last in, first out" (LIFO)—also allows firms to value their inventory at cost but, in addition, permits them to assume that the last goods added to inventory were the first ones sold. Under that assumption, the cost of those more recently added goods should approximate current market value (that is, the cost of replacing the inventory).

Yet another alternative approach—"first in, first out" (FIFO)—is based on the assumption that the first goods sold from a business's inventory have been in that inventory the longest. Like firms that adopt the LIFO method, firms using the FIFO approach can also value their goods at cost. But firms that use the FIFO approach have still another choice—the "lower of cost or market" (LCM) method. Instead of assessing their end-of-year inventory at cost, they can assess that inventory on the basis of its market value and use that valuation if it is lower than the actual cost of acquiring or producing those goods. In addition, businesses that use the FIFO approach can qualify for the "subnormal goods" method of inventory valuation if their goods cannot be sold at market prices because they are damaged or flawed.

This option would eliminate the LIFO method of identifying inventory, as well as the LCM and subnormal-goods methods of inventory valuation. Businesses would be required to use the specific-identification or FIFO methods to account for goods in their inventory and to set the value of that inventory on the basis of cost. Those changes—which would be phased in over a period of four years—would increase revenues by a total of $102 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates.

The main rationale for this option is that it would align tax accounting rules with the way businesses tend to sell their goods. Under many circumstances, firms prefer to sell their oldest inventory first—to minimize the risk that the product has become obsolete or been damaged while in storage. In such cases, allowing firms to use alternative methods to identify and value their inventories for tax purposes allows them to reduce their tax liabilities without changing their economic behavior.

An argument for eliminating the LIFO method is that it allows companies to defer taxes on real (inflation-adjusted) gains when the prices of their goods are rising relative to general prices. Firms that use the LIFO method can value their inventory on the basis of costs associated with newer—and more expensive—inventory when, in fact, the actual items sold may have been acquired or produced at a lower cost at some point in the past. By deducting those higher costs as the price of production, firms are able to defer paying taxes on the amount their goods have appreciated until those goods are sold.

An argument against eliminating the LIFO method relates to the effects of inflation on taxable income. When inventories are valued on the basis of historical costs, price increases that occur between the time the inventory is purchased and the time its value is assessed raise taxable income. That effect tends to be greater with the FIFO method than with the LIFO method because the latter method values inventory by using the purchase prices of more recently acquired goods, thus deferring the effects of inflation on taxable income. However, other elements of the corporate income tax also treat gains that are attributable to inflation as taxable income.

An argument for eliminating the LCM method of inventory valuation under FIFO is that, when prices are falling, it provides a tax advantage for goods that have not been sold. The LCM method allows a business to compare the market value of each item in its end-of-year inventory with the cost to purchase or produce the item and then set the lower of the two as the item's value. The year-end inventory will have a lower total value under LCM than under the cost method if the market value of any item in the inventory is less than its actual cost. Using the LCM method when prices are falling allows the firm to claim a larger deduction for the costs of goods sold, causing the firm's taxable income to fall as a result. In effect, that method allows a firm to deduct from its taxable income the losses it incurred from the decline in the value of its inventory. (That deduction is allowed even though the firm has not sold the goods.) A firm, however, is not required to recognize gains in the value of its inventory when prices are rising, which means that gains and losses are taxed differently. Similarly, firms that use the subnormal-goods method of inventory valuation can immediately deduct the loss, even if the company later sells the good at a profit.

An argument against eliminating the LCM method for tax purposes is that it can simplify inventory valuations by those businesses. To the extent that firms find the LCM method a desirable method of inventory valuation, allowing them to use the same methodology for both financial accounting and tax purposes reduces complexity, particularly for small businesses.

Revenues—Option 31

Subject All Publicly Traded Partnerships to the Corporate Income Tax

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	0.3	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	2.6	5.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Until 1981, all companies whose shares were available for purchase through a public exchange were incorporated and subject to the corporate income tax. The profits of those corporations were, and continue to be, paid to shareholders as dividends or capital gains and taxed again to some extent under the individual income tax. During the 1980s, however, partnerships that were not subject to the corporate income tax began raising capital by offering shares, or "units," on public exchanges. The profits of such partnerships were allocated among the partners and added to their taxable income. Income that was allocated to partners who were individuals (as opposed to corporations) was subject only to the individual income tax. By avoiding the corporate income tax, the partnership form of organization reduced the cost of investing by individuals, making it an increasingly popular choice.

In 1987, the Congress made newly created publicly traded partnerships subject to the corporate income tax unless 90 percent or more of the partnership's revenues were derived from qualifying activities—specifically, activities related to natural resources (including exploration, mining, refining, transportation, storage, and marketing), real estate, and commodity trading. Preexisting publicly traded partnerships that did not meet the 90 percent threshold in 1987 were exempted from that restriction, but only a handful survive today—the rest having incorporated, abandoned the public trading of their units, or been acquired by other companies.

This option would eliminate the exceptions enacted in 1987 and make all publicly traded partnerships subject to the corporate income tax. Between 2017 and 2026, it would increase revenues by $6 billion, according to estimates by the staff of the Joint Committee on Taxation.

An advantage of this option is that it would treat the taxation of different economic activities more similarly. When the tax treatment of economic activities is more uniform, investors are more likely to direct their money to where it would realize the greatest return, not to where it would save the most in taxes. Such efficient investing would increase the overall size of the economy. The option would also encourage companies to choose a form of organization and a method of raising capital that best suit the company, not those that minimize tax liabilities.

Most of the affected companies are engaged in activities related to oil and gas (especially pipeline transportation), and the option would probably increase the price of those products. An advantage of the option is that those higher prices would reduce the consumption of oil and gas and the harmful effects of carbon emissions and other pollutants associated with that consumption. However, increases in the costs of oil and gas would probably cause the cost of transporting all types of goods to rise. A disadvantage of the option is that the resulting increases in the price of goods would probably place a greater burden on lower-income households than on higher-income households.

Another disadvantage of the option is that it would increase the cost of investing in activities that are currently exempt from the corporate income tax and thus would probably reduce such investments. A reduction in investment in oil and gas pipelines could leave regions of the United States with a less reliable energy supply.

RELATED OPTIONS: Revenues, Options 28, 42

RELATED CBO PUBLICATION: *Federal Support for the Development, Production, and Use of Fuels and Energy Technologies* (November 2015), www.cbo.gov/publication/50980

Revenues—Option 32

Repeal the Low-Income Housing Tax Credit

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	*	0.1	0.5	1.3	2.3	3.4	4.6	5.8	7.1	8.4	4.2	33.5

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

* = between zero and $50 million.

Real estate developers who provide rental housing to people with low income may qualify for the low-income housing tax credit (LIHTC), which is designed to encourage investment in affordable housing. The credit covers a portion of the costs incurred for the construction of new housing units and the substantial rehabilitation of existing units.

Each year, the federal government allocates funding to the states for LIHTCs on the basis of a per-resident formula. State or local housing authorities review proposals submitted by developers and select those projects that will receive credits. To qualify for the credit, developers must agree to meet two requirements for at least 30 years: First, they must set aside either 20 percent of a project's rental units for people whose income is below 50 percent of the area's median income or 40 percent of the units for people whose income is below 60 percent of the median. Second, they must agree to limit the rent they charge on the units occupied by low-income people to 30 percent of a set portion of the area's median income. (That portion is either 50 percent or 60 percent and corresponds to the developer's choice regarding the first requirement.) In addition, the buildings have to meet local health, safety, and building codes.

LIHTCs can be used to lower federal tax liability over a period of 10 years. There are two types of credits. One type is reserved for projects that receive financing through tax-exempt bonds; it can equal up to 30 percent of the costs allocable to the set-aside units. The other type of credit generally equals up to 70 percent of costs allocable to the set-aside units. Projects can qualify for larger credits (equal to up to 39 percent of the costs allocable to the set-aside units for the first type of credit or up to 91 percent of such costs for the second type of credit) if they are located in census tracts determined by the Department of Housing and Urban Development to have a large proportion of low-income households.

This option would repeal the low-income housing tax credit starting in 2017, although taxpayers could continue to claim credits granted before 2017 until their eligibility expired. Repealing the LIHTC would increase revenues by $34 billion from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation.

One argument for repealing the low-income housing tax credit is that there are alternative ways to help people with low income obtain safe, affordable housing, generally at less cost to the government. For instance, the Housing Choice Voucher program—sometimes referred to as Section 8 after the part of the legislation that authorized it—provides vouchers that help families pay rent for housing they choose, provided it meets minimum standards for habitation and total rent does not exceed limits set by the federal government. Such vouchers are typically a less expensive way to provide housing assistance than the LIHTC primarily because the costs of constructing a new building or substantially renovating an existing building are higher than the costs of simply using an existing building in most housing markets where low-income households are situated. Further, people with very low income often cannot afford even the reduced rents in the set-aside units of LIHTC projects without additional subsidies. Vouchers are especially helpful to them.

Repeal of the LIHTC could be paired with an increase in housing vouchers. That would, of course, result in less deficit reduction than repeal alone. The net effect on the deficit would depend on the extent to which the voucher program was expanded. One possible approach would be to expand the voucher program to cover the same number of households currently served by the LIHTC; in that case, deficits would still be reduced, on balance. But the number of low-income households qualifying for housing assistance substantially exceeds the number supported through existing programs. Therefore, another possible approach would be to use all of the savings from repeal of the LIHTC to expand the voucher program, which would increase the total number of households receiving assistance; in that case, deficits would be unaffected, on balance.

A rationale against implementing the option is that landlords might be less willing to accept housing vouchers in areas experiencing growing strength in their housing markets. LIHTCs could be more effective at preserving low-income housing in such areas because LIHTC units are provided on the basis of 30-year contracts. In addition, by supporting the construction of new buildings and the substantial rehabilitation of existing buildings, the LIHTC can help improve neighborhoods. For example, one study found that, in New York City between 1991 and 2000, the use of LIHTCs in blighted neighborhoods to replace abandoned buildings with new construction and to build new structures on empty lots increased property values within a few blocks of the newly constructed buildings.[1] Although the positive effect diminished somewhat over time, it remained significant five years after the completion of the projects. Because those benefits seem to be limited to the immediate neighborhoods, such projects might be more appropriately funded by local or state governments rather than the federal government.

1. Ingrid Gould Ellen and others, "Does Federally Subsidized Rental Housing Depress Neighborhood Property Values?" *Journal of Policy Analysis and Management*, vol. 26, no. 2 (Spring 2007), pp. 257–280, http://dx.doi.org/10.1002/pam.20247.

RELATED OPTIONS: Discretionary Spending, Options 22, 23

RELATED CBO PUBLICATIONS: *Federal Housing Assistance for Low-Income Households* (September 2015), www.cbo.gov/publication/50782; *An Overview of Federal Support for Housing* (November 2009), www.cbo.gov/publication/41219; *The Cost-Effectiveness of the Low-Income Housing Tax Credit Compared With Housing Vouchers* (April 1992), www.cbo.gov/publication/16375

Revenues—Option 33

Determine Foreign Tax Credits on a Pooling Basis

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Revenues	4.1	7.9	7.6	8.1	8.7	9.4	9.7	8.6	8.5	9.3	36.4	82.0

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

The U.S. government taxes both the domestic and foreign income of businesses that are incorporated in the United States and operate in this country and abroad. Often, such corporations must also pay income taxes to their foreign host countries. The income that foreign subsidiaries of U.S. multinational corporations earn is generally not subject to U.S. taxation until it is paid to the U.S. parent company—that is, the tax is deferred until the income is repatriated. U.S. corporate income taxes are then assessed on income that exceeds those companies' expenses. Current law provides a system of credits for taxes that U.S. businesses pay to foreign governments; the credits typically offer some relief from what otherwise would amount to double taxation of that repatriated income.

Under current law, the value of a company's foreign tax credit cannot exceed the U.S. taxes the company would pay on that amount of income. Income that is repatriated from a country with a higher corporate tax rate than that in the United States generates "excess credits"—credits from foreign tax liabilities that cannot be used because they exceed the amount owed to the U.S. government. In contrast, income that is repatriated from a country with a lower tax rate generates credits that are not sufficient to offset the entire U.S. tax owed on that income. Absent any further provisions of tax law, the company would face a residual tax in the United States on the income from that lower-tax country.

However, U.S. tax law allows firms to combine the credits generated by repatriating income from high- and low-tax-rate countries on their tax returns. Thus, the excess credits arising from the taxes paid on income repatriated from high-tax countries can be applied to the income repatriated from low-tax countries, effectively offsetting some or all of the U.S. tax liability on income from low-tax countries. One consequence of the current system is that, for any given amount of foreign income that it repatriates, a company can increase the value of its foreign tax credit by repatriating more income from countries with higher tax rates and less from countries with lower tax rates.

Under this option, a company's foreign tax credit would be determined by pooling the company's total income from all foreign countries and the taxes paid to those countries. The total credit would equal the product of all taxes paid to foreign governments and the percentage of foreign income that was repatriated. The credit would not exceed the total amount of U.S. taxes owed on repatriated income. The staff of the Joint Committee on Taxation estimates that the option would increase revenues by $82 billion over the 2017–2026 period.

If this option was implemented, the overall credit rate—the credit as a percentage of total repatriated income—would not depend on the distribution of the repatriated income across foreign countries but would equal the average foreign tax rate on all foreign earnings. In contrast, under current law, a company's overall credit rate is higher if a larger share of its repatriated income is from countries with higher tax rates. Hence, the foreign tax credit would be smaller under the pooling option than under current law for companies that repatriate a greater share of their earnings from countries with higher-than-average tax rates.

One argument in favor of this option is that it would restrict companies' ability to use excess credits from countries with high taxes to offset the U.S. corporate tax on income from countries with low taxes. The current method for computing excess credits makes it advantageous for firms to design and use accounting or other legal strategies to report income and expenses for their U.S. and foreign operations in ways that reduce their overall tax liabilities. By basing the credit on total foreign income and taxes, this option would reduce the incentive for companies to strategically choose subsidiaries from which to repatriate income so as to reduce the amount of taxes they owed—and thus also reduce the incentive for firms to devote resources to strategic tax planning rather than to more productive activities.

An argument against the option is that it would increase incentives to invest in low-tax countries and to retain more of the resulting earnings abroad. Firms would be encouraged to shift investment from high-tax to low-tax countries because of the decline in the value of excess credits. The option would also increase incentives to keep profits from those investments abroad to avoid the higher U.S. taxes on repatriated income. However, many other factors—such as the skill level of a country's workforce and its capital stock—also affect corporations' decisions about where to invest.

RELATED OPTIONS: Revenues, Options 25, 34, 35

RELATED CBO PUBLICATION: *Options for Taxing U.S. Multinational Corporations* (January 2013), www.cbo.gov/publication/43764

Revenues—Option 34

Require a Minimum Level of Taxation of Foreign Income as It Is Earned

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	6.1	18.5	26.2	31.8	33.9	35.0	35.8	36.2	37.7	39.7	116.5	300.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Businesses that are incorporated in the United States are subject to U.S. taxes on both their domestic income and their foreign income. To offset potential double taxation, a foreign tax credit is provided to account for foreign taxes paid on foreign income. Most types of foreign income earned by the foreign subsidiaries of U.S. companies, however, are not subject to U.S. taxation until the income is brought back to the United States—that is, repatriated. There are exceptions to the deferral of U.S. tax payments on that foreign income. Certain types of income—such as interest income—are considered passive (that is, received by taxpayers who are not actively involved in the operation of the business). Other types of income—such as royalty payments—are considered highly mobile (that is, easily shifted across borders). Foreign income categorized as passive or highly mobile is subject to U.S. taxes as it is earned.

Under this option, all future foreign income of U.S. corporations and their foreign subsidiaries would be subject to U.S. taxes as it is earned. Foreign income that is not passive or highly mobile would be taxed at a combined U.S. and foreign tax rate of at least 19 percent. That minimum tax rate would be applied separately for each country in which the U.S. corporation or its foreign subsidiary earns income. If income is taxed by more than one country, then the income would be assigned to the highest-tax country.

To provide a credit for foreign taxes paid, the U.S. tax rate on the taxable foreign earnings in each country would be equal to 19 percent minus 85 percent of the foreign effective tax rate on those earnings. The effective tax rate would be calculated as the ratio of qualifying foreign taxes to foreign income over a 60-month period; qualifying foreign tax payments would include all tax payments that are eligible for foreign tax credits under the current U.S. tax code. (The U.S. tax rate would be zero on earnings for which 85 percent of the foreign effective tax rate is greater than 19 percent.)

The resulting U.S. tax rate would be applied to foreign income that is not passive or highly mobile minus a deduction for return on equity. (That deduction is intended to exempt from the minimum tax the risk-free return—generally approximated by the market interest rate for long-term government bonds—on active investments in each country). Passive and highly mobile foreign income would be taxed at the full U.S. statutory corporate tax rate, and current rules governing foreign tax credits for that income would continue to apply. There would be no further federal tax payments due on foreign income when it is repatriated. If enacted, the option would increase revenues by a total of $301 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates. That increase includes some revenues that would be collected after 2026 under current law.

The main argument in favor of this option is that the current system of deferral provides an incentive to hold profits overseas. Because companies do not have to pay U.S. taxes on foreign income until the income is repatriated, deferral reduces the cost of foreign investment relative to the cost of domestic investment. By ending deferral, this option would reduce the after-tax return on foreign investment, which could increase domestic investment.

Another argument in favor of this option is that it would provide greater certainty about the timing and size of tax payments. That would reduce the gains from strategies that lower businesses' tax liabilities through the use of deferral, which would result in companies' incurring lower tax planning costs. Those resources could be reallocated to more productive activities.

The main argument against this option is that it would put U.S. multinational corporations at a disadvantage relative to foreign multinationals. To the extent that deferral is used to permanently avoid U.S. tax payments, the minimum tax would increase total taxes paid by U.S. multinationals. The increase in tax payments and resulting reduction in after-tax profits could reduce both domestic and foreign investment by U.S. multinationals. (That reduction in domestic investment would offset at least a portion of the increase in domestic investment mentioned above.) The increase in the benefits associated with being a foreign corporation would also increase the incentive for U.S. corporations to be acquired by a foreign corporation or for new companies to incorporate outside of the United States.

Another argument against this option is that the requirement to report tax payments and income on a per-country basis would increase compliance costs for U.S. multinationals. Each foreign subsidiary of a U.S. multinational would have to devote time and resources to allocating its earnings and taxes across all countries in which it operates. Those resources would be diverted from more productive activities.

Compared with an approach that would tax worldwide income as it is earned at the full U.S. statutory corporate tax rate, this option would result in a smaller increase in tax payments for U.S. multinationals, so it would put U.S. multinationals at less of a disadvantage relative to foreign multinationals. U.S. taxation at a reduced rate would, however, be more complicated to administer, as companies and tax-enforcement agencies would have to continue to distinguish passive and highly mobile income from other types of corporate income.

RELATED OPTIONS: Revenues, Options 25, 33, 35

RELATED CBO PUBLICATION: *Options for Taxing U.S. Multinational Corporations* (January 2013), www.cbo.gov/publication/43764

Revenues—Option 35

Further Limit the Deduction of Interest Expense for Multinational Corporations

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	2.6	5.2	5.7	6.3	7.1	7.7	8.0	8.1	8.5	9.0	26.9	68.2

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Interest payments on business loans are generally tax deductible. A consequence of that deductibility is that a multinational corporation can lower its corporate tax payments by having an affiliate in a country with a lower tax rate make a loan to a U.S.-based affiliate. Because the deduction for the interest payment is taken in the United States and the income from the interest payment is taxed by a country with a lower tax rate, income is shifted from the United States to a lower-tax country and overall tax payments are reduced. For multinationals incorporated in the United States, the ability to lower tax payments through interest payments is significantly limited because interest payments received by their low-tax foreign subsidiaries are generally taxed at the full U.S. statutory corporate tax rate in the year in which the payments are made.[1] However, for multinationals incorporated outside of the United States, such payments are not taxed by the United States. For those foreign multinationals, opportunities to lower tax payments through interest are limited only by restrictions on the deduction of interest expense.

The existing restriction on a U.S. company's deduction of interest expense is based on the earnings of the U.S. company and its relation to the companies to which it pays interest. The limit applies mainly to interest paid to a company that is both a "related party" and either entirely or partially exempt from U.S. taxation. (Examples of related parties to whom those rules might apply are a foreign company that owns a U.S. company or other foreign companies that are in the same foreign multinational group as a U.S. company.) Specifically, if the U.S. company's debt-to-equity ratio exceeds 1.5 to 1 and its total net interest expense (the amount of interest paid minus the amount of interest received) exceeds 50 percent of its adjusted taxable income, then any portion of the interest expense above the 50-percent limit that is paid to the types of related companies described above cannot be deducted.[2] A company can "carry forward" (use to reduce its tax liability in a future year) disallowed interest expense indefinitely and then deduct that interest expense from taxable income in that future year. Additionally, if a company's net interest expense is below the allowable level, the company can carry forward its "excess limitation"—the gap between the company's level of net interest expense and the allowable level in a given year—and use it to increase the allowable level of interest expense in any of the next three years.

Information about a company's loans and obligations can be obtained from two main sources: tax returns, which are submitted to tax authorities and are based on tax-accounting methods; and financial statements, which provide information on the company's financial position and are based on accepted financial-accounting methods. Differences in financial- and tax-accounting methods mean that the values reported in financial reports may differ from the values reported on tax returns. Tax returns do not necessarily include information on the other companies that are part of the multinational group, but consolidated financial statements—which combine the financial statements of a parent company and separate legal companies that are owned by that parent company—do. Consolidated financial statements are usually available for any U.S. company that controls (owns the majority of outstanding common stock) or is controlled by another company. Those consolidated financial statements contain the information needed to compare the

1. Those rules are effective at limiting the use of interest payments to shift profits from the United States to other countries, but they are less effective at limiting such shifting between two foreign affiliates.

2. Adjusted taxable income is calculated by adding back certain deductions—such as net interest expense; deductions for depreciation, amortization, and depletion; any deduction for net operating loss; and any deduction for domestic production activities under section 199 of the tax code—to taxable income.

U.S. company's net interest expense with the overall level of net interest expense reported by its multinational group.

Under this option, a U.S. company's allowable deduction of net interest expense would be determined on the basis of the net interest expense reported by the company's multinational group. Specifically, the limit would be based on the overall level of net interest expense reported in the consolidated financial statement of the U.S. company's multinational group. The deduction for net interest expense would be limited if the U.S. company's net interest expense for financial reporting purposes exceeded the U.S. company's proportionate share of the group's net interest expense. The proportionate share—which could take a value from zero to 100 percent—would be equal to the U.S. member's share of the group's earnings before net interest expense, taxes, depreciation, and amortization were taken into account. If there are differences between the interest expense reported for financial purposes and expense reported in tax filings, then the proportion of the deduction for net interest expense that would be disallowed for tax purposes would be equal to the proportion by which the net interest expense for financial reporting purposes exceeded the allowable level.[3] The U.S. company would have the choice of using that group-level approach or instead limiting its deduction of net interest expense to 10 percent of its adjusted taxable income. Carry-forward rules would match those in place under current law. U.S. companies that are not part of a financial reporting group would continue to face the limitations on the deduction of net interest expenses that are currently in place. The option would not apply to financial services companies or to financial reporting groups with a net interest expense of less than $5 million. The option would increase revenues by a total of $68 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates.

The main argument in favor of this option is that it would reduce the tax advantages associated with foreign incorporation by limiting the ability of foreign-owned multinationals to move income out of the United States to lower-tax jurisdictions. Moving to a group-level standard would mean that the interest expense of the group's U.S. affiliate would have to be proportionate to the group's overall level of interest expense. That would prevent foreign multinationals from using loans between affiliates in lower-tax countries and their U.S. affiliates to place a disproportionate amount of debt in those U.S. affiliates, thus reducing income shifting. By lowering the benefit of foreign incorporation, the incentive for U.S. multinationals to change their country of incorporation through mergers (including corporate inversions) would be reduced.

The main argument against this option is that it could result in the denial of tax deductions for normal interest expenses. That would result in U.S. companies' being unable to deduct standard business expenses. Although the option would probably be more effective at targeting excessive interest than a fixed standard, there could still be operational reasons that a U.S. group member would be more leveraged than the rest of its financial reporting group. To the extent that the disallowance increased the cost of attaining funds for the U.S. group member, the limit on the interest expense deduction would decrease investment in the United States.

3. The permitted net interest expense deduction would be zero if the proportionate share of the group net interest expense would have been less than or equal to zero.

RELATED OPTIONS: Revenues, Options 25, 33, 34

RELATED CBO PUBLICATION: *Options for Taxing U.S. Multinational Corporations* (January 2013), www.cbo.gov/publication/43764

Revenues—Option 36

Increase Excise Taxes on Motor Fuels by 35 Cents and Index for Inflation

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	32.5	46.5	47.4	48.1	48.7	49.3	49.8	50.1	50.4	50.6	223.2	473.6

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Revenues from federal excise taxes on motor fuels are credited to the Highway Trust Fund to pay for highway construction and maintenance as well as for investment in mass transit. Those taxes currently are set at 18.4 cents per gallon of gasoline and 24.4 cents per gallon of diesel fuel produced.[1] (State and local excise taxes bring total average tax rates nationwide to about 48 cents per gallon of gasoline and about 54 cents per gallon of diesel fuel.)

This option would increase federal excise taxes on gasoline and diesel fuel by 35 cents per gallon, to 53.4 cents per gallon of gasoline and 59.4 cents per gallon of diesel fuel. In future years, those values would be adjusted to reflect changes in the price index for gross domestic product between 2017 and the most recent year for which data for that price index were available. According to estimates by the staff of the Joint Committee on Taxation, the option would increase federal revenues by $474 billion between 2017 and 2026. (Because higher excise taxes would raise businesses' costs, they would reduce the tax base for income and payroll taxes. The estimates shown here reflect reductions in revenues from those sources.)

One rationale for increasing excise taxes on motor fuels is that the rates currently in effect are not sufficient to fully fund the federal government's spending on highways. A second rationale is that increasing excise taxes on motor fuels would have relatively low collection costs because such taxes are already being collected.

A further rationale for this option is that when users of highway infrastructure are charged according to the marginal (or incremental) costs of their use—including the "external costs" that such use imposes on society—economic efficiency is promoted. Because current fuel taxes do not cover all of those marginal costs, raising fuel taxes by the amount specified in this option would more accurately reflect the external costs created by the consumption of motor fuel. Some of those costs, including those associated with pollution, climate change, and dependence on foreign oil, are directly related to the amount of motor fuel consumed. However, the larger fraction of such costs is related to the number of miles that vehicles travel, the road congestion that arises when people drive at certain times and in certain locations, noise, accidents, and—primarily because of heavy vehicles—pavement damage. (As vehicles become more fuel efficient, the share of external costs attributable to the number of miles traveled rises.) Various studies suggest that, in the absence of a tax on the number of vehicle miles traveled or on other factors that generate external costs, the external costs of motor fuels amount to at least $1 per gallon. If drivers paid no other taxes, then setting taxes on motor fuels so that they equaled external costs would be economically efficient. Even after accounting for the ways in which taxes on motor fuels would compound the costs associated with current taxes on individual and corporate income, excise tax rates on motor fuels would probably have to be substantially higher than the current rates for taxes to cover the costs that drivers impose on society. With a higher tax on fuel, people would drive less or purchase vehicles that use fuel more efficiently, thus reducing some of the external costs. In contrast, paying for highways and mass transit through general revenues provides no incentive for the efficient use of those transportation systems.

An argument against this option is that it would probably be more economically efficient to base a tax on the number of miles that vehicles travel or on other measurable factors that generate external costs. For example, imposing tolls or implementing congestion pricing (charging fees for driving at specific times in given areas) would be

1. A portion of that tax—0.1 cent—is credited to the Leaking Underground Storage Tank Trust Fund.

more direct ways to alleviate congestion. Similarly, a levy on the number of miles driven could be structured to correspond more closely to the costs of repairing damaged pavement than could a tax on motor fuels. However, creating the systems necessary to administer a tax on the number of vehicle miles traveled would be much more complex than increasing the existing excise taxes on fuels. Moreover, because fuel consumption has some external costs that do not depend on the number of miles traveled, economic efficiency would still require taxes on motor fuels even if other fees were assessed at their efficient levels.

Some other arguments against raising taxes on motor fuels involve issues of fairness. Such taxes impose a proportionally larger burden, as a share of income, on middle- and lower-income households (particularly those not well-served by public transit) than they do on upper-income households. Those taxes also impose a disproportionate burden on rural households because the benefits of reducing vehicle emissions and congestion are greatest in densely populated, mostly urban, areas. Finally, to the extent that the trucking industry passed on the higher cost of fuel to consumers (in the form of higher prices for transported retail goods, for instance) those higher prices would further increase the relative burden on people in low-income households and in households—typically situated in rural areas—at some distance from most manufacturers.

An alternative approach would restore the purchasing power that the excise taxes on gasoline and diesel fuel had in 1993—the last time those two taxes were increased—plus an adjustment to include the effects of inflation since that time. Under that approach, the taxes on gasoline and diesel fuel would be increased, respectively, by 12 cents and 16 cents per gallon. Combined with the $70 billion in transfers (mostly from the general fund of the Treasury) provided in the Fixing America's Surface Transportation Act of 2015 (FAST Act), the increased taxes would allow the trust fund to meet obligations provided for under the FAST Act as well as the obligations that would occur from 2020 to 2026 if the obligation levels (as adjusted for projected inflation) in that act were continued.

RELATED OPTION: Revenues, Option 37

RELATED CBO PUBLICATIONS: *How Would Proposed Fuel Economy Standards Affect the Highway Trust Fund?* (May 2012), www.cbo.gov/publication/43198; *Alternative Approaches to Funding Highways* (March 2011), www.cbo.gov/publication/22059; *Spending and Funding for Highways* (January 2011), www.cbo.gov/publication/22003; *Using Pricing to Reduce Traffic Congestion* (March 2009), www.cbo.gov/publication/20241; *Effects of Gasoline Prices on Driving Behavior and Vehicle Markets* (January 2008), www.cbo.gov/publication/41657

Revenues—Option 37

Impose an Excise Tax on Overland Freight Transport

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	21.9	33.2	33.8	34.3	34.9	35.6	36.3	36.9	37.6	38.3	158.1	342.9

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

Existing federal taxes related to overland freight transport consist of a tax on diesel fuel; excise taxes on new freight trucks, tires, and trailers; and an annual heavy-vehicle use tax. Revenues from those taxes are credited to the Highway Trust Fund, which finances road construction and maintenance and mass transit. Railroads, which generally operate on infrastructure they own and maintain, are currently exempt from the diesel fuel tax, other than an assessment of 0.1 cent per gallon for the Leaking Underground Storage Tank Trust Fund.

The two most recent federal surface transportation laws—the Moving Ahead for Progress in the 21st Century Act of 2013 (MAP-21) and the Fixing America's Surface Transportation Act of 2015 (FAST Act)—define and establish a set of national policies to improve the movement of freight. The FAST Act commits funds from the Highway Trust Fund to two programs that focus on freight. (One of them is a grant program designed to reduce congestion and improve "critical freight movements," and the other is a formula-funded program that supports investment in freight projects on the National Highway Freight Network.) Neither act, however, establishes a source of revenue for funding such programs. Under current law, the Highway Trust Fund cannot incur negative balances. As a result, with its existing revenue sources, the trust fund will not be able to support spending at current levels (with adjustments for inflation) beyond 2021, the Congressional Budget Office estimates.[1]

This option would impose a new tax on freight transport by truck and rail. The tax would be 30 cents per mile on freight transport by heavy-duty trucks (Class 7 and Class 8 vehicles in the Federal Highway Administration's vehicle-weight classification). The tax would apply to all types of freight haulers: common carriers (available for hire by any shipper), contract carriers (which work with a limited number of client shippers and can refuse transport jobs), and private fleets (which haul goods only for the fleet owner). Under the option, freight transport by rail would be subject to a tax of 12 cents per mile (per railcar). The tax would not apply to miles traveled by trucks or railcars without cargo. According to estimates by the staff of the Joint Committee on Taxation, the option would increase federal revenues by $343 billion between 2017 and 2026. (Because higher excise taxes would raise businesses' costs, they would reduce the tax base for income and payroll taxes. The estimates shown here reflect reductions in revenues from those sources.)

One rationale for imposing an excise tax on freight transport is that it would promote economic efficiency. Freight transport imposes "external costs" on society, including pavement damage, congestion, accidents, and emissions of air pollutants. Existing taxes on fuel better target emissions than do taxes on miles traveled, but they do not cover the other external costs that freight transport imposes on society. A tax on transport distance would address some of those costs (pavement damage, accidents, and congestion) more directly than increasing the existing fuel tax. The higher tax rate on truck transport reflects the fact that estimates of the external costs imposed by trucks are greater than estimates of those costs for rail. Although the higher rate would induce some shippers to shift some of their freight business from truck to rail, that effect would be small; most companies that ship by truck prefer that mode of transport over rail to a sufficient degree that the difference in tax rates would not alter their choice.

A second rationale is that the tax would create a source of revenue that could be used to lower other taxes, reduce the deficit, or finance public infrastructure projects that

1. See Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

would facilitate the transport of freight. Such projects—which could include building additional transfer stations (where intermodal shipping containers can be shifted between truck and rail), dedicated highway truck lanes, grade separations (bridges and tunnels that keep rail and vehicular traffic apart at intersections), and bypasses to route trucks around crowded sections of highway—would ease traffic congestion and accommodate expected future growth in shipping. Traditionally, infrastructure projects have been funded out of transport tax revenues, but the current taxes on trucks and diesel fuel, which are credited to the Highway Trust Fund, do not provide enough revenue to finance such projects while also building and maintaining federal highways. The trust fund receives no revenue from rail freight transport.

An argument against this option is that it would be costly to administer. It would require that carriers report their miles traveled and that systems be developed to collect the taxes and audit the reported distances. Moreover, because fuel consumption has some external costs that do not depend on miles traveled, economic efficiency would still require taxes on motor fuels even if other fees were assessed at their efficient levels.

Another argument against this option is that it would apply the same tax rate to cargo of all weights, even though external costs tend to be greater for heavier cargo. The tax based on miles traveled would encourage shippers and carriers to maximize the weight per shipment. The tax would also encourage some shifting of truck freight to smaller Class 6 trucks to avoid the tax. Those effects would be constrained by statutory weight limits on roadways and bridges and by the capacities of truck trailers and railcars. An alternative would be to base the tax on weight and distance, but such an approach would be costlier to administer because it would require information on the weight of every shipment.

An additional argument against this option is that the tax would probably be passed on to consumers through increases in the price of final goods. For many types of goods, the price increase would be relatively small because freight transport accounts for less than 5 percent of the cost of the merchandise. For some bulk commodities such as coal, however, the transport cost share is substantially higher, which would cause the tax to have a larger impact on final prices.

RELATED OPTION: Revenues, Option 36

RELATED CBO PUBLICATIONS: David Austin, *Pricing Freight Transport to Account for External Costs*, Working Paper 2015-03 (March 2015), www.cbo.gov/publication/50049; *Alternative Approaches to Funding Highways* (March 2011), www.cbo.gov/publication/22059; *Spending and Funding for Highways* (January 2011), www.cbo.gov/publication/22003; *Using Pricing to Reduce Traffic Congestion* (March 2009), www.cbo.gov/publication/20241

Revenues—Option 38

Increase All Taxes on Alcoholic Beverages to $16 per Proof Gallon

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	5.2	7.0	7.0	7.1	7.2	7.2	7.3	7.4	7.5	7.5	33.5	70.4

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

In 2015, the federal government collected $9.9 billion in revenue from excise taxes on distilled spirits, beer, and wine. Different alcoholic beverages are taxed at different rates. Specifically, the alcohol content of beer and wine is taxed at a much lower rate than the alcohol content of distilled spirits in part because the taxes are determined on the basis of different liquid measures. Distilled spirits are measured in proof gallons, which denote a liquid gallon that is 50 percent alcohol by volume. The current excise tax levied on those spirits, $13.50 per proof gallon, translates to about 21 cents per ounce of pure alcohol. Beer, by contrast, is measured by the barrel, and the current tax rate of $18 per barrel translates to about 10 cents per ounce of pure alcohol (under the assumption that the alcohol content of the beer is 4.5 percent). The current levy on table wine is $1.07 per gallon, or about 6 cents per ounce of pure alcohol (assuming an alcohol content of 13 percent). Wines with high volumes of alcohol, and sparkling wines, face a higher tax per gallon. Last raised in 1991, current excise tax rates on alcohol are far lower than historical levels when adjusted to include the effects of inflation. Additionally, there is currently a tax credit that lowers the effective per-gallon tax rate for small quantities of beer and nonsparkling wine for certain small producers and there is an exemption from tax for small volumes of beer and wine that are for personal or family use. States and some municipalities also tax alcohol; those rates vary substantially and sometimes exceed federal rates.

This option would standardize the base on which the federal excise tax is levied by using the proof gallon as the measure for all alcoholic beverages. The tax would be raised to $16 per proof gallon, thus increasing revenues by $70 billion over the 2017–2026 period, the staff of the Joint Committee on Taxation estimates. (Because excise taxes reduce producers' and consumers' income, higher excise taxes would lead to reductions in revenue from income and payroll taxes. The estimates shown here reflect those reductions.) This option would also eliminate the small producer tax credits and the exemptions for personal use, thus making the tax rate equal across all producers and quantities of alcohol.

A tax of $16 per proof gallon would equal about 25 cents per ounce of alcohol. Under this option, the federal excise tax on a 750-milliliter bottle (commonly referred to as a fifth) of distilled spirits would rise from about $2.14 to $2.54. The tax on a six-pack of beer at 4.5 percent alcohol by volume would jump from about 33 cents to 81 cents, and the tax on a 750-milliliter bottle of wine with 13 percent alcohol by volume would increase from about 21 cents to 82 cents.

Experts agree that the consumption of alcohol creates costs for society that are not reflected in the before-tax price of alcoholic beverages. Examples of those "external costs" include spending on health care that is related to alcohol consumption and covered by the public, losses in productivity stemming from alcohol consumption that are borne by others besides the consumer, and the loss of lives and property that results from alcohol-related accidents and crime.

One argument in favor of raising excise taxes on alcoholic beverages is that they would reduce alcohol use—and thus the external costs of that use—and make consumers of alcoholic beverages pay a larger share of such costs. Research has consistently shown that higher prices lead to less alcohol consumption, even among heavy drinkers.

Moreover, raising excise taxes to reduce consumption might be desirable, regardless of the effect on external costs, if lawmakers believed that consumers underestimated the harm they do to themselves by drinking. Heavy drinking is known to cause organ damage and cognitive impairment; and the links between highway accidents and drinking, which are especially strong among the young, are well-documented. Substantial evidence also indicates that the use of alcohol from an early age can lead to heavy consumption later in life. When deciding how much to drink, people—particularly young people—may not adequately consider such long-term risks to their health. However, many other choices that people make—for example, to consume certain types of food or engage in risky sports—can also lead to health damage, and those activities are not taxed.

An increase in taxes on alcoholic beverages would have disadvantages as well. It would make a tax that is already regressive—one that takes up a greater percentage of income for low-income families than for middle- and upper-income families—even more so. In addition, it would affect not only problem drinkers but also drinkers who imposed no costs on society and who thus would be unduly penalized. Furthermore, higher taxes would reduce consumption by some moderate drinkers whose intake of alcohol is believed to have health benefits. (Moderate alcohol consumption, particularly of wine, has been linked to lower incidence of heart disease, obesity, and stroke and to increases in life expectancy.) In the longer term, changes in health and life expectancy resulting from reduced alcohol consumption would probably affect spending on federal health care, disability, and retirement programs. However, such changes in health and longevity go in opposite directions for moderate and heavy drinkers, so the direction and magnitude of changes in spending are uncertain.

RELATED OPTION: Health, Option 17

RELATED CBO PUBLICATION: *Raising the Excise Tax on Cigarettes: Effects on Health and the Federal Budget* (June 2012), www.cbo.gov/publication/43319

Revenues—Option 39

Impose a 5 Percent Value-Added Tax

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues												
Broad base	0	180	270	280	290	300	320	330	340	350	1,030	2,670
Narrow base	0	110	180	190	190	200	210	220	230	240	670	1,770

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

A value-added tax (VAT) is a type of consumption tax that is levied on the incremental increase in value of a good or service. The tax is collected at each stage of the production process and passed on until the full tax is paid by the final consumer. Although the United States does not have a broad, consumption-based tax, federal excise taxes are imposed on the purchase of several goods (gasoline, alcohol, and cigarettes, for example). In addition, most states impose sales taxes, which, unlike a VAT, are levied on the total value of goods and services purchased.

More than 140 countries—including all members of the Organisation for Economic Co-operation and Development (OECD), except for the United States—have adopted VATs. The tax bases and rate structures of VATs differ greatly among countries. Most European countries have implemented VATs that have a narrow tax base, with certain categories of goods and services—such as food, education, and health care—excluded from the tax base. In Australia and New Zealand, the VAT has a much broader tax base, with exclusions generally limited only to those goods and services for which it is difficult to determine a value. In 2016, the average national VAT rate for OECD countries was 19.2 percent, ranging from 5 percent in Canada to 27 percent in Hungary. All OECD countries that impose a VAT also collect revenues from taxes on individual and corporate income.

This option includes two different approaches that would impose a 5 percent VAT. Each of the approaches would become effective on January 1, 2018—a year later than most of the revenue options presented in this volume—to provide the Internal Revenue Service time to set up and administer the tax.

- The first approach would apply the VAT to a broad base that would include most goods and services. Certain goods and services would be excluded from the base, because their value is difficult to measure. Those include financial services without explicit fees, existing housing services, primary and secondary education, and other services provided by government agencies and nonprofit organizations for little or no fee. (Existing housing services encompass the monetary rents paid by tenants and rents imputed to owners who reside in their own homes. Although existing housing services would be excluded under this alternative, the broad base would include all future consumption of housing services by taxing the purchase of new residential housing.) In addition, government-reimbursed expenditures for health care—primarily costs paid by Medicare and Medicaid—would also be excluded from the tax base under this approach. With those exclusions taken into account, the tax base would encompass approximately 65 percent of household consumption in 2018. This approach would increase revenues by $2.7 trillion over the 2018–2026 period, the staff of the Joint Committee on Taxation (JCT) estimates. (Because a VAT, like excise taxes, reduces the tax base of income and payroll taxes, implementing such a tax would lead to reductions in revenues from those sources. The estimates shown here reflect those reductions.)

- Under the second approach, the VAT would apply to a narrower base. In addition to those items excluded under the broad base, the narrow base would exclude certain goods and services that are considered necessary for subsistence or that provide broad social benefits. Specifically, purchases of new residential housing, food purchased for home consumption, health care, and postsecondary education would be excluded from the tax base.With those exclusions taken into account, the tax base would include about 46 percent of household consumption in 2018. This approach would increase revenues by $1.8 trillion over the 2018–2026 period, according to JCT's estimates.

Both approaches would employ the "credit-invoice method," which is the most common method used by other countries to administer a VAT. That method would tax the total value of a business's sales of a particular product or service, and the business would claim a credit for the taxes paid on the purchased inputs—such as materials and equipment—it used to make the product or provide the service. With a credit-invoice method, goods and services could be either "zero-rated" or "exempt" from the VAT; in both cases, the VAT would not apply to purchased items. If the purchased item was zero-rated, however, the seller would be able to claim a credit for the VAT that had been paid on the production inputs. In contrast, if the purchased item was exempted, the seller would not be able to claim a credit for the VAT paid on the production inputs.

Under both variants, primary and secondary education and other noncommercial services provided by government or nonprofit organizations for little or no fee would be zero-rated, and financial services and existing housing services would be exempt from the VAT. In addition, under the option with the narrow base, food purchased for home consumption, new housing services, health care, and postsecondary education would be zero-rated.

One argument in favor of the option is that it would raise revenues without discouraging saving and investment by taxpayers. In any given period, income can be either consumed or saved. Through exclusions, deductions, and credits, the individual tax system provides incentives that encourage saving, but those types of preferences do not apply to all methods of saving and increase the complexity of the tax system. In contrast to a tax levied on income, a VAT applies only to the amount of income consumed and therefore would not discourage private saving and investment in the economy.

A drawback of the option is that it would require the federal government to establish a new system to monitor compliance and collect the tax. As with any new tax, a VAT would impose additional administrative costs on the federal government and additional compliance costs on businesses. A study conducted by the Government Accountability Office in 2008 showed that all of the countries evaluated in the study—Australia, Canada, France, New Zealand, and the United Kingdom—devoted significant resources to addressing and enforcing compliance.[1] Because such compliance costs are typically more burdensome for smaller businesses, many countries exempt some small businesses from the VAT.

Another argument against implementing a VAT is that, as specified under both alternatives in this option, it would probably be regressive—that is, it would be more burdensome for individuals and families with fewer economic resources than it would be for individuals and families with more economic resources. The regressivity of a VAT, however, depends significantly on how its effects are measured. Furthermore, there are ways to design a VAT—or implement complementary policies—that could ameliorate distributional concerns.

If the burden of a VAT was measured as a share of annual income, the tax would be regressive, primarily because lower-income families generally consume a greater share of their income than higher-income families do. If, however, the burden of a VAT was measured over a much longer period, the tax would appear to be less regressive than if the burden was measured in a single year. For example, the burden of a VAT relative to a measure of lifetime income—which would account for both life-cycle income patterns and temporary fluctuations in annual income—would be less regressive than the burden of a VAT relative to a measure of annual income that does not account for those patterns and anomalies. Furthermore, in the initial year, the distributional effects of a VAT would depend on its impact on consumer prices. Adopting a VAT would probably cause an initial jump in the consumer price index, which would be based on prices that would reflect the new consumption tax. That initial price increase would be equivalent to a onetime implicit tax on existing wealth because of the immediate reduction in purchasing power. To the extent that wealth and annual income are positively correlated, the distributional effects of a VAT in the initial year—if measured relative to annual income—would be less regressive than in subsequent years because of the onetime increase in price levels.

1. See Government Accountability Office, *Value-Added Taxes: Lessons Learned From Other Countries on Compliance Risks, Administrative Costs, Compliance Burden, and Transition,* GAO-08-566 (April 2008), www.gao.gov/products/GAO-08-566.

One way to make a VAT less regressive would be to exclude from the tax base certain basic goods and services—just as the narrow-base alternative of this option does. Applying a VAT to that narrower tax base would be less regressive because low-income individuals and families spend a relatively larger share of their budgets on those basic goods and services than higher-income individuals and families do. (Alternatively, lower rates could be applied to such items.) Those preferences, however, generally would make the VAT more complex and would reduce revenues from the new tax. In addition, a VAT with a narrow base would distort economic decisions to a greater degree than would a VAT with a broader base. An alternative approach to offset the regressive impact of a VAT would be to increase or create additional exemptions or refundable credits under the federal income tax for low-income individuals and families. That approach, however, would add to the complexity of the individual income tax and reduce individual income tax revenues, offsetting some of the revenue gains from a VAT.

There are alternative forms of a broad-based consumption that would potentially be easier to implement or be less regressive. A national retail sales tax, for example, would initially be easier to implement than a VAT. However, it would require the federal government to coordinate tax collection and administration with state and local governments. In addition, there are more incentives to underreport national retail sales taxes because they are collected only when the final user of the product makes a purchase, whereas a VAT is collected throughout the entire production chain. A cash-flow tax would be an alternative to a VAT that would be less regressive. A cash-flow tax applies to the difference between a business's cash receipts and cash payments, which would be equivalent to a consumption tax on income sources other than wages and salaries. Because consumption from wages and salaries would not be included in the tax base, a cash-flow tax would generally have a narrower base than a VAT and would be substantially less regressive than a VAT—and potentially progressive depending on how it was measured. Implementing a cash-flow tax would probably require modifications to the current corporate income tax system but would more easily incorporate the value of financial services in the tax base than a VAT.

RELATED CBO PUBLICATIONS: *Comparing Income and Consumption Tax Bases* (July 1997), www.cbo.gov/publication/10599; *The Economic Effects of Comprehensive Tax Reform* (July 1997), www.cbo.gov/publication/10355; testimony of Robert D. Reischauer, Director, before the Senate Committee on Energy and Natural Resources, *Effects of Energy Taxes and Value-Added Taxes (VAT)* (February 24, 1993), www.cbo.gov/publication/20834; *Distributional Effects of Substituting a Flat-Rate Income Tax and a Value-Added Tax for Current Federal Income, Payroll, and Excise Taxes* (April 1992), www.cbo.gov/publication/20766; *Effects of Adopting a Value-Added Tax* (February 1992), www.cbo.gov/publication/20769

Revenues—Option 40

Impose a Fee on Large Financial Institutions

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	5.2	10.4	10.4	10.4	10.4	10.3	10.4	10.4	10.3	10.3	46.7	98.3

Sources: Staff of the Joint Committee on Taxation; Congressional Budget Office.

This option would take effect in January 2017.

During the financial crisis that occurred between 2007 and 2009, the federal government provided substantial assistance to major financial institutions, effectively protecting many uninsured creditors from losses. Although most of that assistance was ultimately recovered, it could have resulted in great cost to taxpayers. That assistance reinforced investors' perceptions that large financial firms are "too big to fail"—in other words, so important to the financial system and the broader economy that the firms' creditors are likely to be protected by the government in the event of large losses.

In the wake of that crisis, legislators and regulators adopted a number of measures designed to prevent the failure of large, systemically important financial institutions and to resolve any future failures without putting taxpayers at risk. One of those measures provided the Federal Deposit Insurance Corporation (FDIC) with orderly liquidation authority. That authority is intended to allow the FDIC to quickly and efficiently settle the obligations of such institutions, which can include companies that control one or more banks (also known as bank holding companies) or firms that predominantly engage in lending, insurance, securities trading, or other financial activities. In the event that a large financial institution fails, the FDIC will be appointed to liquidate the company's assets in an orderly manner and thus maintain critical operations of the failed institution in an effort to avoid consequences throughout the financial system.

Despite the new safeguards, if one or more large financial institutions were to fail, particularly during a period of broader economic distress, the FDIC might need to borrow funds from the Treasury to implement its orderly liquidation authority. The law mandates that those funds be repaid either through recoveries from the failed firm or through a future assessment on the surviving firms. As a result, individuals and businesses dealing with those firms could be affected by the costs of the assistance provided to the financial system. For example, if a number of large firms failed and substantial cash infusions were needed to resolve those failures, the assessment required to repay the Treasury would have to be set at a very high amount. Under some circumstances, the surviving firms might not be able to pay that assessment without making significant changes to their operations or activities. Those changes could result in higher costs to borrowers and reduced access to credit at a time when the economy might be under significant stress.

Under this option, an annual fee would be imposed beginning in 2017 on financial institutions subject to the orderly liquidation authority—that is, bank holding companies (including foreign banks operating in the United States) with $50 billion or more in total assets and nonbank financial companies designated by the Financial Stability Oversight Council for enhanced supervision by the Board of Governors of the Federal Reserve. The annual fee would be 0.15 percent of firms' covered liabilities, defined primarily as total liabilities less deposits insured by the FDIC. Covered liabilities also include certain types of noncore capital and exclude certain reserves required for insurance policies. The sums collected would be deposited in an interest-bearing fund that would be available for the FDIC's use when exercising its orderly liquidation authority. The outlays necessary to carry out the FDIC's orderly liquidation authority are estimated to be the same under this option as under current law. If implemented on January 1, 2017, such a fee would generate revenues totaling $103 billion from 2017 through 2026, the staff of the Joint Committee on Taxation estimates. (Such a fee would reduce the tax base of income and payroll taxes, leading to reductions in income and payroll tax revenues. The estimates shown here reflect those reductions.)

In its current-law baseline projections for the 2017–2026 period, the Congressional Budget Office accounted for the probability that the orderly liquidation authority would have to be used and that an assessment would have to be levied on surviving firms to cover some of the government's costs. Net proceeds from such assessments are projected to total roughly $5 billion over the next decade. Under the option, CBO expects that the receipts from the fee would provide a significant source of funds for the FDIC to carry out its orderly liquidation authority and thus reduce the likelihood that an assessment would be needed during the coming decade. Therefore, to determine the net effect on revenues, CBO subtracted $5 billion in projected assessments under current law from the amount the new fee is projected to generate ($103 billion), yielding net additional revenues of $98 billion from 2017 through 2026.

At 0.15 percent, the fee would probably not be so high as to cause financial institutions to significantly change their financial structure or activities. The fee could nevertheless affect institutions' tendency to take various business risks, but the net direction of that effect is uncertain; in some ways, it would encourage greater risk-taking, and in other ways, less risk-taking. One approach might be to vary the amount of the fee so that it reflected the risk posed by each institution, but it might be difficult to assess that risk precisely.

The main advantage of this option is that it would help defray the economic costs of providing a financial safety net by generating revenues when the economy is not in a financial crisis, rather than in the immediate aftermath of one. Another advantage of the option is that it would provide an incentive for banks to keep assets below the $50 billion threshold, diminishing the risk of spillover effects to the broader economy from a future failure of a particularly large institution (although at the expense of potential economies of scale). Alternatively, if larger financial institutions reduced their dependence on liabilities subject to the fee and increased their reliance on equity, their vulnerability to future losses would be reduced. The fee also would improve the relative competitive position of small and medium-sized banks by charging the largest institutions for the greater government protection they receive.

The option would also have two main disadvantages. Unless the fee was risk-based, stronger financial institutions that posed less systemic risk—and consequently paid lower interest rates on their debt as a result of their lower risk of default—would face a proportionally greater increase in funding costs than would weaker financial institutions. In addition, the fee could reduce the profitability of larger institutions, which might create an incentive for them to take greater risks in pursuit of higher returns to offset their higher costs.

RELATED OPTION: Revenues, Option 41

RELATED CBO PUBLICATIONS: *The Budgetary Impact and Subsidy Costs of the Federal Reserve's Actions During the Financial Crisis* (May 2010), www.cbo.gov/publication/21491; letter to the Honorable Charles E. Grassley providing information on the President's proposal for a financial crisis responsibility fee (March 4, 2010), www.cbo.gov/publication/21020

Revenues—Option 41

Impose a Tax on Financial Transactions

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	-53.6	13.3	62.9	85.0	92.6	95.9	98.7	101.3	104.1	106.9	200.3	707.3

Source: Staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

The United States is home to large financial markets, with hundreds of billions of dollars in stocks and bonds—collectively referred to as securities—traded on a typical business day. The total dollar value, or market capitalization, of U.S. stocks was roughly $23 trillion in March 2016, and about $265 billion in shares is traded on a typical day. The value of outstanding bond market debt was about $40 trillion at the end of 2015, and average trading volume in debt, concentrated mostly in Treasury securities, amounts to over $700 billion on a typical day. In addition, large volumes of derivatives—contracts that derive their value from another security or commodity and include options, forwards, futures, and swaps—are traded on U.S. financial markets every business day. None of those transactions are taxed in the United States, although most taxpayers who sell securities for more than they paid for them owe tax on their gains.

This option would impose a tax on the purchase of most securities and on transactions involving derivatives. For purchases of stocks, bonds, and other debt obligations, the tax generally would be 0.10 percent of the value of the security. For purchases of derivatives contracts, the tax would be 0.10 percent of all payments actually made under the terms of the contract, including the price paid when the contract was written, any periodic payments, and any amount to be paid when the contract expires. Trading costs for institutional investors tend to be very low—in many cases less than 0.10 percent of the value of the securities traded—so this option would generate a notable increase in trading costs for those investors.

The tax would not apply to the initial issuance of stock or debt securities, transactions in debt obligations with fixed maturities of no more than 100 days, or currency transactions (although transactions involving currency derivatives would be taxed). The tax would be imposed on transactions that occurred within the United States and on transactions that took place outside of the country, as long as any party to an offshore transaction was a U.S. taxpayer (whether a corporation, partnership, citizen, or resident). The tax would apply to transactions occurring after December 31, 2017. This option would be effective a year later than nearly all of the other revenue options analyzed in this report to provide the government and firms sufficient time to develop and implement the new reporting systems that would be necessary to accurately collect the tax.

The tax would increase revenues by $707 billion from 2017 through 2026, according to estimates by the staff of the Joint Committee on Taxation (JCT). The option would result in a revenue loss in 2017 because the transaction tax would lower the value of financial assets and thus lower capital gains. JCT assumes that, until 2020, when all reporting systems are expected to be in place, financial transactions will be underreported. Revenues would be lower if implementation of the option was phased in because of delays in developing the new reporting systems. (Because a financial transaction tax would reduce the tax base of income and payroll taxes, it would lead to reductions in revenues from those sources. The estimates shown here reflect those reductions.) The additional revenues generated by the option would depend significantly on the extent to which transactions subject to the tax fell in response to the policy.

One argument in favor of a tax on financial transactions is that it would significantly reduce the amount of short-term speculation and computer-assisted high-frequency trading that currently takes place and direct the resources dedicated to those activities to more productive uses. Speculation can destabilize markets and lead to disruptive events, such as the October 1987 stock market crash and the more recent "flash crash" that occurred when the stock market temporarily plunged on May 6, 2010. Although neither of those events had significant effects on the general economy, the potential exists for negative spillovers from future events.

A disadvantage of the option is that the tax would discourage all short-term trading, not just speculation—including some transactions by well-informed traders and transactions that stabilize markets. Empirical evidence suggests that, on balance, a transaction tax could make asset prices less stable: In particular, a number of studies have concluded that higher transaction costs lead to more, rather than less, volatility in prices. (However, much of that evidence is from studies conducted before the rise of high-frequency trading programs, which now account for a significant share of trading in the stock market.)

The tax could also have a number of negative effects on the economy stemming from its effects on asset prices and the frequency of trading. Traders and investors would seek to recoup the cost of trading by raising the return they require on financial assets, thereby lowering the value of those assets. However, because the tax would be small relative to the returns that investors with long-term horizons could earn, the effect on asset prices would be partly mitigated when traders and investors reduced the frequency of their trading, which would have a trade-off in terms of lowering liquidity and reducing the amount of information reflected in prices. Consequently, investment could decline (leaving aside the positive effects of higher tax revenues lowering federal borrowing and thus increasing the funds available for investment) because of the following: the increase in the cost of issuing debt and equity securities that would be subject to the tax and the potential negative effects on derivatives trading that could make it more difficult to efficiently distribute risk in the economy. The cost to the Treasury of issuing federal debt would increase (again, leaving aside the effects of deficit reduction) because of the increase in trading costs and the reduction in liquidity. Household wealth would decline with the reduction in asset prices, which would lower consumption.

In addition, traders would have an incentive to reduce the tax they must pay either by developing alternative instruments not subject to the tax or by moving their trading out of the country (although offshore trades by U.S. taxpayers would be taxed). Such effects would be mitigated if other countries enacted financial transaction taxes; currently, many members of the European Union are considering implementing such a tax.

RELATED OPTIONS: Revenues, Options 3, 40

RELATED CBO PUBLICATION: Letter to the Honorable Orrin G. Hatch responding to questions about the effects of a tax on financial transactions that would be imposed by the Wall Street Trading and Speculators Tax Act, H.R. 3313 or S. 1787 (December 12, 2011), www.cbo.gov/publication/42690

Revenues—Option 42

Impose a Tax on Emissions of Greenhouse Gases

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Revenues	57.4	90.3	93.6	96.5	98.6	101.3	104.6	108.1	111.5	115.2	436.5	977.2

Sources: Staff of the Joint Committee on Taxation; Congressional Budget Office.

This option would take effect in January 2017.

Many estimates suggest that the effect of climate change on the nation's economic output, and hence on federal tax revenues, will probably be small over the next 30 years and larger, but still modest, in later years.[1] Nonetheless, significant uncertainty surrounds those estimates. The accumulation of greenhouse gases (GHG) in the atmosphere—particularly carbon dioxide (CO_2), which is released when fossil fuels (such as coal, oil, and natural gas) are burned, and as a result of deforestation—could generate damaging and costly changes in the climate around the world. Although the consequences of those changes are highly uncertain and would probably vary widely across the United States and the rest of the world, many scientists think there is at least some risk that large changes in global temperatures will trigger catastrophic damage. Among the less uncertain effects of climate change on humans, some would be positive, such as fewer deaths from cold weather and improvements in agricultural productivity in certain areas; however, others would be negative, such as the loss of property from storm surges as sea levels rise and declines in the availability of fresh water in areas dependent on snowmelt. Many scientists agree that reducing global emissions of greenhouse gases would decrease the extent of climate change and the expected costs and risks associated with it. The federal government regulates some of those emissions but does not directly tax them.

This option would place a tax of $25 per metric ton on most emissions of greenhouse gases in the United States—specifically, on most energy-related emissions of CO_2 (for example, from electricity generation, manufacturing, and transportation) and some other GHG emissions from large manufacturing facilities. Emissions would be measured in CO_2 equivalents (CO_2e), which reflect the amount of carbon dioxide estimated to cause an equivalent amount of warming. The tax would increase at an annual real (inflation-adjusted) rate of 2 percent. During the first decade the tax was in effect, the Congressional Budget Office estimates, cumulative emissions from sources subject to the tax would fall by roughly 9 percent.

According to estimates by the staff of the Joint Committee on Taxation and CBO, federal revenues would increase by $977 billion between 2017 and 2026. (The tax would increase businesses' costs, which would reduce the tax bases for income and payroll taxes. The estimates shown here reflect the resulting reduction in revenues from those sources.)

The size of the tax used for these estimates was chosen for illustrative purposes, and policymakers who wanted to pursue this approach might prefer a smaller tax or a larger one. The appropriate size of a tax on GHG emissions, if one was adopted, would depend on the value of limiting emissions and their associated costs, the way in which the additional revenues were used, the effect on emissions overseas, and the additional benefits and costs that resulted from the tax.

One argument in support of the option is that it would reduce emissions of greenhouse gases at the lowest possible cost per ton of emissions because each ton would be subject to the same tax. That uniform treatment would increase the cost of producing and consuming goods and services in proportion to the amount of greenhouse gases emitted as a result of that production and consumption. Those higher production costs, and corresponding increases in prices for final goods and services, would create incentives for firms, households, governments, and other entities throughout the U.S. economy to undertake reductions of greenhouse gases that cost up to $25 per metric ton of CO_2e to achieve. This approach would

1. Congressional Budget Office, *Potential Impacts of Climate Change in the United States* (May 2009), www.cbo.gov/publication/41180.

minimize the cost of achieving a given level of emissions because the tax would motivate reductions that cost less than $25 per ton to achieve, but not those that would cost more than $25 per ton. An alternative approach to reducing GHG emissions that is currently being pursued by the federal government is to issue regulations based on various provisions of the Clean Air Act (CAA). However, standards issued under the CAA (for example, specifying an emissions rate for a given plant or an energy-efficiency standard for a given product) would offer less flexibility than a tax and, therefore, would achieve any given amount of emission reductions at a higher cost to the economy than a uniform tax that was applied to all sectors of the economy.

Another argument in favor of a GHG tax is that such a program could generate "co-benefits." Co-benefits would occur when measures taken to reduce GHG emissions—such as generating electricity from natural gas rather than from coal—also reduced other pollutants not explicitly limited by the cap, thereby reducing the harmful effects estimated to be associated with those emissions. However, measures taken to decrease CO_2 emissions could also result in additional costs depending on how the emissions were reduced. For example, increased use of nuclear power could exacerbate potential problems created by the lack of adequate long-term storage capacity for nuclear waste.

An argument against a tax on GHG emissions is that curtailing U.S. emissions would burden the economy by raising the cost of producing emission-intensive goods and services while yielding benefits for U.S. residents of an uncertain magnitude. For example, most of the benefits of limiting emissions and any associated reductions in climate change might occur outside of the United States, particularly in developing countries that are at greater risk from changes in weather patterns and an increase in sea levels. Another argument against this option is that reductions in domestic emissions could be partially offset by increases in emissions overseas if carbon-intensive industries relocated to countries that did not impose restrictions on emissions or if U.S. reductions in energy consumption led to decreases in fuel prices outside of the United States. More generally, averting the risk of future damage caused by emissions would depend on collective global efforts to cut emissions. Most analysts agree that if other countries with high levels of emissions do not cut those pollutants substantially, reductions in emissions in this country would produce only small changes in the climate (although such reductions would still diminish the probability of catastrophic damage).

An alternative approach for reducing emissions of greenhouse gases would be to establish a cap-and-trade program that set caps on such emissions in the United States. Under such a program, allowances that conveyed the right to emit 1 metric ton of CO_2e apiece would be sold at open auction, and the cap would probably be lowered over time. If the caps were set to achieve the same cut in emissions that was anticipated from the tax, then the program would be expected to raise roughly the same amount of revenues between 2017 and 2026 as the tax analyzed here. Both a tax on GHG emissions and a cap-and-trade program for those emissions would represent market-based approaches to cutting emissions and would achieve any desired amount of emission reduction at a lower cost than the regulatory approach described above. In contrast with a tax, a cap-and-trade program would provide certainty about the quantity of emissions from sources that are subject to the cap (because it would directly limit those emissions), but it would not provide certainty about the costs that firms and households would face for the greenhouse gases that they continued to emit.

RELATED CBO PUBLICATIONS: *Effects of a Carbon Tax on the Economy and the Environment* (May 2013), www.cbo.gov/publication/44223; *How Policies to Reduce Greenhouse Gas Emissions Could Affect Employment* (May 2010), www.cbo.gov/publication/41257; *The Costs of Reducing Greenhouse-Gas Emissions* (November 2009), www.cbo.gov/publication/20933; Testimony of Douglas W. Elmendorf, Director, before the Senate Committee on Energy and Natural Resources, *The Economic Effects of Legislation to Reduce Greenhouse-Gas Emissions* (October 14, 2009), www.cbo.gov/publication/41254; *Potential Impacts of Climate Change in the United States* (May 2009), www.cbo.gov/publication/41180

Revenues—Option 43

Increase Federal Civilian Employees' Contributions to the Federal Employees Retirement System

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Revenues	1.5	3.0	4.4	5.9	5.8	5.7	5.6	5.5	5.3	5.2	20.6	47.9

This option would take effect in January 2017.

The federal government provides most of its civilian employees with a defined benefit retirement plan, in the form of an annuity, through the Federal Employees Retirement System (FERS) or its predecessor, the Civil Service Retirement System. Those annuities are jointly funded by the employees and the federal agencies that hire them. Over 90 percent of federal employees participate in FERS, and most of them contribute 0.8 percent of their salary toward their future annuity. Those contributions are withheld from employees' after-tax income—that is, the contributions are subject to income and payroll taxes. The contribution rates for most employees hired since 2012, however, are much higher. First, the Middle Class Tax Relief and Job Creation Act of 2012 increased the contribution rate to 3.1 percent for most employees hired after December 31, 2012. Then, the Bipartisan Budget Act of 2013 increased the contribution rate further to 4.4 percent for most employees hired after December 31, 2013. Agency contributions to FERS do not have any effect on total federal spending or revenues because they are intragovernmental payments, but employee contributions are counted as federal revenues. Annuity payments made to FERS beneficiaries represent federal spending.

Under this option, most employees enrolled in FERS would contribute 4.4 percent of their salary toward their retirement annuity. The contribution rate would increase by 3.6 percentage points for employees who enrolled in FERS before 2013 and by 1.3 percentage points for employees who enrolled in FERS in 2013. The increased contribution rates would be phased in over the next four years. The dollar amount of future annuities would not change under the option, and the option would not affect employees hired in 2014 or later who already make or will make the larger contributions under the Bipartisan Budget Act. If implemented, the option would increase federal revenues by $48 billion from 2017 through 2026, the Congressional Budget Office estimates. Agency contributions would remain the same.

An argument in favor of this option is that retention rates probably would not fall much for most groups of federal employees. Federal employees receive, on average, substantially more total compensation—the sum of wages and benefits—than private-sector workers in similar occupations and with similar education and experience. In fact, a substantial number of private-sector employers no longer provide health insurance for their retirees or defined benefit retirement annuities, instead offering only defined contribution retirement plans that are less costly; in contrast, the federal government provides a defined benefit retirement plan, a defined contribution retirement plan, and health insurance in retirement. Therefore, even if federal employees hired before 2014 had to contribute somewhat more toward their annuity, their total compensation would, on average, still be higher than that available in the private sector. In addition, because this option would not change the compensation of federal employees hired after 2014, who are already contributing 4.4 percent of their salary toward their retirement annuity, the option would probably not further affect the quality of new recruits. Moreover, that is an advantage because recruits hired after 2014 are typically younger than other workers, and younger workers are particularly susceptible to competition from the private sector where their compensation is generally more favorable.

An argument against this option is that retention rates would probably fall substantially among the most experienced and highly qualified federal employees. Employees who have served long enough to be eligible for a FERS annuity immediately upon leaving the federal workforce are forgoing annuity payments by remaining in federal service. Many of those employees might choose to retire instead of making larger contributions to the annuity on top of forgoing payments. Also, some highly qualified federal employees have more lucrative job opportunities in the private sector than in the federal government, in part because private-sector salaries have grown faster than federal salaries since 2010. More of those employees would leave for the private sector under this option.

The option would also further accentuate the difference in the timing of compensation provided by the federal government and the private sector. Because many private-sector employers no longer provide health insurance for their retirees or defined benefit retirement annuities, a significantly greater share of total compensation in the private sector is paid to workers immediately, whereas federal employees receive a larger portion of their compensation in retirement. If that shift by private firms indicates that workers prefer to receive more of their compensation right away, then shifting federal compensation in the opposite direction—which this option would do by reducing current compensation while maintaining retirement benefits—would be detrimental to the retention of federal employees. If lawmakers wanted to reduce the total compensation of federal employees while maintaining or increasing the share of that compensation provided immediately, they could consider modifying the formula used to calculate federal annuities (see Mandatory Spending, Option 12, in this report) or making other changes to salaries and benefits.

RELATED OPTION: Mandatory Spending, Option 12

RELATED CBO PUBLICATIONS: *Comparing the Compensation of Federal and Private-Sector Employees* (January 2012), www.cbo.gov/publication/42921; Justin Falk, *Comparing Benefits and Total Compensation in the Federal Government and the Private Sector,* Working Paper 2012-04 (January 2012), www.cbo.gov/publication/42923

CHAPTER

5

Health Options

The federal government provides budgetary resources for health care in three ways—through mandatory outlays for health care programs, subsidies for health care that are conveyed through reductions in federal taxes, and spending for health programs funded through annual discretionary appropriations. In fiscal year 2015, the most recent year of available data, the total for all three came to about $1.4 trillion.

Net mandatory outlays for Medicare and Medicaid, the federal government's two largest health care programs, totaled an estimated $890 billion, roughly one-quarter of all federal spending in 2015. Other mandatory spending for health care programs included subsidies for health insurance purchased in the marketplaces established under the Affordable Care Act and related spending, the Children's Health Insurance Program (CHIP), the Federal Employees Health Benefits program for civilian retirees, and the TRICARE for Life program for military retirees. All told, mandatory spending for health care totaled $1.0 trillion in 2015.

In addition, the federal tax code gives preferential treatment to payments for health insurance and health care, primarily by excluding premiums for employment-based health insurance from income and payroll taxes. The staff of the Joint Committee on Taxation (JCT) estimates that the income tax expenditure for that exclusion was $146 billion in 2015; the Congressional Budget Office estimates a similar payroll tax expenditure.[1] (Tax expenditures are exclusions, deductions, preferential rates, and credits in the tax system that resemble federal spending by providing financial assistance to specific activities, entities, or groups of people.) Together, the two subsidies totaled about $270 billion in 2015. Other tax preferences related to health care amounted to about $26 billion.

The federal government also supports many health programs that are funded through annual discretionary appropriations: Taken together, discretionary spending for public health activities, health and health care research initiatives, health care programs for veterans, and certain other health-related activities totaled about $120 billion in 2015. (The federal government also helps pay for health insurance premiums for its civilian workers, but that funding is part of agency budgets and is excluded from this discussion.) In addition, the Department of Defense spent an estimated $40 billion in 2015 on health care for active-duty members, retirees, and their families.

CBO expects that under current law, federal budgetary costs related to health will rise as a share of gross domestic product (GDP). Policy changes could reduce federal deficits by reducing outlays for mandatory health care programs or by limiting tax preferences for health care, for example. Reductions in discretionary spending on health programs would lower total appropriations if the statutory caps set by the Budget Control Act of 2011 and subsequent legislation also were reduced or if appropriations were provided at amounts below those caps.

Trends in Health-Related Federal Spending and Revenues

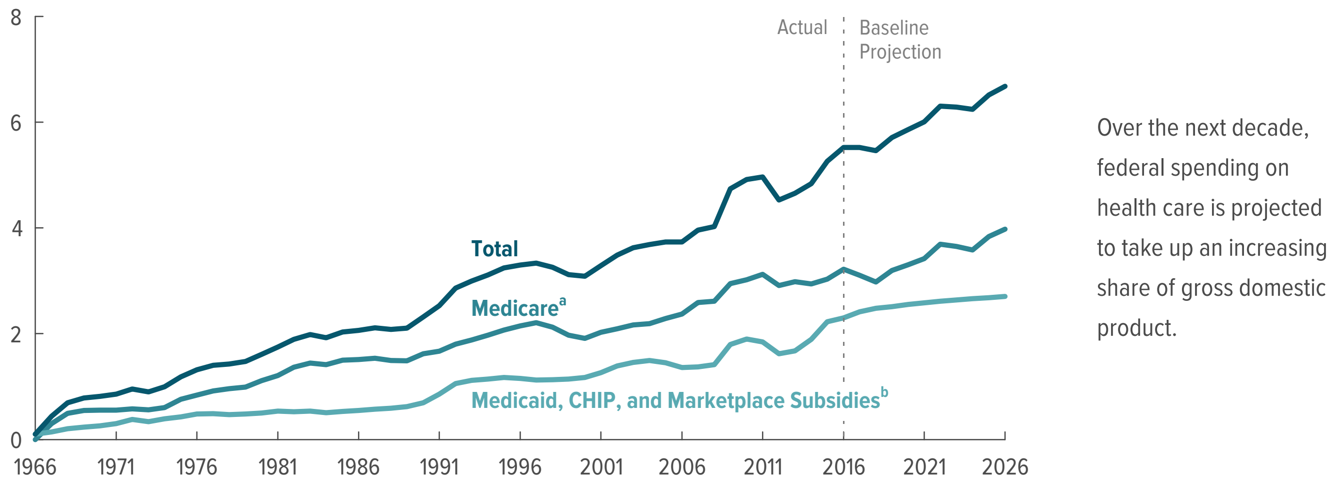
Spending for Medicare and Medicaid has grown sharply over recent decades, in part because of rising enrollment in those programs. Rising health care spending per beneficiary also has driven spending growth in those programs. Moreover, growth in such spending has outstripped GDP growth during the past few decades. In 1975, a decade after Medicare and Medicaid were created, federal spending, net of offsetting receipts for those

1. Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2015–2019*, JCX-141R-15 (December 2015), http://go.usa.gov/xkSeb.

Figure 5-1.

Federal Spending on the Major Health Care Programs, by Category

Percentage of Gross Domestic Product



Source: Congressional Budget Office (as of August 2016).

CHIP = Children's Health Insurance Program.

a. Net Medicare spending (includes offsetting receipts from premium payments by beneficiaries, recoveries of overpayments made to providers, and amounts paid by states from savings on Medicaid's prescription drug costs).

b. Spending to subsidize health insurance purchased in the marketplaces established under the Affordable Care Act and provided through the Basic Health Program and spending to stabilize premiums for health insurance purchased by individual people and small employers.

programs, accounted for 1.2 percent of GDP.[2] By 1985, that share was 2.0 percent of GDP, and it more than doubled over the next three decades: In 2015, net federal spending for Medicare and Medicaid was 5.0 percent of GDP. Between 1985 and 2015—as a result of demographic and legislative changes alike—the share of the population enrolled in Medicare rose from 13 percent to 17 percent, and average annual enrollment in Medicaid rose from 8 percent to 23 percent of the population.

An important reason for the rise in spending for health care per beneficiary in recent decades has been the emergence, adoption, and widespread diffusion of new medical technologies and services. Other contributing factors include increases in personal income and the expanded scope of health insurance coverage. (Those factors also have led to increases in per capita health care spending in the private sector.) All together, over the past few decades, health care spending per beneficiary has expanded more rapidly than the economy has, although the rate of increase in health care spending per beneficiary has abated recently. In CBO's judgment, such spending will continue to grow relatively slowly over the next decade.

Nevertheless, in CBO's latest baseline projections, mandatory outlays for health care programs over the next decade continue to exert pressure on the federal budget overall, primarily because of the burgeoning number of Medicare beneficiaries but also because of ongoing growth in health care spending per beneficiary in all of those programs. Under an assumption that current laws governing the programs generally remain unchanged, net federal spending for Medicare, Medicaid, CHIP, and subsidies for premiums and cost sharing in the health insurance marketplaces is projected by CBO to reach 6.7 percent of GDP in 2026, compared with 5.3 percent in 2015 (see Figure 5-1).[3] (Outlays for Social Security, by

2. Net Medicare spending includes the federal government's receipts from premium payments by beneficiaries, recoveries of overpayments made to providers, and amounts paid by states from savings on Medicaid's prescription drug costs.

3. Subsidies for health insurance coverage purchased through the marketplaces take two forms: tax credits that cover a portion of the premiums and additional subsidies that reduce cost sharing. The premium subsidies are structured as refundable tax credits, and CBO and JCT estimate that the amounts of those credits generally exceed the amount of federal income tax that recipients would otherwise owe. The amounts that offset taxes are classified as revenue losses, and the amounts that exceed tax liabilities are classified as outlays. Cost-sharing subsidies also are categorized as outlays.

contrast, are projected to be 6.0 percent of GDP in 2026.) All told, spending for those major health care programs accounts for about one-third of the total increase in federal spending that CBO projects through 2026.[4]

The projected rise in the number of beneficiaries of the major federal health care programs has two main causes. First is the aging of the population, which, over the next 10 years, will result in an increase of about one-third in the number of people enrolled in Medicare as people in the baby-boom generation retire. Second, and less important, is the continued expansion of federal subsidies for health insurance expected under current law, which will increase the number of Medicaid recipients and the number of people purchasing health insurance through the marketplaces.

Most of the projected spending in the major federal health care programs is for people age 65 or older. Despite the significant expansion of federal support for health care for lower-income people in recent years, only about one-fifth of federal spending for the major health care programs in 2026 is projected to finance care for people without disabilities who are under the age of 65. CBO projects that roughly another one-fifth would fund care for people who are blind or have another disability, and about three-fifths would fund care for people who are 65 or older.

The tax expenditure stemming from the exclusion from taxable income of employers' contributions for health care and workers' premiums for health insurance—described in this volume as the exclusion for employment-based health insurance—depends on the number of people enrolled in employment-based health insurance (in 2015, about 57 percent of the population under age 65 was in that category, CBO and JCT estimate) and on health care spending per person. That tax expenditure equaled 1.5 percent of GDP in 2015; it is projected to remain close to that percentage for the coming decade. Although per capita health care costs are expected to continue to grow faster than the economy—a development that will tend to increase the tax expenditure relative to GDP—the smaller share of the population under age 65 with employment-based coverage and the excise tax on high-cost employment-based insurance plans (set to begin in 2020) will tend to decrease the tax expenditure relative to GDP.

Analytic Method Underlying the Estimates Related to Health

CBO and JCT estimated the budgetary effects of the options in this chapter relative to CBO's March 2016 baseline projections.[5] CBO's 10-year baseline projections for mandatory spending and revenues incorporate the assumption that current laws generally remain unchanged. They also incorporate estimates of future economic conditions, demographic trends, and other developments that reflect the experience of the past several decades and the effects of broad changes to the nation's health care and health insurance systems that are occurring under current law.

As directed by section 257 of the Balanced Budget and Emergency Deficit Control Act of 1985, CBO's baseline projections for individual discretionary programs reflect the assumption that current appropriations will continue in future years, with adjustments to keep pace with inflation. (Although CBO follows that law in constructing baseline projections for individual components of discretionary spending, its baseline projections of overall discretionary spending incorporate the caps and automatic spending reductions put in place by the Budget Control Act.)

Options in This Chapter

Most of the 18 options in this chapter would either decrease mandatory spending on health programs or increase revenues (or, equivalently, reduce tax expenditures) as a result of changes in tax provisions related to health care. Several others involve discretionary spending. Some options would result in a reallocation of health care spending—from the federal government to businesses, households, or state governments, for example—and most would give parties other than the federal government stronger incentives to control costs while exposing them to more financial risk.

Fifteen options are similar in scope to others in this report. For each, the text provides background information, describes the possible policy change or changes,

4. Because funding for CHIP is set to expire at the end of September 2017, under the rules governing baseline projections, funding and enrollment for that program are assumed to decline after that year.

5. Congressional Budget Office, *Updated Budget Projections: 2016 to 2026* (March 2016), www.cbo.gov/publication/51384.

presents the estimated effects on spending or revenues, and summarizes arguments for and against the changes.

The other three address broader approaches to changing federal health care policy, all of which would offer lawmakers a variety of ways to alter current law. For each one, the amount of federal savings and the consequences for stakeholders—beneficiaries, employers, health care providers, insurers, and states—would depend crucially on its details. Those three broad options are as follows:

- Impose caps on federal spending for Medicaid (Option 2),
- Change the cost-sharing rules for Medicare and restrict medigap insurance (Option 7), and
- Reduce tax preferences for employment-based health insurance (Option 18).

Another way to reduce federal spending on health care would be to convert Medicare to a premium support system. Under such a program, beneficiaries would purchase health insurance from a list of competing plans, and the federal government would pay part of the cost of the coverage. Past proposals for such a conversion have differed in many respects, including the way that the federal contribution would be set and the way that contribution might change over time. In 2013, CBO analyzed the effects of two illustrative options on federal spending and beneficiaries' choices and payments.[6] The agency currently is refining its modeling approach and updating its analysis to account for new data; it expects to release updated estimates in 2017.

All 18 options in this chapter would have consequences beyond their effects on the federal budget. Some would influence people's behavior as they participated in the health care system. Others would focus on the actions of health care providers or health care plans. Still others would change the ways the government paid providers or alter the federal or state role in paying for health care services. One option would promote better health in the population—and increase federal revenues—by collecting a higher excise tax on cigarettes. Some options could shift the sources or types of health insurance coverage or cause different types of health care to be sought and delivered. Whether that care was delivered more efficiently or was more appropriate or of higher quality than it would be otherwise would hinge on the responses of those affected.

6. See Congressional Budget Office, *A Premium Support System for Medicare: Analysis of Illustrative Options* (September 2013), www.cbo.gov/publication/44581. CBO last updated those estimates in 2014; see Congressional Budget Office, *Options for Reducing the Deficit: 2015 to 2024* (November 2014), www.cbo.gov/publication/49638.

Health—Option 1 Function 550

Adopt a Voucher Plan and Slow the Growth of Federal Contributions for the Federal Employees Health Benefits Program

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Mandatory Outlays[a]	0	0	-0.5	-1.3	-2.1	-3.1	-4.1	-5.2	-6.5	-7.8	-4.0	-30.6
Change in Discretionary Spending												
Budget authority	0	0	-0.6	-1.2	-2.0	-2.8	-3.7	-4.6	-5.7	-7.0	-3.8	-27.5
Outlays	0	0	-0.6	-1.2	-2.0	-2.8	-3.7	-4.6	-5.7	-7.0	-3.8	-27.5

This option would take effect in January 2019.

a. Includes estimated savings by the Postal Service, whose spending is classified as off-budget.

The Federal Employees Health Benefits (FEHB) program provides health insurance coverage to 4 million federal workers and annuitants, as well as to approximately 4 million of their dependents and survivors. In 2016, those benefits are expected to cost the government (including the Postal Service) about $35 billion. Policyholders, whether they are active employees or annuitants, generally pay 25 percent of the premium for lower-cost plans and a larger share for higher-cost plans; the federal government pays the rest of the premium. That premium-sharing structure provides some incentive for federal employees to choose plans with lower premiums, although the incentive is smaller than it would be if they realized the full savings from choosing such plans. The premium-sharing structure also imposes some competitive pressure on insurers to hold down premiums—but again, less pressure than would exist if employees paid the full cost of choosing more expensive plans.

This option would replace the current premium-sharing structure with a voucher, starting in January 2019. The voucher, which would be excluded from income and payroll taxes, would cover roughly the first $6,100 of a self-only premium, the first $13,200 of a self-plus-one premium, or the first $14,000 of a family premium. The Congressional Budget Office calculated those amounts by taking its estimates of the government's average expected contributions to FEHB premiums in 2018 and then increasing them by the projected rate of inflation between 2018 and 2019 (as measured by the consumer price index for all urban consumers). Each year, the voucher would continue to grow at the rate of inflation, rather than at the average rate of growth for FEHB premiums. That would produce budgetary savings because FEHB premiums grow significantly faster than inflation in CBO's projections. (The expected rate of growth for FEHB premiums is similar to the expected rate for private insurance premiums.)

By reducing federal agencies' payments for FEHB premiums for current employees and their dependents, this option would reduce discretionary spending by an estimated $27 billion from 2019 through 2026, provided that appropriations were reduced to reflect those lower costs. The option also would reduce mandatory spending for FEHB by $32 billion because the Treasury and the Postal Service would make lower payments for FEHB premiums for annuitants and postal workers. (That number includes estimated savings by the Postal Service, whose spending is classified as off-budget.) In addition, the option would have some effects that increased mandatory spending. CBO anticipates that starting in 2019, the option would cause some FEHB participants to leave the program. Some of those participants would enroll in coverage through the health insurance marketplaces established under the Affordable Care Act (ACA), some would enroll in Medicare, some would enroll in employment-based coverage (through a spouse, for example), and some would become uninsured. As a result, marketplace subsidy costs would increase by $170 million, and Medicare spending would increase by an estimated

$1 billion.[1] Overall, the option would reduce mandatory spending by an estimated $31 billion from 2019 through 2026.

Revenues also would be affected by the option, but CBO expects that the net change would be negligible. Some of the people who became uninsured would pay penalties to the government, as the ACA specifies. That increase in revenues would be roughly offset because of changes that would take place in the number of people with employment-based insurance and changes in the costs of that insurance. Those changes would affect the share of total compensation that takes the form of taxable wages and salaries and the share that takes the form of nontaxable health benefits; taxable compensation would increase for some people and decrease for others.

An advantage of this option is that it would increase enrollees' incentive to choose lower-premium plans: If they selected plans that cost more than the voucher amount, they would pay the full additional cost. For the same reason, the option would strengthen price competition among health care plans participating in the FEHB program. Because enrollees would pay no premium for plans that cost no more than the value of the voucher, insurers would have a particular incentive to offer such plans.

The option also could have several drawbacks. First, because the voucher would grow more slowly over time than premiums would, participants would eventually pay more for their health insurance coverage. In 2026, on average, participants would contribute more than $700 more for a self-only premium, $1,500 more for a self-plus-one premium, and $1,600 more for a family premium than they would under current law, CBO estimates. Some employees and annuitants who would be covered under current law might therefore decide to forgo coverage altogether. Second, many large private-sector companies currently provide health care benefits for their employees that are comparable to what the government provides. Under this option, the government benefits could become less attractive than private-sector benefits, making it harder for the government to attract highly qualified workers. Finally, the option would cut benefits that many federal employees and annuitants may believe they have already earned.

1. In general, people whose employers offer insurance coverage are not eligible for marketplace subsidies. However, an exemption exists for people whose contribution for health insurance would exceed a specified percentage of their income. By increasing enrollees' premium contributions, this option would boost the number of federal employees eligible for marketplace subsidies through that exemption.

RELATED CBO PUBLICATIONS: *Comparing the Compensation of Federal and Private-Sector Employees* (January 2012), www.cbo.gov/publication/42921; *Characteristics and Pay of Federal Civilian Employees* (March 2007), www.cbo.gov/publication/18433; *The President's Proposal to Accrue Retirement Costs for Federal Employees* (June 2002), www.cbo.gov/publication/13806; *Comparing Federal Employee Benefits With Those in the Private Sector* (August 1998), www.cbo.gov/publication/11100

Health—Option 2 Function 550

Impose Caps on Federal Spending for Medicaid

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Caps on Overall Spending, With Growth of Caps Based on the CPI-U[a]												
Change in Mandatory Outlays	0	0	-35.1	-50.3	-63.6	-77.5	-92.4	-108.2	-123.4	-139.1	-149.0	-689.6
Change in Revenues[b]	0	0	-0.4	-0.6	-0.8	-1.0	-1.3	-1.5	-1.8	-2.1	-1.8	-9.6
Decrease in the Deficit	0	0	-34.7	-49.7	-62.8	-76.5	-91.1	-106.7	-121.6	-137.0	-147.2	-680.0
Caps on Overall Spending, With Growth of Caps Based on the CPI-U Plus 1 Percentage Point[a]												
Change in Mandatory Outlays	0	0	-25.1	-36.5	-45.8	-55.5	-66.1	-77.4	-87.8	-98.5	-107.4	-492.7
Change in Revenues[b]	0	0	-0.3	-0.4	-0.5	-0.7	-0.8	-1.0	-1.2	-1.4	-1.3	-6.4
Decrease in the Deficit	0	0	-24.8	-36.1	-45.3	-54.8	-62.5	-76.4	-86.6	-97.1	-106.2	-486.3
Caps on Spending per Enrollee, With Growth of Caps Based on the CPI-U[c]												
Change in Mandatory Outlays	0	0	0	-47.0	-59.7	-71.4	-83.0	-95.6	-107.2	-119.7	-106.6	-583.5
Change in Revenues[b]	0	0	0	-0.5	-0.6	-0.8	-1.0	-1.2	-1.4	-1.6	-1.2	-7.0
Decrease in the Deficit	0	0	0	-46.4	-59.1	-70.6	-82.1	-94.4	-105.8	-118.1	-105.5	-576.5
Caps on Spending per Enrollee, With Growth of Caps Based on CPI-U Plus 1 Percentage Point[c]												
Change in Mandatory Outlays	0	0	0	-32.3	-40.2	-47.0	-53.8	-60.6	-67.4	-73.2	-72.5	-374.4
Change in Revenues[b]	0	0	0	-0.4	-0.4	-0.5	-0.6	-0.7	-0.8	-0.9	-0.8	-4.2
Decrease in the Deficit	0	0	0	-31.9	-39.8	-46.5	-53.2	-59.5	-66.6	-72.3	-71.7	-370.2

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

CPI-U = consumer price index for all urban consumers.

a. This alternative would take effect in October 2019.

b. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

c. This alternative would take effect in October 2020.

Overview of the Issue

Medicaid is a joint federal-and-state program that covers acute and long-term health care for groups of low-income people, chiefly families with dependent children, elderly people (people over the age of 65), nonelderly people with disabilities, and—at the discretion of individual states—other nonelderly adults whose family income is up to 138 percent of the federal poverty guidelines. Under current law, the federal and state governments share in the financing and administration of Medicaid. The federal government provides the majority of Medicaid's funding; establishes the statutory, regulatory, and administrative structure of the program; and monitors state compliance with the program's rules. As part of its responsibilities, the federal government determines which groups of people and medical services states must cover if they participate in the program and which can be covered at states' discretion. For their part, the states administer the program's daily operations, reimburse health care providers and health plans, and determine which eligibility and service options to adopt. The result is wide variation among states in enrollment, services covered, providers' and health plans' payment rates, and spending per capita, among other elements.

In 2015, the states received $350 billion in federal funding for Medicaid and spent $205 billion of their own funds for the program. Under current law, almost all federal funding is open-ended: If a state spends more because enrollment increases or costs per enrollee rise, larger federal payments are automatically generated. On average, the federal government pays about 63 percent of program costs, with a range among the states of 51 percent to the current high of 80 percent, reflecting the variation in state per capita income and in the share of enrollees (if any) in each state that became eligible for Medicaid as a result of the optional expansion of that program under the Affordable Care Act (ACA). Through 2016, the federal government paid all costs for enrollees who became eligible as a result of the ACA. The federal government will cover a slightly declining share of costs for that group from 2017 to 2019, and it will cover 90 percent of costs in 2020 and beyond.

Medicaid spending has consumed a rising share of the federal budget over the past several decades, representing a growing percentage of gross domestic product (GDP)—a trend that the Congressional Budget Office projects will continue in the future. Over the past 20 years, federal Medicaid spending has risen at an average rate of slightly more than 7 percent annually as a result of general growth in health care costs, mandatory and optional expansions of program eligibility and covered services, and the amount of state spending that receives federal matching payments.

CBO expects that although federal Medicaid spending will grow more slowly in the next decade, it will continue to increase faster than GDP growth and general inflation, in part because of continued growth in health care costs and in part because more states are expected to expand Medicaid coverage under the ACA. (To date, 31 states and the District of Columbia have done so.) Medicaid spending is projected to rise at an average rate of 5 percent a year, whereas GDP is projected to increase by about 4 percent a year on a nominal basis, and general inflation is expected to average about 2 percent a year. Under current law, CBO estimates, Medicaid's share of federal noninterest spending will rise from 10 percent in 2015 to 11 percent in 2026.

Lawmakers could make structural changes to Medicaid to decrease federal spending on the program. Among the possibilities are reducing the scope of covered services, eliminating eligibility categories, repealing the ACA expansion, reducing the federal government's share of total Medicaid spending, or capping the amount that states receive from the federal government to operate the program. This option focuses on the last approach, although the others could have similar implications for federal and state spending or for individual enrollees, depending on the way states were permitted to, or decided to, respond to such policy changes.

From the federal government's perspective, capping Medicaid funding to states could confer several advantages relative to current law. For example, the caps could generate budgetary savings in greater or lesser amounts depending on their level, and setting spending limits would make federal costs for Medicaid more predictable. Federal spending caps also would curtail states' current ability to increase federal Medicaid funds—an ability created by the open-ended nature of federal financing for the program—and could reduce the relatively high proportion of program costs now covered by the federal government. Because the federal government matches states' Medicaid spending, an additional state dollar spent on Medicaid is worth more to a state than an additional state dollar spent outside the program. Therefore, states have considerable incentive to devote more of their budgets to Medicaid than they would otherwise and to shift other unmatched program expenditures into Medicaid. For example, states have sometimes chosen to reconfigure health programs—previously financed entirely with state funds—in order to qualify for federal Medicaid reimbursement. And most states finance at least a portion of their Medicaid spending through taxes collected from health care providers with the intention of returning the collected taxes to those providers in the form of higher Medicaid payments, thereby boosting federal Medicaid spending without a concomitant increase in state spending. Those incentives would be reduced under a capped program.

Caps on federal Medicaid spending also could present several disadvantages relative to current law. Capped federal spending would create uncertainty for states as they plan future budgets because it could be difficult to predict whether Medicaid spending would exceed the caps and thus require additional state spending. If the limits on federal payments were set low enough, additional costs—perhaps substantial costs—would be shifted to states. States then would need to decide whether to commit more of their own revenues to Medicaid or reduce spending by cutting payments to health care providers and health plans, eliminating optional services, restricting eligibility for enrollment, or (to the extent feasible) arriving at more efficient methods for delivering services. Moreover, depending on the caps' structure, Medicaid might no longer serve as a countercyclical source of federal funds for states during economic downturns. That is, the states might not automatically receive more federal funds if a downturn caused an increase in Medicaid enrollment. In addition, because Medicaid programs differ widely from state to state—and because spending varies widely (and grows at varying rates) for different enrollee categories within a state—federal policymakers could find it difficult to set caps at levels that accurately reflected states' costs. Finally, it might be difficult to set caps that balanced the competing goals of creating incentives for efficiency and generating federal savings, providing funding to states that was sufficient to generally maintain the scope of their programs, and designing caps that did not disadvantage states that already have established efficient programs while benefiting states that have not.

Key Design Choices That Would Affect Savings

A variety of designs for caps could be considered that would significantly affect federal Medicaid savings, and they could interact in complicated ways. The key areas to consider include the following:

- Whether to set overall or per-enrollee caps;
- What categories of Medicaid spending and eligibility categories to include in the spending limits;
- Which year's spending to use to set the base year and what growth factor, or percentage rate, to use to increase the caps over time;
- How much flexibility to grant to states to make changes to the program; and
- Whether optional expansion of coverage under the ACA also would be subject to the caps (thus creating special complexities for states that have not yet expanded coverage but that might do so in the future).

Overall or Per-Enrollee Caps. Among the first questions are those that involve whether to pursue a cap on federal Medicaid spending across the board or to provide each state with a fixed amount of funding for each enrollee. In general, overall caps would consist of a maximum amount of funding that the federal government would give a state to operate Medicaid. Once established, and depending on the way they were scheduled to increase, the federal caps generally would not fluctuate in response to rising or falling enrollment or as a result of changes in the cost of providing services.

Overall caps could be structured in one of two main ways. First, the federal government could provide block grants at amounts that would not change, regardless of fluctuations in costs or enrollment. Alternatively, the federal government could maintain the current financing structure—paying for a specific share of a state's Medicaid spending—but capping the total amount provided to states. In that case, states would bear all additional costs above the federal caps, but the state and the federal government would share the savings if spending fell below the caps. In CBO's view, however, if caps were set below current projections of federal Medicaid spending, such savings would be unlikely. Given the incentive to maximize federal funding, CBO expects that states would generally structure their programs to qualify for all available federal funds up to the amount of the caps.

Caps on per-enrollee spending would set an upper limit on the amount a state could spend on care for Medicaid enrollees, on average. Under such a plan, the federal government would provide funds for each person enrolled in the program, but only up to a specified amount per enrollee. As a result, each state's total federal funding would be calculated as the product of the number of enrollees and the per-enrollee spending cap. (Individual enrollees whose care proved more expensive than the average could still generate additional federal payments, as long as the total per capita average did not exceed the cap.) Unlike an overall spending cap, such an approach would allow for additional funding if enrollment rose (when a state chose to expand eligibility under the ACA, for example, or as a result of an enrollment increase during an economic downturn). Funding would decline if Medicaid enrollment fell (for example, when a state chose to restrict enrollment or when enrollment fell as result of an improving economy).

Several structures are possible for per-enrollee caps. Fixed, monthly, per-enrollee federal payments could be set in the same way that public or private payers set payments to managed care companies. Caps could be set on the basis of average federal spending per enrollee for all Medicaid beneficiaries or for people by eligibility category. In those circumstances, the federal government would count the enrollees overall or the number in each category and multiply that sum by the spending limit per enrollee. For caps based on eligibility category, the overall limit on

Medicaid spending for each state would be the sum of the groups' limits. A similar but more flexible approach would be to set a total limit consisting of the sum of the limits for the groups as above, but to allow states to cross-subsidize groups (that is, to spend more than the cap for some groups and less for others) as long as the state's total spending limit was maintained.

Spending Categories. Policy options to cap federal Medicaid spending could target all Medicaid spending or spending for specific categories of services. Most federal Medicaid spending covers acute care ($244 billion in 2015) or long-term care ($75 billion in 2015); both types of spending could be divided among various subcategories. Other spending categories include payments (known as DSH payments) to hospitals that serve a disproportionate share of Medicaid enrollees and uninsured patients, spending under the Vaccines for Children (VFC) program, and administrative spending. (The total in 2015 for those three categories was $31 billion.) In general, the more spending categories included, the greater the potential for federal budgetary savings.

Eligibility Categories. In addition to setting the types of spending to cap, policymakers would face choices about which groups of Medicaid enrollees to include. As with service categories, the more eligibility categories covered, the greater the potential for federal savings. For example, caps could limit federal spending (either overall or per enrollee) only for children and certain adults but leave spending unchanged for elderly and disabled enrollees. Because the latter two groups of enrollees currently account for about 48 percent of Medicaid spending—and are projected to account for about 45 percent in 2026—caps that did not apply to them would produce far smaller savings than caps that covered all groups (assuming that the other characteristics of the two sets of caps were the same).

Per-enrollee caps could establish one average per-person cost limit for all enrollees or establish separate limits for different types of enrollees. If there was more than one per-enrollee cap, separate caps could be established for any number of specific categories. For example, past proposals have considered separate caps for the elderly, people with disabilities, children, and nondisabled, nonelderly adults. Separate caps also could be established for pregnant women, adults added as a result of the expansion of Medicaid under the ACA, or other particular groups.

The choice of creating only one or more than one per-enrollee cap (and if so which groups to select for each cap) could affect whether and to what extent the states would have an incentive to maximize enrollment of some groups over others. A single cap for all enrollees would average the costs of groups without regard to substantial differences in health status between some groups, thus creating financial incentives for states to enroll people whose costs were expected to be below the cap. For example, per-enrollee spending for children and nonelderly, nondisabled adults, on average, is below that for elderly patients and people with disabilities. Therefore, the enrollment of every additional child and nonelderly, nondisabled adult would help a state to remain below its total spending limit, and the enrollment of every additional elderly or disabled enrollee would make that goal more difficult to achieve. However, the degree to which states could effectively maximize enrollment of people in one category compared with another would depend on the degree of flexibility states were given to keep their costs below the caps.

Base-Year Spending. Establishing caps on federal spending for Medicaid would generally begin with selecting a recent year of Medicaid outlays as a "base year" and calculating that year's total spending for the service categories and eligibility groups to be included. The base year is not necessarily the first year in which the caps take effect, which could be any year in the budget window, but the year from which the future cap amounts are projected (as described in the next section). Thus, for overall and per-enrollee spending caps alike, the selection of the base year is important: A higher base-year amount would lead to higher caps (and lower federal savings) than a lower base-year amount would.

An important consideration in selecting a base year is whether to use a past or future year. Most proposals use a past year because Medicaid expenditures are known and because states cannot increase spending in the base year to boost their future spending limits (by raising payment rates for providers and health plans, making additional one-time supplemental payments, or moving payments for claims from different periods into the base year).

Choosing a past year as a base also essentially locks in the spending that resulted from prior choices regarding the design of a state's Medicaid program, including the choice of whether to expand Medicaid. Once caps were set on the basis of states' past choices, states would find it increasingly difficult to make changes that increased spending, for example, by significantly raising payment rates or voluntarily adding covered services (which some might consider a desirable outcome if a principal goal of the cap is to constrain state spending). In contrast to the case under current law, those changes would not lead to higher federal payments. In addition, states that have made efforts to operate their programs efficiently to keep costs low would receive caps that reflected that efficiency and were, all else equal, lower than the caps of states with inefficient programs. Therefore, those efficient states would have less flexibility to reduce spending to comply with the caps while inefficient states would have more flexibility. Ways to address this issue would include supplementing base-year spending amounts or assigning higher growth rates for low-spending states to give them more room to change their programs over time. However, that approach would reduce the federal savings generated by the caps.

Growth Factors. The growth factor sets an annual rate of increase to inflate the spending limits in future years. The growth factor could be set to meet specific savings targets or achieve specific policy purposes. For example, if a growth factor was set roughly equal to the rate of increase projected for Medicaid spending under current law, little or no budgetary savings might be anticipated, but some other policy objective could be met, such as protecting the federal government from unanticipated cost increases in the future. Alternatively, a growth factor could be set to make the increase in federal Medicaid spending—overall or per enrollee—match changing prices in the economy as measured, for example, by the consumer price index for all urban consumers (CPI-U). Policymakers also could set a rate to reflect the growth in health care costs per person, perhaps as measured by the per capita increase in national health expenditures, or a rate that was consistent with economic growth as measured by the increase in per capita GDP. Growth factors that were tied to price indexes or to overall economic growth, however, would not generally account for increases in the average quantity or intensity of medical services of the sort that have occurred in the past.

For overall spending caps, which would not provide additional funds automatically if Medicaid enrollment rose, the growth factor could be tied to some measure of population growth (such as the Census Bureau's state population estimates) or changes in the unemployment rate to account for increases in enrollment. A growth factor also could be any legislated rate designed to produce a desired amount of savings.

In general, the lower the growth factor relative to CBO's projected growth rate for federal Medicaid spending under current law, the greater would be the projected federal budgetary savings. But the lower the growth factor, the greater the possibility that federal funding would not keep pace with increases in states' costs per Medicaid enrollee or (in the case of overall caps) with increases in Medicaid enrollment, thus raising the likelihood that states would not be able to maintain current services or coverage. Under proposals that led to significant reductions in federal funding, many states would find it difficult to offset the reduced federal payments solely through improvements in program efficiency. Those states would have three potential approaches available to them: Raise additional revenues; cut other state programs to transfer resources to Medicaid; or change the program through some combination of reducing payments to providers and health plans, curtailing covered services, and decreasing enrollment. If reductions in federal revenues were large enough, states would probably resort to a combination of all such approaches.

New Flexibility for States. Some proponents of caps consider additional state flexibility an essential feature of proposals to limit Medicaid spending. However, the structure of Medicaid's financing and the degree of state flexibility are, in principle, separate issues: Under a federal spending cap, the flexibility available under current law could remain the same or be altered to give states more or fewer options. (Under current law, states' flexibility could be increased or decreased as well.) If spending caps were coupled with new state flexibility, the federal government could cede more control to states for a range of program features, including administrative requirements, managed care contracting rules, ways to deliver health care, cost-sharing amounts, work requirements, eligibility categories, and covered medical services. That new flexibility would make it easier for states to adjust their spending in response to limits on federal funding. Alternatively, federal spending caps could include a maintenance-of-effort requirement that would prevent states from changing eligibility categories or covered medical benefits before the caps took effect. In either case, the degree of state flexibility would be unlikely to affect the federal savings created by the caps; CBO expects that states would structure their programs to draw federal payments up to the caps' amount.

The Optional Medicaid Expansion. Since January 2014, states have been permitted to extend eligibility for Medicaid to most people whose income is below 138 percent of the federal poverty guidelines. Under the terms of the ACA, the federal government currently covers a much larger share of the cost of providing Medicaid coverage to people made eligible by the expansion than it does for other Medicaid enrollees. That higher federal share is set at 100 percent through 2016 and then declines gradually to 90 percent by 2020, where it remains thereafter. The Medicaid expansion adds complexity to the design of federal spending caps, particularly for states that choose to adopt the expansion after the base year.

For states that have not yet adopted the ACA expansion, data from a prior base year would reflect spending only for groups of people who were eligible before expansion. Should any of those states subsequently adopt the expansion, the annual limits imposed by an overall spending cap would fail to account for the spending of expansion enrollees. For per-enrollee caps, the additional enrollment from the coverage expansion would generate additional federal spending, but average per capita spending for adults in the base year would not account for the higher federal payment for newly eligible people or for any differences in expected costs related to the health status of those new enrollees compared with costs for people who would have been eligible before the expansion.

In designing Medicaid caps, lawmakers could address those issues in one of several ways:

- Select a base year far enough in the future to allow time for states that chose to do so to adopt the expansion and for enrollment to become fairly stable. Using a future base year, however, could allow states to boost their spending that year, thus increasing federal spending limits and reducing federal savings.

- Leave spending uncapped for people who enrolled as a result of the expansion, but cap spending only for nonexpansion enrollees. That approach would remove most of the complications created by the optional-coverage group, but it also would leave a large amount of Medicaid spending uncapped and reduce the potential federal savings. (CBO projects that federal spending for adults made eligible by the ACA will total $134 billion, or 21 percent of total Medicaid spending, in 2026.)

- Allow the Secretary of Health and Human Services to add an estimate of future spending attributable to the expansion for states that chose to adopt the expansion after the base year. For overall caps, the Secretary could adjust the spending limits to reflect the estimated additional costs of newly eligible people and previously eligible people who would enroll only in response to the expansion. For per-enrollee caps, the Secretary could modify the caps for newly eligible adults to reflect the higher federal matching rates for that group and to allow for any differences in expected costs related to the health status of that group compared with people who enrolled under the existing eligibility rules. The Secretary also could establish an entirely separate per-enrollee cap for the newly eligible enrollees that was based on estimated costs for their coverage.

- Base the caps on total combined federal and state spending to avoid the complexity of differing matching rates for expansion and pre-expansion adults. For overall caps, the upper spending limit would still require an adjustment to reflect the additional anticipated enrollment attributable to the expansion. For per-enrollee caps, combining federal and state spending limits would circumvent problems associated with the use of different matching rates but would not account for differences in expected health costs between the two groups.

Another question related to the optional expansion concerns whether capping federal Medicaid spending might cause some states that would otherwise expand coverage to reject the option instead. Limits on federal Medicaid payments represent a potential shifting of costs to states, which in turn would affect states' budget processes and program decisions. States could reduce Medicaid costs and lessen financial risk by dropping the optional expansion or deciding to adopt it later. CBO anticipates that the more that caps reduce federal funding below the amounts projected under current law, the greater the likelihood that states would discontinue or reject the optional expansion unless the cap's structure was such that participating in the expansion did not make complying with the cap more difficult.

To the extent that states responded to caps by terminating or rejecting the optional expansion, most of the new or potential enrollees would lose access to Medicaid coverage, although some would gain access to the health insurance marketplaces established by the ACA. Specifically, people whose income was between 100 percent and 138 percent of the federal poverty guidelines who lost Medicaid eligibility would qualify for premium assistance tax credits to buy coverage through the marketplaces. Most of the people whose income was below the federal poverty guidelines but who no longer had access to Medicaid would become uninsured; the rest would enroll in other coverage, principally through an employer. For overall caps, enrollment changes would not affect the Medicaid savings, but would reduce net budgetary savings because of increased spending on marketplace subsides and decreased revenues from additional employer coverage. For per-enrollee caps, the net budgetary effect of fewer states' adopting the expansion would be to increase federal savings, CBO estimates, because the savings from the reduction in Medicaid coverage would be larger than the increase in spending for marketplace subsidies and revenue loss from additional employer coverage.

Specific Alternatives and Estimates

CBO analyzed two types of limits on federal Medicaid spending: overall spending caps and per-enrollee caps. For both types, CBO chose 2016 as the base year. Overall caps would take effect in October 2019; per-enrollee caps would take effect one year later. That additional year would be the minimum necessary to allow for the complex data gathering needed to arrive at state-specific caps for each enrollee group (as discussed below in the section on data availability). For overall and per-enrollee caps alike, federal matching rates would continue as they are under current law, but Medicaid's DSH and VFC spending would be excluded. DSH spending is already capped and VFC spending covers vaccinations for some children who might not be Medicaid enrollees. The caps also would exclude the spending that Medicaid incurs for Medicare cost sharing and premiums of enrollees who are eligible for both programs. Administrative spending would be financed in the same manner as under current law.

To illustrate a range of savings, CBO used a pair of alternative growth factors for each type of cap: either the annual change in the CPI-U or the change in the CPI-U plus one percentage point (referred to here as CPI-U plus 1). Under each alternative, states would retain their current-law authority concerning optional benefits, optional enrollees, and payment rates for providers and health plans.

For the per-enrollee spending caps, CBO assumed that separate spending limits would be set for each of the four main Medicaid eligibility groups in each state: the elderly, people with disabilities, children, and nondisabled, nonelderly adults. States would not be permitted to cross-subsidize groups. CBO also assumed that the Secretary of Health and Human Services would make a new data source available to capture the necessary spending and enrollment information for the four groups.

To address the complexities related to the optional Medicaid expansion, CBO assumed that the Secretary would adjust each type of cap to reflect estimated additional spending in any state that adopted the expansion after the base year. Per-enrollee caps would be imposed on combined federal and state spending (overall caps would not). By that method, if combined federal and state spending exceeded the caps, the percentage of the excess spending above the cap would be cut from the federal payment to states: If a state overspent its per-enrollee cap by 5 percent, for example, the federal payment to the state would be reduced by the same amount.

Under the specifications listed here, CBO estimates that the overall caps would generate gross savings to the federal government of $709 billion between 2019 and 2026 under the CPI-U growth factor or $506 billion under the CPI-U plus 1 growth factor, for savings of about 17 percent and 12 percent, respectively, from the current-law projection of total federal Medicaid spending for the period. Gross savings from the two varieties of overall caps would represent about 23 percent and 16 percent, respectively, of projected federal Medicaid spending in 2026.

The gross savings under this option would be partially offset. Reductions in federal Medicaid spending resulting from the overall caps would represent large reductions in revenues for states. Therefore, in CBO's assessment, the states would take a variety of actions to reduce a portion of the additional costs that they would face, including restricting enrollment. For people who lose Medicaid coverage, CBO and the staff of the Joint Committee on Taxation (JCT) estimate that roughly three-quarters would become uninsured. The rest of that group of people would instead obtain subsidized coverage through the health insurance marketplaces established under the ACA or, if available, choose to enroll in employment-based health insurance. For the CPI-U alternative, the agencies estimate that the additional marketplace and employment-based coverage would increase outlays by $20 billion and decrease revenues by $10 billion from 2019 to 2026. For the CPI-U plus 1 alternative, the agencies estimate that the additional coverage would increase outlays by $13 billion and decrease revenues by $6 billion over the same period. The effects on revenues stem from decreases in taxable compensation associated with increases in employment-based insurance and decreases in tax liability associated with increases in the number of people receiving tax credits to purchase health insurance through the marketplaces. As a result, the net effect on the deficit would be a savings of $680 billion between 2019 and 2026 under the CPI-U growth factor or $486 billion under the CPI-U plus 1 growth factor.

CBO estimates that per-enrollee caps would generate gross savings for the federal government of $598 billion between 2020 and 2026 using the CPI-U growth factor or $383 billion using CPI-U plus 1, for savings of about 16 percent and 10 percent, respectively, from the current-law projection of total federal Medicaid spending for the period. The gross savings would represent about 20 percent and 12 percent, respectively, of projected federal Medicaid spending in 2026.

Some of the difference in gross savings between the overall and per-enrollee caps results from the later start for per-enrollee caps. If the overall caps also took effect in 2020, the gross savings would be $673 billion for the alternative using the CPI-U and $480 billion for the one using the CPI-U plus 1.

The gross savings under this option would be partially offset because, as with overall caps, the federal savings associated with per-enrollee caps would represent large reductions in revenues for states, and CBO expects that states would take a variety of similar actions to offset a portion of the additional costs that they would face. Although per-enrollee caps provide additional federal payments for each enrollee, per-enrollee caps below projections of federal per-enrollee spending would create a loss of revenues to states for each enrollee. Therefore, CBO anticipates that some states also would take action to restrict enrollment under per-enrollee caps. As with overall caps, CBO and JCT estimate that roughly three-quarters of enrollees who lost Medicaid coverage would become uninsured. The remainder would instead either obtain subsidized health insurance through the marketplaces or enroll in an employment-based plan. For the CPI-U alternative, the agencies estimate that the additional coverage would increase outlays by $15 billion and decrease revenues by $7 billion from 2020 to 2026. For the CPI-U plus 1 alternative, the agencies estimate that the coverage would increase outlays by $9 billion and decrease revenues by $4 billion over the same period. As a result, the net effect on the deficit would be a savings of $576 billion between 2020 and 2026 under the CPI-U growth factor or $370 billion under the CPI-U plus 1 growth factor.

Other Considerations

Because caps on federal Medicaid spending would represent a fundamental restructuring of Medicaid financing, several other considerations would need to be addressed. In addition to their consequences for the federal budget, the limits on federal spending would require new administrative mechanisms for full implementation. The Centers for Medicare & Medicaid Services (CMS, the federal agency within the Department of Health and Human Services that administers Medicaid) would need to establish a mechanism for enforcing the caps to account for the delayed availability of the necessary data to calculate the final limits. Administrative data on Medicaid spending and enrollment do not currently provide enough information to establish per-enrollee caps such as those modeled in this option. Such data would need to be developed. Beyond the challenges of implementation, the caps on Medicaid spending could have significant consequences for states and enrollees.

Enforcement. Before overall or per-enrollee caps could take effect, CMS would need to establish mechanisms to ensure state compliance. The nature of that enforcement would depend on legislative direction given to the Secretary for establishing the caps. If the growth factors for either type of cap were based on the value of some specific measure of economic activity, such as the CPI-U (as opposed to a fixed growth factor that consisted of an annual increase of a certain percentage), CMS would not know the final spending limits until after the end of the fiscal year, when the measure would be finalized, unless growth from some earlier period was used instead. Per-enrollee caps would require additional delays because final enrollment data for any year would not be available for at least several months after the fiscal year's end. In addition, states usually make accounting adjustments to a prior year's spending long after the end of the fiscal year. Such delays would prevent CMS from calculating and states from determining the final limits on a current year's spending until well into the next fiscal year. Although states could attempt to forecast the limits and could update those forecasts over the course of a year, it would be difficult to precisely target spending to remain below the caps; states therefore could face reductions in funding triggered by spending above the caps.

Data Availability. States currently report enough data for CMS to determine per-enrollee spending in only two eligibility categories: newly eligible adults and all other enrollees combined. To set per-enrollee caps on the basis of currently available data, lawmakers could establish either a single overall per-enrollee cap that represented average spending in all Medicaid eligibility categories or two caps—one for each of the groups of enrollees for which data were available. As stated above, broad categories for per-enrollee caps create incentives to favor the enrollment of people in eligibility categories with lower rather than higher costs. Alternatively, if lawmakers wanted to establish caps for the four principal groups considered under this option (the elderly, people with disabilities, children, and nondisabled, nonelderly adults), they could direct the Secretary to rely on internal state data regarding enrollment among and spending for the four groups, or they could direct the Secretary to make available a new uniform state-reported data source for the relevant information. Relying on state-submitted data might create an incentive for states to submit enrollment and spending data that would maximize the caps, whereas requiring the Secretary to establish a new uniform data set would require additional time to design, develop, and implement the new system.

Effects on States. Capping federal Medicaid spending would fundamentally change the program's federal-and-state division of financing. In particular, if the maximum federal commitment under the caps was below the federal expenditures that would have otherwise occurred (as would be the case for the alternatives discussed above), such caps would shift responsibility for the program's costs to the states.

In the CPI-U or CPI-U plus 1 alternatives, the savings to the federal government would represent lost revenues to states, and those losses would increase over time as the gap grew larger between the states' costs and the federal payments.

The caps on federal Medicaid payments also would expose states to increased financial risk arising from changes in the marketplaces or in the broader economy—elements over which the states have little control, if any. If overall caps were adopted and the economy entered a recession, for example, the growth of federal Medicaid payments would be unlikely to keep pace with the rising enrollment and need for services. (Between 2007 and 2010, Medicaid enrollment increased by about 14 percent.) Under a system of per-enrollee caps with growth based on the CPI-U or CPI-U plus 1, federal payments would rise with enrollment but would not respond if cost growth for health care exceeded growth in the index. If the growth of per-enrollee caps was based on a health care–specific index, such as national health expenditures per capita, payments would adjust to average changes in the nationwide health care system but not to idiosyncratic changes in any particular state's health care system—and the federal savings would be smaller than those under the alternative using the CPI-U.

With lower federal funding and greater budgetary uncertainty, states would have a stronger incentive than under current law to reduce the costs of their Medicaid programs. To help states reduce costs, some proponents of Medicaid caps consider new programmatic flexibility for states to be an essential feature of such a policy. That flexibility could take various forms: States could be permitted to administer their programs without the need to meet some or all of CMS's current administrative requirements; experiment with new ways to deliver health care to enrollees; or reduce payment rates to providers and health plans, eliminate services, or reduce coverage for current-law eligibility groups. Greater flexibility could permit states to offset the losses of federal funding estimated under this option without having to raise additional revenues or cut other state programs. Whether states would have enough flexibility to prevent cuts in enrollment or in services would depend largely on how much states needed to cut spending to stay below the caps.

Effects on Enrollees. The ways in which Medicaid spending caps affected individual enrollees would depend greatly on how states responded to the caps, which in turn would be affected by the particular structure of their programs. If a state chose to leave its Medicaid programs unchanged and instead found other ways to offset the loss of federal funds, enrollees would notice little or no change in their Medicaid coverage. By contrast, enrollees could face more significant effects if a state reduced providers' payment rates or payments to managed care plans, cut covered services, or curtailed eligibility—either in keeping with current law or to a greater extent, if given the flexibility. If states reduced payment rates, fewer providers might be willing to accept Medicaid patients, especially given that, in many cases, Medicaid's rates are already significantly below those of Medicare or private insurance for some of the same services. If states reduced payments to Medicaid managed care plans, some plans might shrink their provider networks, curtail quality assurance, or drop out of the program altogether. If states reduced covered services, some enrollees might decide either to pay out of pocket or to forgo those services entirely. And if states narrowed their categories of eligibility (including the optional expansion under the ACA), some of those enrollees would lose access to Medicaid coverage, although some would become eligible for subsidies for private coverage through the market-places or could choose to enroll in employment-based insurance, if available, which would affect federal revenues, as discussed previously.

RELATED OPTION: Mandatory Spending, Option 13

RELATED CBO PUBLICATION: *Federal Grants to State and Local Governments* (March 2013), www.cbo.gov/publication/43967

Health—Option 3 **Function 550**

Limit States' Taxes on Health Care Providers

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
Lower the safe-harbor threshold to 5 percent	0	-1.4	-1.5	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-6.1	-15.9
Lower the safe-harbor threshold to 4 percent	0	-3.4	-3.7	-4.0	-4.2	-4.4	-4.6	-4.9	-5.2	-5.6	-15.3	-39.9

This option would take effect in October 2017.

Medicaid is a joint federal-and-state program that pays for health care services for low-income people in various demographic groups. State governments operate the program under federal statutory and regulatory oversight, and the federal government reimburses a portion of each state's costs at matching rates that generally range from 51 percent to 80 percent, depending on the per capita income of the state and on the share of enrollees (if any) in each state that became eligible for Medicaid as a result of the optional expansion of that program under the Affordable Care Act. The rest of the funding must come from state revenues, either from general funds or from another source. Most states finance at least a portion of their Medicaid spending through taxes collected from health care providers. In the early 1990s, the Congress required states that taxed health care providers to collect those taxes at uniform rates from all providers of the same type. Those rules were created because some states were taxing Medicaid providers either exclusively or at higher rates than other providers of the same type (hospitals, for example) with the intention of returning the collected taxes to those providers in the form of higher Medicaid payments. Such "hold harmless" provisions were leading to large increases in federal Medicaid outlays but not to concordant increases in states' Medicaid spending, despite the expectation created under Medicaid's matching-rate formula.

However, federal law grants a "safe harbor" exception to hold-harmless provisions when a state collects taxes that do not exceed 6 percent of a provider's net patient revenues. This option would lower the safe-harbor threshold, starting in October 2017, to 5 percent or 4 percent. The Congressional Budget Office estimates that capping the threshold at 5 percent would reduce mandatory spending by $16 billion between 2017 and 2026 and that capping it at 4 percent would reduce mandatory spending by $40 billion over that period.

Lowering the safe-harbor threshold would reduce the amount of taxes that states could collect from providers without incurring reductions in federal payments. Under the new limits, states would need to decide whether to continue spending the same amount (and make up the difference out of other revenues) or to cut spending by the difference between the old and new thresholds. In the first case, states might replace lost revenue by raising additional general revenues or by reducing spending elsewhere in their budgets and transferring those amounts to Medicaid spending. In that case, the federal government would continue to match the same amount of state spending, and there would be no change in federal spending. Alternatively, states could decide not to replace the lost revenue and instead cut their Medicaid spending. That choice would reduce federal spending because the matched amounts would be smaller.

CBO expects that different states would respond to a lower safe-harbor threshold in different ways along a continuum. Most states would probably not replace all of the revenues lost as a result of the lower threshold for the taxation of providers. The health care providers being taxed directly benefit from higher Medicaid payment rates, making the imposition of such taxes an easier choice for states than alternative choices for replacing such revenues. However, most states would be unlikely to cut Medicaid spending by the full amount of the lost revenues because they might deem other choices to be preferable. CBO anticipates that, on average, states would replace half of the lost revenues, but that estimate is highly uncertain.

The main rationale for this option is that it would lower Medicaid spending by limiting a state financing mechanism that has inflated federal payments to states for Medicaid beyond the amount the federal government would have paid in the absence of such taxes. An argument against this option is that, to the extent that states cut back spending on Medicaid in response to the lost revenues, health care providers could face lower payment rates that might make some of them less willing to treat Medicaid patients. Moreover, some Medicaid enrollees could face a reduction in services or possibly lose their eligibility for the program if states restricted enrollment to curtail costs.

Health—Option 4 **Function 550**

Repeal All Insurance Coverage Provisions of the Affordable Care Act

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays[a]	0	-110	-157	-169	-184	-197	-210	-223	-235	-248	-621	-1,733
Change in Revenues[b]	0	-30	-39	-42	-50	-56	-61	-67	-73	-79	-161	-498
Decrease in the Deficit	0	-81	-118	-127	-134	-141	-149	-156	-162	-169	-460	-1,236

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

a. Estimates include effects on Social Security outlays, which are classified as off-budget.

b. Estimates include effects on Social Security payroll tax receipts, which are classified as off-budget.

The federal government currently regulates and subsidizes health insurance coverage through various provisions, many of them included in the Affordable Care Act (ACA). Although the ACA has numerous other provisions as well, the following elements specifically concern insurance coverage:

- Subsidized health insurance is now available to many individual people and families, who can purchase that coverage through designated marketplaces.
- Insurers who sell plans either through the marketplaces or directly to consumers must provide specific benefits and amounts of coverage. They cannot deny coverage or vary premiums because of an enrollee's health status, and they can vary premiums only on the basis of age, tobacco use, and geographic location.
- States are permitted but not required to expand eligibility for Medicaid to include adults whose income is up to 138 percent of the federal poverty guidelines (also called the federal poverty level), with the federal government paying nearly all of the costs for expanding Medicaid coverage to those new enrollees.
- Under a provision known as the individual mandate, most citizens of the United States (and noncitizens who are lawfully present in the country) must obtain health insurance or pay a penalty for not doing so.
- Under a provision known as the employer mandate, employers with 50 or more employees generally must either offer health insurance coverage that meets specific standards or pay a penalty for declining to do so.
- A federal excise tax is scheduled to be imposed on certain employment-based health plans with relatively high premiums.

All of those provisions have led to significant increases in the number of people with insurance coverage, but they also have been controversial, and there have been proposals to repeal some or all of them. This option, which would take effect in January 2018, would repeal all of the ACA's insurance coverage provisions—including but not limited to the subsidies, regulations, penalties, and taxes described above.[1] This option would not repeal the ACA entirely, however. In particular, the increases in taxes and the reductions in federal payments for Medicare and other programs resulting from other provisions of the ACA would remain in force.

This option would reduce the deficit by $1,236 billion, the Congressional Budget Office and the staff of the Joint Committee on Taxation (JCT) estimate. Those net savings would largely result from the repeal of the new subsidies for Medicaid and for plans purchased through

1. For additional details, see Congressional Budget Office, *Federal Subsidies for Health Insurance Coverage for People Under Age 65: 2016 to 2026* (March 2016), p. 15, www.cbo.gov/publication/51385. For an analysis of the potential effects of a full repeal, see Congressional Budget Office, *Budgetary and Economic Effects of Repealing the Affordable Care Act* (June 2015), www.cbo.gov/publication/50252. Although the savings from repealing the insurance coverage provisions could be used to finance an alternative system of subsidies, and the act's regulatory provisions could be replaced with others designed to reduce premiums or increase insurance coverage, analysis of such options (which could be designed in myriad ways) is beyond the scope of this report.

the marketplaces (gross savings of $1,751 billion through 2026, consisting of a reduction in outlays and an increase in revenues) that would be partially offset by a repeal of penalties and taxes and by other effects (totaling $516 billion through 2026).

The largest amount of gross savings comes from reducing federal outlays for Medicaid and the Children's Health Insurance Program ($950 billion), and the next largest comes as a result of eliminating the federal subsidies for insurance purchased through the marketplaces or a related program, the Basic Health Program ($794 billion). Because the premium subsidies for marketplace plans are structured as refundable tax credits, a portion of the savings would take the form of reduced outlays (to the extent that the credit amounts exceed enrollees' income tax liability); the remainder would take the form of higher tax revenues.

The gross savings generated under this option would be partially offset by the effects of eliminating several of the ACA's provisions that are projected to reduce federal deficits under current law. The elimination of those provisions would affect both revenues and outlays. Significant sources of costs include the repeal of the provisions that impose penalties on some employers ($169 billion) and uninsured people ($35 billion) and those that impose an excise tax on certain high-premium insurance plans ($79 billion). Increases in employment-based coverage stemming from a repeal would reduce revenues as well because most payments for that coverage are exempt from income and payroll taxes.

Repealing the insurance coverage provisions of the ACA also would cause large changes both in the number of people with health insurance and in the sources of that coverage. CBO and JCT estimate that this option would boost the number of people under age 65 who are uninsured by about 23 million in most years before 2026—from about 28 million under current law to about 51 million in 2026. In 2026, the number of people with employment-based coverage would increase by about 10 million, the number with coverage purchased individually (including through the marketplaces) would decrease by 14 million, and the number of people with coverage through Medicaid would decrease by 19 million.

Under this option, CBO and JCT anticipate that, on average, premiums also would be lower in the nongroup market (in which health insurance is purchased directly by people) than they are under current law. That effect would arise from reductions in the scope of benefits covered and in the share of costs covered by health insurance (resulting in a corresponding increase in out-of-pocket costs for insured people). Moreover, the people who obtained health insurance in the nongroup market would be expected to be healthier, on average, than those obtaining such coverage under current law because less healthy people could be denied coverage altogether under this option or could face substantially higher premiums that could make such coverage unaffordable.

One argument in favor of this option is that it would rescind the current-law individual mandate along with its associated penalties, which hurt some people financially. (Under that mandate, people generally must either purchase health insurance or pay a penalty.) For the reasons discussed above, premiums in the nongroup market would be lower, on average, under this option.

Another argument in favor of this option is that it is likely to increase employment-based insurance coverage for some workers, in part because the narrower choices for obtaining insurance outside the workplace would encourage employers to offer coverage and employees to take up that coverage. In addition, it would reduce costs for some employers: They would no longer be subject to a penalty if they did not offer insurance, and they would not incur the costs of reporting to the Internal Revenue Service on their employees' insurance coverage.

An additional argument in favor of this option is that both the total number of hours worked and gross domestic product would rise. In previous work, CBO projected that the labor force would be smaller by about 2 million full-time-equivalent workers in 2025 under the ACA than it would have been in the absence of that law. Under this option, those effects would largely be reversed.

An argument against this option concerns the resulting large increases in the number of people who would end up without health insurance. On average, out-of-pocket costs in the nongroup market would rise, and the availability of affordable insurance would fall for people who are in poor health or have low income. In many cases, older people and those in poor health would be denied coverage altogether in the nongroup market. The lack of subsidies for coverage would render insurance unaffordable for many people who, under current law, could purchase nongroup coverage. Moreover, repealing the subsidies for purchases in the nongroup market would create a tax inequity: Employment-based health insurance would continue to receive favorable tax treatment; insurance bought by individual people generally would not.

Another rationale against this option is that its largest effects would fall on low-income adults who, once the Medicaid expansion was rescinded, might lose access to comprehensive health insurance. Low-income adults generally have less access to employment-based health insurance than other adults do because many of them work part time or for employers that do not offer coverage.

RELATED OPTION: Health, Option 5

RELATED CBO PUBLICATIONS: *Federal Subsidies for Health Insurance Coverage for People Under Age 65: 2016 to 2026* (March 24, 2016), www.cbo.gov/publication/51385; letter to the Honorable Mike Enzi regarding the budgetary effects of H.R. 3762, the Restoring Americans' Healthcare Freedom Reconciliation Act, as passed by the Senate on December 3, 2015 (December 11, 2015), www.cbo.gov/publication/51090; *Budgetary and Economic Effects of Repealing the Affordable Care Act* (June 2015), www.cbo.gov/publication/50252; Edward Harris and Shannon Mok, *How CBO Estimates the Effects of the Affordable Care Act on the Labor Market,* Working Paper 2015-09 (December 2015), www.cbo.gov/publication/51065

Health—Option 5 Function 550

Repeal the Individual Health Insurance Mandate

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Mandatory Outlays	0	-22	-34	-37	-42	-44	-46	-49	-52	-55	-134	-381
Change in Revenues[a]	0	4	6	5	4	3	3	3	4	4	18	35
Decrease in the Deficit	0	-26	-39	-42	-45	-47	-50	-53	-56	-59	-152	-416

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

a. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

The Affordable Care Act (ACA) includes a provision, generally called the individual mandate, that requires most U.S. citizens and noncitizens who lawfully reside in the country to have health insurance that meets specified standards. People who have no health insurance (and who are not exempt from the mandate) must pay a penalty that is collected by the Internal Revenue Service in the greater of two amounts: either a fixed charge for every uninsured adult in a household plus half that amount for each child, or an income-based assessment set at 2.5 percent of the household's income above the filing threshold for its income tax filing status. The dollar-amount penalty is $695 per uninsured adult in 2016 and is set to rise annually with the rate of general inflation. Penalties are subject to caps and are prorated for people who are uninsured for only part of a year.

Under current law, the individual mandate and its associated penalties increase federal deficits by encouraging people to obtain subsidized coverage—through Medicaid, the health insurance marketplaces established under the ACA, or employment-based plans (which receive indirect subsidies to the extent that premiums for that coverage are excluded from taxable compensation). Penalty payments from uninsured people partially offset those costs. Between 2017 and 2026, the Congressional Budget Office and the staff of the Joint Committee on Taxation (JCT) project, the federal government will collect $38 billion in penalty payments from uninsured people.

Beginning in January 2018, this option would eliminate the individual mandate; the ACA's other provisions (including marketplace subsidies) would remain in place. CBO and JCT estimate that this option would reduce federal budget deficits by $416 billion between 2018 and 2026. Under this option, the loss of penalty revenue would be more than offset by the savings from reduced spending on federal subsidies for health insurance coverage.

This option would decrease outlays by $381 billion between 2018 and 2026, CBO and JCT estimate. Most of that amount (about $279 billion) would come from a drop in Medicaid enrollment. In addition, between 2018 and 2026, federal spending on subsidies for insurance purchased through the marketplaces would decline by $96 billion. (Those subsidies fall into two categories: those that cover a portion of participants' health insurance premiums and those that reduce out-of-pocket payments required under insurance policies.) Other effects would account for the remaining $6 billion reduction in outlays.

CBO and JCT estimate that this option would increase revenues by $35 billion between 2018 and 2026. The removal of the mandate would increase tax revenues by about $56 billion because reductions in employment-based coverage would result in more taxable compensation for employees. Revenues would increase by an additional $16 billion because a portion of the decrease in marketplace subsidies for health insurance premiums would be provided in the form of increases in recipients' tax payments. (The subsidies for health insurance premiums are structured as refundable tax credits: The portions that exceed taxpayers' other income tax liabilities are classified as outlays; those that reduce tax payments are classified as reductions in revenues.) The increase in revenues over the period from 2018 to 2026 would be partially offset by a $35 billion loss from eliminating the individual mandate's penalties. Other effects would account for an additional $1 billion reduction in revenues.

A repeal of the individual mandate would cause a substantial reduction in the number of people with health insurance, CBO and JCT estimate. Under current law, about 28 million people under age 65 in the United States would be uninsured in 2026. This option would change that number as follows: About 2 million fewer people would have employment-based coverage, about 6 million fewer people would obtain nongroup policies (insurance people can purchase directly either in the marketplaces or from insurers outside the marketplaces), and about 7 million fewer people would have coverage under Medicaid. All together, the agencies estimate, 43 million people would be uninsured in 2026.

CBO and JCT estimate that a repeal of the individual mandate also would result in higher premiums for coverage purchased through the nongroup market. Health plans in the nongroup market would still be required to conform to the ACA's rules for that coverage. Insurers could not deny coverage or vary premiums because of an enrollee's health status nor limit coverage because of preexisting medical conditions. They would be permitted to make only limited adjustments to premiums because of age, tobacco use, and geographic location. Those features are most attractive to applicants who expect to have relatively high costs for health care, and CBO and JCT anticipate that repealing the individual mandate would tend to cause smaller reductions in coverage among older and less healthy people and larger reductions among younger and healthier people, thus increasing premiums in the nongroup market.

The effects of such adverse selection, however, would be mitigated somewhat by other factors—including the marketplace subsidies (which make health insurance less costly and more attractive to younger and healthier enrollees who are eligible for those subsidies) and the annual open-enrollment periods in the nongroup market (which reduce the incentive for people to wait until they become ill to obtain coverage). Moreover, the available subsidies would greatly reduce the effect of premium increases on coverage among subsidized enrollees. CBO and JCT estimate that adverse selection would increase premiums for policies in the nongroup market, whether purchased through the marketplaces or not, by roughly 20 percent relative to premiums under current law. That change, in turn, would increase federal per capita costs for people receiving subsidies through the marketplaces.

Many proponents of this option argue that the decision to obtain health insurance is a private matter that should be beyond the reach of the federal government. Another argument in the option's favor is that the mandate and its associated penalties reduce the financial well-being of some people. Because of the rating rules in place for nongroup coverage, young and healthy enrollees without large subsidies effectively cross-subsidize older, less healthy enrollees when they are required to purchase insurance or pay a penalty. An additional concern is that the current system uses the Internal Revenue Service to enforce the mandate, increasing the complexity of the tax system and interfering with other efforts to increase tax compliance. Finally, the mandate necessitates reporting requirements that raise the costs of complying with the tax code both for individual enrollees and for their insurers.

Many opponents of the option point to the reductions in coverage and increases in premiums that are likely to occur and argue that it is appropriate for the government to require people to have health insurance in order to prevent those outcomes. Another argument against the option holds that penalizing people who do not obtain coverage improves economic efficiency. In particular, by increasing the private costs of being uninsured, the individual mandate encourages people to obtain coverage and, in that way, might reduce the social costs of caring for people without insurance. In some cases, uninsured people pay less than the costs of the care they receive, resulting in lower payments to providers or higher costs for others. In the absence of a mandate, those social costs would probably increase relative to the case under current law.

RELATED OPTION: Health, Option 4

RELATED CBO PUBLICATIONS: *Federal Subsidies for Health Insurance Coverage for People Under Age 65: 2016 to 2026* (March 2016), www.cbo.gov/publication/51385; *Private Health Insurance Premiums and Federal Policy* (February 2016), www.cbo.gov/publication/51130

Health—Option 6 **Function 550**

Introduce Minimum Out-of-Pocket Requirements Under TRICARE for Life

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Mandatory Outlays												
MERHCF	0	*	*	-1.4	-2.4	-2.6	-2.8	-3.0	-3.2	-3.3	-3.7	-18.6
Medicare	0	0	0	-0.4	-1.1	-1.3	-1.4	-1.4	-1.5	-1.6	-1.5	-8.7
Total	0	*	*	-1.9	-3.4	-3.9	-4.1	-4.4	-4.7	-5.0	-5.2	-27.3

This option would take effect in January 2020.

MERHCF = Department of Defense Medicare-Eligible Retiree Health Care Fund; * = between zero and $50 million.

TRICARE for Life (TFL) was introduced in 2002 as a supplement to Medicare for military retirees and their Medicare-eligible family members. The program pays nearly all medical costs not covered by Medicare and requires few out-of-pocket fees. Because the Department of Defense (DoD) is a passive payer in the program—it neither manages care nor provides incentives for the cost-conscious use of services—it has virtually no means of controlling the program's costs. In contrast, most public and private programs that pay for health care either manage the care or require enrollees to pay deductibles or copayments up to a specified threshold. In 2015, DoD spent $10 billion for the care delivered to Medicare-eligible beneficiaries by military treatment facilities and by civilian providers (in addition to the amount spent for those patients through Medicare).

This option would introduce minimum out-of-pocket requirements for TFL beneficiaries. For calendar year 2020, TFL would not cover any of the first $750 of an enrollee's cost-sharing payments under Medicare and would cover only 50 percent of the next $6,750 in such payments. Because all further costs would be covered by TFL, enrollees would not be obligated to pay more than $4,125 in 2020. Those dollar limits would be indexed to growth in average Medicare costs (excluding Part D drug benefits) for later years. Currently, military treatment facilities charge very small or no copayments for hospital services provided to TFL beneficiaries. To reduce beneficiaries' incentives to avoid out-of-pocket costs by switching to military facilities, this option would require TFL beneficiaries seeking care from those facilities to make payments that would be roughly comparable to the charges they would face at civilian facilities.

This option would reduce spending for Medicare as well as for TFL because higher out-of-pocket costs would lead beneficiaries to use somewhat fewer medical services. All together, including some small implementation costs in 2018 and 2019, this option would reduce federal spending devoted to TFL beneficiaries by $27 billion between 2018 and 2026, the Congressional Budget Office estimates. About two-fifths of those savings would come from reduced spending for medical services both from Medicare and from the fund that pays for TFL expenditures because of reduced demand for those services. The rest would represent a shift of spending from the federal government to military retirees and their families.

An advantage of this option is that greater cost sharing would increase TFL beneficiaries' awareness of the cost of health care and promote a corresponding restraint in their use of medical services. Research has generally shown that introducing modest cost sharing can reduce medical expenditures without causing measurable increases in adverse health outcomes for most people.

A disadvantage is that this option could discourage some patients (particularly low-income patients) from seeking preventive medical care or from managing their chronic conditions under close medical supervision, which might negatively affect their health.

RELATED OPTIONS: Health, Options 7, 15

RELATED CBO PUBLICATIONS: *Approaches to Reforming Military Health Care* (forthcoming); *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *Approaches to Reducing Federal Spending on Military Health Care* (January 2014), www.cbo.gov/publication/44993

Health—Option 7 **Function 570**

Change the Cost-Sharing Rules for Medicare and Restrict Medigap Insurance

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
Establish uniform cost sharing for Medicare with daily inpatient copayments	0	0	0	-2.3	-2.9	-2.9	-2.7	-2.4	-2.3	-2.4	-5.2	-17.9
Establish uniform cost sharing for Medicare	0	0	0	-2.4	-3.1	-3.0	-2.8	-2.6	-2.3	-2.4	-5.5	-18.6
Restrict medigap plans	0	0	0	-4.8	-6.4	-6.6	-6.7	-6.6	-6.7	-6.7	-11.2	-44.5
Combine the second and third alternatives above[a]	0	0	0	-7.5	-10.0	-10.1	-9.9	-9.6	-9.5	-9.6	-17.5	-66.2

This option would take effect in January 2020.

a. If the second and third alternatives were enacted together, the total effect would be greater than the sum of the effects of each alternative because of interactions between them.

Overview of the Issue

For people who have Medicare or any other type of health insurance coverage, payments for health care fall into two broad categories: premiums and cost sharing. A premium is a fixed, recurring amount paid by an enrollee in advance for an insurance policy (which then limits financial risk by covering some or all costs of health care goods and services). Cost sharing consists of out-of-pocket payments that enrollees are required to make when they receive health care. The basic Medicare benefit can leave beneficiaries responsible for a substantial amount of cost sharing, so many people obtain supplemental coverage. Many beneficiaries obtain such coverage through a former employer or through a state Medicaid program. Others choose what is known as a medigap plan, an individual insurance policy that covers most or all of Medicare's cost sharing.

In general, premiums distribute the cost of medical care among all enrollees; cost sharing concentrates costs on people who use more medical care. Insurance plans typically vary three basic elements to determine the cost-sharing obligations of their enrollees:

- The deductible, an initial amount of spending below which an enrollee pays all costs;
- The catastrophic cap, a limit on an enrollee's total out-of-pocket spending; and
- The share of costs an enrollee pays between the deductible and the catastrophic cap (which may vary according to the type of service covered).

Deductibles and catastrophic caps typically apply on an annual basis. In between those points, the portion of the cost borne by the enrollee is usually specified as a percentage of the total cost of an item or service (in which case it is called coinsurance) or as a fixed amount for each item or service (in which case it is called a copayment). If other aspects of an insurance plan are the same, lower cost-sharing requirements translate to higher premiums—because insurers must charge more to cover their higher share of medical spending—and higher cost-sharing requirements translate to lower premiums.

Research has shown that people who are not subject to cost sharing tend to use more medical care than do people who are required to pay some or all of the costs of their care out of pocket. The RAND health insurance experiment conducted from 1974 to 1982 examined a nonelderly population and showed that health care spending was about 45 percent higher for participants without any cost sharing than for those who effectively faced a high deductible; average spending for people with intermediate levels of cost sharing fell between spending for those two groups.[1] More recent studies also concluded that higher cost sharing led to lower health care spending: A 2010 study found that in response to higher cost sharing, Medicare beneficiaries reduced both the number of visits to physicians and the use of prescription drugs to a degree roughly consistent with the results of the RAND experiment.[2]

Those findings have driven interest in using additional cost sharing as a tool to restrain the growth of health care spending. However, increases in cost sharing expose people to additional financial risk and may deter some enrollees from obtaining necessary care, including preventive care, that could limit the need for more expensive care in the future.[3] In the RAND experiment, cost sharing reduced the use of effective care and less effective care (as defined by a team of physicians) by roughly equal amounts. Although the RAND researchers found that cost sharing had no effect on health in general, among the poorest and sickest participants, those with no cost sharing were healthier by some measures than those who faced some cost sharing. In theory, to address the concern that patients might forgo necessary care, insurance policies could be designed to apply less cost sharing for services that are preventive or unavoidable and more cost sharing for services that are discretionary or that provide limited health benefits. In practice, however, that distinction can be difficult to draw, so trade-offs often occur between providing insurance protection and restraining total spending on health care.

Medicare's Current Cost Sharing. In the traditional fee for-service portion of the Medicare program (Parts A and B), the cost sharing that enrollees face varies significantly depending on the type of service provided. Under Part A, which primarily covers the services of hospitals and other facilities, enrollees are liable for a separate deductible for each "spell of illness" or injury for which they are hospitalized. That deductible will be $1,316 in 2017. In addition, enrollees are subject to substantial daily copayments for extended stays in hospitals and skilled nursing facilities. Under Part B, which mainly covers outpatient services (such as visits to a doctor), enrollees face an annual deductible that will be $183 in 2017. Once their spending on Part B services has reached that deductible amount, enrollees generally pay 20 percent of allowable costs for most Part B services, although cost sharing is higher for some outpatient hospital care. Certain services that Medicare covers—such as preventive care, certain hospice services, home health visits, and laboratory tests—require no cost sharing. Because of those variations, enrollees lack consistent incentives to weigh relative costs when choosing among treatment options. Moreover, Medicare patients who incur extremely high medical costs may be obligated to pay significant amounts because the program does not have a catastrophic cap on cost sharing.

Medicare's cost sharing differs in two significant ways from that of private plans, which provide health insurance for most people under age 65. First, private health insurance plans generally are less complicated because they typically have a single annual deductible that includes all or most medical costs rather than the separate deductibles for hospital and outpatient services under fee-for-service Medicare. Second, unlike fee-for-service Medicare, most private health insurance plans include a catastrophic cap on out-of-pocket costs that limits enrollees' annual spending—so those plans provide more protection from financial risk than Medicare does. Medicare is not unique, however, in charging different cost-sharing amounts for different types of services; many private insurance plans do that as well.

Although proposals to change Medicare's cost sharing generally focus on the traditional fee-for-service program, roughly a third of Medicare enrollees choose private insurance plans (known as Medicare Advantage plans) instead. In order to contract with the Medicare program, Medicare Advantage plans must provide catastrophic caps on cost sharing and meet other federal requirements. However, those plans have some flexibility in structuring other cost-sharing requirements as long as the overall value of the benefit is at least equal to the benefit that fee-for-service Medicare provides. In general, cost-sharing

1. See Joseph P. Newhouse and the Insurance Experiment Group, *Free for All? Lessons From the RAND Health Insurance Experiment* (Harvard University Press, 1993).

2. See Amitabh Chandra, Jonathan Gruber, and Robin McKnight, "Patient Cost-Sharing and Hospitalization Offsets in the Elderly," *American Economic Review,* vol. 100, no. 1 (March 2010), pp. 193–213, http://dx.doi.org/10.1257/aer.100.1.193.

3. CBO has examined the effects of expanding coverage for preventive services and generally found that doing so would generate savings from reduced use of other services that offset only a small portion of the costs of the preventive services. See Congressional Budget Office, letter to the Honorable Nathan Deal regarding the budgetary effects of expanding governmental support for preventive care and wellness services (August 2009), www.cbo.gov/publication/20967.

requirements in Medicare Advantage plans are lower than those in the fee-for-service program. Such features as out-of-pocket caps make Medicare Advantage plans more like plans in the private insurance market.

Part D of Medicare, which provides coverage for prescription drugs, also is administered by private insurers that set their plans' cost sharing (subject to certain statutory and regulatory requirements). By 2020, the standard Part D benefit will include a deductible, a range of spending over which enrollees face 25 percent coinsurance, and a catastrophic threshold above which enrollees are liable for 5 percent of their drug costs. Beyond those required elements, Part D insurers have some ability to specify which drugs are covered and the cost sharing enrollees must pay, requiring more cost sharing for expensive, brand-name drugs and less for generic drugs. Because private insurers administering Medicare Advantage and Part D plans can specify cost-sharing requirements (within limits) and Medicare enrollees can choose a plan on the basis of cost sharing and other factors, proposals to redesign Medicare's cost sharing generally do not focus on those parts of the program. Consequently, policies that would affect cost sharing in Medicare Advantage or Part D are not included in this option.

Supplemental Insurance for Medicare Enrollees. About 85 percent of people who enroll in fee-for-service Medicare have some form of supplemental insurance that reduces or eliminates their cost-sharing obligations and protects them from high medical costs. (Such coverage of cost sharing is uncommon outside fee-for-service Medicare and thus is another difference between that program and typical private insurance.) About 20 percent of enrollees in fee-for-service Medicare receive cost-sharing coverage from Medicaid, which is available to Medicare enrollees with low income and few assets. (Those enrollees often are referred to as dual-eligible beneficiaries.) About 40 percent of fee-for-service enrollees have supplemental coverage through a current or former employer, which tends to reduce, but not eliminate, their cost-sharing liability.[4] About 20 percent of enrollees purchase medigap policies individually, and 5 percent have some other form of supplemental coverage.

Federal law requires medigap plans to conform to one of 10 standard plan types that vary by the extent of their coverage of cost sharing. Roughly half of medigap enrollees choose a plan that offers first-dollar coverage, which pays all deductibles, copayments, and coinsurance. Most other enrollees choose a plan that provides first-dollar coverage for Part A and covers all cost sharing above the deductible for Part B. Starting in 2020, the Medicare Access and CHIP Reauthorization Act of 2015 (MACRA) will prohibit new Medicare beneficiaries from purchasing the most popular types of supplemental plans—those that cover the Part B deductible.

According to a study for the Medicare Payment Advisory Commission, Medicare spends 27 percent more per person on enrollees who have medigap coverage and 14 percent more per person on enrollees who have supplemental coverage from a former employer than it does on enrollees without supplemental coverage.[5] Those estimates are largely consistent with the results of older studies of the relationship between supplemental coverage and Medicare spending, and they take into account various ways in which medigap policyholders and other Medicare enrollees may differ. The researchers also concluded that those differences in spending were mainly attributable to higher use of discretionary or preventive services by people with supplemental coverage, particularly those with first-dollar coverage. Another study demonstrated that spending by Medicare enrollees with supplemental coverage was growing more rapidly than spending by enrollees without such coverage.[6]

Unadjusted differences in spending between groups with and without supplemental coverage partly reflect differences in their health status, but research has generally shown that the differences in spending were still large, even after adjusting for enrollees' health status. People with medigap policies may differ from other Medicare enrollees in other ways because medigap coverage is not assigned randomly, as it might be in a scientific experiment or trial. The 2010 study of Medicare beneficiaries'

4. Some Medicare enrollees are currently employed and have health insurance through their employer, in which case Medicare generally supplements that coverage. As a result, those workers might not benefit from enrolling in Part B of Medicare, so they typically enroll only in Part A.

5. Christopher Hogan, *Exploring the Effects of Secondary Coverage on Medicare Spending for the Elderly* (submitted by Direct Research to the Medicare Payment Advisory Commission, August 2014), http://go.usa.gov/x8XvP (PDF, 389 KB).

6. See Ezra Golberstein and others, "Supplemental Coverage Associated With More Rapid Spending Growth for Medicare Beneficiaries," *Health Affairs*, vol. 32, no. 5 (May 2013), pp. 873–881, http://dx.doi.org/10.1377/hlthaff.2012.1230.

response to increases in cost sharing is important because it more closely resembled an experiment. That study also showed that about 20 percent of the gross savings generated by higher cost sharing for physician visits and prescription drugs—stemming from reduced use—was offset by increases in hospital spending, perhaps because people delayed treatment until a condition worsened.[7]

Collectively, such research provides considerable evidence that Medicare enrollees who are subject to less cost sharing—because of more generous supplemental insurance—use more medical services than other enrollees do. Enrollees with supplemental coverage are liable for only a portion of the costs of any additional services they use (through any remaining cost sharing and through the effect on their premiums for supplemental coverage); taxpayers (through Medicare) bear most of the cost for the additional services.

Key Design Choices That Would Affect Savings

Policymakers could alter Medicare's cost sharing and restrict medigap coverage in various ways to produce savings for the federal government, reduce total health care spending, and create greater uniformity in cost sharing for Medicare enrollees. Those different ways also would alter the distribution of health care costs between healthier and less healthy enrollees.

In particular, there are four main ways to alter cost sharing in Medicare: Deductibles could be increased, decreased, or combined; coinsurance rates and copayments could be changed; a catastrophic cap could be added; and additional limits could be imposed on supplemental insurance coverage of Medicare's cost-sharing obligations. Such changes would interact in important ways. For example, higher deductibles or coinsurance rates would cause enrollees to reach a catastrophic cap more quickly (and at a lower amount of total spending), and limits on supplemental insurance would expose more enrollees to changes in Medicare's cost-sharing rules and thus increase the effects of those changes on Medicare spending. Policymakers also could grandfather current enrollees by applying changes only to new enrollees.

Deductibles. In general, raising the Part A and Part B deductibles would generate savings for the federal government in two ways. First, higher deductibles would increase the initial cost borne by enrollees, leading to a corresponding reduction in the cost borne by the government. Second, some enrollees would choose to forgo some care because of its higher cost, decreasing the amount of health care for which the federal government would be required to pay. The Part A and Part B deductibles could be increased separately, or they could be combined into a single yearly deductible for all services covered by traditional fee-for-service Medicare. Depending on the dollar amount of that combined deductible, federal spending would decrease, increase, or remain the same.

Proposals for a combined deductible generally call for setting it between the current Part A and Part B deductibles. That approach would tend to increase cost sharing for the roughly 65 percent of enrollees who have only Part B spending in a given year and decrease cost sharing for the roughly 20 percent of enrollees who have some Part A spending (usually for an inpatient hospital stay). (About 15 percent of enrollees use no Part A or Part B services in a given year.) In principle, a combined deductible could also encompass spending for drugs under Part D, but such a change would be complicated because Part D is administered separately by private insurance plans.

Coinsurance and Copayments. Raising coinsurance rates and copayments would reduce federal spending in the same way that higher deductibles would, shifting some costs from the federal government to Medicare enrollees and causing enrollees to forgo some care because of higher out-of-pocket costs. Applying higher coinsurance or copayments to types of care that patients are likely to forgo at higher prices, such as elective surgery, would tend to emphasize that effect, decreasing the amount of care provided and thereby magnifying the budgetary effects. Conversely, applying higher cost sharing to types of care for which patients are particularly insensitive to price, such as emergency surgery, would tend to increase costs for enrollees with little effect on the amount of care provided. Some proposals envision wide-ranging changes to Medicare's cost-sharing rules, whereas others would apply changes more narrowly, by introducing coinsurance or copayments for specific services that do not currently require cost sharing, such as home health care, laboratory tests, or the first 20 days of a stay in a skilled nursing facility.

Policymakers face trade-offs in changing coinsurance and copayment rules to reduce Medicare's costs. Coinsurance

7. See Amitabh Chandra, Jonathan Gruber, and Robin McKnight, "Patient Cost-Sharing and Hospitalization Offsets in the Elderly," *American Economic Review,* vol. 100, no. 1 (March 2010), pp. 193–213, http://dx.doi.org/10.1257/aer.100.1.193.

can make patients more sensitive to the cost of their care, but it also can give them less clarity about what the total costs will be. That trade-off is particularly important for someone facing a hospital admission, use of a particular drug, or other costly aspects of health care. Coinsurance can encourage patients to choose lower-cost services, but it can also significantly increase their financial burden. In addition, when coinsurance is combined with an out-of-pocket cap, all subsequent services will be exempt from cost sharing. Patients in that circumstance have no incentive to use services prudently. To manage that trade-off, many private health plans charge a daily copayment for hospital stays (subject to a limit) instead of collecting coinsurance. (Medicare also charges a daily copayment for hospital care, but only for extremely long stays.)

Catastrophic Caps. Most private insurance plans include a catastrophic cap that limits enrollees' out-of-pocket costs; Medicare Parts A and B have no catastrophic cap on cost sharing. Thus, without other changes to Medicare's cost-sharing rules, establishing a catastrophic cap would increase Medicare spending—by requiring the program to pay the entire cost of care above a cap and possibly by increasing the amount of care enrollees sought that exceeded the cap because they would no longer face costs for additional care. Generally, a higher cap would produce a smaller increase in federal spending.

For enrollees in fee-for-service Medicare who have supplemental coverage, adding a catastrophic cap to Medicare would reduce the costs paid by their supplemental policies, resulting in lower premiums for those policies but little change in enrollees' financial risk. For enrollees without supplemental coverage, establishing a cap would reduce financial risk and decrease out-of-pocket costs once their spending exceeded the cap. Imposing modest cost sharing above the catastrophic cap (as in Part D) could preserve some incentive for enrollees who exceeded the cap to use medical care judiciously (although supplemental coverage of that additional cost sharing would eliminate that incentive).

Supplemental Coverage of Medicare's Cost Sharing. About 20 percent of enrollees in fee-for-service Medicare purchase medigap policies, and about 40 percent have retiree coverage through a current or former employer. By reducing or eliminating enrollees' cost-sharing obligations, those policies can mute the incentives for prudent use of medical care that cost sharing is designed to generate. Lawmakers could impose three types of restrictions on supplemental coverage of Medicare's cost-sharing obligations:

- Supplemental policies could be barred from paying for care until an enrollee's out-of-pocket spending reached a specified amount, thus prohibiting medigap plans from offering first-dollar coverage. That limit could be set to match Medicare's deductibles, which would force all enrollees with medigap plans to pay for costs out of pocket until they reached those deductible amounts.

- The percentage or dollar amount of cost sharing above the deductible that medigap plans pay could be limited. Such limits could allow for a catastrophic cap—above which a medigap policy could cover all cost sharing—to reduce enrollees' financial risk. Both that and the previous restriction could be applied to retiree coverage as well as to medigap plans, but regulations on retiree coverage would be more complex to administer than those on medigap insurance.

- A surcharge could be imposed on enrollees who buy medigap policies with first-dollar coverage. (Retiree policies generally do not provide first-dollar coverage.) That surcharge, which could be a flat fee or a percentage of the policy's premium, could be designed to reflect the effect of such coverage on Medicare's costs. To the extent that enrollees continued to buy first-dollar policies, however, total spending on health care would be higher than it would be if such policies were prohibited.

Grandfathering. Another design question for policymakers is whether changes to the rules for cost sharing and supplemental insurance should apply to all Medicare enrollees. One rationale for grandfathering medigap policyholders is that changing the terms of medigap policies already purchased could be considered unfair or unduly burdensome. Medicare enrollees who do not buy medigap insurance when they turn 65 may be charged much higher premiums for such insurance if they delay the purchase until they develop health problems. Thus, many Medicare enrollees pay medigap premiums for years to ensure access to the financial protection of supplemental insurance if their health deteriorates. In the near term, however, the effects on Medicare spending would be smaller if current enrollees were exempt from changes to cost sharing or restrictions on medigap plans, and operating several sets of rules would add to the program's administrative complexity.

Specific Alternatives and Estimates

CBO examined four ways to reduce federal spending on Medicare by modifying its cost-sharing provisions for Part A and Part B services. (Prescription drug coverage under Part D would not change.) The alternatives would apply to all enrollees, with no grandfathering.

The first alternative would seek to simplify Medicare's current mix of cost-sharing requirements by replacing them with a single annual deductible of $750 that would cover most Part A services and all Part B services, a uniform coinsurance rate of 20 percent for all spending above the deductible on those services, and an annual out-of-pocket cap of $7,500. The only exception to those rules would be for inpatient hospital services, for which beneficiaries would be charged a copayment of $250 per day—for up to five days for each hospital spell—instead of the current combination of deductibles and copayments. Medicare would cover all costs for inpatient care after the first five days of each spell. The inpatient hospital copayments would not count toward the combined deductible, but the cost of hospital copayments and all coinsurance would count toward a beneficiary's annual spending cap. CBO estimates that if those changes took effect in January 2020 and if the various thresholds were indexed to increase in later years at the same rate as average fee-for-service Medicare costs per enrollee, this approach would reduce federal outlays by $18 billion between 2020 and 2026.

The second alternative would replace Medicare's current cost sharing with a single annual deductible of $750 for all Part A and Part B services, a uniform coinsurance rate of 20 percent for amounts above that deductible (including inpatient expenses), and an annual out-of-pocket cap of $7,500. This benefit design is the same as the design in the first alternative except that hospital inpatient spending is subject to the 20 percent uniform coinsurance rather than daily inpatient copayments. CBO estimates that if those changes took effect in January 2020 and if the amounts of the various thresholds were indexed as specified in the first alternative, this approach would reduce federal outlays by $19 billion between 2020 and 2026. Estimated savings are greater for this alternative than for the first alternative because Medicare would cover less of the cost for hospital inpatient spending.

The third alternative would leave Medicare's cost-sharing rules unchanged and would not affect employment-based supplemental coverage but would restrict current and future medigap policies. Specifically, it would bar those policies from paying any of the first $750 of an enrollee's cost-sharing obligations for calendar year 2020 and would limit their coverage to 50 percent of the next $6,750 of an enrollee's cost sharing. (Medigap policies would cover all further cost sharing, so policyholders would not pay more than $4,125 in cost sharing in 2020.) CBO estimates that if this option took effect in January 2020 and if the various dollar thresholds were indexed as specified in the first alternative, federal outlays would be reduced by $45 billion between 2020 and 2026.

The fourth alternative combines the changes from the second and third alternatives. All medigap plans would be prohibited from covering any of the new $750 combined deductible for Part A and Part B services, and in 2020, the annual cap on an enrollee's out-of-pocket obligations (including payments by supplemental plans on an enrollee's behalf) would be $7,500. For spending that occurred after the deductible was met but before the cap was reached, medigap policyholders would face a uniform coinsurance rate of 10 percent for all services, whereas Medicare enrollees without supplemental coverage would face a uniform coinsurance rate of 20 percent for all services. In 2020, those provisions would limit medigap enrollees' out-of-pocket spending (excluding medigap premiums) to $4,125; Medicare enrollees without supplemental coverage would pay no more than $7,500 out of pocket. If, like the other alternatives, this combined version took effect in January 2020 and if the various thresholds were indexed to the growth of per-enrollee Medicare costs thereafter, CBO estimates that federal outlays would be $66 billion lower than under current law from 2020 to 2026. Those savings would exceed the sum of the savings from the second and third alternatives because the changes to the cost-sharing rules for Medicare and the restrictions on medigap policies interact, increasing medigap enrollees' exposure to cost sharing. In CBO's estimation, this alternative would further reduce their use of care and thus lower the federal government's costs.

The budgetary effects of changing Medicare's cost-sharing rules would depend to a large extent on the way each alternative was structured. To illustrate that variability, CBO estimated the effects on federal spending of making several types of changes to the deductible and the catastrophic cap in 2020, the first year in which the alternatives would take effect. CBO examined modifications of the second alternative, which would establish uniform cost sharing for Medicare. Raising the deductible by $100 (from $750 to $850) while keeping the catastrophic cap at $7,500 would increase CBO's estimate of federal savings for 2020 through 2026 from about $19 billion to $35 billion. Raising the catastrophic cap by $500 (from $7,500 to $8,000) while keeping the deductible at $750 would increase the estimate to $41 billion. Conversely, lowering the deductible by $100 (from $750 to $650) while keeping the catastrophic cap at $7,500 would reduce CBO's estimate of federal savings to $1 billion. Reducing the catastrophic cap by $500 (from $7,500 to $7,000) while keeping the deductible at $750 would eliminate all savings and increase federal spending to about $5 billion over the period.

Estimates of savings in these alternatives are lower than those that CBO has published in past versions of this volume. In 2014, for example, CBO estimated that changing Medicare's cost-sharing rules would save $54 billion over 10 years and that changing medigap rules would save $53 billion.[8] Those differences arise for several reasons. First, because CBO now estimates that more time would be needed to implement such policies, the savings over the next 10 years for those alternatives would be smaller. Second, CBO made technical improvements in modeling cost-sharing liabilities for Medicare's beneficiaries that reduced the savings that could be achieved from changing Medicare cost-sharing rules. Third, some of MACRA's provisions now prohibit new Medicare beneficiaries from purchasing medigap plans to cover the Part B deductible; those provisions reduced the savings that could be achieved from making additional changes to the medigap rules.

Other Considerations

Substantial changes to the cost-sharing structure of fee-for-service Medicare and the coverage provided by medigap plans would not only reduce costs to the federal government but also would affect Medicare enrollees, other types of supplemental insurance, and administration of the Medicare program.

Effects on Enrollees. The cost-sharing and medigap changes included in this option would affect total health care spending for Medicare enrollees (by changing the amount of health care services they use) and the way in which that spending was divided between the federal government and enrollees and among enrollees themselves. The restrictions on medigap coverage also would affect the premiums enrollees' would pay as well as how much of enrollees' cost-sharing obligations the plans would cover.

Under current law, CBO estimates, Medicare's costs for the average fee-for-service enrollee will be about $13,000 in 2020 and the average enrollee will have about $2,400 in cost-sharing obligations, which may be paid by the enrollee directly out of pocket, by supplemental insurance, or through some combination of the two.[9] Those averages mask substantial variation in individuals' cost-sharing obligations, stemming from differences in health and the use of medical care. For example, in CBO's projections, only one-quarter of enrollees have cost-sharing obligations of more than $2,600 in 2020; their obligations average about $7,100, compared with an average of about $750 for the other three-quarters of fee-for-service enrollees.

Under the fourth alternative, which combines changes in the Medicare benefit with changes in coverage by medigap policies, CBO estimates that Medicare's costs for the average fee-for-service enrollee would be $12,800 in 2020, or $200 below its estimate under current law. However, under the alternative's specific cost-sharing changes and medigap restrictions, enrollees' average cost-sharing obligations would not change because the higher fraction of total health care costs they paid as cost sharing would be offset, on average, by savings from the resulting reduction in their use of health care. (Various combinations of deductibles, coinsurance, catastrophic caps, and medigap restrictions could increase or decrease enrollees' average cost-sharing obligations.) Even so, that alternative would alter the distribution of cost-sharing obligations among enrollees: One-quarter would face cost-sharing obligations of more than $3,200 in 2020; their obligations would average about $6,100. The obligations of the other three-quarters would average about $1,100.

8. See Congressional Budget Office, *Options for Reducing the Deficit: 2015 to 2024* (November 2014), p. 49, www.cbo.gov/publication/49638.

9. That estimate of the average cost per enrollee is based on gross outlays by the Medicare program, so it excludes enrollees' cost-sharing obligations and does not account for offsetting premium payments. The average net per-enrollee cost to Medicare, which accounts for premium payments, would be lower than that gross measure.

(Roughly 10 percent of enrollees would reach the $7,500 cap on cost-sharing obligations.) Those changes reflect a relatively large average decrease in obligations for enrollees with serious illnesses that require extensive care or extended hospitalization and a relatively small average increase in obligations for healthier enrollees who use less care.

For the first alternative, which would add a daily inpatient copayment to a combined deductible and a catastrophic cap, CBO estimates that Medicare's costs for the average fee-for-service enrollee in 2020 would be $12,900, or $100 less than its current-law estimate. Cost-sharing obligations would increase for most beneficiaries, but those with inpatient hospital stays would, on average, pay less of their overall costs and consume slightly more inpatient care. Average cost sharing for beneficiaries with no inpatient hospital stays would rise from the current-law amount of $1,200 to $1,500 by 2020. For beneficiaries with any inpatient hospital stays, average cost sharing would decrease from $7,300 under current law to $5,200. Reductions in financial obligations would be particularly large for beneficiaries with hospital stays of more than 60 days; their average cost sharing would decrease from $23,000 under current law to $7,300 under the first alternative.

The medigap restrictions under the four alternatives would increase the average amount of cost sharing a medigap policyholder paid out of pocket and would decrease, to roughly the same extent, the average amount a medigap plan paid on an enrollee's behalf. Because medigap insurers must compete for business and are subject to state insurance regulations, they would most likely reduce premiums to reflect that reduction in their costs. Overall, most medigap policyholders would have lower health care expenses under this option because their medigap premiums would decrease more than their out-of-pocket payments would increase (mainly because most of a medigap plan's liabilities are generated by a small share of policyholders). However, under this option, in any given year, some enrollees would face higher combined costs for medigap premiums and out-of-pocket payments.

Beyond altering how and how much Medicare enrollees paid for care, the changes included in the alternatives CBO considered would have other effects on enrollees. The changes would give Medicare beneficiaries stronger incentives to use medical services more prudently. However, as noted above, studies have shown that people who are subject to higher cost sharing reduce their use of effective health care and ineffective health care. To avoid reductions in effective care, enrollees' cost sharing could be selectively reduced or eliminated for high-value services—an approach called value-based insurance design. In practice, defining such services can be challenging, and the use of value-based design in private insurance plans has been limited. Furthermore, restricting medigap coverage would prevent Medicare enrollees from buying policies with the low levels of cost sharing that they have shown a preference for in the past. Although most medigap enrollees would have lower overall health care costs under this option, some enrollees would prefer the financial certainty and simplicity of a medigap plan that covered all of their cost-sharing obligations. Those enrollees would probably object to any legislation or regulation that denied them access to full supplemental coverage for their cost sharing.

Effects on Supplemental Insurance. Altering Medicare's cost-sharing structure and limiting supplemental coverage would probably lead to changes in medigap premiums and in enrollees' demand for medigap policies. If those plans were barred from paying the first $750 of an enrollee's cost-sharing liabilities and then from fully covering all cost sharing up to a catastrophic cap—as in the second and third alternatives—the costs borne by medigap plans would decrease; as a result, so would premiums for those plans. On the one hand, lower premiums would make medigap policies more appealing. On the other hand, the restrictions on medigap benefits would reduce the value of such policies to enrollees.

A key reason that people buy medigap coverage is for protection against high out-of-pocket costs. Adding a catastrophic cap to Medicare would reduce financial risk for enrollees in the traditional fee-for-service program who lack supplemental coverage. Therefore, adding a catastrophic cap to Medicare and restricting the coverage provided by medigap plans would probably cause some enrollees, particularly healthier beneficiaries, to forgo purchasing supplemental insurance. Those beneficiaries would tend to consume less health care, and thus to have lower cost sharing, than sicker enrollees would. A decrease in medigap enrollment by relatively healthy people would increase average per-enrollee costs for medigap plans, leading to higher policy premiums (if everything else was equal).

Altering the cost-sharing structure of Medicare, as in the first, second, and fourth alternatives, also would affect costs for employers that provide supplemental coverage for retirees. A unified deductible would tend to increase costs for employers, but the introduction of a catastrophic cap would decrease their costs, particularly for retirees with very high costs for health care. The net effect on an employer's costs would depend on the extent of the coverage and on the health of the retirees. Additionally, the creation of a catastrophic cap for Medicare might cause some employers to scale back or discontinue supplemental coverage for current or future retirees, on the theory that their retirees would be sufficiently protected from financial risk by Medicare alone.

Changing the structure of Medicare cost sharing or supplemental plans also could affect enrollment in Medicare Advantage plans, which currently may provide first-dollar coverage and also must set out-of-pocket spending limits. Policy changes that prohibited medigap plans from providing first-dollar coverage would tend to make Medicare Advantage plans more attractive to some beneficiaries and increase Medicare Advantage enrollment. Setting catastrophic limits on spending, however, would tend to make Medicare Advantage less attractive and decrease Medicare Advantage enrollment. The net effects of changes in enrollment in Medicare Advantage plans on federal spending are unclear and would depend on which plans were affected.

CBO estimates that implementing a unified deductible and catastrophic cap as described above would decrease federal spending on Medicaid by a small amount between 2020 and 2026. Those provisions would have two largely offsetting effects. First, the introduction of a catastrophic cap would shift costs from Medicaid to Medicare for some enrollees with high medical expenses. Second, the unified deductible and uniform coinsurance rate would shift some costs from Medicare to Medicaid for enrollees with lower medical expenses. Under the alternatives examined above, CBO estimates, the net result of those offsetting changes would be a small overall decrease in federal spending on Medicaid.

Because the effects of changes in cost sharing would vary from one state to another, estimates of their implications for federal spending on Medicaid are highly uncertain. Many states cap cost-sharing payments to providers of Medicare services to keep the total amounts that providers receive at or below Medicaid's payment rates for the same services. Because the amounts that many state Medicaid programs pay providers are below those established for Medicare, some states end up covering only a small portion—if any—of Medicare beneficiaries' cost-sharing obligations. That constraint reduces the effects on Medicaid spending that would otherwise arise from a change in Medicare's cost sharing.[10] CBO accounts for the average effects of state-level variation in Medicaid payment policies, but the agency's analysis does not incorporate detailed estimates of different states' cost-sharing limits.

Administrative Effects. Altering the cost-sharing rules for Medicare and medigap plans would raise myriad administrative issues. Health care providers might not know how much to collect from a Medicare enrollee during an office visit because it might be difficult to determine whether the enrollee's cost-sharing payments had reached the combined deductible or exceeded the new catastrophic cap. Moreover, administering the new cost-sharing structure would require coordination that currently does not exist among the organizations that review and process Medicare claims, insurers that provide supplemental coverage, and Medicare. In addition, changes to Medicare's cost-sharing structure could affect the total amount of bad debt from unpaid cost-sharing obligations owed to service providers. At the same time, lower enrollment in supplemental plans and reduced use of medical care by some enrollees with supplemental coverage would decrease the amount of billing paperwork for some insurers.

10. Some of those unpaid cost-sharing obligations ultimately are covered by Medicare's payments to providers for bad debt, which are also reflected in the savings estimate.

RELATED OPTION: Health, Option 6

Health—Option 8 Function 570

Increase Premiums for Parts B and D of Medicare

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
Increase basic premiums	0	-5	-12	-20	-30	-42	-47	-49	-54	-59	-67	-318
Freeze income thresholds for income-related premiums	0	0	0	*	-1	-2	-3	-4	-5	-7	-1	-22
Both alternatives above[a]	0	-5	-12	-20	-31	-43	-48	-52	-57	-63	-68	-331

The first and third alternatives would take effect in January 2018; the second would take effect in January 2020.

* = between –$500 million and zero.

a. If both alternatives were enacted together, the total effect would be less than the sum of the effects of each alternative because of interactions between them.

All enrollees in Medicare's Part B (which covers physicians' and other outpatient services) or Part D (the outpatient prescription drug benefit, which is delivered through private-sector companies) are charged basic premiums for that coverage. Under current law, the Part B premium is $121.80 per month, or about 25 percent of the average costs per enrollee over age 65. (Premiums can be higher or lower for enrollees who receive Part B benefits through Medicare Advantage, the private insurance option for Medicare beneficiaries.) Currently, the average monthly premium for a standard Part D plan is $34.10, which covers 25.5 percent of the average per capita costs of the basic benefit. Low-income enrollees and those with few assets receive subsidies to cover some or all of their premiums.

Enrollees with relatively high income pay an income-related premium (IRP) at an amount that is determined on the basis of the beneficiary's modified adjusted gross income (adjusted gross income plus tax-exempt interest). In 2016, the combined monthly premiums range from $170.50 to $389.80 for Part B and from $46.80 to $107.00 for Part D. The amounts are set so that the basic premium and the IRP together will cover between 35 percent and 80 percent of an enrollee's costs.

Under current law, the income thresholds for the higher premiums for Parts B and D are divided among four brackets, which are frozen through 2019. The lowest bracket is set at $85,000 for single beneficiaries or $170,000 for married couples filing joint tax returns. The thresholds will increase by about 2 percent in 2020 and will be indexed after that for general price inflation. (The Medicare Access and CHIP Reauthorization Act of 2015 lowered certain income thresholds for the IRPs, so more beneficiaries are affected by them. That law also changed the thresholds' rate of increase starting in 2020.)

The Congressional Budget Office currently projects that the share of enrollees subject to income-related premiums will increase from 8 percent in 2016 to 9 percent in 2019, as income growth pushes more enrollees' income above the thresholds. That share is projected to rise gradually from 9 percent in 2020 to 10 percent in 2026 as growth in income for affected enrollees slightly outpaces indexing of the thresholds.

This option would raise the premiums for Part B and Part D under one of three alternative approaches:

- A first alternative would increase basic premiums from 25 percent of Part B costs per enrollee and 25.5 percent of Part D costs per enrollee to 35 percent of each program's costs. That increase would take effect over five years, beginning in January 2018. For Part B, the share of costs per enrollee covered by the basic premium would rise by 2 percentage points each year through 2022 and then remain at 35 percent. For Part D, that share would increase by 1.5 percentage points in the first year and by 2 percentage points each year from 2019 through 2022 and then remain at 35 percent. By 2026, basic premiums would reach $176 per month for Part B and $62 per month (the average premium for a standard plan) for Part D.

Those changes would not affect the total premiums of enrollees paying the IRP. In all, this alternative would decrease net Medicare spending (total Medicare spending minus beneficiaries' premiums and other offsetting receipts) by $318 billion between 2018 and 2026, CBO estimates.

- A second alternative, which would take effect in January 2020, would add seven years to the current freeze on the income thresholds for determining the IRPs, extending that freeze through 2026. CBO estimates that, as a result, net Medicare spending would be reduced by $22 billion between 2020 and 2026, and the share of enrollees paying an IRP would rise from 9 percent in 2019 to 13 percent in 2026.

- A third alternative would combine the first two, starting in January 2018 and continuing in January 2020. It would increase basic premiums for Parts B and D to 35 percent of costs per enrollee and freeze the income thresholds for income-related premiums. Those changes would reduce net Medicare spending by $331 billion through 2026, CBO estimates. (That amount is slightly less than the sum of the savings from the other two alternatives separately because of interactions between the two policies.) This alternative would raise premiums for most enrollees and would increase to 13 percent the share of enrollees paying an IRP in 2026.

One rationale in favor of this option is that it would reduce the pressure on the working-age population to pay for benefits being received by older groups. (Because of demographic changes, the number of Medicare beneficiaries per worker has been increasing substantially as the baby-boom generation retires, thus increasing that pressure.) Another rationale is that by absorbing a larger share of enrollees' income, higher Part D premiums would increase competitive pressure in the market for prescription drug plans, thus giving enrollees a stronger incentive to choose less expensive plans. Such pressure could cause prescription drug plans to reduce their bids slightly, generally leading to lower premiums for those plans along with reducing the federal government's costs and lowering the total cost of drugs for Medicare beneficiaries. Similar effects on costs for hospital care or outpatient services could accrue if enrollees sought out lower-cost Medicare Advantage plans, although such effects are not included in the estimates shown here.

A disadvantage of this option is that it would reduce many enrollees' disposable income by increasing basic premiums and freezing all of the income thresholds. A growing share of enrollees would become subject to the IRP in later years because people's nominal income tends to rise over time (even though their purchasing power might not increase). Although the disposable income of low-income enrollees whose Medicare premiums are paid by Medicaid would not decrease, another disadvantage of this option is that state Medicaid programs would face higher costs for some enrollees, such as certain low-income Part B enrollees who have limited assets.

Health—Option 9 | Function 570

Raise the Age of Eligibility for Medicare to 67

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
Medicare	0	0	0	-1.7	-3.4	-5.4	-7.4	-9.7	-12.3	-15.2	-5.1	-55.2
Social Security[a]	0	0	0	-0.1	-0.3	-0.5	-0.7	-0.8	-1.0	-1.2	-0.4	-4.6
Medicaid and subsidies through health insurance marketplaces	0	0	0	1.0	2.2	3.6	5.1	6.8	8.7	10.4	3.2	37.8
Total	0	0	0	-0.8	-1.5	-2.3	-3.0	-3.7	-4.7	-6.0	-2.3	-22.0
Change in Revenues[b]	0	0	0	-0.1	-0.2	-0.3	-0.5	-0.7	-0.8	-1.0	-0.3	-3.5
Decrease in the Deficit	0	0	0	-0.7	-1.3	-2.0	-2.5	-3.1	-3.8	-5.0	-2.1	-18.4

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2020.

a. Estimates include the effects on Social Security outlays, which are classified as off-budget.

b. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

Under current law, the usual age of eligibility to receive Medicare benefits is 65, although younger people may enroll after they have been eligible for Social Security disability benefits for two years. The average period that people are covered under Medicare has increased significantly since the program's creation because of a rise in life expectancy. In 1965, when Medicare was established, a 65-year-old man could expect to live another 12.9 years, on average, and a 65-year-old woman another 16.3 years. Since then, life expectancy for 65-year-olds has risen by more than four years—to 18.1 years for men and 20.6 years for women. That trend, which results in higher program costs, will almost certainly continue.

This option would raise the age of eligibility for Medicare by two months each year, starting in 2020 (people born in 1955 will turn 65 that year), until it reaches 67 for people born in 1966 (who would become eligible for Medicare benefits in 2033). It would remain at 67 thereafter. Social Security's full retirement age, or FRA (the age at which workers become eligible for full retirement benefits), has already been increased from 65 to 66 and is scheduled to rise further during the coming decade, reaching 67 for people born in 1960; they will turn 67 in 2027. (People can claim reduced retirement benefits—but not Medicare benefits—starting at age 62, which is the most common age to do so.) Under this option, Medicare's age of eligibility would be below the FRA until 2033.

Implementing this option would reduce federal budget deficits between 2020 and 2026 by $18 billion, according to estimates by the Congressional Budget Office and the staff of the Joint Committee on Taxation (JCT). That figure results from a projection of a $22 billion decrease in outlays and a $4 billion decrease in revenues over that period. The outlay reduction would stem from decreases in Medicare and Social Security spending, partially offset by increases in outlays for Medicaid and for federal subsidies for insurance purchased through the marketplaces established under the Affordable Care Act.

This option would lower Medicare outlays by reducing the number of people enrolled at any given time from that under current law. In calendar year 2020, when this option would take effect, about 3.4 million people will become eligible for Medicare coverage on the basis of their age, CBO estimates. Under this option, that group would see its benefits delayed by two months. By calendar year 2026, the benefits of 3.7 million people would be delayed by 14 months. Total spending on Medicare as a result would be $55 billion lower between 2020 and 2026 than under current law.

CBO anticipates that most people who become eligible for Medicare after age 65 under this option would continue their existing coverage or switch to another form of coverage between age 65 and the new eligibility age. CBO also expects that the number of people without health insurance would increase slightly. CBO estimates that in 2026, about 45 percent of the 3.7 million people affected by this option would obtain insurance from their own or a spouse's employer or former employer, about 25 percent would purchase insurance through the nongroup market (insurance purchased directly either in the health insurance marketplaces or from insurers outside the marketplaces), about 25 percent would receive coverage through Medicaid, and about 5 percent would become uninsured. To develop those estimates, CBO examined data on the patterns of health insurance coverage among people a few years younger than Medicare's current eligibility age. The figures were then adjusted to account for changes in sources of health insurance and in participation in the labor force as people age.

The option also would reduce outlays for Social Security retirement benefits by an estimated $5 billion over the 2020–2026 period because raising the eligibility age for Medicare would induce some people to delay claiming retirement benefits.

In CBO's estimation, the reduction in Social Security spending would be fairly small because raising Medicare's eligibility age would have little effect on people's decisions about when to claim retirement benefits. Historical evidence indicates that people are more likely to wait until reaching the FRA to claim retirement benefits than they are to claim such benefits when they reach the age of eligibility for Medicare.[1]

CBO also expects future decisions about claiming retirement benefits to be less linked to Medicare's eligibility age than has historically been the case because of greater access to health insurance through Medicaid and through the nongroup market. Increased access through Medicaid stems from a provision of the Affordable Care Act that permits, but does not require, states to expand eligibility to include low-income adults under age 65. In the nongroup market, that increased access stems from subsidies for plans purchased through the marketplaces and from the provision that prevents insurers from denying coverage or varying premiums on the basis of an enrollee's health status. (Insurers are, however, permitted to vary premiums by age, tobacco use, and geographic location.) As a result, it is now easier for some people who give up employment-based insurance upon retirement to qualify for Medicaid or to purchase health insurance in the nongroup market, in some cases with a federal subsidy. Because the federal government subsidizes those sources of insurance, the savings for Medicare and Social Security under the option would be substantially offset by increases in federal spending and by decreases in revenues.

Under this option, federal outlays for Medicaid would increase for two groups of people between the age of 65 and the new Medicare eligibility age: dual-eligible beneficiaries (Medicare enrollees who also are eligible for full benefits under Medicaid) and enrollees who would be Medicaid beneficiaries before turning 65 but who, under current law, would lose that eligibility once they qualified for Medicare at age 65. For this option, CBO assumed that the age limit for Medicaid would increase in tandem with Medicare's eligibility age. Hence, this option would cause Medicaid to remain the primary source of coverage for members of both groups until they reached the new eligibility age for Medicare. As a result, federal outlays for Medicaid between 2020 and 2026 would be $20 billion higher under this option, CBO projects.

This option also would increase outlays for subsidies for health insurance coverage purchased through the marketplaces because some people, instead of obtaining Medicare coverage at age 65, would continue or newly obtain subsidized health insurance through the marketplaces when they were between age 65 and the new eligibility age for Medicare. In addition, the resulting increase in the average age of people purchasing health insurance coverage through the nongroup market would slightly increase premiums for all people enrolled in that market, which would in turn increase spending on subsidies for people purchasing coverage through the marketplaces. CBO and JCT estimate that this option would increase outlays for subsidies for coverage through the marketplaces between 2020 and 2026 by $18 billion. (Those subsidies fall into two categories: subsidies to cover a portion of participants' health insurance premiums and subsidies to reduce the out-of-pocket payments required under insurance policies.)

1. Joyce Manchester and Jae Song, "What Can We Learn From Analyzing Historical Data on Social Security Entitlements?" *Social Security Bulletin*, vol. 71, no. 4 (November 2011), pp. 1–13, http://go.usa.gov/xku5d.

Under this option, revenues would decline because a portion of the increase in marketplace subsidies for health insurance premiums would be provided in the form of reductions in recipients' tax payments. (The subsidies for health insurance premiums are structured as refundable tax credits; the portions of such credits that exceed taxpayers' other income tax liabilities are classified as outlays, whereas the portions that reduce tax payments are classified as reductions in revenues.) Revenues also would decline because of a small net increase in employers' spending on nontaxable health insurance benefits, which in turn would reduce collections of income and payroll taxes. This option would reduce revenues between 2020 and 2026 by $4 billion, CBO and JCT estimate.

All told, CBO estimates, by 2046, spending on Medicare (net of offsetting receipts) would be about 2 percent less under this option than it would be under current law, amounting to 5.6 percent of gross domestic product rather than 5.7 percent. On the basis of its estimates for 2020 through 2026, CBO projects that roughly three-fifths of the long-term savings from Medicare under this option would be offset by changes in federal outlays for Social Security, Medicaid, and subsidies for coverage through the marketplaces as well as by reductions in revenues.

An argument in favor of this option is that as life expectancy increases, the increase in the eligibility age for Medicare would help the program return to focus on the population it originally served—people in their last years of life—and support the services most needed by that group. CBO projects that by 2046, life expectancy for 65-year-olds will be 20.4 years for men and 22.8 years for women, compared with 12.9 years and 16.3 years in 1965. There is some evidence that, for many people, the increase in life expectancy has been accompanied by better health into old age.[2] Those findings suggest that raising Medicare's age of eligibility would not diminish its ability to provide health benefits to people near the end of life.

An argument against this option is that it would shift costs that are now paid by Medicare to individual people, to employers that offer health insurance to their retirees, and to other government health insurance programs. About 300,000 more people would be uninsured under this option in 2026, CBO estimates, and they thus might receive lower quality care or none at all; others would end up with a different source of insurance and might pay more for care than they would have as Medicare beneficiaries. Employers' costs of providing group plans for their retirees would increase because those plans would remain the primary source of coverage until the retirees reached the new eligibility age for Medicare. In addition, states' spending on Medicaid and the federal costs of subsidies for health insurance purchased through the marketplaces would increase.

This option's net effect on national health care spending is unclear because of the potential difference in costs borne by different payers to provide coverage for people between age 65 and the new eligibility age for Medicare. One study showed that spending on some procedures declined when people switched coverage at age 65 from private health insurance to Medicare; the decline was driven mostly by price differences between private health insurance and Medicare.[3]

2. See for example, Michael Chernew and others, *Understanding the Improvement in Disability Free Life Expectancy in the U.S. Elderly Population*, Working Paper 22306 (National Bureau of Economic Research, June 2016), www.nber.org/papers/w22306.

3. Jacob Wallace and Zirui Song, "Traditional Medicare Versus Private Insurance: How Spending, Volume, and Price Change at Age Sixty-Five," *Health Affairs*, vol. 35, no. 5 (May 2016), pp. 864–872, http://dx.doi.org/10.1377/hlthaff.2015.1195.

RELATED OPTION: Mandatory Spending, Option 20

RELATED CBO PUBLICATION: *Raising the Ages of Eligibility for Medicare and Social Security* (January 2012), www.cbo.gov/publication/42683

Health—Option 10 **Function 570**

Reduce Medicare's Coverage of Bad Debt

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays												
Reduce the percentage of allowable bad debt to 45 percent	0	-0.3	-0.8	-1.4	-1.8	-2.0	-2.1	-2.1	-2.3	-2.5	-4.3	-15.3
Reduce the percentage of allowable bad debt to 25 percent	0	-0.5	-1.6	-2.8	-3.5	-4.0	-4.1	-4.2	-4.7	-5.0	-8.5	-30.6

This option would take effect in October 2017.

When hospitals and other providers of health care are unable to collect out-of-pocket payments from their patients, those uncollected funds are called bad debt. Historically, Medicare has paid some of the bad debt owed by its beneficiaries on the grounds that doing so prevents those costs from being shifted to others (that is, to private insurance plans and people who are not Medicare beneficiaries). Bad debt that is partly paid for by Medicare is called allowable bad debt. In the case of dual-eligible beneficiaries—Medicare beneficiaries who also are eligible for Medicaid benefits—allowable bad debt also includes any out-of-pocket payments that remain unpaid by Medicaid. Under current law, Medicare reimburses eligible facilities—hospitals, skilled nursing facilities, various types of health centers, and facilities treating end-stage renal disease—for 65 percent of allowable bad debt. The Congressional Budget Office estimates that Medicare spending on bad debt was $3.3 billion in 2015.

This option would reduce federal spending on Medicare by decreasing the share of allowable bad debt that the program reimburses to eligible facilities. The reductions would start to take effect in fiscal year 2018, and they would be phased in evenly over the course of three years.

CBO examined two alternatives. The first would reduce the percentage of allowable bad debt that Medicare reimburses participating facilities from 65 percent to 45 percent by 2020. That approach would save $15 billion between 2018 and 2026, CBO estimates. The second would reduce the percentage from 65 percent to 25 percent, saving $31 billion.

In both cases, CBO's assessment was that providers' responses to the changes would have negligible effects on the federal budget. If reducing federal payments for bad debt led hospitals to engage in cost shifting—that is, requiring private insurers to pay higher rates to make up for lost Medicare revenues—the cost of private insurance plans would rise, and so would the cost of federal subsidies for those plans. But research has shown that providers' ability to engage in cost shifting is limited and depends on such factors as local market power and contracting arrangements with insurers. Furthermore, some research has demonstrated that Medicare payment reductions have led to *lower* private payment rates.[1]

An argument for this option is that lowering Medicare's reimbursement of bad debt would increase facilities' incentive to collect funds from Medicare patients. Reducing coverage of bad debt could also encourage facilities to discuss treatment costs with Medicare patients ahead of time, examine their alternatives more carefully, and set up manageable payment plans as needed. In addition, Medicare currently reimburses facilities for allowable bad debt but does not reimburse doctors or other noninstitutional

1. See, for example, Chapin White and Vivian Yaling Wu, "How Do Hospitals Cope With Sustained Slow Growth in Medicare Prices?" *Health Services Research*, vol. 49, no. 1 (February 2014), pp. 11–31, http://dx.doi.org/10.1111/1475-6773.12101; Chapin White, "Contrary to Cost-Shift Theory, Lower Medicare Hospital Payment Rates for Inpatient Care Lead to Lower Private Payment Rates," *Health Affairs*, vol. 32, no. 5 (May 2013), pp. 935–943, http://dx.doi.org/10.1377/hlthaff.2012.0332; and Austin B. Frakt, "How Much Do Hospitals Cost Shift? A Review of the Evidence," *Milbank Quarterly*, vol. 89, no. 1 (March 2011), pp. 90–130, http://dx.doi.org/10.1111/j.1468-0009.2011.00621.x.

providers, so this option would reduce that disparity. Also, the reimbursement of bad debt was originally intended to reduce the incentive for cost shifting—but as this discussion just noted, the evidence for cost shifting is mixed, possibly meaning that the need for such reimbursement is smaller than originally thought.

An argument against this option is that facilities might have difficulty collecting additional payments from enrollees or other sources—especially in the case of dual-eligible beneficiaries and enrollees without other supplemental coverage, such as private medigap plans or coverage from former employers. (Currently, Medicaid programs are frequently not required to pay all out-of-pocket expenses for dual-eligible enrollees. As a result, the out-of-pocket expenses for those enrollees constitute a large portion of bad debt.) The option would therefore lead to an effective cut in Medicare's payment rates, just as reductions to the updates to Medicare payments continue to take place over the next few years. Also, institutional providers might try to mitigate the impact of this option by limiting their treatment of dual-eligible Medicare beneficiaries and for those without other supplemental coverage. The option could place additional financial pressure on institutional providers that treat a disproportionate share of those enrollees, potentially reducing their access to care or quality of care.

Health—Option 11 **Function 570**

Require Manufacturers to Pay a Minimum Rebate on Drugs Covered Under Part D of Medicare for Low-Income Beneficiaries

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Mandatory Outlays	0	0	-7	-15	-18	-18	-19	-20	-22	-26	-40	-145

This option would take effect in January 2019.

Medicare Part D is a voluntary, federally subsidized prescription drug benefit program delivered to beneficiaries by private-sector plans. Federal subsidies for Part D drug benefits, net of the premiums paid by enrollees, totaled about $63 billion in calendar year 2013. (Federal subsidies include payments to stand-alone prescription drug plans and Medicare Advantage plans; they exclude subsidies to employers for prescription drug coverage provided outside of Part D for retirees.) Private drug plans can limit their costs for providing benefits to their Part D enrollees by negotiating to receive rebates from manufacturers of brand-name drugs in return for charging enrollees smaller copayments for those drugs. The negotiation of rebate amounts is a business strategy for a Part D plan that is most effective when a few manufacturers' drugs are competing for market share in the treatment of a particular medical condition. The Congressional Budget Office estimates that in 2013, manufacturers' rebates paid to Part D plans amounted to about 18 percent of gross spending on all brand-name drugs under Part D.

Before Part D took effect in 2006, dual-eligible beneficiaries—Medicare enrollees who also were eligible for full benefits under Medicaid—received drug coverage through Medicaid. Under federal law, drug manufacturers that participate in Medicaid (which is a joint federal-and-state program) must pay a portion of their revenues to the federal and state governments through rebates. In 2010, those rebates increased from 15.1 percent to 23.1 percent of the average manufacturer price (AMP) for a drug. (The AMP is the amount, on average, that manufacturers receive for sales to retail pharmacies.) If a drug's price rises faster than overall inflation, the drug manufacturer pays a larger rebate. And those inflation-based rebates can be significant: In 2013, for example, the average statutory rebate under Medicaid, weighted by the dollar amount of drug purchases, was 63 percent of the AMP; about half of that came in the form of inflation-based rebates.

When Medicare Part D was established, dual-eligible beneficiaries were automatically enrolled in its Low-Income Subsidy (LIS) program, which typically covers premiums and most cost sharing required under the basic Part D benefit. LIS enrollees—most of whom are dual-eligible beneficiaries—accounted for about 30 percent of Part D enrollment in 2013, and their drug costs represented about 50 percent of total spending for Part D enrollees' drugs in that year. Currently, the rebates on drug sales to LIS enrollees and on those sold to other Part D enrollees are set through negotiations between the Part D plans and the drug manufacturers.

Starting in 2019, this option would require manufacturers to pay a rebate to the federal government for brand-name drugs sold to LIS enrollees. As under Medicaid, the rebate would be at least 23.1 percent of the drug's AMP plus an additional, inflation-based amount if warranted. In many cases, a manufacturer might already have negotiated discounts or rebates that applied to all Part D enrollees equally. In those instances, any difference between the negotiated amount and the amount of the total rebate owed by the manufacturer would be paid to the federal government. If, however, the average Part D rebate for the drug was already more than 23.1 percent of the AMP plus the inflation-based rebate, the federal government would receive no rebate. Participation in the program would be mandatory for manufacturers who wanted their drugs to be covered by Part B (Medical Insurance) and Part D of Medicare, by Medicaid, and by the Veterans Health Administration.

CBO estimates that this option would reduce federal spending by $145 billion through 2026 because, on average, the rebates negotiated for brand-name drugs are smaller than the statutory discounts obtained by Medicaid. However, drug manufacturers would be expected to set higher "launch" prices for new drugs as a way to limit the effect of the new rebate, particularly for new drugs that do not have close substitutes. Over time, that response would reduce the savings to Medicare from this option. Those higher prices also would affect other drug purchasers: Employment-based health insurance plans would probably negotiate larger rebates to offset a portion of the higher prices, but state Medicaid programs would pay more for new drugs, which in turn would increase federal spending.

In addition, this option could change manufacturers' incentives to offer Part D plans rebates for existing drugs—but the pressures on those rebates would push in both directions, so CBO concluded that the average rebates would not change appreciably. In general, manufacturers offer rebates in exchange for preferred coverage of their drugs in order to increase sales and market share. A key provision of the option is that the amount of a rebate that a manufacturer paid to a Part D plan would count toward the total rebate that manufacturer owed the federal government. On the one hand, that provision would make it less costly for manufacturers to increase their rebates as a way to boost sales to non-LIS enrollees. On the other hand, the higher required rebate for sales of drugs to LIS enrollees would reduce the benefit to manufacturers of increasing those sales. The net effects of the reductions—in both the costs and in the benefits of offering rebates—are unclear and would vary by drug. But the overall effects on rebates for existing drugs would probably be negligible, in CBO's estimation.

An argument in favor of this option is that the Part D benefit could provide the same amount of drugs to Medicare beneficiaries at a lower total cost, particularly for brand-name drugs with no close substitutes whose prices are less subject to market competition. An argument against the option is that the lower revenues that manufacturers receive for drugs under Part D could cause them to reduce their investments in research and development.

The development of "breakthrough" drugs would be least affected by any decline in investments, CBO expects, because purchasers of those drugs tend to be willing to pay more for them. Manufacturers initially can set a higher price for a breakthrough drug, which can offset a portion of the new rebate without substantially affecting sales. Consequently, Medicare's savings under this option would be limited for new drugs because of their higher launch prices, and, eventually, the savings on existing brand-name drugs would dissipate as those drugs lost patent protection and were replaced by less expensive generic versions.

There is a precedent for requiring rebates: Before 2006, manufacturers were already paying rebates to Medicaid for drugs purchased by the dual-eligible population (who were then enrolled under Medicaid's drug benefit). However, the new rules also would apply to drugs purchased by LIS enrollees who were not dual-eligible beneficiaries, and therefore (all else being equal) the total required rebate would be larger than it was when dual-eligible beneficiaries received drug coverage through Medicaid. In addition, because of the 2010 increase in the rebate required for drugs sold under coverage by Medicaid, the reduction in manufacturers' incentives to invest in research and development would probably be greater under this option than under the earlier system.

RELATED CBO PUBLICATIONS: *Competition and the Cost of Medicare's Prescription Drug Program* (July 2014), www.cbo.gov/publication/45552; *Spending Patterns for Prescription Drugs Under Medicare Part D* (December 2011), www.cbo.gov/publication/42692

Health—Option 12 **Functions 550, 570**

Consolidate and Reduce Federal Payments for Graduate Medical Education at Teaching Hospitals

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays	0	-1.1	-1.6	-2.1	-2.8	-3.4	-4.1	-4.8	-5.4	-6.4	-7.6	-31.9

This option would take effect in October 2017.

Hospitals with teaching programs receive funds from Medicare and Medicaid for costs related to graduate medical education (GME). The Medicare payments cover two types of costs: those for direct graduate medical education (DGME) and those for indirect medical education (IME). DGME costs are for the compensation of medical residents and institutional overhead. IME costs are other teaching-related costs—for instance, the added demands placed on staff as a result of teaching activities and the greater number of tests and procedures ordered by residents as part of the learning and teaching process. As for the Medicaid payments, the federal government matches a portion of what state Medicaid programs pay for GME. The Congressional Budget Office estimates that total mandatory federal spending for hospital-based GME in 2016 was more than $10 billion, of which roughly 90 percent was financed by Medicare and the remainder by Medicaid. Teaching hospitals also receive funding from other federal agencies—which is discretionary rather than mandatory spending—as well as funding from private sources.

Medicare's DGME payments are based on three factors: a hospital's costs per resident in 1984, indexed for subsequent inflation; the hospital's number of residents, which is subject to a cap; and the share of total inpatient days at the hospital accounted for by Medicare beneficiaries. Medicare's IME payments are calculated differently: For every increase of 0.1 in the ratio of full-time residents to the number of beds in a hospital, they rise by about 5.5 percent. (To increase that ratio by 0.1, a 100-bed hospital, for example, would have to add 10 full-time residents.)

Beginning in October 2017, this option would consolidate all mandatory federal spending for GME into a grant program for teaching hospitals. Total funds available for distribution in fiscal year 2018 would be a fixed amount equaling the sum of Medicare's 2016 payments for DGME and IME and Medicaid's 2016 payments for GME. Total funding for the grant program would then grow with inflation as measured by the consumer price index for all urban consumers (CPI-U) minus 1 percentage point per year. Payments would be apportioned among hospitals according to the number of residents at a hospital (up to its existing cap) and the portion of the hospital's inpatient days accounted for by Medicare and Medicaid patients.[1]

In CBO's estimation, the option would reduce mandatory spending by $32 billion between 2018 and 2026. By 2026, the annual savings would represent about 30 percent of projected federal spending for GME under current law. Over that period, most of the savings would stem from the slower growth in GME funding over time.

An argument for reducing the overall subsidy for GME is that federal payments under current law exceed hospitals' actual teaching costs. The Medicare Payment Advisory Commission (MedPAC) has consistently found that the IME adjustment is overstated. In its most recent analysis, MedPAC estimates that an IME adjustment about one-third the size of the current one would reflect the indirect costs that teaching hospitals actually incur. That analysis suggests that a smaller subsidy would not unduly affect hospitals' teaching activities. A smaller subsidy also would remove an incentive for hospitals to have a greater number of residents than necessary. Another argument for this option is that consolidating federal funding for medical education would reduce the costs of administering the program for the government and teaching hospitals.

1. Aggregate federal payments would be fixed under this option, so the budgetary effects would not change if the option also removed the existing cap on the number of subsidized residency slots. Removing the cap might allow the existing slots to be allocated more efficiently among hospitals, but it also would create an incentive for hospitals to expand their residency programs in an attempt to receive a larger share of the fixed total. Because the net effects on hospitals' residency programs would be difficult to predict, CBO chose to examine an option that retained the cap.

An argument against the option is that reducing the federal subsidy for GME could lead teaching hospitals to shift the composition of their residency programs toward specialists and away from primary care residents. In response to the caps on Medicare-funded residency slots, which were put into place in 1996, hospitals did not stop expanding their residency programs—but they did tend to favor specialists over primary care residents because employing specialists tends to be more financially attractive. If hospitals responded to further reductions in federal GME subsidies in the same way, shifting the mix of their residents even more toward medical specialties, they would exacerbate a recent trend that could limit the number of primary care doctors in the future. Alternatively, hospitals might respond to the reduced subsidy by lowering residents' compensation and making them responsible for more of the cost of their medical training.

Another argument against the option is that some teaching hospitals use part of their GME payments to fund care for uninsured people. The option could therefore disproportionately affect hospitals that treat a larger number of uninsured patients. Furthermore, states could lose some discretion to direct Medicaid GME payments to hospitals because the federal government would be administering the grant program. Finally, even if payments were initially equal to hospitals' costs, the payments would grow more slowly than inflation and thus would probably not keep pace with increases in costs. Over time, therefore, hospitals and residents might bear an increasing share of the costs of operating a residency program.

Health—Option 13 **Functions 550, 570**

Limit Medical Malpractice Claims

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays[a]	0	-0.2	-1.6	-4.3	-6.9	-7.6	-7.9	-8.1	-8.9	-9.5	-13.0	-54.9
Change in Revenues[b]	0	0.1	0.3	0.5	0.8	0.9	1.0	1.0	1.1	1.1	1.7	6.9
Decrease in the Deficit	0	-0.3	-1.9	-4.8	-7.7	-8.5	-8.9	-9.2	-10.0	-10.6	-14.7	-61.9
Change in Discretionary Spending												
Budget authority	0	*	-0.1	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.5	-1.9
Outlays	0	*	-0.1	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.5	-1.9

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2018.

* = between –$50 million and zero.

a. Includes estimated savings by the Postal Service, whose spending is classified as off-budget.

b. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

Sometimes people are harmed in the course of their medical treatment. In such cases, state laws permit patients to undertake legal action against physicians or other health care providers and to seek monetary compensation for their injuries. The laws that govern medical malpractice claims have twin objectives: to deter providers' negligent behavior (by forcing those who are found at fault to pay damages) and to compensate patients for economic losses (such as lost wages and medical expenses) and noneconomic losses (often called pain and suffering). Malpractice claims are generally pursued in state, rather than federal, courts.

To reduce the risk of having to pay malpractice claims on their own, nearly all health care providers purchase malpractice insurance. Those purchases affect medical costs when they are passed along to health plans and patients in the form of higher charges for health care services. Providers' efforts to reduce their risk of facing malpractice claims also can lead to patients' using more health care services than would be the case in the absence of that risk.

Starting in 2018, this option would:

- Cap awards for noneconomic damages at $250,000;
- Cap awards for punitive damages either at $500,000 or at twice the value of awards for economic damages (such as for lost income and medical costs), whichever is greater;
- Shorten the statute of limitations to one year from the date of discovery of an injury for adults and to three years for children;
- Establish a fair-share rule (under which a defendant in a lawsuit is liable only for the percentage of a final award that is equal to his or her share of responsibility for the injury) to replace the current rule of joint-and-several liability (under which each defendant is individually responsible for the entire amount of an award);
- Allow evidence of claimants' income from collateral sources (such as life insurance payouts and health insurance reimbursements, which can reduce the costs to claimants of being harmed) to be introduced at trial; and
- Cap attorneys' fees. (Typically, attorneys charge fees equal to one-third of total awards and waive their fees if no award is made; the cap would reduce that percentage for larger awards.)

Some states place limits such as these on malpractice claims; others have fewer restrictions. This option would help standardize medical malpractice laws across the country.

Placing federal limits on malpractice claims would reduce total health care spending in two ways, the Congressional Budget Office estimates. First, premiums for malpractice insurance would cost less as average malpractice awards became smaller and fewer people filed claims (because of the diminished incentive to sue), and that cost reduction would generally accrue to health plans and patients in the form of lower charges for health care services. Second, research suggests that placing limits on malpractice claims would decrease the prescription, and therefore the use, of health care services to a small extent because providers who faced a smaller risk of legal action might order fewer diagnostic procedures, for example.

Together, those two factors would cause this option to reduce total health care spending by about 0.5 percent, CBO estimates. (For this option, CBO expects that changes enacted in late 2017 would take full effect after about four years, allowing time for insurance companies to adjust malpractice insurance rates and providers to modify their practice patterns.) Because study results differ on whether the effects on Medicare spending would be proportionally larger or smaller than those for other payers, CBO estimated that the percentage reduction in total spending would be the same for all payers, including Medicare. On the one hand, Medicare's spending is largely determined by the costs of providing care in the fee-for-service part of the program, which does not generally use the mechanisms employed by many private plans to limit the use of services that offer little or no benefit to patients. By itself, that consideration would suggest that the effects of the option on Medicare spending would be larger. On the other hand, Medicare beneficiaries are much less likely to sue for malpractice (all other factors equal), suggesting that the effects would be smaller.

This option would reduce mandatory spending by $55 billion between 2017 and 2026, CBO projects. That estimate accounts for the effects on outlays for Medicare and Medicaid, subsidies for nongroup coverage purchased through the health insurance marketplaces established under the Affordable Care Act, and health insurance for retired federal employees. Savings in discretionary spending, including outlays for health insurance for current federal employees, for example, would amount to approximately $2 billion over that 10-year period if the amounts appropriated for federal agencies were reduced accordingly.

By decreasing private-sector spending on health care, this option also would affect federal revenues. A substantial amount of health care is covered under employment-based health insurance, a nontaxable form of compensation. Because the premiums that employers pay are excluded from employees' taxable income, lowering that cost to employers would boost the share of employees' income that was subject to taxation. That shift, combined with the effect on revenues of the reduction in premium tax credits for coverage purchased through the marketplaces, would increase federal tax revenues by about $7 billion over the next 10 years, CBO estimates.

A rationale in favor of this option is that the resulting lower cost of malpractice insurance would help increase the supply of some specialists in certain regions of the country. For example, some obstetricians, who could be deterred from practicing in places where the annual cost of malpractice insurance is particularly high (premiums can exceed $200,000 in some areas), might relocate or leave the practice of medicine altogether. Limits on malpractice claims also could curtail the provision of unnecessary or redundant services. Yet another rationale is that such limits could discourage some lawsuits in cases where negligence did not actually occur.

An argument against this option is that limiting malpractice claims could make it harder for people to obtain full compensation for injuries that are caused by medical negligence. Another argument is that reducing the size of awards might cause health care providers to exercise less caution, which could increase the number of medical injuries attributable to malpractice. However, conclusions published in the economic literature about the effects of changes in malpractice laws on health are mixed—perhaps because some types of limits on medical malpractice claims cause providers to reduce the intensity of services but also avert the risk of unintended, harmful side effects of those services. Some people might oppose this option because it would be a federal preemption of state laws. Currently, many states either specify higher limits on liability, loss, or damage claims than those proposed in this option or do not limit such claims at all.

RELATED CBO PUBLICATIONS: Cost estimate for H.R. 5, Help Efficient, Accessible, Low-Cost, Timely Healthcare (HEALTH) Act of 2011 (March 10, 2011), www.cbo.gov/publication/22053; letter to the Honorable Bruce L. Braley responding to questions on the effects of tort reform (December 29, 2009), www.cbo.gov/publication/41881; letter to the Honorable John D. Rockefeller IV providing additional information on the effects of tort reform (December 10, 2009), www.cbo.gov/publication/41812; letter to the Honorable Orrin G. Hatch about CBO's analysis of the effects of proposals to limit costs related to medical malpractice (October 9, 2009), www.cbo.gov/publication/41334

Health—Option 14 **Function 050**

End Congressional Direction of Medical Research in the Department of Defense

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Discretionary Spending												
Budget authority	0	-1.2	-1.2	-1.3	-1.3	-1.3	-1.4	-1.4	-1.4	-1.4	-5.0	-11.9
Outlays	0	-0.1	-0.5	-0.9	-1.1	-1.2	-1.3	-1.3	-1.3	-1.4	-2.6	-9.2

This option would take effect in October 2017.

Savings for this option are measured against CBO's baseline, which takes the most recent appropriation and increases it for future years by the agency's projection of inflation in the economy. For most other budget options for national defense, savings are measured in relation to the Department of Defense's 2017 Future Years Defense Program and CBO's extension of that plan.

The Department of Defense (DoD) typically plans to conduct modest amounts of medical research and development (R&D), focusing on areas of inquiry that are relevant mainly to the armed services. Past projects have included the testing of hard body armor and studies of traumatic brain injury and other conditions that are more prevalent among service members than in the general population. The Congress often makes additional, unrequested appropriations and directs DoD to undertake other research. Over the past three fiscal years, for example, DoD has requested a total of $2.4 billion and the Congress has appropriated $5.5 billion for medical R&D. During those years, the Congress funded projects to develop treatments for several diseases that are no more common among military personnel than they are in the general U.S. population—breast cancer, ovarian cancer, and prostate cancer, for example. The Congress also has requested research on diseases that either would disqualify potential recruits or would provide grounds for medical discharge—amyotrophic lateral sclerosis, muscular dystrophy, and multiple sclerosis, for example.

This option, which would take effect in October 2017, would end Congressional direction of the department's medical R&D, and it would end Congressional appropriations above DoD's requests for that budget account. The Congressional Budget Office estimates that the option would reduce the need for discretionary budget authority by $12 billion from 2018 through 2026. Outlays would decrease by $9 billion. Those savings would be realized so long as the projects were not transferred directly to the National Institutes of Health (NIH) or some other part of the federal government.

An advantage of this option is that it would end the practice of having DoD conduct research on diseases and conditions that are unrelated to military service and for which the military health system may not have particular expertise. That research could be conducted by NIH, although a simple redirection of the research effort to NIH would not achieve savings in the federal budget. If the research was transferred to NIH, the Congress could direct that the research focus on those narrowly defined topics or it could require their funding out of NIH's discretionary appropriation if that agency determined the projects to have more promise or greater value than other proposed research. This option also would help DoD to comply with the caps on discretionary spending for national defense under the Budget Control Act, although research redirected to NIH would be subject to the corresponding caps for nondefense discretionary spending.

A disadvantage of this option is that research projects would be forgone that might have led to improved treatments or even cures for various diseases. Although those diseases may have low prevalence among the military population, their prevalence would be higher not only in the general U.S. population but perhaps also among military family members or among military retirees and their families.

Health—Option 15 **Function 050**

Modify TRICARE Enrollment Fees and Cost Sharing for Working-Age Military Retirees

											Total	
Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2017–2021	2017–2026
Change in Discretionary Spending												
Budget authority	0	*	-1.4	-2.0	-2.1	-2.3	-2.4	-2.6	-2.8	-2.9	-5.4	-18.4
Outlays	0	*	-1.1	-1.9	-2.1	-2.2	-2.4	-2.5	-2.7	-2.9	-5.0	-17.8
Change in Mandatory Outlays	0	0	*	*	*	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.4
Change in Revenues[a]	0	0	-0.1	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.6	-2.0
Increase in the Deficit	0	0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	1.6

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2019.

* = between –$50 million and $50 million.

a. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

More than 9 million people are eligible to receive health care through TRICARE, a program run by the military health care system. Among its beneficiaries are 1.4 million members of the active military and the other uniformed services (such as the Coast Guard), certain reservists, retired military personnel, and their qualified family members. The costs of that health care have been among the fastest-growing portions of the defense budget over the past 15 years, more than doubling in real (inflation-adjusted) terms since 2001. In 2015, the Department of Defense (DoD) spent about $50 billion for health care, and over the next 15 years, the Congressional Budget Office projects, DoD's health care costs will increase by 36 percent in real terms.

In 2015, about 25 percent of military health care spending was for working-age retirees (generally, beneficiaries who, although retired from military service, are under age 65 and thus not yet eligible for Medicare) and their family members: 3.2 million beneficiaries in all. Some 1.6 million people (or about 50 percent of that group) were enrolled in TRICARE Prime, which operates like a health maintenance organization. Subscribers pay an annual enrollment fee of $283 (for individual coverage) or $565 (for family coverage). Working-age retirees who do not enroll in TRICARE Prime may participate in TRICARE Extra (a preferred provider network) or Standard (a traditional fee-for-service plan) without enrolling or paying an enrollment fee. (A beneficiary who chooses an in-network provider for a given medical service is covered under Extra; if he or she chooses an out-of-network provider for a different medical service—even in the same year—that service is covered under TRICARE Standard.)

Starting in January 2019, and indexed thereafter to nationwide growth in per capita spending on health care, under this option TRICARE's enrollment fees, deductibles, and copayments for working-age military retirees would increase as follows:

- Beneficiaries with individual coverage could pay $650 annually to enroll in TRICARE Prime. The annual cost of family enrollment would be $1,300. (That family enrollment fee is about equivalent to what would result from increasing the $460 annual fee first instituted in 1995 by the nationwide growth in health care spending per capita since then.)
- For the first time, retired beneficiaries in TRICARE Standard or Extra would have to enroll and pay $100 for individual or $200 for family coverage for a year.
- The annual deductible for individual retirees (or surviving spouses) for TRICARE Standard or Extra would rise to $500; the family deductible would be $1,000 annually.

- All copayments for medical treatments under TRICARE Prime would increase. For example, the copayment for a medical visit to a Prime provider in the civilian network would rise from the current $12 to $30 in 2019. Then, copayments would grow in line with the nationwide growth in health care spending per capita.

CBO estimates that, combined, those modifications would reduce discretionary outlays by $18 billion between 2018 and 2026, under the assumption that appropriations would be reduced accordingly. Under this option, CBO estimates, about 200,000 retirees and their family members would leave TRICARE Prime because of the higher out-of-pocket costs they would face. Many would switch to Standard or Extra, which are less costly to the government.

This option would have partially offsetting effects on mandatory spending. On the one hand, mandatory spending would increase when some retirees enrolled in other federal health care programs, such as Medicaid (for low-income retirees) or the Federal Employees Health Benefits program (FEHB, for those who complete a career in the federal civil service after military retirement). On the other hand, mandatory spending would decrease as a result of the new cost sharing for retirees of the Coast Guard, the uniformed corps of the National Oceanic and Atmospheric Administration, and the Public Health Service. (TRICARE's costs for those three uniformed services are paid from mandatory appropriations; DoD's costs are paid from annual discretionary appropriations.) Overall, in CBO's estimation, mandatory spending would decline by $400 million between 2019 and 2026 under this option because spending for people in those three uniformed services would fall by a larger amount than spending for Medicaid and FEHB annuitants would rise.

CBO and the staff of the Joint Committee on Taxation estimate that under this option, federal tax revenues would decline by $2 billion between 2019 and 2026 because some retirees would enroll in employment-based plans in the private sector and therefore experience a shift in compensation from taxable wages to nontaxable fringe benefits.

One rationale for this option is that the federal government established TRICARE coverage and space-available care at military treatment facilities to supplement other health care for military retirees and their dependents as a safety net rather as a replacement for benefits offered by postservice civilian employers. The migration of retirees from civilian coverage into TRICARE is one factor in the rapid increase in TRICARE spending since 2000.

An argument against this option is that current retirees joined and remained in the military with the understanding that they would receive free or very low cost medical care in retirement. Imposing new cost sharing might have the effect of making health care coverage unaffordable for some military retirees and their dependents; it also could adversely affect military retention. Another potential disadvantage is that the health of users who remained in TRICARE might suffer if higher copayments led them to forgo seeking needed health care or timely treatment of illnesses. However, their health might not be affected significantly if the higher copayments fostered more disciplined use of medical resources and primarily discouraged the use of low-value health care.

RELATED OPTION: Health, Option 6

RELATED CBO PUBLICATIONS: *Approaches to Reforming Military Health Care* (forthcoming); *Long-Term Implications of the 2017 Future Years Defense Program* (forthcoming); *Approaches to Reducing Federal Spending on Military Health Care* (January 2014), www.cbo.gov/publication/44993

Health—Option 16 **Function 700**

End Enrollment in VA Medical Care for Veterans in Priority Groups 7 and 8

											Total	
Billions of Dollars	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017–2021**	**2017–2026**
Change in Discretionary Spending												
Budget authority	0	-5.4	-5.5	-5.7	-5.9	-6.0	-6.2	-6.4	-6.6	-6.8	-22.5	-54.6
Outlays	0	-4.8	-5.4	-5.6	-5.8	-6.0	-6.2	-6.4	-6.6	-6.8	-21.7	-53.5
Change in Mandatory Outlays	0	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	10.3	25.2

This option would take effect in October 2017.

Discretionary savings accrue to the Department of Veterans Affairs; increases in mandatory outlays are projected for the Medicare and Medicaid programs and federal spending on subsidies to purchase insurance through the health insurance marketplaces established under the Affordable Care Act.

Veterans who seek medical care from the Veterans Health Administration (VHA) are assigned to one of eight priority groups on the basis of disability status and income, among other factors. For example, enrollees in priority groups 1, 2, and 3 have compensable service-connected disabilities, their income is not considered, and their care is mostly free. Veterans in priority group 7 have no service-connected disabilities, and their annual income is above a national income threshold set by VHA but below a (generally higher) geographic threshold. Those in priority group 8 have no service-connected disabilities, and their income is above both the national and the geographic thresholds. In 2015, about 2 million veterans were assigned to priority groups 7 and 8.

Although veterans in priority groups 7 and 8 pay no enrollment fees, they are charged copayments and VHA can bill their private insurance plans for reimbursement. Together, the copayments and insurance cover about 17 percent of VHA's costs of care for that group. In 2015, VHA incurred $5.2 billion in net costs for those patients, or about 9 percent of the department's total spending for medical care (excluding spending from the medical care collections fund, which collects or recovers funds from first- or third-party payers to help pay for veterans' medical care). When priority groups were established in 1996, the Secretary of the Department of Veterans Affairs was given the authority to decide which groups VHA could serve each year. By 2003, VHA could no longer adequately serve everyone, and the department cut off enrollment in priority group 8, although anyone already enrolled could remain. The rules changed again in 2009 to reopen certain new enrollments in that group.

Starting in fiscal year 2018, this option would close priority groups 7 and 8: No new enrollments would be accepted, and current enrollments would be canceled. The action would curtail spending for veterans who have no service-connected disabilities and whose incomes are above the national threshold. Discretionary outlays would be reduced, on net, by $54 billion from 2018 through 2026, the Congressional Budget Office estimates. Because this option would increase use of other federal health care programs, mandatory spending would rise by $25 billion for Medicare, Medicaid, and federal subsidies provided through the health insurance marketplaces established under the Affordable Care Act.

An advantage of this option is that VHA could focus on the veterans with the greatest service-connected medical needs and the fewest financial resources. In 2015, nearly 90 percent of enrollees in priority groups 7 and 8 had other health care coverage, mostly through Medicare or private health insurance. As a result, the vast majority of veterans who would lose access to VHA would have other sources of coverage, including the health insurance marketplaces.

A disadvantage of the option is that veterans in priority groups 7 and 8 who have come to rely on VHA, even in part, might find their health care disrupted. Some veterans—particularly those with income just above the thresholds—might find it difficult to locate other affordable care.

RELATED CBO PUBLICATIONS: *Comparing the Costs of the Veterans' Health Care System with Private-Sector Costs* (December 2014), www.cbo.gov/publication/49763; testimony of Heidi L.W. Golding, Analyst, before the Senate Committee on Veterans' Affairs, *Potential Costs of Health Care for Veterans of Recent and Ongoing U.S. Military Operations* (July 27, 2011), www.cbo.gov/publication/41585; *Potential Costs of Veterans' Health Care* (October 2010), www.cbo.gov/publication/21773

Health—Option 17

Increase the Excise Tax on Cigarettes by 50 Cents per Pack

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Change in Mandatory Outlays[a]	*	*	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.3	-0.9
Change in Revenues[b]	3.0	3.7	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.3	17.1	34.0
Decrease in the Deficit	-3.0	-3.7	-3.6	-3.6	-3.5	-3.5	-3.5	-3.5	-3.5	-3.4	-17.4	-34.9

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2017.

* = between –$50 million and zero.

a. Estimates include the effects on Social Security outlays, which are classified as off-budget.

b. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

Both the federal government and state governments tax tobacco products. Currently, the federal excise tax on cigarettes is $1.01 per pack, and the average state excise tax on cigarettes is $1.53 per pack. In addition, settlements that the major tobacco manufacturers reached with state attorneys general in 1998 require the manufacturers to pay fees (which are passed on to consumers) that are equivalent to an excise tax of about 60 cents per pack. Together, those federal and state taxes and fees boost the price of a pack of cigarettes by $3.14, on average.

This option would raise the federal excise tax on cigarettes by 50 cents per pack beginning in 2017. That rate increase would also apply to small cigars, which are generally viewed as a close substitute for cigarettes and are currently taxed by the federal government at the same rate as cigarettes. The Congressional Budget Office and the staff of the Joint Committee on Taxation (JCT) estimate that the option would reduce deficits by $35 billion from 2017 to 2026: Revenues would rise by $34 billion, and outlays would decline by almost $1 billion, mainly as a result of reduced spending for Medicaid and Medicare. (Because excise taxes reduce the income base for income and payroll taxes, an increase in excise taxes would lead to reductions in revenues from those sources. The estimates shown here reflect those reductions.)

Extensive research shows that smoking causes a variety of diseases, including many types of cancer, cardiovascular diseases, and respiratory illnesses. Tobacco use is considered to be the largest preventable cause of early death in the United States. CBO estimates that a 50 cent increase in the excise tax would cause smoking rates to fall by roughly 3 percent, with younger smokers being especially responsive to higher cigarette prices. Smoking rates would remain lower in the future than they would be under current law because a smaller share of future generations would take up smoking. As a result, the higher tax would lead to improvements in health, not only among smokers themselves but also among nonsmokers who would no longer be exposed to secondhand smoke. Those improvements in health would, in turn, increase longevity.

Although the budgetary impact of raising the excise tax on cigarettes would stem largely from the additional revenues generated by the tax (net of the reductions in income and payroll taxes noted above), the changes in health and longevity also would affect federal outlays and revenues. Improvements in the health status of the population would reduce the federal government's per-beneficiary spending for health care programs, which would initially reduce outlays for those programs. But that reduction in outlays would erode over time because of the increase in longevity; a larger elderly population would place greater demands on federal health care and retirement programs in the future. The effect of greater longevity on federal spending would gradually outweigh the effect of lower health care spending per beneficiary, and federal outlays would be higher after that than they are under current law. In addition to the direct effect of the excise tax, revenues also would rise as a result of improvements in health, which would lower premiums for private health insurance. The corresponding reduction in employers' contributions for health insurance premiums, which are not subject to income or payroll taxes, would ultimately be passed on to workers in the form of higher taxable compensation, raising federal revenues.[1]

One rationale for raising the excise tax on cigarettes is that tobacco consumers may underestimate the addictive power of nicotine and the harm that smoking causes. Teenagers, in particular, may not have the perspective necessary to evaluate the long-term effects of smoking. Raising the tax on cigarettes would reduce the number of smokers, thereby reducing the damage that people would do to their long-term health. However, many other choices that people make—for example, to consume certain types of food or engage in risky sports—also can lead to health damage, and those activities are not taxed. Also, studies differ on how people view the risks of smoking, with some research concluding that people underestimate those risks and other research finding the opposite.

Another rationale for raising the excise tax on cigarettes is that smokers impose costs on nonsmokers that are not reflected in the before-tax cost of cigarettes. Those costs, which are known as external costs, include the damaging effects that cigarette smoke has on the health of nonsmokers and the higher health insurance premiums and greater out-of-pocket expenses that nonsmokers incur as a result. However, other approaches—aside from taxes—can reduce the external costs of smoking or make individual smokers bear at least some of those costs. For example, many local governments prohibit people from smoking inside restaurants and office buildings.

An argument against raising the tax on cigarettes is the regressive nature of that tax, which takes up a larger percentage of the earnings of lower-income families than of middle- and upper-income families. The greater burden of the cigarette tax on people with lower income occurs partly because lower-income people are more likely to smoke than are people from other income groups and partly because the amount that smokers spend on cigarettes does not rise appreciably with income.

1. When estimating legislative proposals and policy options that would reduce budget deficits, CBO and JCT generally assume that gross domestic product would not change. CBO relaxed that assumption in its 2012 report *Raising the Excise Tax on Cigarettes: Effects on Health and the Federal Budget*. Thus, the budgetary effects shown in that report also included the revenues from the increase in labor force participation that would result from a healthier population.

RELATED OPTION: Revenues, Option 38

RELATED CBO PUBLICATION: *Raising the Excise Tax on Cigarettes: Effects on Health and the Federal Budget* (June 2012), www.cbo.gov/publication/43319

Health—Option 18

Reduce Tax Preferences for Employment-Based Health Insurance

Billions of Dollars	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total 2017–2021	Total 2017–2026
Replace the Excise Tax With a Limit on the Income and Payroll Tax Exclusions for Employment-Based Health Insurance Set at the 50th Percentile of Premiums												
Change in Mandatory Outlays	0	0	0	4	6	6	7	7	8	9	10	47
Change in Revenues[a]	0	0	0	24	49	61	70	80	90	101	73	476
Decrease in the Deficit	0	0	0	-20	-44	-55	-63	-73	-82	-92	-64	-429
Replace the Excise Tax With a Limit on the Income and Payroll Tax Exclusions for Employment-Based Health Insurance Set at the 75th Percentile of Premiums												
Change in Mandatory Outlays	0	0	0	2	2	2	3	3	4	3	4	19
Change in Revenues[a]	0	0	0	8	18	23	28	33	38	44	27	193
Decrease in the Deficit	0	0	0	-7	-16	-21	-25	-30	-35	-41	-23	-174
Replace the Excise Tax With a Limit on Only the Income Tax Exclusion for Employment-Based Health Insurance												
Change in Mandatory Outlays	0	0	0	3	3	4	4	4	5	5	6	29
Change in Revenues[a]	0	0	0	14	30	37	42	47	54	60	44	283
Decrease in the Deficit	0	0	0	-12	-26	-33	-38	-43	-48	-55	-38	-254

Sources: Congressional Budget Office; staff of the Joint Committee on Taxation.

This option would take effect in January 2020.

a. Estimates include the effects on Social Security payroll tax receipts, which are classified as off-budget.

Overview of the Issue

The federal tax system provides preferential treatment for health insurance that people buy through an employer. Unlike cash compensation, employers' payments for employees' health insurance premiums are excluded from income and payroll taxes. In most cases, the amounts that workers pay for their own share of health insurance premiums is also excluded from income and payroll taxes. Contributions made to certain accounts to pay for health costs are excluded from income and payroll taxes as well. In all, that favorable tax treatment cost the federal government about $275 billion in forgone revenues in 2016, and that cost will probably rise over time as the cost of health care rises. The tax preferences will continue even after a new excise tax takes effect in 2020 and somewhat reduces their consequences.

Further reducing the tax preferences for employment-based health insurance would raise federal revenues. It also would reduce the number of people with employment-based coverage, boost enrollment in the health insurance marketplaces established under the Affordable Care Act, and increase the number of people without insurance. And it would make total spending on health care lower than it would have been otherwise.

Current Law. The federal tax system subsidizes employment-based health insurance both by excluding employers' premium payments from income and payroll taxes and by letting employees at firms that offer "cafeteria plans" (which allow workers to choose between taxable cash wages and nontaxable fringe benefits) pay their share of premiums with before-tax earnings. The tax system also subsidizes health care costs *not* covered by insurance by excluding from income and payroll taxes the contributions made to various accounts that employees can use to pay for those costs. Examples include employers' contributions to health reimbursement arrangements (HRAs), employees' contributions to flexible spending arrangements (FSAs), and employers' and employees' contributions to health savings accounts (HSAs). On average, people with higher income or more expensive health insurance plans receive larger subsidies.

The favorable tax treatment of employment-based health benefits is the largest single tax expenditure by the federal government. (Tax expenditures are exclusions, deductions, preferential rates, and credits in the tax system that resemble federal spending in that they provide financial assistance to specific activities, entities, or groups of people.) Including effects both on income taxes and on payroll taxes, that exclusion is projected to equal 1.5 percent of gross domestic product over the 2017–2026 period.

The excise tax that is due to start in 2020 will effectively reduce the tax subsidy for employment-based health insurance. It will be levied on employment-based health benefits—consisting of employers' and employees' tax-excluded contributions for health insurance premiums and contributions to HRAs, FSAs, or HSAs—whose value exceeds certain thresholds. The excise tax will thus curtail the current, open-ended, tax exclusions. (Even when the excise tax is in effect, however, employment-based health insurance will still receive a significant tax subsidy, and that subsidy will still be larger for people with higher income.)

The excise tax will equal 40 percent of the difference between the total value of tax-excluded contributions and the applicable threshold. If employers and workers did not change their coverage in response to the tax, roughly 5 percent to 10 percent of people enrolled in an employment-based health plan in 2020 would have some tax-excluded contributions in excess of the thresholds, according to estimates of the Congressional Budget Office and the staff of the Joint Committee on Taxation (JCT). (However, CBO and JCT do expect people's responses to the tax to reduce that share, discussed below.)

In 2020, CBO and JCT project, the thresholds will be $10,800 for individual coverage and $29,100 for family coverage. (Those thresholds will be slightly higher for retirees who are 55 to 64 years old and for workers in certain high-risk professions. Further adjustments will be made for age, sex, and other characteristics of an employer's workforce.) After 2020, the thresholds will be indexed to the growth of the consumer price index for all urban consumers (CPI-U), which measures inflation. Because health insurance premiums will probably continue to rise faster than inflation, the excise tax will probably affect a growing number of people over time. As a result, CBO and JCT project, revenues stemming from the tax will rise from $3 billion in 2020 to $20 billion in 2026.

Effects of Current Law. The tax exclusions have effects that include encouraging the use of employment-based insurance, making it likelier that healthy people will buy health insurance (which lowers the average cost of insurance), and increasing spending on health care. Another effect is that higher-income workers receive larger subsidies than lower-income workers do.

Encouraging the Use of Employment-Based Insurance. By subsidizing employment-based health insurance, the tax preferences encourage firms to offer it and workers to enroll in it. Such insurance would be attractive to employers and employees in any case, because it pools risks within groups of workers and their families and reduces the administrative costs of marketing insurance policies and collecting premiums. But the preferences give employment-based insurance additional appeal. In 2015, according to a Medical Expenditure Panel Survey, 84 percent of private-sector employees worked for an employer that offered health insurance coverage; 76 percent of those employees were eligible for that coverage (the rest were ineligible for various reasons, such as working only part time); and 75 percent of the eligible workers chose to enroll.

Reducing Adverse Selection. A major problem that can occur in insurance markets is adverse selection, in which less healthy people are likelier to buy health insurance (or to buy certain types of plans) than healthier people are. Adverse selection occurs because insurance provides more benefit to enrollees with above-average costs—and is therefore more attractive to them—and less benefit to people with below-average costs. As premiums increase to cover the less healthy enrollees, the healthier ones may stop buying insurance, which results in another price increase—a spiral that may continue until the market is very small or nonexistent. Adverse selection also can reduce markets' efficiency by making it harder for insurers to predict costs for a group of potential enrollees.

Employment-based health insurance and the tax preferences that encourage its use limit adverse selection in several ways. Employers generally select a workforce on the basis of criteria other than health care costs, so most workforces consist of a mix of healthier and less healthy people. Pooling risks across such a workforce reduces the variability of average health care spending for the group. Also, once employers are offering health insurance, they tend to pay a large share of premiums in order to encourage employees to enroll—making the employees' share small in relation to their expected health care costs, encouraging them to buy insurance, and reducing adverse selection. The tax exclusions also limit adverse selection by reducing the after-subsidy price of insurance, encouraging even the healthy to enroll.

Recent changes in regulations governing markets for nongroup (that is, individually purchased) health insurance—which are separate from markets for employment-based insurance—reduce the problem of adverse selection in that market. In addition, subsidies are now available in the nongroup market. Those changes have weakened the rationale for subsidizing employment-based insurance because the nongroup market now provides an alternative way of providing insurance—one that is available to people regardless of their health and that subsidizes their coverage. Nevertheless, employment-based insurance is still a relatively efficient way of providing insurance because its administrative costs are much lower than those in the nongroup market.

Increasing Health Care Spending. The tax preferences for employment-based health insurance contribute to the growth of health care spending. That occurs because the preferences encourage workers to favor health care over other goods and services that they could purchase and also because the tax exclusions encourage employers to compensate their workers with a combination of health insurance coverage and cash wages rather than entirely with cash wages (which the employees would be unlikely to spend on health care to the same extent). Furthermore, the tax exclusions are currently open-ended (and will be until the excise tax takes effect in 2020). That is, their value increases with an insurance plan's premium, encouraging people to enroll in plans that cover a greater number of services, cover more expensive services, or require enrollees to pay a smaller share of costs. As a result, people use more health care—and health care spending is higher—than would otherwise be the case.

Concern about that effect has lessened somewhat in recent years because employment-based insurance plans that require workers to pay a higher share of health costs have become more common. For example, 29 percent of people with employment-based coverage reported enrolling in a high-deductible health plan in 2016, up from 8 percent in 2008.

Subsidizing Workers With Different Income Differently. Another concern about the tax exclusions is that they subsidize workers with different income differently. The value of the exclusions is generally larger for workers with higher income, partly because those workers face higher income tax rates (although they may face lower rates of payroll taxation) and partly because they are more likely to work for an employer that offers coverage. Because larger subsidies go to higher-income workers, who are more likely to buy insurance even without the tax exclusions, and smaller subsidies go to lower-income workers, who are less likely to buy coverage, the exclusions are an inefficient means of increasing the number of people who have health insurance, and they are regressive in the sense of giving larger benefits to people with higher income.

The forthcoming excise tax will be levied on insurers and on employers who offer their own insurance plans, but economic theory and empirical evidence suggest that the cost will ultimately be passed on to workers. CBO and JCT expect that in many cases, that will occur when employers and workers decide to avoid paying the tax by shifting to health plans with premiums below the thresholds. In those cases, the money that would otherwise have been used to pay for the more expensive premiums would generally increase either workers' wages or employers' profits, both of which are taxable. Because workers with higher income will pay higher marginal tax rates on those increased wages, the result will be a reduction in the tax exclusions' regressive nature. When employers and workers do not shift to lower-cost health plans to avoid the excise tax, the costs of that tax will be spread equally among workers, JCT and CBO expect. However, workers with higher income are more likely to be enrolled in high-cost plans and thus more likely to have their subsidies reduced in the first place.

Most workers will have health benefits whose value is below the thresholds and therefore will be largely unaffected by the excise tax. Consequently, the existing tax preferences and the new excise tax will continue to subsidize employment-based health insurance and to provide larger subsidies to higher-income people.

Key Design Choices That Would Affect Savings

Lawmakers who wanted to design laws to reduce the tax preferences for employment-based health insurance could take various approaches. Those approaches would have different effects on federal revenues, on the taxes owed by people at various income levels, on employers' and employees' choices about health insurance plans, and on their resulting health care costs. One approach would involve modifying both the current tax exclusions and the upcoming excise tax. Another approach—one that is not examined in this volume—would replace the current tax exclusions with an income tax credit for employment-based health insurance.

In general, reducing the tax preferences for employment-based health insurance would tend to lower the number of people with such insurance. It also would increase out-of-pocket payments by people enrolled in employment-based insurance, which would decrease spending on health care and increase the financial burden on people with substantial health problems. The precise effect, however, would depend on the specific features of any policy change.

Modifying the Tax Exclusions and the Excise Tax. Lawmakers could cancel the excise tax that is scheduled to take effect under current law and instead subject contributions for health insurance premiums, along with contributions to various health-related accounts, to income or payroll taxation. If lawmakers did that, they would have to decide whether to tax all of the contributions or only some of them. For example, the exclusions could be retained, but with an upper limit that applied to all taxpayers, or the exclusions could be phased down for higher-income people. Such limits also could be allowed to vary according to other characteristics of employees that are associated with average health costs, such as age, sex, or occupation. (The forthcoming excise tax includes several adjustments of that sort. For instance, the threshold above which health care costs are taxed is higher for some groups of people whose average costs are high because they work in dangerous occupations.)

Lawmakers also would need to decide whether to subject the contributions to income taxation, payroll taxation, or both. On average, enrollees in employment-based plans face slightly higher federal income tax rates than payroll tax rates. Specifically, CBO and JCT estimate that those workers' average marginal income tax rate—that is, the rate that applies to the last dollar of their earnings—will be about 20 percent in 2020, whereas their average marginal payroll tax rate (including both the employer's and the employee's shares of payroll taxes) will be about 14 percent. Therefore, subjecting contributions to income taxation would raise slightly more revenue than subjecting them to payroll taxation, all else being equal, and doing both would raise the most revenue.

Even if the average income tax rate and the average payroll tax rate for enrollees in employment-based plans were the same, subjecting contributions to income taxation and to payroll taxation would have very different effects on the tax liability of people in different income groups. Higher-income people are likely to have higher marginal income tax rates but lower marginal payroll tax rates than lower-income people. Among people with employment-based insurance, therefore, subjecting contributions to income taxation would raise the tax liability of higher-income people more than that for lower-income people. The opposite would be true if contributions were subjected to payroll taxation.

Subjecting contributions to taxation would reduce insurance coverage, but the reduction would be smaller if the contributions were subjected to income taxation than if they were subjected to payroll taxation (provided that the same upper limit applied in each case). That difference is primarily attributable to the fact that lower-income people are more likely than higher-income people to forgo insurance when the after-tax price of their insurance goes up. (Higher-income people are more likely to stay enrolled in insurance—because they tend to have more assets to protect, higher demand for health services, and a larger penalty to pay if they forgo insurance.) Also, for lower-income people, the average marginal tax rate is smaller for income taxes than for payroll taxes. Subjecting their contributions to income taxation would not reduce their after-tax compensation (and thus increase the after-tax price of their health insurance) as much as subjecting their contributions to payroll taxation would. They would be less likely to forgo insurance, and overall reductions in insurance coverage would be smaller. At the same time, because higher-income people, on average, face a higher marginal income tax rate than marginal payroll tax rate, more higher-income people would stop enrolling in insurance if their contributions were subjected to income taxation than if they were subjected to payroll taxation. However, that reduction in insurance coverage for higher-income people would be smaller than the reduction for lower-income people because higher-income people are less responsive to price changes in health insurance.

Replacing the Tax Exclusions With a Tax Credit. Another approach to reducing tax preferences for employment-based health insurance would be to replace the current tax exclusions with an income tax credit. If the credit was a fixed dollar amount for everyone and was refundable—so that people could receive money back from the government if their credit exceeded the amount of federal income tax that they owed—all workers would receive the same value from the credit, regardless of their tax bracket or their health care costs. If the credit was a fixed dollar amount but was nonrefundable, low-income workers, who have little or no income tax liability, would benefit much less. Alternatively, the credit's value might not be a fixed dollar amount; it could be phased out for people with higher income. In any of those designs, the credit would have a set dollar value for a given worker, so that the worker could not increase it by purchasing more extensive or more costly insurance.

Lawmakers would face various trade-offs as they set the value of such a tax credit. A larger credit would increase the number of people who obtained health insurance, but would reduce the amount of tax revenues collected. Phasing down the credit for people with higher income would focus it on people who would be less likely to obtain insurance otherwise, but that approach also would raise effective income tax rates for people whose credit was being phased down, potentially distorting their decisions about how much to work.

One disadvantage of switching to a refundable tax credit is that administering it would be substantially more complex than administering the current tax exclusions. A potential drawback of a flat tax credit is that it would offer the same benefit to everyone, regardless of their health status. The current tax exclusions, by contrast, offer an extra benefit to people who are less healthy, because those people tend to use more health services and to enroll in plans with higher premiums.

Specific Alternatives and Estimates

CBO and JCT analyzed three alternatives for reducing the tax preference for employment-based health insurance. Each alternative would take effect in 2020, and all would follow the first approach outlined above, replacing the excise tax on high-cost plans with a limit on the tax exclusions. Two alternatives would limit the exclusions from income and payroll taxation; the third would limit the exclusion from income taxation but continue the unlimited exclusion from payroll taxation. Those policy changes would increase the tax liability and affect the behavior of people with high premiums for employment-based health plans, but the specific increases in taxes and changes in behavior would be different under each approach.

Replace the Excise Tax With a Limit on the Income and Payroll Tax Exclusions Set at the 50th Percentile of Premiums. The first alternative would eliminate the excise tax and instead impose a limit on the extent to which employers' and employees' contributions for health insurance premiums—and to FSAs, HRAs, and HSAs—could be excluded from income and payroll taxation. Specifically, starting in 2020, contributions that exceeded $7,700 a year for individual coverage and $19,080 for family coverage would be included in employees' taxable income for both income and payroll taxes. Those limits, which are equal to the estimated 50th percentile of health insurance premiums paid by or through employers in 2020, would be indexed for inflation after 2020 by means of the CPI-U. The same limits would apply to the deduction for health insurance available to self-employed people. Because the limits would be lower than the thresholds scheduled to take effect for the excise tax—for example, $10,800 for individual coverage in 2020—federal tax subsidies would be lower as well.

This alternative would decrease cumulative federal deficits by $429 billion by 2026, CBO and JCT estimate. By reducing the appeal of employment-based health insurance, it also would cause about 4 million fewer people to have such coverage in 2026 than would have it under current law. Of those people, about 2 million would buy coverage through the health insurance marketplaces, fewer than 500,000 would enroll in Medicaid, and about 1 million would be uninsured. (Those numbers do not add up to the total because of rounding.)

The reduction in the deficit would stem from several changes in revenues and outlays that partially offset each other. Income and payroll tax revenues would rise by $547 billion through 2026 because the number of people with employment-based coverage would decline and because many of those who retained such coverage would receive a smaller benefit from the tax exclusion. (For example, in 2026, the capped tax exclusions would reduce the combined federal income and payroll tax liability of people with employment-based coverage by an average of $1,420; that reduction would be $5,280 under current law.) Additional penalty payments by certain employers and individuals resulting from changes in health insurance coverage also would increase revenues, although only by a small amount. However, additional tax credits for coverage purchased through the marketplaces would reduce revenues, as would the repeal of the excise tax. In all, revenues through 2026 would be $476 billion higher than under current law. The alternative also would boost federal outlays by $47 billion through 2026, primarily because of increased spending on Medicaid and on subsidies for insurance purchased through the marketplaces.

Replace the Excise Tax With a Limit on the Income and Payroll Tax Exclusions Set at the 75th Percentile of Premiums. Just as the first alternative would, the second alternative would eliminate the excise tax and impose limits on the extent to which contributions could be excluded from income and payroll taxation. In this alternative, however, the limits would be higher: $9,520 a year for individual coverage and $23,860 for family coverage. Those limits are equal to the estimated 75th percentile of health insurance premiums paid by or through employers in 2020. Again, they would be indexed for inflation by means of the CPI-U after 2020.

The second alternative would decrease cumulative federal deficits by $174 billion by 2026, CBO and JCT estimate. Specifically, it would increase revenues by $193 billion and outlays by $19 billion. Also, like the first alternative, this one would reduce the appeal of employment-based health insurance, causing about 2 million fewer people to have it in 2026 than would have it under current law. In that year, about 1 million more people would buy coverage through the marketplaces, fewer than 500,000 more people would enroll in Medicaid, and about 1 million more people would be uninsured.

Replace the Excise Tax With a Limit on Only the Income Tax Exclusion Set at the 50th Percentile of Premiums. The third alternative would eliminate the excise tax and impose a limit on the extent to which contributions could be excluded from income taxation; exclusions for payroll taxation would remain unlimited. Specifically, starting in 2020, contributions that employers or workers made for health insurance—and for health care costs through FSAs, HRAs, and HSAs—that exceeded $7,700 a year for individual coverage and $19,080 for family coverage would be included in employees' taxable income for income taxes. Those are the same limits as the ones in the first alternative, and once again, they would be indexed for inflation in subsequent years by means of the CPI-U. As the discussion above explained, limiting the tax exclusion for income taxes only would raise more revenue, and reduce insurance coverage less, than limiting the exclusion for payroll taxes only would (so long as the same limit applied in each case).

The third alternative would decrease cumulative federal deficits by $254 billion by 2026, CBO and JCT estimate: Revenues would be $283 billion higher, and outlays would be $29 billion higher. That alternative would cause about 3 million fewer people to have employment-based insurance in 2026 than would have it under current law. Of those people, about 2 million would buy coverage through the health insurance marketplaces, fewer than 500,000 would enroll in Medicaid, and about 1 million would be uninsured.

Other Considerations

Reducing tax preferences for employment-based health insurance would affect many aspects of health care in the United States, including the growth of health care costs, the health of the population, the decisions that employers and workers make about insurance coverage, and the number of people without health insurance.

Effects on Health Care Costs. Replacing the excise tax with a limit on the tax exclusions that is lower than the excise tax thresholds would make health care spending lower than it would be under current law. The current tax preferences for employment-based insurance give health insurance plans an incentive to cover more services, to cover more expensive services, and to require enrollees to pay a smaller share of the costs than would be the case otherwise. The excise tax will effectively scale back those tax preferences. The alternatives examined here would increase taxes for a larger share of employment-based plans than the excise tax will—giving employers and their workers less incentive to buy expensive health insurance, reducing upward pressure on the price and use of health care, and encouraging greater use of cost-effective care.

Effects on People's Health. By reducing the incentive to buy expensive coverage and increasing the incentive to buy insurance plans in which people pay more out of pocket, all three of the alternatives analyzed here would reduce the amount of care received and worsen some people's health. That conclusion is supported by an experiment conducted by the RAND Corporation from 1974 to 1982 in which nonelderly participants were randomly assigned to health insurance plans.[1] The experiment showed that plans requiring more out-of-pocket payments reduced the use of both effective and less effective care, as defined by a team of physicians. Differences in out-of-pocket requirements had no effect on most participants' health, but among the poorest and sickest participants, those who faced no requirements of that kind were healthier by some measures than those who did.

Effects on Employers and Workers. By increasing the tax liability of people enrolled in high-cost employment-based plans more than the excise tax will, the alternatives considered here would probably increase the financial burden on some people with substantial health problems. In particular, some employers and workers would avoid the increased tax liability by shifting to plans with lower premiums and requirements for more out-of-pocket payments, which would increase costs the most for people who used the most services.

In general, workers with higher income face higher income tax rates and are more likely to enroll in plans with high premiums. Therefore, limiting the exclusion from income taxation, as the third alternative does, would reduce that benefit more for people with higher income. The two alternatives that limit the exclusion not only for income taxation but also for payroll taxation would still increase tax liabilities more for higher-income people, on average, because they tend to enroll in plans with higher premiums.

Under all three alternatives, employees of firms that had a less healthy workforce or that operated in an area with above-average health care costs would be more likely to see their tax liability increase. In higher-cost areas, those increases in people's tax liability might exert pressure on health care providers and insurers to reduce prices or decrease unnecessary care.

Although these alternatives would reduce total spending on health care, they would increase after-tax premiums for some people enrolled in employment-based insurance, particularly those whose premiums were above the limits imposed by each alternative and who therefore would newly be paying taxes on that portion of their premiums. In addition, because all three alternatives would impose a limit on the exclusion that was lower than the excise tax thresholds that exist under current law, employers would have a heightened incentive to keep premiums low, which could cause them to refrain from hiring older workers (who tend to spend more on health care and to raise average premiums) or to reduce the compensation of older workers. That effect would be particularly likely among employers with fewer employees over whom to spread risks.

Effects on the Number of Uninsured People. The tax increases in these alternatives would lead fewer employers to offer health insurance, thus increasing the number of uninsured workers. Most people whose employers stopped offering coverage would buy it in the nongroup market, either in the health insurance marketplaces or elsewhere. The federal subsidies available to low-income people through the marketplaces would give many of those people an affordable alternative to the employment-based coverage that they had lost, and the penalty for lacking insurance would give many high-income people an incentive to buy insurance even without a subsidy. Nevertheless, some workers whose employers stopped offering health insurance would forgo coverage, CBO and JCT anticipate.

1. See Joseph Newhouse, *Free for All? Lessons From the RAND Health Insurance Experiment* (Harvard University Press, 1993).

RELATED CBO PUBLICATIONS: *Federal Subsidies for Health Insurance Coverage for People Under Age 65: 2016 to 2026* (March 2016), www.cbo.gov/publication/51385; *The Distribution of Major Tax Expenditures in the Individual Income Tax System* (May 2013), www.cbo.gov/publication/43768

CHAPTER

6

The Budgetary Implications of Eliminating a Cabinet Department

The past few decades have seen various proposals to eliminate one or more Cabinet departments. One of the goals of those proposals has been to terminate activities thought to be better performed by state and local governments or the private sector; another has been to increase programs' effectiveness through reorganization. This chapter focuses on a third goal: achieving budgetary savings. How much could be saved by shuttering 1 of the 15 current departments depends crucially on whether its programs would be terminated or transferred to a new department or agency—and, if they were transferred, on whether they would continue without significant change or in altered form. In general, achieving substantial savings would require eliminating or significantly reducing programs, perhaps in some of the ways discussed throughout this volume of budget options.

Eliminating a department could result in considerable budgetary savings to the federal government if some or all of the programs operated by that department were also terminated. The amount of savings would eventually be equal to the department's full budget for the canceled programs, minus any income that the department had received through its operation of those programs. Initially, however, the government could incur onetime costs for terminating programs or activities, such as the cost of paying accrued annual leave and unemployment benefits to federal employees whose jobs had been eliminated or of paying penalties for canceling leases for office space.

In contrast, eliminating a department while transferring its programs in essentially unchanged form to other departments or agencies would probably result in little or no budgetary savings, because most of the costs incurred by departments are the costs of the programs themselves. At best, simply transferring a program to another department might reduce administrative support costs, but in most cases, such costs are much smaller than the costs of the program's activities. In particular, 70 percent of the combined budgets of the 15 departments provides individuals, state and local governments, businesses, and organizations with grants, subsidies, insurance benefits, and interest payments—which all, or nearly all, constitute program costs; with the Department of Defense and interest payments on the public debt excluded, that share rises to 84 percent. That collection of payments includes, for example, payments for individuals' health care, grants and loans for postsecondary education, grants to state governments for highway projects, and payments to farm producers for crop insurance claims. In contrast, only 12 percent of the combined budgets of the 15 departments is for personnel, an area that is likely to include more administrative costs. For some departments, such as the Department of Education, personnel costs are only a small percentage of their total budget because their main responsibility is to administer grants or other activities that primarily provide money to state and local governments, individuals, or other entities. For other departments, such as the Department of Homeland Security (DHS), personnel costs are a much larger share of their budget because they are producing a service themselves, such as screening passengers at airports.

Transferring programs and reducing them, altering them, or combining them with other programs could yield larger savings than simply transferring them if lawmakers chose to reduce total funding for the newly combined programs. In some cases, the funding reductions might be implemented without reducing total payments or services provided to beneficiaries. That result would require that the combined programs were operated more efficiently than they were in their old organizational structure and that the funding reductions were smaller than the efficiency gains. Such efficiency gains might arise from reducing overlap or duplication of effort among programs; for example, aid might reach intended recipients at a lower cost if the number of field offices could be reduced. (Consolidation might also increase a program's effectiveness if it made participation easier for the intended beneficiaries, but that outcome would not tend to reduce federal costs.) However, combined programs might operate less efficiently than the original programs in their old organizational structure if the cultures of different operating units were difficult to reconcile or if reduced management staffing led to inadequate oversight, thereby increasing the potential for waste, fraud, and abuse.

In deciding whether to eliminate any of the current departments and whether to terminate, move, or reorganize its programs and activities, lawmakers would confront a variety of questions about the appropriate role of the federal government. In particular, lawmakers would face decisions about whether the department's activities should be carried out by the public sector at all, and if so, whether the federal government was the most effective level of government to conduct them. Even if lawmakers concluded that state and local governments were best positioned to operate a program or activity, they would still have to decide whether the federal government should coordinate particular activities that crossed state borders and whether programs administered by different states should meet national standards. In addition, lawmakers would face choices about how to organize the federal government's activities most efficiently. Those choices would involve considerations about such issues as effective management capacity and Congressional oversight.

Although each of those choices would reflect lawmakers' judgments about the role and operation of the federal government, each would also have consequences for the federal budget. To provide information about those consequences, this chapter provides an overview of the budgets of the Cabinet departments; information on the cost of programs operated by three of the departments most frequently proposed for elimination (Commerce, Education, and Energy); and policy and implementation issues that would arise if lawmakers were to consider eliminating a department.

An Overview of the Budgets of the Cabinet Departments

Since the creation of the Department of Homeland Security in 2002, the Cabinet has included 15 departments. Together, those departments account for the majority of the federal government's budget. (The rest is allocated to independent agencies, such as the Social Security Administration and the Office of Personnel Management; to the legislative and judicial branches; and to a number of public corporations and other entities.) Individually, the departments' budgets vary widely in size and composition.

The Size of Departmental Budgets

The size of individual departments' budgets, as measured by their net expenditures, or outlays, in fiscal year 2015, ranged from $9 billion for the Department of Commerce to $1.0 trillion for the Health and Human Services (HHS). The departments with the three largest budgets—HHS, Defense, and the Treasury—accounted for about three-fourths of the spending by all the departments. The next three largest departments were Veterans Affairs, Agriculture, and Education.

Departments' budgets can also be measured by their obligations, which are their financial commitments. Obligations in a given year typically differ from outlays in that year because some obligations are never spent, and some are spent after the year in which they were made.[1] As discussed below, some information about obligations is useful in analyzing departments' budget allocations.

The Composition of Departmental Budgets

Information on the composition of a department's budget—in particular, its balance of program and administrative costs—helps to show what kinds of changes would have to be made to attain significant budgetary savings if that department was eliminated and some or all of its programs were transferred elsewhere. To the extent that the department's funding is for program costs, savings could be realized by making

1. Obligations also differ from budget authority, which is the authority provided by law to incur obligations. Budget authority can differ from obligations for the same reasons that obligations can differ from outlays: Some budget authority is never obligated, whereas some is obligated in a year other than the one in which it was provided.

changes in how the programs operate or in how much money is provided for them. To the extent that the department's funding is for administrative costs, savings might be realized if the receiving agency could absorb some portion of the administrative costs within its existing budget—particularly if its existing workforce assumed some responsibility for administering the transferred programs. However, such savings would not necessarily happen—for example, if the transferred programs overtaxed the management capacity of the receiving agency.

Unfortunately, the available data do not fully identify administrative costs. Certain costs can be identified as primarily administrative by the name of the budget account or by the office that incurs them, but that method does not yield comparable results across departments because they structure their accounts and offices differently.

Another way to shed light on a department's balance of program costs and administrative support costs is through the "object classification" system of the Office of Management and Budget. That system classifies the budgets of federal agencies into categories and subcategories, some of which are likelier than others to be dominated either by program costs or by administrative costs. However, the federal budget does not provide detailed annual data about those object classes for agencies' outlays. Rather, such details are provided for agencies' obligations.

Data on obligations can overstate the budgetary savings that could be realized by eliminating a department, however. For one thing, some obligations are reimbursable, meaning that they are financed by fees or other charges that are collected in payment for goods and services provided by the government.[2] A program's reimbursable obligations do not represent budgetary savings that would be achieved if that program was eliminated, because in that case, the fees or charges that finance the obligations would also be eliminated.[3] For example, the Patent and Trademark Office's obligations—which are all reimbursable, because its operations are funded entirely by fees charged to patent applicants—do not indicate savings that would be achieved if the office was eliminated, because once it was gone, the patent application fees would be gone as well. The discussion here therefore excludes reimbursable obligations and considers only the remaining obligations, which are known as "direct."

But even direct obligations overstate potential budgetary savings. One reason is that some direct obligations are intragovernmental transfers, which budgets may count more than once because they affect multiple budget accounts. For example, the direct obligations of HHS were $1.4 trillion in 2015, a considerably larger sum than the $1.0 trillion of outlays cited above, mainly because $280 billion of intragovernmental transfers was counted as obligations once when they were paid to Medicare's trust funds and again when money was drawn from those funds to pay for Medicare benefits.

Another reason that direct obligations can overstate potential savings is that some of them are financed by excise taxes, which might be eliminated along with an eliminated program. For example, most of the obligations paid by the Transportation Department's Highway Trust Fund and Airport and Airway Trust Fund are financed by specific excise taxes. In 2015, those taxes yielded $55 billion. If lawmakers terminated the department's highway and airport grant programs, they might also eliminate the taxes—so savings in 2015 would have been $55 billion less than the amount of direct obligations suggested.

Notwithstanding their limitations as indicators of potential budgetary savings, direct obligations are the focus of this chapter because the federal budget provides object-class data for them. Those object classes consist of four primary categories—grants and fixed charges, contractual services and supplies, personnel compensation and benefits, and acquisition of assets—each of which is divided into subcategories that provide more detail. A fifth "other" category consists almost entirely of financial transfers to or from trust funds, such as the Hospital

2. In total, the 15 departments had about $280 billion in reimbursable obligations in 2015, representing 7 percent of their total obligations. The Defense Department accounted for 61 percent of those reimbursable obligations; in percentage terms, however, such obligations were more important in the budgets of the Departments of Commerce, Energy, and the Interior.

3. Reimbursable obligations can also reflect goods or services that the federal government provides to itself, such as costs incurred by a department's central administrative office for procurement or security that are reimbursed by an originating office in the same department or in another one. In such cases, the obligations by the administrative office are classified as reimbursable, but the obligations by the originating office are not. Reducing the originating office's obligations would result in budgetary savings, and such obligations are included in the figures presented here.

Box 6-1.

The Treatment of Federal Credit Programs in This Analysis

Given the budget rules applicable to federal credit programs—those that provide loans, loan guarantees, or lines of credit—the Congressional Budget Office adjusted the obligations data obtained from the Office of Management and Budget in order to focus on the costs of new credit extended in 2015.

Under the Federal Credit Reform Act (FCRA), the budgetary cost of credit provided in a given year is its expected subsidy cost to the government, defined as the net cash outlays expected over the life of the credit, converted to a present value using discount rates determined by the government's cost of borrowing.[1] In particular, the budgetary cost of the loans from a program in a given year is not the dollar volume of those loans but instead is a function of the projected loan defaults, recoveries on the defaults, the interest rates charged on the loans, and the federal government's borrowing costs. The subsidy cost of a cohort of loans can be negative—that is, the loans can be recorded in the budget as reducing the deficit—if the projected interest payments on the loans and any fees charged to cover subsidy costs together outweigh the projected defaults.

Under FCRA accounting, agencies are required to report not only the estimated cost of newly issued credit, but also changes to their estimates of the cost of credit extended in previous years.[2] Such changes may be caused by, for example, changes in interest rates or factors affecting default rates.[3]

For the purpose of estimating the annual spending that might yield savings if a department was eliminated, CBO focused on the costs that reflect program activities in a single year. Accordingly, CBO adjusted the obligations data to include only those associated with new credit in 2015, leaving out the effects resulting from reestimates of the costs of credit issued in earlier years.[4]

1. Using the government's cost of borrowing to discount the future cash flows of a credit program does not reflect the cost of market risk—the risk that the program will have higher costs when the economy as a whole is performing poorly and resources are more highly valued. An alternative measure of the cost of extending credit, called fair-value accounting, attempts to value market risk as private institutions would; typically, that approach involves using higher discount rates, which reduce the present value of future loan repayments and therefore yield higher estimates of the cost of loans to the government. See Congressional Budget Office, *Fair-Value Accounting for Federal Credit Programs* (March 2012), www.cbo.gov/publication/43027.
2. Agencies are also required to report a credit program's actual cash flows in and out of the government in nonbudgetary financing accounts. The amounts shown in such accounts represent the financing of costs already included when the credit was issued and are not included in the Office of Management and Budget's budget totals nor in CBO's analysis.
3. The obligations data for the budget accounts of individual credit programs include only positive estimated costs. Costs for new credit that are estimated to be negative and downward reestimates of the costs of credit issued in previous years are recorded in separate receipt accounts, because the programs do not have budget authority to use those negative costs to offset other costs (in other words, to spend the savings). CBO adjusted the data to include any negative estimated costs associated with credit programs.
4. In a previous version of this analysis using data for 2012, CBO adjusted the data only for the federal student loan program, by far the largest credit program within the three departments discussed in detail (Commerce, Education, and Energy). The present analysis adjusts the 2015 data for all credit programs of the Cabinet departments.

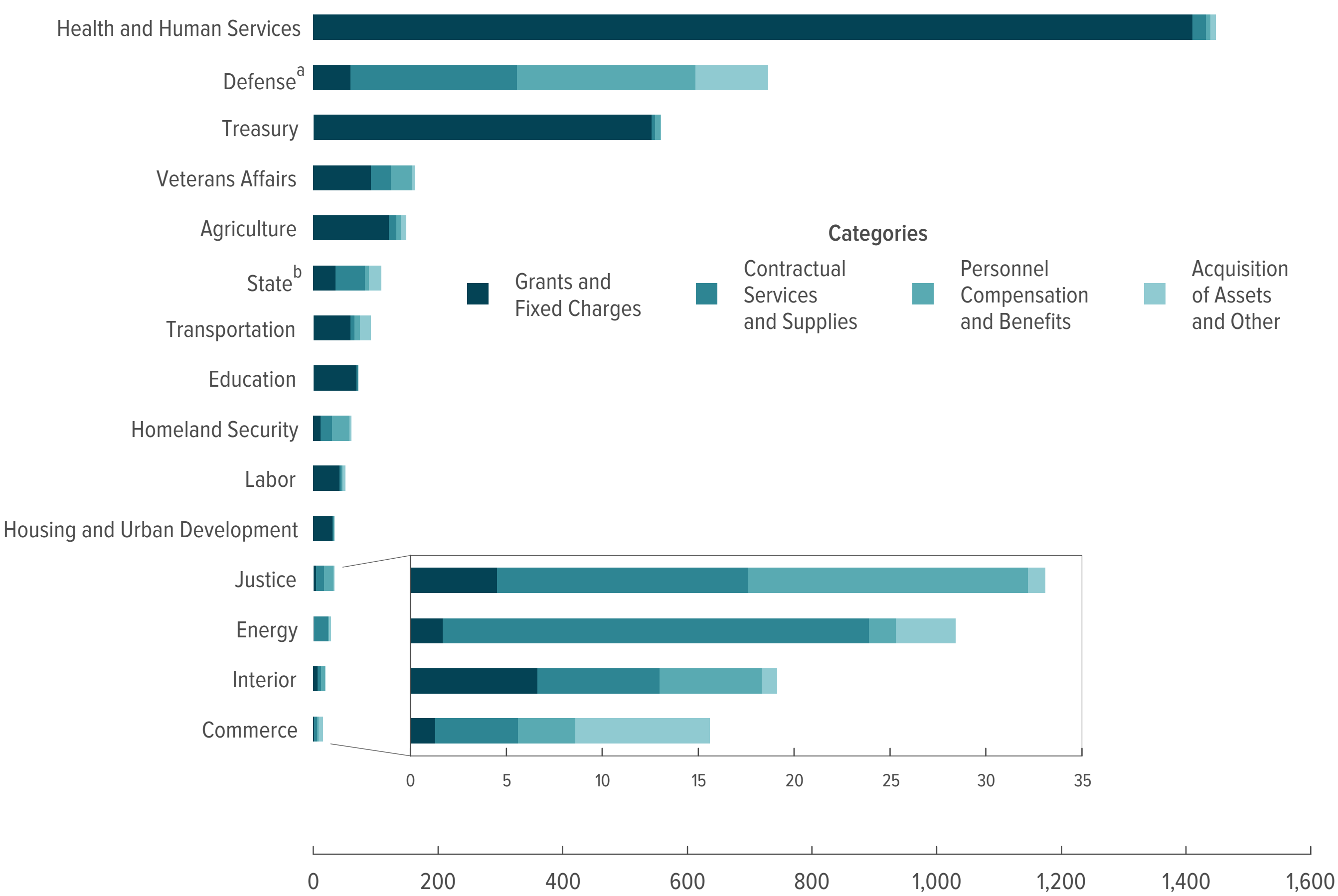
Insurance Trust Fund and the Airport and Airway Trust Fund. The amounts that the Congressional Budget Office presents for 2015 include adjustments to the obligations for federal credit programs to focus on the cost of credit extended that year. (See Box 6-1 and Figure 6-1.)

Grants and Fixed Charges. This category of obligations encompasses grants, subsidies, and predetermined payments for insurance claims, interest payments (largely on the federal debt), and refunds. For the 15 departments combined, the category is dominated by payments to individuals (or to third parties on their behalf)—primarily for health care (through Medicare, Medicaid, veterans' medical care, and various smaller programs), but also for military pensions, the Supplemental Nutrition Assistance Program, tuition assistance for postsecondary education, refundable tax credits, and many other

Figure 6-1.

Direct Obligations, by Department, 2015

Billions of Dollars



Source: Congressional Budget Office, using data from the Office of Management and Budget.

Amounts shown are net of budgetary savings recorded in 2015 for new loans and loan guarantees. Those savings include $15 billion for the Department of Housing and Urban Development (from mortgage insurance programs), $4.3 billion for the Department of Education (from the student loan program), $0.4 billion for the Department of Agriculture (from programs for rural community facilities, electricification, and telecommunications), $0.4 billion for the Department of State (from the Overseas Private Investment Corporation), and less than $25 million each for the Departments of Transportation, Veterans Affairs, Energy, and Commerce.

The categories are from the Office of Management and Budget's object classification system. "Grants and Fixed Charges" includes grants, subsidies, insurance claims, interest payments, and refunds. "Other," which represents 1.1 percent of direct obligations by the Cabinet departments in 2015, consists almost entirely of financial transfers to or from trust funds.

a. Includes obligations reported in the budget under three headings: Department of Defense—Military Programs ($574 billion); Other Defense—Civil Programs ($146 billion); and Corps of Engineers—Civil Works ($9 billion).

b. Includes obligations reported in the budget under the headings Department of State and International Assistance Programs. Nearly $40 billion of the total direct obligations shown were for the Military Sales Program.

Table 6-1.

Direct Obligations for Grants and Fixed Charges, by Department, 2015

Department	Percentage of Direct Obligations Allocated to Grants and Fixed Charges	Direct Obligations for Grants and Fixed Charges (Billions of dollars)	Total Direct Obligations (Billions of dollars)	Primary Activities or Programs Funded by Grants and Fixed Charges
Treasury	97	543	558	Interest paid on the federal debt; refundable tax credits, such as the earned income tax credit
Health and Human Services	97	1,410	1,448	Medicare; Medicaid
Education	96	69	72	Grants to public school districts; aid to postsecondary students
Housing and Urban Development	94	31	34	Public housing; rental assistance programs
Labor	83	43	51	Unemployment Trust Fund; job training and assistance
Agriculture	81	121	149	Food and nutrition assistance programs, such as the Supplemental Nutrition Assistance Program
Transportation	64	59	92	Grants to state and local governments for highways and transit systems; grants-in-aid for airport planning and development
Veterans Affairs	57	92	163	Compensation, pension, and readjustment benefits for veterans
Interior	34	7	19	Mineral lease payments to states; grants to states for wildlife and fish restoration; funds and programs for Native Americans

Continued

purposes.[4] The category also includes payments to state and local governments to fund a wide variety of activities, including elementary and secondary education and the construction of highways and wastewater treatment systems. The rest of the category consists of payments to businesses, organizations, and affiliated people, such as farmers, researchers at universities, small businesses, and hospitals. Complete data on the distribution of grants and fixed charges are not readily available, but 2015 outlay data show that, interest payments aside, individuals received more than 11 times as much from the 15 departments as state and local governments did.

Grants and fixed charges accounted for 70 percent of all direct obligations by the Cabinet departments in 2015, and they represented the majority of the obligations made by 8 of the 15 departments (see Table 6-1). They are largely or entirely program costs, not administrative costs; to reduce them, the government would have to reduce funding for agencies' substantive programs and activities.

Contractual Services and Supplies. Some agencies of the federal government carry out substantial portions of their work through contracts with third parties for various services and supplies. Such contracts accounted for 13 percent of direct obligations by the Cabinet departments in 2015. The Department of Energy made the greatest use of contracts; they represented more than 75 percent of its 2015 obligations. In the combined budgets of the State Department and related international assistance programs, contracts—mostly in the Military Sales Program—represented 44 percent of 2015 obligations. Contracts also accounted for more than

4. Obligations for benefits from the Military Retirement Fund are classified as insurance claims and indemnities, although contributions to the fund from the Treasury and the Defense Department are classified as personnel compensation and benefits.

Table 6-1. Continued

Direct Obligations for Grants and Fixed Charges, by Department, 2015

Department	Percentage of Direct Obligations Allocated to Grants and Fixed Charges	Direct Obligations for Grants and Fixed Charges (Billions of dollars)	Total Direct Obligations (Billions of dollars)	Primary Activities or Programs Funded by Grants and Fixed Charges
State[a]	33	35	109	Foreign Military Financing Program; Economic Support Fund; Global Health Programs; Migration and Refugee Assistance
Homeland Security	18	11	61	Disaster Relief Fund; grants to state and local governments for emergency management programs
Justice	14	4	33	Assistance to state and local law enforcement agencies; Crime Victims Fund
Commerce	8	1	16	Grants for economic development assistance, management of coastal and ocean resources, and research
Defense[b]	8	59	729	Pensions for military retirees
Energy	6	2	28	Grants for research, development, and demonstration projects in sustainable transportation, renewable power, and energy-efficiency projects

Source: Congressional Budget Office, using data from the Office of Management and Budget.

Amounts shown are net of budgetary savings recorded in 2015 for new loans and loan guarantees. Those savings include $15 billion for the Department of Housing and Urban Development (from mortgage insurance programs), $4.3 billion for the Department of Education (from the student loan program), $0.4 billion for the Department of Agriculture (from programs for rural community facilities, electrification, and telecommunications), $0.4 billion for the Department of State (from the Overseas Private Investment Corporation), and less than $25 million each for the Departments of Transportation, Veterans Affairs, Energy, and Commerce. “Grants and Fixed Charges,” a category from the Office of Management and Budget’s object classification system, includes grants, subsidies, insurance claims, interest payments, and refunds.

a. Includes obligations reported in the budget under the headings Department of State and International Assistance Programs. Nearly $40 billion of the total direct obligations shown were for the Military Sales Program.

b. Includes obligations reported in the budget under three headings: Department of Defense—Military Programs; Other Defense—Civil Programs; and Corps of Engineers—Civil Works.

30 percent of the budgets of the Justice, Defense, Interior, and Homeland Security Departments.

The contractual services and supplies category includes a range of subcategories, some of which are likelier than others to include relatively large shares of administrative costs. In particular, contracts for travel and transportation and for rent, communications, and utilities are likelier to represent administrative costs than are contracts for research and development, the operation and maintenance of equipment, and the operation and maintenance of facilities.

The departments vary in their distribution of obligations among the subcategories. Particularly worth attention are the Department of Defense, because it accounts for more than half of the 15 departments’ total direct obligations for contracts, and the Department of Energy, because it relies more heavily on contracts than any other department does. Contracts for travel and transportation and for rent, communications, and utilities were about 1 percent of the direct obligations for contracts in 2015 made by the Energy Department, but about 10 percent of those made by the Defense Department

Table 6-2.

Selected Departments' Direct Obligations for Contractual Services and Supplies, by Type, 2015

	Direct Obligations for Contractual Services and Supplies (Billions of Dollars)			Percentage of Department's Direct Obligations for Contractual Services and Supplies		
	Defense[a]	Energy	Other Departments	Defense	Energy	Other Departments
Supplies	40	*	18	15	1	10
Research and Development	45	1	3	17	4	2
Operation and Maintenance of Equipment	35	*	4	13	1	2
Operation and Maintenance of Facilities	11	17	4	4	77	2
Travel and Transportation	14	*	5	5	**	3
Rent, Communications, and Utilities	10	*	13	4	1	7
Other Goods and Services From Federal Sources	59	*	19	22	1	11
Other Services From Nonfederal Sources	19	1	93	7	6	54
Other[b]	35	2	15	13	9	9
Total	**268**	**22**	**174**	**100**	**100**	**100**

Source: Congressional Budget Office, using data from the Office of Management and Budget.

* = between zero and $500 million; ** = between zero and 0.5 percent.

a. Includes obligations reported under three headings in the budget: Department of Defense—Military Programs; Other Defense—Civil Programs; and Corps of Engineers—Civil Works.

b. Includes contracts classified as providing advisory and assistance services, medical care, subsistence and support of persons (including board, lodging, and other care), and printing and reproduction.

and by the other 13 departments taken as a group (see Table 6-2). In contrast, contracts for research and development, the operation and maintenance of equipment, and the operation and maintenance of facilities accounted for more than 80 percent of the direct obligations for contracts by the Energy Department, about 35 percent of those by the Defense Department, and just 6 percent of those by the other departments taken as a group.

The extent to which funds in the remaining subcategories—such as supplies, other goods and services from federal sources, and other services from nonfederal sources—are used for administrative purposes cannot be determined without more detailed analysis of each department. Some supplies, for example, are used primarily for administrative purposes, but much of the Defense and Veterans Affairs Departments' funding obligated for supplies (which accounts for 87 percent of all obligations for supplies) is more directly mission-oriented.

Personnel Compensation and Benefits. Of the Cabinet departments' 2015 direct obligations, 11 percent was for personnel compensation and benefits. Three departments—Defense, Veterans Affairs, and Homeland Security—accounted for 69 percent, 8 percent, and 6 percent, respectively, of the total. The departments that obligated the largest shares of their budgets for personnel costs were Homeland Security and Justice (both 44 percent) and Defense (39 percent). Eliminating a department and transferring its programs elsewhere could yield savings in this category if total federal employment fell as a result of the transfer.

Acquisition of Assets and Other. Of the departments' 2015 direct obligations, acquisition of assets—mostly equipment, but also land, structures, investments, and loans—accounted for 4 percent of the total. The category was dominated by the Defense Department, which obligated 74 percent of the total funds (including 93 percent of those for equipment and 67 percent of those for land and structures) and by the international assistance programs reported here with the State Department, which accounted for 12 percent of the obligations (including 74 percent of those for investments and loans, primarily representing capital contributions and loans to the International Monetary Fund).[5] Assets are generally acquired for use in program activities, but they can also be acquired for administrative support, as in the case of software systems for payroll management.

The "other" category, virtually all of which consists of transfers to or from trust funds, represented 1 percent of departmental obligations in 2015. Obligations to those funds are ultimately used for purposes classified in the other categories. For example, the $8 billion credited to the Highway Trust Fund subsequently supports grants to state governments, and the roughly $7 billion obligated to the Public Safety Trust Fund in the Commerce Department (representing 42 percent of the department's 2015 direct obligations) is a repayment of loans from the Treasury's general fund for asset acquisition—for the creation of a nationwide broadband network for first responders.

Commerce, Education, and Energy: Departmental Budgets by Program

The Departments of Commerce, Education, and Energy are among those most frequently mentioned in comments about eliminating Cabinet departments. In 1982, for example, the Reagan Administration proposed eliminating the Department of Energy, which had been created just five years earlier; and in 1995, the House of Representatives passed a budget resolution that recommended doing away with all three departments.[6] This section examines how those departments' direct obligations were allocated in fiscal year 2015, both by office and program and by object class.

The funds of the three departments were obligated in sharply different ways. As noted above, a large share of the Commerce Department's budget was for a transfer associated with acquiring an asset (namely, a broadband network for first responders); in contrast, the Education Department's budget was obligated almost entirely for grants, and the Energy Department's budget was dominated by contractual services and supplies (see Table 6-3). Achieving substantial budgetary savings from eliminating one of these departments (or any other) would require reducing or eliminating the programs operated by that department. Smaller savings might be realized without cutting back on payments or services provided to beneficiaries if the programs were combined with programs at other departments, but only if the programs were managed more efficiently than they had been; the combination might also result in less efficient management.

Department of Commerce

The Department of Commerce has the smallest budget of any Cabinet department, with direct obligations of $16 billion in fiscal year 2015. Its 11 agencies have a variety of missions, which means that the benefits and costs of various proposals to eliminate the department could differ greatly, depending on which of the agencies, if any, were retained and on the changes that were made to programs in those retained agencies.

The total size and distribution of the department's obligations in 2015 were both heavily influenced by a onetime event: the transfer of $6.6 billion to the Public Safety Trust Fund, to be used to fund the creation of the nationwide FirstNet broadband network for public safety personnel. With that transfer included, the department's obligations were allocated as follows: 8 percent for grants and fixed charges, 19 percent for contractual services and supplies, 28 percent for personnel compensation and benefits, and 45 percent for the acquisition of assets and "other." Without that transfer, total obligations would have been $9 billion, and the category shares would have been 15 percent, 33 percent, 48 percent, and 4 percent.

In addition to being the smallest Cabinet department in budgetary terms, the Commerce Department is unique in having the largest share of reimbursable obligations; in fiscal year 2015, they totaled $5.0 billion, representing 36 percent of the department's total obligations (without the transfer to the Public Safety Trust Fund).[7] Indeed,

5. Though international assistance programs are grouped here with the State Department, as they are in the President's budget, obligations to the International Monetary Fund are administered by the Treasury Department.

6. House Committee on the Budget, *Concurrent Resolution on the Budget—Fiscal Year 1996: Report to Accompany H. Con. Res. 67*, House Report 104-120 (May 15, 1995), http://go.usa.gov/WKNB.

7. With that transfer included, 24 percent of the department's total obligations in 2015 were reimbursable; the same proportion also applied to the Energy Department.

Table 6-3.

Selected Departments' Direct Obligations, by Object Class, 2015

Millions of Dollars

	Grants and Fixed Charges	Contractual Services and Supplies	Personnel Compensation and Benefits	Acquisition of Assets and Other	Total
			Department of Commerce		
National Telecommunications and Information Administration	0	19	29	6,624	6,672
National Oceanic and Atmospheric Administration[a]	803	3,187	1,580	274	5,844
Bureau of the Census	0	510	580	15	1,105
National Institute of Standards and Technology	241	236	360	55	892
International Trade Administration	7	212	263	7	489
Other	251	149	208	3	611
Total	**1,302**	**4,313**	**3,020**	**6,978**	**15,613**
			Department of Education		
Office of Federal Student Aid[b]	25,559	1,274	194	2	27,029
Office of Elementary and Secondary Education	21,515	64	0	2	21,581
Office of Special Education and Rehabilitative Services	16,027	3	0	0	16,030
Office of Postsecondary Education	2,373	14	0	0	2,387
Office of Vocational and Adult Education	1,707	17	0	0	1,724
Office of Innovation and Improvement	1,094	26	0	0	1,120
Office of English Language Acquisition	732	6	0	1	739
Institute of Education Sciences	235	353	2	2	592
Departmental Management	0	179	394	9	582
Total	**69,242**	**1,936**	**590**	**16**	**71,784**
			Department of Energy		
National Nuclear Security Administration	68	9,700	378	1,304	11,450
Energy Programs[c]	1,482	7,548	481	740	10,251
Environmental and Other Defense Activities	115	4,748	351	1,005	6,219
Departmental Administration	1	127	148	0	276
Power Marketing Administration[d]	1	31	29	48	109
Total	**1,667**	**22,154** [e]	**1,387**	**3,097**	**28,305**

Source: Congressional Budget Office, using data from the Office of Management and Budget.

a. Amounts shown are net of $3 million in budgetary savings recorded in 2015 for new loans made in the Fisheries Finance Program.

b. Amounts shown are net of $4.3 billion in budgetary savings recorded in 2015 for new student loans.

c. Amounts shown are net of $21 million in budgetary savings recorded in 2015 for new Title 17 Innovative Technology loans and loan guarantees.

d. The Power Marketing Administration had $4.8 billion in total obligations; however, all but $109 million was reimbursable.

e. Contracts for the operation and maintenance of facilities made up 77 percent of the total shown.

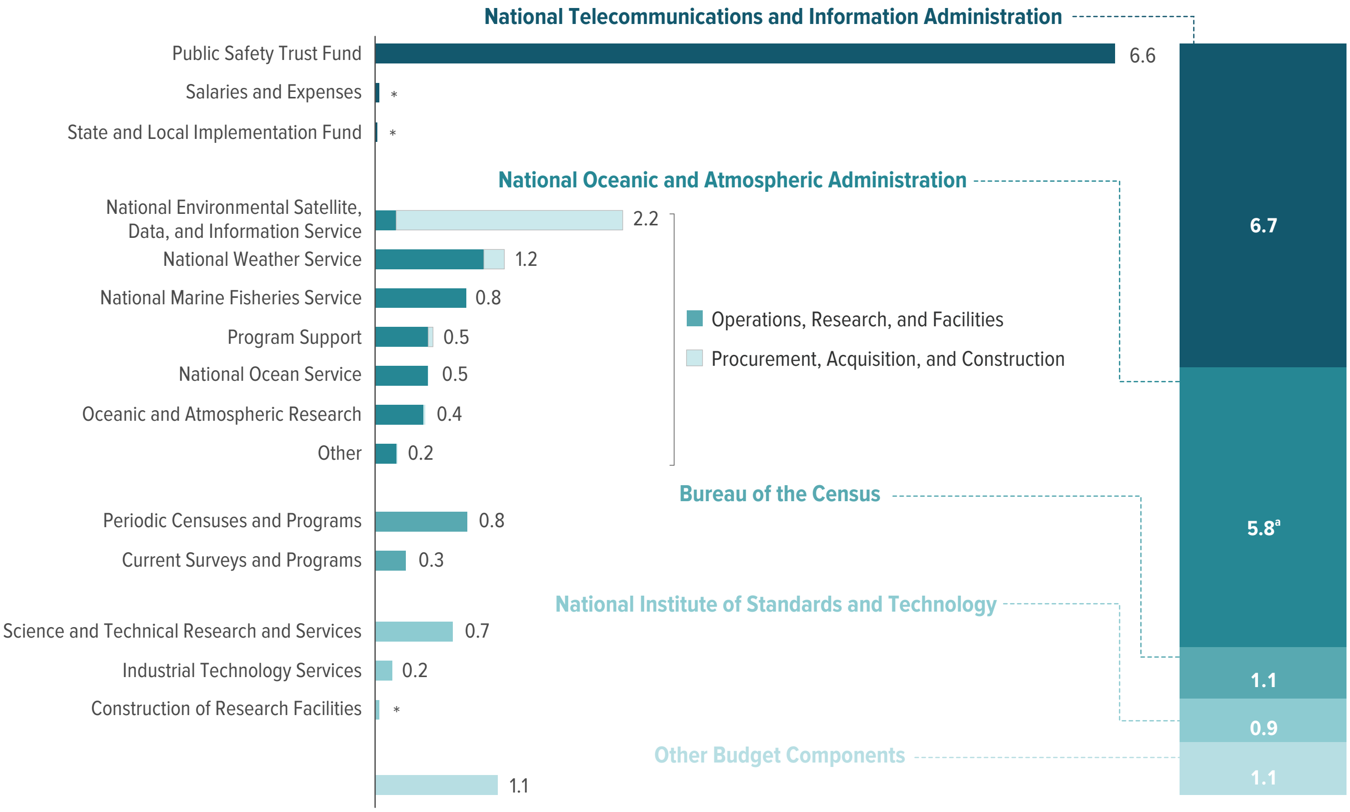
two of the department's agencies are funded entirely by fees and other offsetting collections. The Patent and Trademark Office, with $3.2 billion in reimbursable obligations, accounted for the majority of the department's total, and the National Technical Information Service represented an additional $175 million.[8] Eliminating either of those offices would yield no net savings to the federal budget, because cutting the spending would also mean forgoing the income.

8. Most of the rest of the department's reimbursable obligations were for the Bureau of the Census, the National Oceanic and Atmospheric Administration, and overall management of the department.

Figure 6-2.

Direct Obligations of the Department of Commerce, 2015

Billions of Dollars



Source: Congressional Budget Office, using data from the Office of Management and Budget.

* = between zero and $50 million.

a. Amount shown is net of $3 million in budgetary savings recorded in 2015 for new loans made in the Fisheries Finance Program.

National Telecommunications and Information Administration. Of the nine Commerce Department agencies with direct obligations in 2015, the largest in budgetary terms was the National Telecommunications and Information Administration (NTIA), because of the $6.6 billion transfer for the network for first responders (see Figure 6-2 and Table 6-4). That transfer aside, the NTIA had obligations of $52 million, which is consistent with the $66 million it obligated in 2012, before significant funds were allocated for the network.

National Oceanic and Atmospheric Administration. In most years, the National Oceanic and Atmospheric Administration (NOAA) is by far the largest Commerce agency in budgetary terms. In 2015, it accounted for $5.8 billion in direct obligations, representing 37 percent of the departmental total with the transfer to NTIA included and 65 percent with it excluded. Almost all of NOAA's budget was obligated for five offices and for program support:

- The National Environmental Satellite, Data, and Information Service, which operates geostationary and polar orbiting satellites and manages a global environmental database;
- The National Weather Service, which provides weather forecasts and alerts;
- The National Marine Fisheries Service, which addresses issues related to fish stocks, marine mammals, and endangered species within the waters of the United States Exclusive Economic Zone;

Table 6-4.

Direct Obligations of the Department of Commerce, by Budget Account, 2015

Budget Account	Millions of Dollars
National Telecommunications and Information Administration	
Public Safety Trust Fund	6,632
Salaries and Expenses	39
State and Local Implementation Fund	1
Subtotal	6,672
National Oceanic and Atmospheric Administration[a]	
Operations, Research, and Facilities	3,396
Procurement, Acquisition, and Construction	2,283
Pacific Coastal Salmon Recovery	65
Fisheries Disaster Assistance	45
Promote and Develop Fishery Products and Research Pertaining to American Fisheries	33
Limited Access System Administration Fund	11
Environmental Improvement and Restoration Fund	9
North Pacific Fishery Observer Fund	3
Medicare-Eligible Retiree Health Fund Contribution	1
Fisheries Enforcement Asset Forfeiture Fund	1
Fisheries Finance Program[b]	-3
Subtotal	5,844
Bureau of the Census	
Periodic Censuses and Programs	828
Current Surveys and Programs	277
Subtotal	1,105
National Institute of Standards and Technology	
Scientific and Technical Research and Services	697
Industrial Technology Services	156
Construction of Research Facilities	39
Subtotal	892
International Trade Administration	
Operations and Administration	484
Grants to Manufacturers of Worsted Wool Fabrics	5
Subtotal	489
Economic Development Administration	
Economic Development Assistance Programs	238
Salaries and Expenses	34
Subtotal	272

Continued

- Program support, which provides for maintaining and repairing NOAA's aircraft and marine fleet through the Office of Marine and Aviation Operations, as well as more general management and administrative support;

- The National Ocean Service, which provides maps and other products and services related to navigation, supports state and territorial programs to manage coastal resources, responds to oil spills and hazardous materials releases, and manages marine sanctuaries; and

- The Office of Oceanic and Atmospheric Research, which conducts and funds research related to climate, weather, air chemistry, the oceans, and coastal and marine resources.

Table 6-4. Continued

Direct Obligations of the Department of Commerce, by Budget Account, 2015

Budget Account	Millions of Dollars
Bureau of Industry and Security	105
Departmental Management	
Salaries and Expenses	59
Office of the Inspector General	34
Gifts and Bequests	6
Herbert C. Hoover Building Renovation and Modernization	5
Subtotal	104
Economics and Statistics Administration	100
Minority Business Development Agency	30
Total, Department of Commerce	**15,613**

Source: Congressional Budget Office, using data from the Office of Management and Budget.

Two other departmental components had only reimbursable obligations: the Patent and Trademark Office and the National Technical Information Service.

a. The National Oceanic and Atmospheric Administration's budget accounts for operations, research, and facilities and for procurement, acquisition, and construction fund the agency's programs in the National Environmental Satellite, Data, and Information Service; the National Weather Service; the National Marine Fisheries Service; the National Ocean Service; and the Office of Oceanic and Atmospheric Research, as well as program support activities.

b. Amount shown is net of budgetary savings recorded in 2015 for new loans.

In terms of object classes, contractual services and supplies dominated NOAA's 2015 obligations, representing more than half of the total (see Table 6-3 on page 286). Roughly half of the obligations in that category were for purchases of satellites from the National Aeronautics and Space Administration, or NASA (classified as contracts for "other goods and services from federal sources"). Personnel costs accounted for about one-quarter of NOAA's obligations, grants (primarily to university scientists for research and to states for purposes that included the management of coastal zones and fisheries) for 14 percent, and asset acquisition for 5 percent.

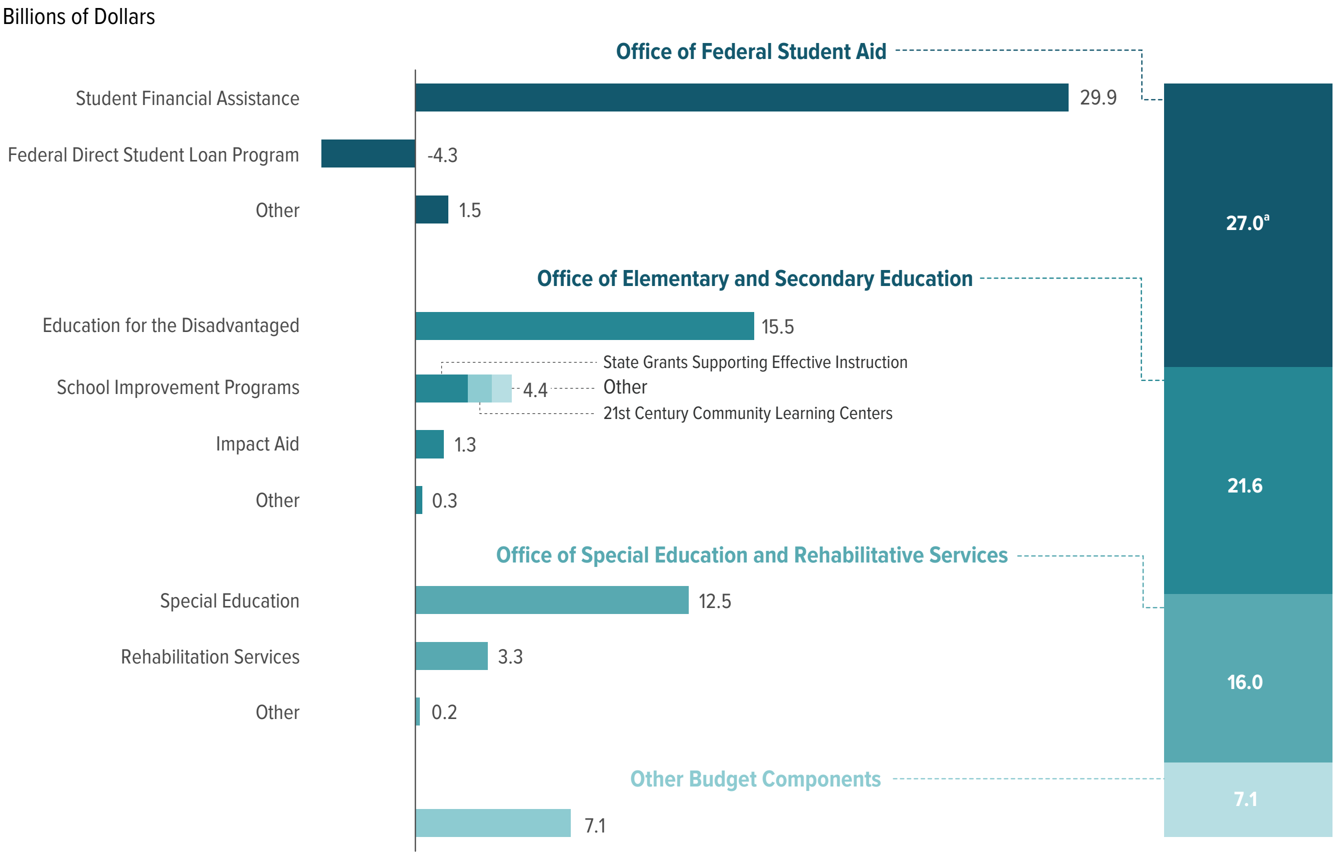
Bureau of the Census. The agency with the next-largest budget in 2015 was the Bureau of the Census, which had direct obligations of $1.1 billion. Its budget from year to year is strongly influenced by the decennial census cycle; for example, direct obligations in 2010, the year the latest decennial census was conducted, were much greater, at $6 billion. The bureau conducts decennial and five-year censuses, the annual American Community Survey, and other annual, quarterly, and monthly surveys that collect economic and demographic data.

National Institute of Standards and Technology. The fourth-largest agency in the Commerce Department in 2015 was the National Institute of Standards and Technology (NIST), which had direct obligations of $0.9 billion. The institute funds laboratories where researchers from NIST and elsewhere in government, academia, and industry investigate issues relating to measurement and standards—the types of measurements producers of nanoparticles can use to monitor quality, for example, or methods for testing electronic systems of health records. It also provides funding for 58 Hollings Manufacturing Extension Partnership centers around the country, which support local manufacturers by giving them access to technology, resources, and industry experts.

Other Components of the Commerce Department's Budget. The rest of the department's budget covers five other agencies and departmental management, with collective obligations of $1.1 billion in 2015. The largest of the five is the International Trade Administration, which promotes exports by U.S. businesses and is responsible for enforcing U.S. laws against imports deemed to be unfairly traded. The second-largest, the Economic

Figure 6-3.

Direct Obligations of the Department of Education, 2015



Source: Congressional Budget Office, using data from the Office of Management and Budget.

a. Amount shown is net of $4.3 billion in budgetary savings recorded in 2015 for new student loans.

Development Administration, differs from other agencies in the department in that most of its budget—almost 90 percent in 2015—is spent on grants, which are awarded to economically distressed communities on the basis of competitive applications. The other three agencies and departmental management accounted for a total of $339 million in direct obligations.

Department of Education

More than 95 percent of the total 2015 budget of the Department of Education, which covers seven offices, an institute, and departmental management, was obligated for grants to students pursuing postsecondary education or to state and local governments. Loans made to postsecondary students in 2015 were recorded as saving $4 billion for the federal government, because the government's cost of borrowing is projected to be below the interest rates charged on the loans and because defaults are not expected to outweigh the difference. With those savings excluded, the department had direct obligations of $76 billion in 2015; with those savings included, the total came to $72 billion (see Figure 6-3, Table 6-3 on page 286, and Table 6-5).

Office of Federal Student Aid. In 2015, the office that is responsible for federal student aid had direct obligations of $28 billion for Pell grants, $2 billion for campus-based activities (supplemental educational opportunity grants and federal work-study assistance), and $1 billion for the administration of student aid, mostly for the cost of contractual services, in addition to the estimated budgetary savings of $4 billion from new student loans.

Office of Elementary and Secondary Education. The office that deals with elementary and secondary education had direct obligations of $22 billion in 2015. The

Table 6-5.

Direct Obligations of the Department of Education, by Budget Account, 2015

Budget Account	Millions of Dollars
Office of Federal Student Aid	
Student Financial Assistance	29,876
Federal Direct Student Loan Program[a]	-4,333
Student Aid Administration	1,467
TEACH Grant Program	16
Student Financial Assistance Debt Collection	3
Subtotal	27,029
Office of Elementary and Secondary Education	
Education for the Disadvantaged	15,534
School Improvement Programs	4,428
Impact Aid	1,279
Safe Schools and Citizenship Education	216
Indian Education	124
Subtotal	21,581
Office of Special Education and Rehabilitative Services	
Special Education	12,527
Rehabilitation Services	3,291
Gallaudet University	120
National Technical Institute for the Deaf	67
American Printing House for the Blind	25
Subtotal	16,030
Office of Postsecondary Education	
Higher Education	2,165
Howard University	222
Subtotal	2,387
Office of Vocational and Adult Education	1,724
Office of Innovation and Improvement	1,120
Office of English Language Acquisition	739
nstitute of Education Sciences	592
Departmental Management	
Program Administration	426
Office for Civil Rights	100
Office of Inspector General	56
Subtotal	582
Total, Department of Education	**71,784**

Source: Congressional Budget Office, using data from the Office of Management and Budget.

a. Amount shown is net of budgetary savings recorded in 2015 for new student loans.

funds were spent almost entirely on grant programs authorized in the Elementary and Secondary Education Act of 1965, as amended by the No Child Left Behind Act of 2001 and other acts. Most of the programs allocate grants to states on the basis of specified formulas, and the states in turn distribute the funds to school districts on the basis of formulas or, in some cases, competitions.

Obligations in 2015 were largest for the following programs:

- Education for the Disadvantaged grants to school districts, which are based on the number of students from low-income families;
- School Improvement Programs, which include grants that states can distribute for a wide variety of purposes intended to increase student achievement and improve the quality and effectiveness of teachers and principals; 21st Century Community Learning Center grants, which support learning opportunities for school-age children outside school hours; as well as other grant programs; and
- Impact Aid, which compensates school districts for the cost of educating "federally connected children," such as those who live on military bases.

Office of Special Education and Rehabilitative Services. The Office of Special Education and Rehabilitative Services had direct obligations of $16 billion in 2015. The largest amounts were obligated for special education (almost entirely for grants to states for special education and related services for children with disabilities) and rehabilitation services and disability research (almost entirely for grants to states to fund vocational rehabilitation services).

Other Components of the Education Department's Budget. The rest of the department consists of the Office of Postsecondary Education, the Office of Vocational and Adult Education, the Office of Innovation and Improvement, the Office of English Language Acquisition, and the Institute of Education Sciences. Those entities, along with the department's management, accounted for $7 billion in direct obligations in 2015.

Department of Energy

The operations of the Energy Department are different from those of the Commerce and Education Departments in two important ways. First, much of the department's spending is for programs related to national defense, so policymakers weighing the costs and benefits of eliminating the department would have to take national security considerations into account. Second, a uniquely large share of the Energy Department's budget is allocated to contractual goods and services—particularly contracts for the operation and maintenance (O&M) of facilities. That subcategory alone represented 60 percent of the department's 2015 obligations; in contrast, it accounted for less than 2 percent of the Defense Department's obligations that year and about 0.1 percent of the combined budgets of the other 13 Cabinet departments. Sixteen of the Energy Department's 17 national laboratories, plus five other sites controlled by the National Nuclear Security Administration (NNSA), are operated entirely by contractors.

The Energy Department's budget is presented in four broad categories plus management (see Figure 6-4 and Table 6-6). The three largest of the four—the NNSA, energy programs, and environmental and other defense activities—accounted for more than 98 percent of the department's direct obligations in 2015.

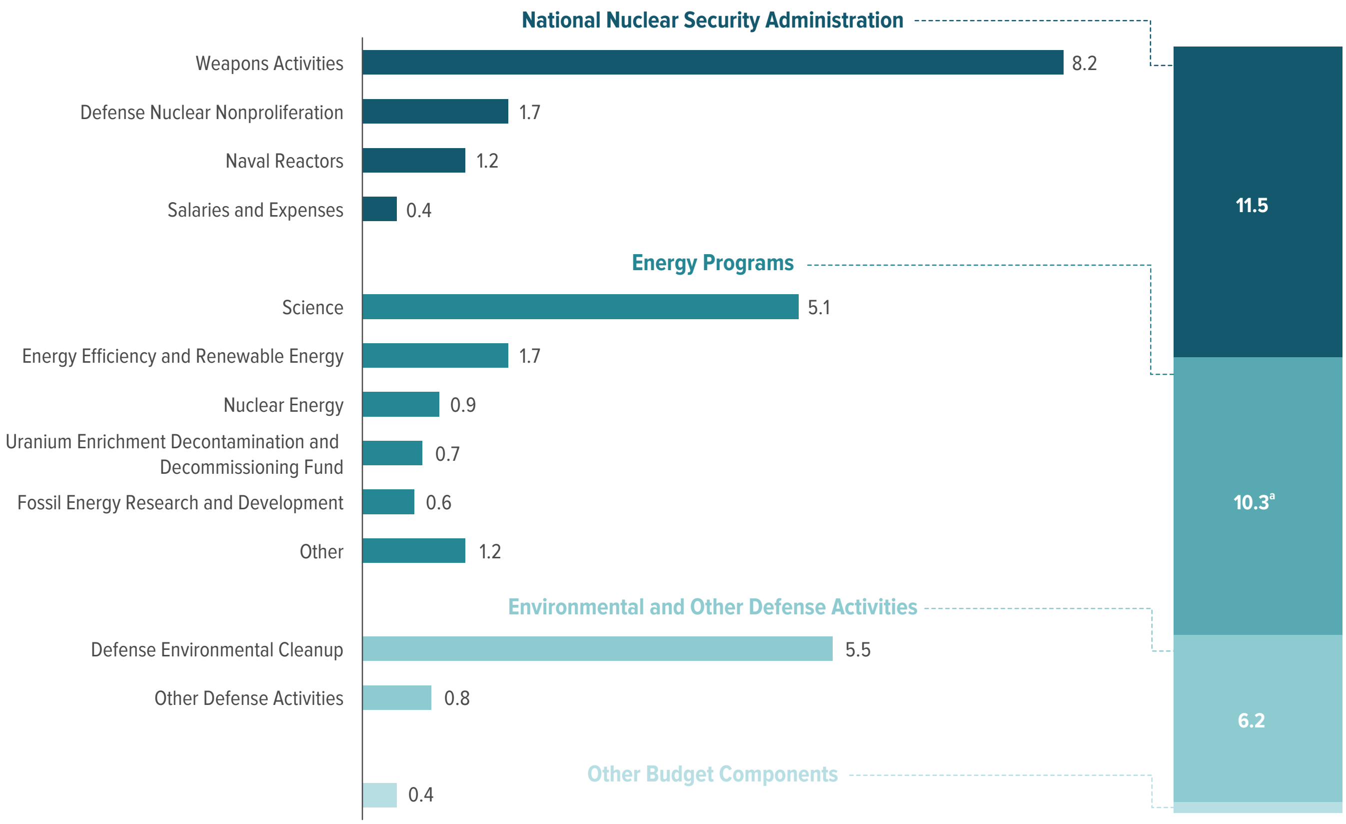
National Nuclear Security Administration. The largest component of the Energy Department's budget is the NNSA, which had direct obligations of $11 billion in 2015, 40 percent of the departmental total. Of that sum, $8 billion was obligated for weapons activities, including management of the stockpile of nuclear weapons; scientific and technical studies to maintain the safety and reliability of those weapons; stewardship of the sites where the weapons and other nuclear materials are housed; processing and management of spent nuclear materials; and efforts to provide security for NNSA personnel and facilities, as well as for the transportation of nuclear weapons and materials. An additional $1.7 billion was obligated for defense nuclear nonproliferation; it funded efforts to create a plutonium reprocessing facility, keep nuclear weapons materials at vulnerable sites secure, and monitor the proliferation of nuclear weapons and materials. For the NNSA as a whole, facilities O&M contracts accounted for 74 percent of the $11 billion total. Acquisition of land and structures accounted for another 11 percent (see Table 6-3 on page 286).

Energy Programs. The second-largest component of the department's budget, energy programs, had direct obligations of $10 billion in 2015. Half of that amount

Figure 6-4.

Direct Obligations of the Department of Energy, 2015

Billions of Dollars



Source: Congressional Budget Office, using data from the Office of Management and Budget.

a. Amount shown is net of $21 million in budgetary savings recorded in 2015 for new Title 17 Innovative Technology loans and loan guarantees.

was obligated for the Science account, which primarily supported research at the national laboratories in a wide portfolio of areas: basic energy sciences, high-energy physics, nuclear physics, biological and environmental research, advanced scientific computing, fusion energy, and other areas. Also relatively large was the budget account for Energy Efficiency and Renewable Energy, which funded a variety of programs, including those focusing on vehicle and building technologies, solar energy, alternative fuels, and weatherization.[9]

9. For more detailed information on the energy programs of the Department of Energy, see Congressional Budget Office, *Federal Support for the Development, Production, and Use of Fuels and Energy Technologies* (November 2015), www.cbo.gov/publication/50980.

Environmental and Other Defense Activities. This component of the Energy Department's budget accounted for $6 billion of direct obligations in 2015. Most of the obligations were for cleanup efforts at sites contaminated by the production of nuclear weapons, particularly the Hanford Site in the state of Washington and the Savannah River Site in South Carolina. Of the $6 billion in obligations, 47 percent was for facilities O&M contracts, 21 percent for contracts for other nonfederal services, and 15 percent for the acquisition of land and structures.

Other Components of the Energy Department's Budget. The other two components of the Energy Department's budget are departmental administration and the power marketing administration (PMA).

Table 6-6.

Direct Obligations of the Department of Energy, by Budget Account, 2015

Budget Account	Millions of Dollars
National Nuclear Security Administration	
Weapons Activities	8,167
Defense Nuclear Nonproliferation	1,685
Naval Reactors	1,234
Salaries and Expenses	364
Subtotal	11,450
Energy Programs	
Science	5,130
Energy Efficiency and Renewable Energy	1,727
Nuclear Energy	909
Uranium Enrichment Decontamination and Decommissioning Fund	683
Fossil Energy Research and Development	572
Advanced Research Projects Agency—Energy	253
Nondefense Environmental Cleanup	246
Strategic Petroleum Reserve Petroleum Account	240
Strategic Petroleum Reserve	202
Electricity Delivery and Energy Reliability	143
Energy Information Administration	117
Advanced Technology Vehicles Manufacturing Loan Program	19
Elk Hills School Lands Fund	16
Naval Petroleum and Oil Shale Reserves	6
Payments to States Under Federal Power Act	4
Northeast Home Heating Oil Reserve	4
Nuclear Waste Disposal	1
Title 17 Innovative Technology Loan Guarantee Program[a]	-21
Subtotal	10,251
Environmental and Other Defense Activities	
Defense Environmental Cleanup	5,468
Other Defense Activities	751
Subtotal	6,219
Departmental Administration	
Departmental Administration	228
Office of the Inspector General	48
Subtotal	276
Power Marketing Administration[b]	
Construction, Rehabilitation, Operation and Maintenance, Western Area Power Administration	88
Operation and Maintenance, Southwestern Power Administration	17
Western Area Power Administration, Borrowing Authority, Recovery Act	4
Subtotal	109
Total, Department of Energy	**28,305**

Source: Congressional Budget Office, using data from the Office of Management and Budget.

a. Amount shown is net of budgetary savings recorded in 2015 for new loans and loan guarantees.

b. The Power Marketing Administration had $4.7 billion in total reimbursable obligations.

Together, they accounted for direct obligations of $385 million in 2015. That figure excludes almost $5 billion in reimbursable obligations by the regional PMAs, which are offset by sales of electricity from hydropower facilities.

Policy and Implementation Issues

The advantages and disadvantages of various possible changes to federal programs are presented in the preceding chapters of this report. But in considering whether to close a Cabinet department—and if so, which of its programs to terminate, move unchanged to a new department or agency, or move in a reduced, altered, or combined form—lawmakers would face a number of questions beyond those directly relating to the programs' merits. This section discusses three. First, if a program was moved, what would be the transition costs and the long-term costs or benefits? Second, if a program was terminated, to what extent would it be replaced by efforts by the private sector or by state and local governments? And third, what steps would be legally required to terminate a program, and what types of termination costs would be incurred?

Costs and Benefits of Moving a Program

Programs may be moved from one administrative home to another for reasons other than the pursuit of budgetary savings. Indeed, the four Cabinet departments created since the 1970s—Energy in 1977, Education in 1980, Veterans Affairs in 1989, and Homeland Security in 2002—were formed primarily to facilitate coordination and communication within the government or to provide greater prominence to certain activities or policy areas.

Whatever policymakers' motivations for moving a program, doing so would probably entail significant transition costs in the short run and might increase or decrease costs in the long run. The transition costs would include physical moving expenses, rental payments on offices at two locations until the lease on the original space expired, and costs to integrate administrative systems for acquisitions, asset management, human resources, budgeting and planning, and financial management. Costs that are less visible in budgets could be incurred as well; moving could disrupt an agency's operations, for instance, or lead to conflicts and coordination problems because of differences in organizational culture. The creation of the Department of Homeland Security serves as an example of the challenges that arise from integrating many existing governmental units. Ten years after the department's creation, a former commandant of the Coast Guard (which had been transferred from the Transportation Department to DHS) noted that budget presentations by various departmental agencies reflected the different appropriation structures that they had used before the department existed, making it "difficult to clearly differentiate, for example, between personnel costs, operations and maintenance costs, information technology costs, and capital investment."[10]

In the long run, spending on a transferred program would be determined by the amount of appropriations it receives (for a discretionary program) or eligibility rules and formulas (for a mandatory program)—but the cost of achieving a given level of program outputs could go up or down as a result of a transfer. Costs for administrative support activities could decrease if a transferred program was administered more efficiently—with fewer people or less office space, for example—in its new home. In addition, costs for direct program activities, such as interactions with beneficiaries, could decrease if the transfer allowed a reduction in efforts that were redundant or at cross-purposes with those of other programs. The Government Accountability Office has issued a series of reports on "fragmentation, overlap, and duplication" in federal programs; the 2011 report noted, for example, that the Small Business Administration and the Departments of Commerce, Housing and Urban Development, and Agriculture collectively administer 80 economic development programs, including 21 that focus on supporting efforts of entrepreneurs.[11] However, overlap among programs is not necessarily inefficient, and simply reducing spending on overlapping programs may reduce the total output of the programs—for example, total benefits to recipients, in the case of grant programs. Lawmakers might or might not view that result as desirable. Further, administrative and program costs of a transferred program per unit of output could be higher if the administrative structure in the new location was more unwieldy, if the cultures of different operating units were difficult to

10. Testimony of Thad W. Allen, Admiral, U.S. Coast Guard (retired), before the Senate Committee on Homeland Security and Governmental Affairs (July 12, 2012), http://go.usa.gov/WK7j.

11. Government Accountability Office, *Government Operations: Opportunities to Reduce Potential Duplication in Government Programs, Save Tax Dollars, and Enhance Revenue*, GAO-11-318SP (March 1, 2011), p. 43, www.gao.gov/products/GAO-11-318SP.

combine, or if waste, fraud, or abuse increased because management capacity was overtaxed.

The benefits and costs of shifting a program might depend on the agency or department selected as its new home. Two relevant factors are the compatibility of organizational cultures and the availability of suitable infrastructure, such as field offices and data systems. The choice of a new administrative home may not be clear-cut. For example, the Defense Department would seem to be an appropriate new home for the defense-related activities currently conducted by the Energy Department, but the separation of responsibility for nuclear weapons themselves and for the systems and personnel that would deliver those weapons has been a feature of federal policy since 1946. As another example, making the Internal Revenue Service (IRS) the new home for the Education Department's student financial aid programs would also present both advantages and disadvantages. On the one hand, the IRS already collects financial data from households (much of the same data that the Free Application for Federal Student Aid requires, in fact) and both collects and disburses funds. On the other hand, a significant fraction of students and families who want financial aid might be unwilling to submit additional financial information to the IRS. The advantages and disadvantages would need to be weighed and compared with those of moving the financial aid programs elsewhere—for instance, to the Department of Health and Human Services, which was originally the Department of Health, Education, and Welfare.

Responses by the Private Sector and by State and Local Governments

If the federal government eliminated or significantly reduced one or more federal programs, the private sector and state and local governments might increase their own activities in the affected areas. However, the extent and nature of those responses would differ substantially among programs. In many cases, the responses of the private sector and of state and local governments would replace only a small share of the eliminated federal benefits or services, primarily because of differences in priorities and constraints on resources.

The Private Sector. The nature of the goods or services previously provided by a terminated federal program would greatly affect the extent to which the private sector would step in to replace that program. In cases in which a program's goods and services were primarily commercial, in the sense that others would voluntarily pay enough to cover the cost of producing them, the private sector might fully replace the federal role. One example is electricity generation. Generating facilities owned by the Tennessee Valley Authority or by the various power marketing administrations in the Energy Department could be transferred or sold to private firms or to the states. However, selling assets that generate income would not necessarily improve the government's long-term financial position, although it would generally improve the budget deficit in the years when sales occurred.

Conversely, in cases in which users (or some users) would not voluntarily pay enough to cover the cost of producing a program's goods and services, the private sector would be unlikely to fill the federal role if the program was eliminated. Some such cases involve goods or services that are produced most efficiently by a single provider and then can be shared by many consumers at little incremental cost—the collection and dissemination of data of broad public interest, for example. A private firm might not find it worthwhile to conduct the surveys underlying the consumer price index if it could not restrict the results to those who paid for access. Also, such information would be most efficiently collected by a single entity, rather than competing ones, so if that entity was private, policy issues about regulating a monopoly would arise.

Other cases in which the private sector would probably not fill the role of a terminated federal activity involve goods or services whose value depends on the government's sovereign power. For example, no one would pay for a license from one private provider to use a portion of the electromagnetic spectrum if a second private provider could issue the same license to someone else.

Still other cases in which it could be hard for the private sector to fully replace federal programs involve activities that serve noncommercial purposes along with commercial purposes. Consider federal insurance products, such as the flood insurance offered by the Department of Homeland Security and the crop insurance sold by the Agriculture Department. The flood insurance program includes a substantial effort to map flood risks, which would be costly for private insurers to continue; indeed, they might be less willing to offer flood insurance in the absence of that effort.[12] Federal crop insurance is heavily subsidized, serving not only to reduce the variability in farm producers' incomes but also to raise those incomes, on average. How large a market would exist for private crop insurance in the absence of the federal coverage is unclear—and because such insurance would not be subsidized, it would not raise average incomes.

In some cases in which federal programs mix commercial and noncommercial purposes, the private sector would probably replace part of a federal program if it was terminated. Student loans are an example. The federal government's sovereign powers allow it to enforce loan contracts in ways that private lenders cannot; for instance, it can garnish the income tax refunds of a borrower who defaults. Private lenders therefore concentrate on students whose risk of default is thought to be lower, such as those attending law or medical schools. If the federal loan programs were eliminated, private lenders would expand the scope of their lending, but they probably would not serve all students who would have borrowed from federal loan programs.

State and Local Governments. Eliminating a department while restructuring, scaling back, or abolishing its programs might prompt stronger responses from state and local governments than from the private sector, because the bulk of federal spending is associated with programs that seek to achieve noncommercial purposes rather than commercial purposes. In particular, some state and local governments might want to provide benefits or services within their jurisdictions that were formerly provided by federal programs. Several factors would probably determine the extent to which state and local governments replaced the federal role.

First, the greater the local, as opposed to national, benefits of federally funded activities, the more that state and local governments would tend to replace lost federal funding. In contrast, state and local governments would do less to replace reduced or terminated programs that had primarily provided benefits beyond their boundaries. For instance, programs that fund basic research, such as the research conducted at the Energy Department's national laboratories, provide benefits that fall outside any particular state.

Second, state and local governments would probably do more to replace lost federal funding in program areas that already had substantial involvement by those governments than in areas that did not. Examples of areas where state and local governments currently play large roles include primary and secondary education and transportation infrastructure.[13]

Third, state and local governments would step into roles being vacated by federal programs more vigorously when their own fiscal situations were stronger than when they were weaker. State and local governments would face their own trade-offs in deciding whether to offset forgone federal benefits or services, and if so, how to reduce spending elsewhere or raise additional taxes or other revenues.[14] (Similar choices among policy priorities arise when state and local governments receive federal block grants with few restrictions on the use of the funds.) Those trade-offs could be particularly difficult for state and local governments that had previously received federal grants that significantly redistributed income to their jurisdictions from elsewhere in the country. Another challenge is that most states have balanced-budget requirements, which would make it particularly hard for them to replace federal programs whose spending increases during economic downturns, because such downturns reduce state revenues.

Fourth, state and local governments whose policy preferences regarding certain benefits and services were more closely aligned with the federal government's preferences would tend to replace a larger share of any step-down in federal support. Having the preferences of state and local governments play a larger role in determining policies would allow those governments to design programs differently, which could be more efficient when the benefits and costs of a program were confined to individual states or when experimentation and variation from state to state yielded valuable information for the nation as a whole. Conversely, it could be less efficient when the decisions

12. Another aspect of the National Flood Insurance Program that the private sector could not readily provide would be its minimum standards for building codes and land-use restrictions in floodplains.

13. Indirect evidence that states would increase their spending on highways if the federal government reduced its own spending on them comes from a 2004 report by the Government Accountability Office, which found that the availability of federal funding for highways encouraged state and local governments to reallocate their own funds for other purposes. See Government Accountability Office, *Federal-Aid Highways: Trends, Effects on State Spending, and Options for Future Program Design*, GAO-04-802 (August 31, 2004), www.gao.gov/products/GAO-04-802.

14. See Congressional Budget Office, *Federal Grants to State and Local Governments* (March 2013), www.cbo.gov/publication/43967.

made in one jurisdiction had significant consequences elsewhere. Moreover, greater flexibility in designing programs at the state level could undermine a federal objective of uniform standards for all states.

Legality of Program Termination

Eliminating a federal program would involve a complex set of policy choices but generally would not pose insuperable legal obstacles. The Congress could terminate some programs simply by not appropriating funds for them. To end other programs, the Congress would have to modify related laws. In either case, costs would continue for existing contracts and other legal requirements, and certain new costs would be incurred, such as the cost of paying for accrued annual leave and unemployment benefits to federal employees whose work had ended.

Constitutional Requirements. Only a few programs fulfill one of the federal government's constitutional requirements, but terminating such a program could violate the Constitution, unless the Constitution was amended or the requirement was assigned to another entity. For instance, the Constitution requires that the government conduct a decennial census; eliminating the Department of Commerce would require the federal government to make alternative plans to meet that requirement.

A second kind of constitutional obstacle involves the effect that eliminating certain federal programs could have on the protection of constitutional rights. For example, the Sixth Amendment guarantees the accused in a criminal prosecution the right "to have the Assistance of Counsel for his defence," which courts have subsequently interpreted to require the provision of counsel to the indigent. Eliminating the public defender program could therefore lead to violations of the Sixth Amendment.

Requirements of International Treaties and Agreements. Some federal programs are responsible for implementing obligations under treaties or agreements that the United States has entered into with other countries. International treaties typically have weak legal enforcement mechanisms or none at all; however, eliminating programs that fulfill treaty obligations could have consequences for U.S. citizens. For example, a determination by the World Trade Organization that the United States had failed to comply with its treaty obligations could result in the imposition of tariffs by other governments against U.S. exports.

Statutory Requirements. Most spending programs could be eliminated by modifying one or more laws, such as those that directly established and financed the programs. Terminating some federal activities, however, would require changes to other programs with which they interact. To eliminate the Bureau of Labor Statistics, for instance, lawmakers would need either to reassign the responsibility for calculating certain statistics, such as the consumer price index, or to amend the tax code and federal programs that are currently indexed to those statistics.

Contractual Requirements. The Congress could eliminate programs involving contracts that imposed requirements on the federal government, but doing so would probably entail costs for canceling or renegotiating the contracts or for litigating or settling lawsuits for breach of contract. In some cases, the federal government might be able to achieve savings by terminating a contract or otherwise renegotiating with the other parties to the contract, though it would probably avoid only a fraction of the remaining costs owed under the contract. In other cases, including legal settlements that the government had already made, the costs would probably be unavoidable. In the 1980s, for example, the Department of Energy entered into contracts with utilities to dispose of their nuclear waste, but it missed the 1998 deadline for accepting such waste. The federal government has entered into settlement agreements requiring that it reimburse dozens of those utilities; the reimbursements would have to be made even if the Department of Energy was closed.

Tort Liability. Some federal programs have generated legal obligations that the government cannot easily dismiss without incurring tort liability.[15] For example, eliminating the Department of Energy's cleanup efforts at sites contaminated by the production of nuclear weapons could lead to liability for environmental damage. Some of the liability (and litigation) costs might be avoided if lawmakers changed the relevant environmental laws and immunized the federal government from lawsuits.[16]

15. A tort is a wrongful act or an infringement of a right (other than under contract) leading to civil legal liability.

16. Ending the Energy Department's defense cleanup programs could also raise issues of domestic or international security.

List of Tables and Figures

Tables

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About This Document

At the request of the House and Senate Committees on the Budget, the Congressional Budget Office periodically issues a compendium of budget options to help inform federal lawmakers about the implications of possible policy choices. This volume presents 115 options for altering spending and revenues to reduce federal budget deficits.

The options discussed in this report come from a variety of sources, including legislative proposals, various Administrations' budget proposals, Congressional staff, other government entities, and private groups. The options are intended to reflect a range of possibilities rather than to rank priorities or present a comprehensive list. The inclusion or exclusion of a particular option does not represent an endorsement or rejection by CBO. In keeping with CBO's mandate to provide objective, impartial analysis, this report makes no recommendations.

This volume is the result of work by more than 130 people at CBO, whose names are listed on the following pages, as well as the staff of the Joint Committee on Taxation.

The report is available on CBO's website (www.cbo.gov/publication/52142).

Keith Hall
Director

December 2016

Overview

The spending estimates that appear in this report were prepared by the staff of the Congressional Budget Office's Budget Analysis Division (supervised by Theresa Gullo, Holly Harvey, Sam Papenfuss, Tom Bradley, Kim Cawley, Chad Chirico, Sheila Dacey, Jeffrey Holland, and Sarah Jennings); Health, Retirement, and Long-Term Analysis Division (supervised by Linda Bilheimer, David Weaver, Jessica Banthin, Phil Ellis, Lyle Nelson, and Julie Topoleski); and Financial Analysis Division (supervised by Damien Moore). Most of the revenue estimates were prepared by the staff of the Joint Committee on Taxation, although some were done by CBO's Tax Analysis Division (supervised by John McClelland, Mark Booth, Ed Harris, and Janet Holtzblatt) and Budget Analysis Division.

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Center for Western Priorities

A Fair Share:

The Case for Updating Federal Royalties

June 20, 2013

www.WesternPriorities.org

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Summary

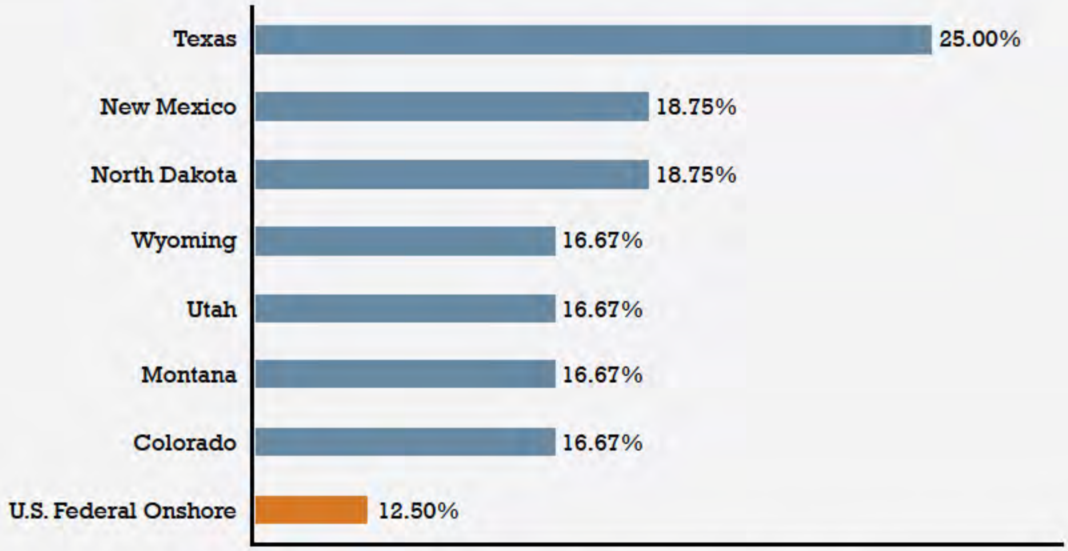
FEDERAL ROYALTY RATES ARE SHORTCHANGING WESTERN STATES & TAXPAYERS

Antiquated federal royalty rates are depriving taxpayers and many Western states of urgently needed revenue that could be used to pay down the national debt, expand access to hunting, fishing, and recreation opportunities, protect public lands, and improve infrastructure strained by oil and gas drilling operations.

The federal onshore royalty rate has not been updated since the 1920s, remaining at 12.5 percent.[1] Most oil and gas producing states in the Western United States charge a significantly higher royalty rate than the federal government—typically a rate of 16.67 percent or 18.75 percent—to produce oil and gas on state-owned lands. Texas collects twice the federal rate in royalties.

By charging royalty rates lower than oil and gas producing Western states, the federal government is leaving revenues on the table and shortchanging taxpayers.

COMPARISON: FEDERAL ONSHORE ROYALTY RATES ARE MUCH LOWER THAN STATE RATES [2]



The royalties that the federal government receives from oil and gas production are split between the U.S. Treasury and the originating states. While oil and gas companies generate billions in profits each quarter,[3] energy rich states in the Rocky Mountain West—Colorado, Montana, New Mexico, Utah, and Wyoming—are being deprived of between \$400 million and \$600 million in gross revenues annually because of the low federal onshore royalty rate.

The Bureau of Land Management (BLM)—an agency within the Department of the Interior—leases federal lands to oil and gas companies. In return, these companies pay royalties to the agency to compensate taxpayers for the extraction of nonrenewable, publicly owned oil and gas resources.

Under this system, oil and gas companies manage leases to drill on approximately 37.8 million acres of federal public lands.[4] In fiscal year 2012, those leases produced over $2.5 billion in royalty payments.[5] However, failing to update the royalty payment structure costs the states and taxpayers significant revenue each year.

The federal onshore royalty rate should be increased to provide a fair return to states and taxpayers. The law requires the BLM to assess a royalty rate of "not less than" 12.5 percent; the President and the Secretary of the Interior have the executive authority to increase that rate without Congressional action.[6]

Sequester cuts and budgetary restrictions have strained local, state, and federal budgets, creating a significant need to revisit our royalty policies. This paper looks at current federal royalty rates and examines opportunities for taxpayers to receive a fair return on energy resources while encouraging the diligent development of federal oil and gas leases.

PUBLIC LANDS AND THE CURRENT ROYALTY STRUCTURE

Public lands are part of our nation's legacy and are an economic driver in the West. These lands contribute to Westerners' quality of life and are a magnet for businesses that create jobs and grow economies. America's public lands offer millions of people a refuge to hike, camp, hunt and fish. They provide wildlife habitats, sources of drinking water and clean air for towns and cities, and supplies of natural resources including timber, minerals, oil and natural gas.

The BLM, one of the four major federal land management agencies, oversees the 700 million acres of federally owned subsurface mineral resources, in addition to managing 245 million surface acres.[7] The BLM is charged with managing these lands for multiple uses, maximizing their benefits to current and future Americans, and striking a balance between land protection and resource development.[8]

When the BLM leases land to private companies, the companies are obligated to repay the public for the use of the lands, as well as the raw materials that are extracted.

The royalties that companies pay to extract oil and gas from federal lands are an important source of federal revenues. According to a 2010 report by the Government Accountability Office (GAO), royalties from oil and gas development "represent one of the federal government's largest nontax sources of revenue."[9]

Along with royalty payments—the largest source of revenues from oil and gas extraction on federal lands—the federal government also generates revenues from oil and gas leasing through bonus bids and rental payments.

Royalties: An energy company pays royalties to a landowner—the federal government, state government, tribal government, or a private landowner—for the right to extract oil and natural gas from their land. Royalties are assessed as a percentage on the value of the oil or natural gas extracted.[10] Royalty payments contributed 89 percent of all federal onshore oil- and natural gas-related revenues in 2012.[11]

Bonus Bids: Federal oil and gas leases are offered through a competitive bidding process. A company must bid at least $2 per acre to lease federal public land, but bids often range much higher.[12] In 2012, bonus bids contributed about 10 percent of all federal onshore oil and natural gas revenues.[13]

Rental Payments: Rentals are paid on leases that are not currently in production and not making royalty payments. A company holding a lease on public lands, but not currently producing on that land, must pay the federal government an annual rental fee of $1.50 per acre in the first 5 years and $2.00 per acre each year thereafter.[14] In 2012, despite nearly 21 million idle acres of leased land, rental payments accounted for less than two percent of federal onshore oil and natural gas revenues.[15/16] Because rental rates are so low, companies are sitting on thousands of leases. Presently, there are nearly 7,000 approved permits, ready for drilling and energy extraction, sitting idle.[17]

FEDERAL AND STATE ROYALTY DISTRIBUTION

Royalties generated on federal lands provide a direct benefit to the states where extraction takes place. The revenues collected are distributed through a formula that returns approximately half of the revenues to the state where drilling occurred—the remainder is deposited into the U.S. Treasury. The one exception is Alaska, where 90 percent of revenues are returned to the state.[18]

Over the last five years, oil and gas production on federal lands has generated almost $14 billion in revenues, a significant portion of which was redistributed to the states where the drilling took place.[19] In FY 2012 alone, the federal government disbursed over $1.3 billion to states where drilling occurs. A significant portion of that amount was distributed to states in the Rocky Mountain West.[20]

Royalty payments distributed from the federal government to the states are an important source of funds to help alleviate the community and economic impacts of oil and gas development by subsidizing the construction and maintenance of public facilities, like schools and roads.

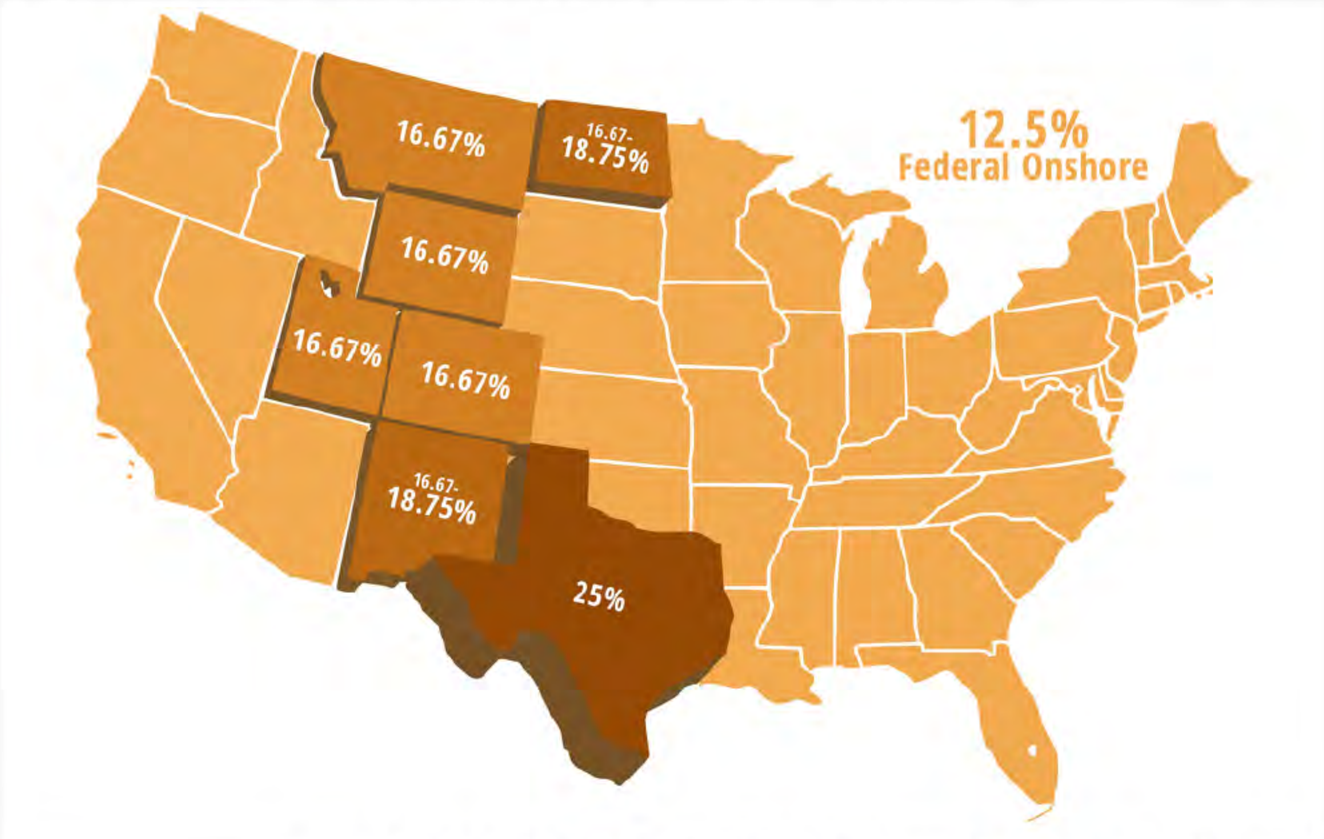
In Colorado, for instance, federal royalties are distributed to counties, municipalities and school districts.[21] In Utah, the large majority of federal royalties are dispersed to maintain local highways in communities impacted by energy development and to the state agencies and towns directly affected by oil and gas development.[22]

FEDERAL OIL AND GAS ROYALTY DISTRIBUTIONS TO WESTERN STATES, FY 2012[23]

FEDERAL ROYALTY RATES BELOW RATES OF MOST WESTERN STATES

States receive a portion of royalty payments from federal lands, and also assess their own royalties on oil and gas extracted from state owned lands. These lands—State Trust Lands—were granted by the federal government to states upon their entering the Union.[24]

Our analysis finds that states in the West—where many federally owned lands are located—charge significantly higher royalty rates to develop oil and gas on state lands. While the federal government charges 12.5 percent on the value of oil and natural gas produced onshore, most Western states charge between 16.67 percent and 18.75 percent. That's anywhere from 33 percent and 50 percent higher than the federal onshore rate. Texas charges a royalty rate of 25 percent, or twice the federal rate.



North Dakota and New Mexico adjust royalty rates on state lands based on the location of known production areas and the likelihood of discovering oil and gas. New Mexico charges 16.67 percent on more speculative lands and 18.75 percent inside known production areas. Similarly, a 16.67 percent royalty is charged in most of North Dakota, but the state levies an 18.75 percent in the counties lying above the Bakken Formation.

In 2007, the federal government recognized that it was not receiving a fair return on federal offshore leases, which, at the time, were 12.5 percent. President George W. Bush's Interior Secretary, Dirk Kempthorne, amended offshore royalty rates to reflect fair market value. Companies drilling for oil and natural gas offshore now pay a royalty of 18.75 percent.[25] More recently, former Secretary of the Interior Ken Salazar championed increasing the federal onshore royalty rate. Each of the previous four Department of the Interior budgets called for increasing the onshore rate, but no action has been taken.[26]

HIGHER RATES DO NOT SIGNIFICANTLY SLOW DRILLING

Resource price, technology and geology largely determine when and where it is profitable for a company to drill for oil and gas. Economic data shows that small, yet fiscally meaningful differences in tax and royalty policy do not significantly affect oil and gas production.[27]

A recent comparative analysis revealed that states with higher oil and gas taxes are not placed at a competitive disadvantage.

Wyoming, for example, has the highest effective tax rate in the West but still remains a national leader in production. At the same time, Montana has among the lowest effective tax rates in an attempt to attract the industry, yet drillers are much more interested in drilling in North Dakota despite the state's relatively higher rates.[28]

Because of Montana's oil and gas tax policy, a new well in Montana will generate $800,000 less for the state than an identical well drilled across the border in North Dakota. Despite this disparity, drilling in North Dakota continues to boom as drilling in Montana lags behind. This suggests that higher rates are not impacting companies' investment decisions.[29]

Flickr @ Jeremy Buckingham

POLICY OPTIONS TO ENSURE AMERICANS GET A FAIR SHARE

The Administration has options to encourage the diligent development of federal oil and gas leases, while ensuring American taxpayers are receiving a fair return on publicly owned oil and natural gas resources.

Increase Federal Royalties to Mirror Rates Charged by the States

One option is to create parity between federal and state royalties by increasing the minimum federal rate. While the BLM may consider adopting a 25 percent rate—on par with Texas—a more practical approach is to mirror the federal onshore royalty rate with the rates charged by the majority of states. Raising the base royalty rate to 16.67 percent or 18.75 percent for all federal onshore leases will generate significant new revenues for the U.S. Treasury and for oil and gas producing states.

Sliding Scale Based on Oil and Natural Gas Prices

Rather than charging a flat royalty rate, the BLM may consider adopting a variable rate that adjusts with the market price of oil and natural gas. Under this alternative, the royalty rate would rise incrementally as the price for oil and gas increases. For instance, when oil is selling at $50 per barrel, a royalty rate of 16.67 percent could be assessed. If the price reaches $75 per barrel, then the federal government could charge an 18.75 percent rate. And, if the price rises above $100 per barrel, the royalty rate could be set at 22.5 percent. Precise royalty rates and associated fuel prices would be negotiated to maximize taxpayer returns as oil and gas prices rise and fall.

Sliding Scale Based on the Location of Known Resources

The federal government may also consider adopting two royalty rates: a lower rate in areas that are more speculative and a higher rate in known production areas. This is a common policy at the state level; both New Mexico and North Dakota charge a higher rate on lands where oil and gas companies are having the most success.[30] Similarly, the BLM may consider assessing a 16.67 percent rate on speculative lands, while levying a higher rate in more established production areas. This approach provides an incentive to companies exploring for oil and gas in more speculative areas, while ensuring they pay a fair share on lands with known, high quality resources.

Escalating Royalty Rate to Encourage Diligent Development

To incentivize companies to develop oil and gas leases in a timely manner, the federal government could adopt an escalating royalty rate. A company that chooses to hold onto a lease without taking steps to develop would pay a higher royalty rate after production begins. For example, a company that begins producing energy during the first two years of a lease could pay an 18.75 percent royalty rate, while a company that takes longer than five years to begin extraction could pay 22.5 percent.

Increase Rental Rates to Encourage Diligent Development

Current rental rates are too low to discourage companies from stockpiling and sitting on thousands of acres of public land. The federal government could incentivize diligent development by making it more expensive to leave leased lands idle. Under current rules, sitting on undeveloped leases costs $1.50 per acre during the first five years of a lease and $2.00 per acre during the next five years; a 33 percent increase. The federal government could look towards the states, like Texas, which charges $5 per acre during the first three years of a lease, then $25 per acre for each ensuing year that the lease remains undeveloped; a 500 percent increase.[31]

PROJECTED REVENUE FROM A FAIRER ROYALTY RATE

The Obama Administration's most recent budget calls for advancing royalty reform, including raising the minimum royalty rate, encouraging diligent development, and evaluating other common sense oil and gas management reforms. **The President's budget estimates that reform would generate $2.5 billion in net revenue to the U.S. Treasury over the decade.**[32]

In addition to paying down the debt and offsetting some sequestration cuts, a portion of new revenues could be spent on conserving public lands. This includes restoring lands damaged by oil and gas drilling, purchasing lands from willing sellers to protect water supplies for nearby communities, and protecting more public lands for hunting, fishing, and recreation.

The President's budget does not include the benefits that higher federal revenue sharing payments would bring to states.

An economic analysis by the Center for Western Priorities reveals how continued royalty stagnation impacts the states and projects how states stand to benefit from modernizing the federal onshore royalty rates. The analysis finds that in 2012 alone, **between $400 and $600 million in additional revenue would have been generated and distributed to states in the Rocky Mountain West**, if royalty rates were increased to 16.67 percent or 18.75 percent.

The two states with the most mineral extraction on federal lands, New Mexico and Wyoming, lost over $150 million each in 2012 because of low federal royalty rates.

INCREASE IN GROSS ROYALTY REVENUE TO WESTERN STATES (FY 2012)

State	Royalty Rate: 16.67%	Royalty Rate: 18.75%
Colorado	$36,600,000	$54,856,000
Montana	$5,790,000	$8,678,000
New Mexico	$155,502,000	$233,066,000
Utah	$43,909,000	$65,811,000
Wyoming	$161,219,000	$241,634,000
Five State Total	$403,019,000	$604,045,000

Simplifying Assumptions

- The analysis estimates changes in gross revenue and does not consider changes in net revenue from increasing royalty rates.
- The analysis does not consider the changes of higher royalty rates to other tax interactions, like tax loopholes and federal income tax deductions.
- The analysis does not consider the effect of changes to bonus bids or rental rates.
- The analysis does not consider changes in oil and gas production levels.
- The analysis assumes that 50 percent of the revenues flow to the states and 50 percent of the revenues flow into the U.S. Treasury.

CONCLUSION

Taxpayers are losing out on significant revenue that could be used to reduce our national debt and alleviate the impacts of oil and gas drilling on communities because the federal government charges a decades-old royalty rate on onshore oil and natural gas leases. While little action has been taken to address the imbalance, the issue has not gone wholly unnoticed. The GAO raised concerns in 2008, writing, "the Congress and the public are justifiably concerned about whether the federal government is getting a fair return for its energy resources as oil and gas company profits have reached record levels."[33]

The Department of the Interior has the authority to reform onshore royalty rates.[34] Former Interior Secretary Ken Salazar proposed raising onshore royalty rates to 18.75 percent.[35] The President's fiscal year 2013 budget recommends, "making administrative changes to federal oil and gas royalties, such as adjusting royalty rates."[36] The BLM's fiscal year 2014 budget calls for royalty reforms, including "evaluating minimum royalty rates for oil, gas, and similar products; [along with] adjusting onshore royalty rates."[37]

Given the country's current fiscal situation, it is imperative that the federal government examine all potential sources of revenue. Ensuring that taxpayers are capturing their share of the booming oil and natural gas sector is a reasonable starting point.

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SABIN CENTER FOR CLIMATE CHANGE LAW

A Mitigation-Based Rationale for Incorporating a Climate Change Impacts Fee into the Federal Coal Leasing Program

By Michael Burger

September 2016

The Sabin Center for Climate Change Law develops legal techniques to fight climate change, trains law students and lawyers in their use, and provides the legal profession and the public with up-to-date resources on key topics in climate law and regulation. It works closely with the scientists at Columbia University's Earth Institute and with a wide range of governmental, non-governmental and academic organizations.

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EXECUTIVE SUMMARY

On January 15, 2016, Interior Secretary Sally Jewell announced the Department of the Interior (DOI or Interior) and Bureau of Land Management(BLM) would conduct a comprehensive environmental review of the federal coal leasing program and, if appropriate, update the regulatory and programmatic scheme for the first time in more than thirty years. The twin goals of the review are to ensure a fair return to the American people and to properly account for the program's environmental impacts, including climate change.

Arguably, the single best way for Interior and BLM to account for the climate impacts of the federal coal leasing program, to protect public lands from climate change impacts and to manage the program in such a way as to meet the United States' domestic and international climate goals is to make permanent the temporary moratorium on issuing new leases – to "leave it in the ground." However, this is not the only potential management approach the agency may adopt. One alternative would be to impose a carbon price on federal coal. To assess its options, BLM can undertake an environmental review under the National Environmental Policy Act (NEPA) that accounts for greenhouse gas (GHG) emissions under a range of alternative scenarios and that uses the Social Cost of Carbon and Social Cost of Methane, or perhaps some other metrics, to assign a monetary value to associated climate impacts.

To complement this presumptive analytic framework, this paper develops an argument for using a mitigation-based rationale to deliver a climate change impacts fee on coal extracted from federal lands, and provides suggestions for how Interior and BLM can approach an analysis of the possibility in its programmatic environmental impact statement (Programmatic EIS). The paper makes several key points:

1. **The federal government has a duty to mitigate climate impacts from downstream GHG emissions associated with the coal leasing program**

There are at least four potential non-statutory sources of the federal government's affirmative duty to mitigate greenhouse gas emissions and associated climate impacts from federal coal: the principles of international law and the requirements set forth under the United Nations Framework Convention on Climate Change; the public trust doctrine; the federal common law of public nuisance; and private nuisance under state common law. Although it is plausible that none

of these sources would result in an affirmative court decision holding the government liable for a breach of its duty, that shortfall does not negate the existence of the duty itself.

The statutes and regulations that govern Interior's management of public lands provide other, and potentially even more forceful, sources for a duty to mitigate upstream and downstream greenhouse gas emissions and associated climate change impacts arising from the federal coal leasing program. Pursuant to the Federal Land Policy and Management Act (FLPMA), the Mineral Leasing Act (MLA) and NEPA, BLM has a duty to analyze and implement mitigation measures for the adverse environmental, social and public health impacts attributable to its management of fossil fuels on public lands.

2. **The federal government has the discretion to mitigate climate impacts from downstream GHG emissions associated with the coal leasing program**

Even if the duty to mitigate is of uncertain scope or enforceability, FLPMA, the MLA and NEPA all confer a definite discretion to mitigate climate change impacts. The multiple use mandate and unnecessary and undue degradation prohibition of FLPMA, the public interest requirements of the MLA and the ambitious goals and specific analytical requirements of NEPA individually and taken together grant the agencies broad discretion to mitigate foreseeable impacts, and to require compensation for impacts that cannot be avoided or minimized.

3. **The duties imposed on and remedies available against lessors under tort and property law offer a persuasive rationale for assigning a climate change impacts fee to federal coal**

Climate change impacts from the coal leasing program's downstream GHG emissions will occur in locations, and to persons, both proximate to and remote from a given leased parcel. These impacted locations will include the leased parcel, other public lands and resources under BLM's jurisdiction, other federal lands and resources under Interior's jurisdiction, and private and public property within and outside the United States.

Impacts to federal lands—including the leased parcel and off-site lands—and even to the public fisc, more broadly writ, are compensable under the general principles of property law. For instance, it is a general principle of property law that tenants are required to restore leased property to its former condition, or else be subject to termination and/or damages. And although there may not be a hornbook principle along these lines to cite to, it makes profound sense that a lessor has within its authority the ability to protect its other properties, or to require compensation for impacts to them, from activities it permits on its land.

Moreover, the federal government, as lessor to coal mining companies, could, in principle, be held liable for damages for the climate change impacts associated with downstream GHG emissions. Section 379A of the Restatement (Second) of Torts and Section 18(4) of the Restatement (Second) of Property maintain similar standards for lessor liability for remote nuisances or personal injuries attributable to lessees' activities. Because the federal government is consenting to the coal mining, and because the federal government is at this time well aware that coal leasing either involves an unreasonable risk or else contributes to the identifiable nuisance of climate change impacts, these principles of lessor liability put the government on the theoretical hook for damages.

4. Federal statutes, regulations and policy provide Interior and BLM with ample authority to adopt a fee as a form of compensatory mitigation

BLM has recognized that compensatory mitigation for unavoidable or residual climate change impacts arising from agency decisions is fully consistent with its mission and its multiple use mandate and that it possesses the discretion to require it, and has clarified that doing so is in fact the agency's policy. A climate change impacts fee for downstream GHG emissions fits within the agency's NEPA obligations and its compensatory mitigation policy.

The climate change impacts at issue in this paper are those that occur as a result of GHG emissions both at the coal mine and downstream, when the extracted coal is transported and eventually combusted for its end use. These downstream GHG emissions are considered "indirect effects" under NEPA, and the climate change impacts associated with those emissions are unavoidable or "residual" impacts. In undertaking the Programmatic EIS, Interior has recognized that NEPA requires it to analyze downstream emissions – a conclusion that comports with the current trajectory of courts' interpretations of NEPA. Under NEPA, then, the agency must also identify and assess appropriate mitigation measures for these emissions, including compensatory mitigation measures. The mitigation measures discussed in the Programmatic EIS should follow the "mitigation hierarchy," and should include both a "net zero" emissions offset program as well as a climate change impacts fee.

A climate change impacts fee would be consistent with recent directives, including the Presidential Memorandum *Mitigating Impacts on Natural Resources from Development and Encouraging Related Private Investment*; Secretarial Order 3330, *Improving Mitigation Policies and Practices of the Department of the Interior*; and "Landscape-Scale Mitigation Policy," a new chapter in its Departmental Manual, which effectively operationalizes Order 3330. The sum total of the White House and Interior guidance is that BLM can and should assess and potentially implement mitigation measures, which might operate through any number of mechanisms, including lease stipulations and chargeable fees, among other things. The mitigation measure should first seek to avoid GHG emissions and their climate impacts; second, seek to minimize emissions and impacts; and third, compensate for unavoidable impacts, as through a climate change impacts fee.

5. Technical issues that the agency should address in the course of assessing this course of action through the Programmatic EIS

There are a number of key questions to address in developing a mitigation framework in any context: 1) whether to mitigate; 2) when to mitigate; 3) what mitigation should be required; 4) technical issues surrounding how to mitigate. The question of whether to mitigate was addressed above. The question of when to mitigate is one of practical consequence: advance mitigation in this context, based on acreage or projected production, might result in overcharging lessees and so basing mitigation on actual production would seem to be a more reasonable approach. The questions of what mitigation should be required and what technical issues the agency will necessarily confront are more complex they are. They are treated in summary form below.

a. *What mitigation should be required*

The Presidential Memorandum *Mitigating Impacts from Natural Resource Development* identifies three types or categories of resources: irreplaceable resources; resources that are important, scarce or sensitive; and other resources managed consistent with an agency's mission and objectives. There is an argument to be made that the climate in which human civilization took shape and in which we continue to exist constitutes an irreplaceable resource, and that the appropriate mitigation measure for continued GHG emissions and climate change impacts is avoidance. If BLM concludes that the climate is not an irreplaceable resource warranting avoidance to the maximum extent practicable the agency must conclude that it is nonetheless an important and sensitive resource, and that the appropriate mitigation standard is a minimum of no net loss, and preferably a net benefit. Such mitigation could be pursued on a number of different scales: planetary, national or regional.

b. *How to calculate a climate change impacts fee*

The question of what the proper amount to charge for federal coal has been the subject of several economic analyses, and this paper does not seek to answer it. Rather, the paper identifies a number of fee-related issues Interior and BLM should consider in the environmental review. These include: whether to use the Social Cost of Carbon and the Social Cost of Methane or other metrics; how to account for intervening actors; how to account for regulations on power plants and other coal users; how to account for the different carbon intensity of coal; whether and how to account for historic emissions; whether and how to account for historic costs; and how to account for the impacts different prices will have on different companies, industry sectors, states, tribes, and local communities. The paper also looks at different mechanisms for compensatory mitigation—such as in lieu fees, mitigation banks and permittee-responsible measures.

6. A Sample Framework for Developing a National Compensatory Mitigation Strategy for the Federal Coal Leasing Program

In considering employing a climate change impacts fee as a compensatory mitigation strategy for the federal coal leasing program BLM will not be starting from scratch. The paper uses the bureau's Regional Mitigation Strategies for Solar Development as a template to develop an analytic framework for the coal leasing program. Accordingly, the paper offers one set of possible responses that result in establishment of a climate change impacts fee as a compensatory mitigation strategy.

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I. Introduction

Since the enactment of the Mineral Leasing Act (MLA) in 1920 the United States federal government has leased public lands to private companies to mine coal, often at a steep discount, and often with little or no accounting for the broad scope of coal's environmental externalities.[1] The raft of environmental legislation that passed through Congress in the 1970s addressed these issues to some degree. For example, the Federal Coal Leasing Amendment Act required the United States to, among other things, recover "fair market value" for the leases; the National Environmental Policy Act (NEPA) required the federal government to assess, analyze and disclose potential adverse environmental impacts from federal actions, including cumulative and indirect effects; and the Clean Air Act and the Clean Water Act addressed aspects of air quality and water pollution by imposing new permit requirements on mining operations. To date, however, the coal leasing program has not adequately addressed the upstream and downstream impacts of federal coal leases — air pollution associated with the extraction, transportation and combustion of coal that contributes significantly to smog, acid rain and, most importantly here, climate change.

Climate change poses an enormous threat to the lives and well-being of individuals and communities across the world, and to ecosystems, wildlife and other natural and cultural resources.[2] The harmful impacts of global climate change include sudden-onset events that can devastate physical and social infrastructure and immediately threaten human lives and safety, as well as more gradual forms of environmental degradation that can over the course of time undermine access to homes, water, food, and other key resources that support the lives and livelihoods of individuals, communities and even entire nations. In the United States, climate change impacts—including increased average temperatures and heat waves, increased frequency and severity of extreme storm events, sea level rise and ocean acidification—pose numerous risks across many sectors, including but not limited to increased heat-related illnesses and deaths, dirtier air, damaged and disappearing coastlines, longer droughts, strains on water quantity and

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[1] Although this paper addresses the coal leasing program specifically, the points made here are in many instances equally applicable to federal oil and gas leasing programs, as well. As the federal government pursues its climate goals it should prioritize making consistent its management of mineral resources, its oversight of fossil fuel transportation and nodes, and its regulation of greenhouse gas emissions.

[2] *See generally* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2014: IMPACTS, ADAPTATION, AND VULNERABILITY (2014).

quality, increasingly frequent and severe floods and wildfires, invasive species, thawing permafrost and degraded fisheries and ecosystems.[3] Public lands managed by the U.S. Department of the Interior and the U.S. Forest Service, among other federal agencies, share these risks, which threaten the environmental, economic, scientific, recreational and other uses to which our public lands are put.[4]

On January 15, 2016, Interior Secretary Sally Jewell issued Order No. 3338, declaring that the Department of the Interior (DOI or Interior) would conduct a comprehensive review of the federal coal leasing program and, if appropriate, update the regulatory and programmatic scheme for the first time in more than thirty years.[5] Order No. 3338 also announced that Bureau of Land Management (BLM) would prepare a discretionary Programmatic Environmental Impact Statement (Programmatic EIS) under NEPA, which will provide a "vehicle" for considering "whether and how the program may be improved and modernized to foster the orderly development of BLM administered coal on Federal lands in a manner that gives proper consideration to the impact of that development on important stewardship values, while also ensuring a fair return to the American public."[6] Order No. 3338 specifically calls on the Programmatic EIS to consider "the climate impacts of continued Federal coal production and combustion and how to address those impacts in the management of the program to meet both the Nation's energy needs and its climate goals, as well as how best to protect the public lands from climate change impacts."[7]

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[3] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment 195 (Jerry M. Melillo et al. eds., 2014).

[4] *See, e.g.*, Exec. Order No. 13,653, 78 Fed. Reg. 66,819, 66,819 (Nov. 6, 2013) ("The impacts of climate change—including an increase in prolonged periods of excessively high temperatures, more heavy downpours, an increase in wildfires, more severe droughts, permafrost thawing, ocean acidification, and sea-level rise—are already affecting communities, natural resources, ecosystems, economies, and public health across the Nation"); Jessica E. Halofsky et al., Climate Change Adaptation in United States Federal Natural Resource Science and Management Agencies: A Synthesis (2015) (summarizing adaptation activities by natural resource management agencies in 2013–14).

[5] Discretionary Programmatic Environmental Impact Statement to Modernize the Federal Coal Program, Sec'y of the Interior Order No. 3338 (Jan. 15, 2016).

[6] *Id.* at 1.

[7] *Id.* at 8. Order No. 3338 also establishes the related goals of ensuring that the American public receives fair market value (or a "fair return") from the sale of the coal, and assessing whether the program "adequately accounts for externalities related to Federal coal production, including environmental and social impacts."

Arguably, the single best way for Interior and BLM to account for the climate impacts of the federal coal leasing program, to protect public lands from climate change impacts and to manage the program in such a way as to meet the United States' climate goals is to make permanent the temporary moratorium on issuing new leases. The numbers on this point are telling: As part of its participation in the Paris Agreement to the United Nations Framework Convention on Climate Change (UNFCCC), the United States has committed to reduce economy-wide greenhouse gas (GHG) emissions by 26–28% below 2005 levels by 2025, which will put the country on a trajectory to achieve emission reductions of 80% or more by 2050.[8] This emissions reduction target is part of a broader commitment on the part of the U.S. and the 177 other signatories of the Paris Agreement to limit global warming to "well below" a 2 °C increase above pre-industrial temperatures, and to seek to limit it to 1.5 °C.[9] According to one recent study, in order to achieve this goal over 80% of global coal reserves <u>and 92% of U.S. coal reserves</u> must remain unused to have even a 50% chance of meeting the 2 °C target.[10] Thus, the best way to avoid and/or minimize adverse climate change impacts from federal coal is quite simply to "leave it in the ground."

Id. Greenhouse gas emissions are one of the externalities that should be accounted for when determining whether the American public is receiving fair market value from the sale of the coal. *See* EXECUTIVE OFFICE OF THE PRESIDENT OF THE U.S., THE ECONOMICS OF COAL LEASING ON FEDERAL LANDS: ENSURING A FAIR RETURN TO TAXPAYERS (2016); Alan Krupnick et al., *Should We Price Carbon from Federal Coal?*, RESOURCES, Spring/Summer 2015, at 16.

[8] To achieve this, we must lower annual emissions to 5460–5312 million metric tons of carbon dioxide equivalent ($MtCO_2e$) by 2025 (a reduction of 1410–1558 $MtCO_2e$ over 2014 levels). *U.S. Cover Note, INDC and Accompanying Information*, UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (Mar. 31, 2015), http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf (submitting the U.S.'s intended nationally determined contribution to the UNFCCC Secretariat). These figures are based on the EPA GHG inventory estimates for 2005 GHG emissions and 2014 emissions (which were used as a baseline for current emissions, since these are the most recent estimates). U.S. ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2014 (2016). Notably, even with the Clean Power Plan and other existing regulations, the U.S. is not yet on track to achieve these reductions—additional measures will be needed to meet the 2025 target. *See* JOHN LARSON ET AL., RHODIUM GROUP, TAKING STOCK: PROGRESS TOWARD MEETING US CLIMATE GOALS (2016); DOUG VINE, CTR. FOR CLIMATE & ENERGY SOLUTIONS, ACHIEVING THE UNITED STATES' INTENDED NATIONALLY DETERMINED CONTRIBUTION (2016), http://www.c2es.org/docUploads/achieving- us-indc.pdf.

[9] U.N. Framework Convention on Climate Change, *Adoption of the Paris Agreement*, U.N. Doc. FCCC/CP/2015/L.9/Rev.1, art. 2 (Dec. 12, 2015) [hereinafter *Paris Agreement*].

[10] Christophe McGlade & Paul Ekins, *The Geographical Distribution of Fossil Fuels Unused When Limiting Global Warming to 2 °C*, 517 NATURE 187 (2015) (regional estimates of unburnable reserves were based on an "economically optimal" distribution).

However, a directive to "leave it in the ground" is not the only potential management approach the agency may adopt. To understand the implications of different approaches, BLM can and should calculate and assess the full scope of potential GHG emissions associated with the federal coal leasing program under a number of different alternatives, ranging from the "leave it in the ground" alternative to a worst-case, "burn it all" alternative. In addition, BLM can and should calculate and assess the full scope of potential climate change impacts attributable to those emissions. Although it remains difficult to attribute particular climate impacts to specific GHG emissions, and although any attribution remains to some degree uncertain, the federal government has developed the Social Cost of Carbon and the Social Cost of Methane to provide a robust, quantitative means by which to calculate and assess climate impacts.[11] For the purposes of analysis and focus, this paper assumes that BLM will undertake an appropriate environmental review that accounts for the full range of GHG emissions and that uses the Social Cost of Carbon and Social Cost of Methane to put a monetary value to associated climate impacts.

To complement this presumptive analytic framework, this paper develops an argument for using a mitigation-based rationale to deliver a climate change impacts fee on coal extracted from federal lands. Assuming that at least some new federal coal leases will be issued under the revised program, or that existing leases may be renewed, BLM has the legal authority to seek to compensate for the adverse environmental, social and public health impacts attributable to the resulting GHG emissions — and it makes policy sense to do so. Pursuant to NEPA and its implementing regulations, upstream GHG emissions—emissions from the extraction of coal from federal lands—are direct effects of a coal lease; downstream GHG emissions—emissions from the transportation and combustion of the coal—are indirect effects. The climate change impacts attributable to those upstream and downstream emissions, then, are unavoidable (or "residual") impacts from a coal leasing program that involves the issuance of new leases or renewal of existing ones, and so properly the subject of compensatory mitigation, such as a climate change impacts

[11] *See* INTERAGENCY WORKING GRP. ON SOC. COST OF CARBON, TECHNICAL SUPPORT DOCUMENT—TECHNICAL UPDATE OF THE SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866 (2013, *revised* 2015); INTERAGENCY WORKING GRP. ON SOC. COST OF GREENHOUSE GASES, ADDENDUM TO TECHNICAL SUPPORT DOCUMENT ON SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866: APPLICATION OF THE METHODOLOGY TO ESTIMATE THE SOCIAL COST OF METHANE AND THE SOCIAL COST OF NITROUS OXIDE (2016).

fee.[12] As a matter of regulatory design, this climate change impacts fee could come as part of the bonus bid on a lease, as an in-lieu fee, as part of the regulatory rental fee, as a stand-alone lease condition, as part of the royalty calculation or in some other form. As a matter of environmental review, a climate change impacts fee could serve as an element of one of the alternatives being analyzed. However, it may be even more useful to analyze the concept as an independent alternative—that is, as an element of program design, or as an adder or overlay to all of the other alternatives.[13] The latter approach would more easily allow the agency to assess the efficacy and repercussions of a range of different fees.

This paper proceeds in five parts, of which this Introduction is the first. Part II addresses the question of whether the federal government has either a duty to mitigate climate impacts from downstream GHG emissions associated with the coal leasing program or the discretion to do so. This section seeks to answer this question by examining the obligations and limitations imposed by international law, the public trust doctrine, our common law and relevant federal statutes. Part III argues that duties imposed on and remedies available against lessors under tort and property law offer a persuasive rationale for assigning a climate change impacts fee to federal coal. Part IV argues that federal statutes, regulations and policy provide Interior and BLM with ample authority to do so. Part V identifies some of the technical issues that the agency should address in the course of assessing this course of action through the Programmatic EIS.

II. The Federal Government's Duty to Mitigate Climate Change Impacts

The federal government's ownership of the federal public domain is absolute, analogous to though not precisely the same as title in fee simple.[14] Congress, consistent with the authority granted by the Property Clause of the U.S. Constitution, possesses the powers both of "proprietor

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[12] *See infra* Section II.C.

[13] *See* Final Guidance for Federal Departments and Agencies on the Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact, 76 Fed. Reg. 3843 (Jan. 21, 2011); *see also* 43 CFR § 46.130(a) (2015) ("The mitigation measures can be analyzed either as elements of alternatives or in a separate discussion of mitigation.").

[14] *See* RESTATEMENT (THIRD) OF PROP.: WILLS AND OTHER DONATIVE TRANSFERS § 24.2 (AM. LAW INST. 2011) (discussing relationship of fee simple absolute to notions of inheritance).

and of legislature"; these powers are "subject to no limitations."[15] In its capacity as proprietor, Congress has the power to withdraw and reserve, dispose and convey, and otherwise limit the use of federal lands. In its capacity as regulator, Congress is empowered to "make all needful rules and regulations."[16]

There are, of course, important limits on the federal government's ownership, and these limits necessarily influence how Interior and BLM should approach the revision of the federal coal leasing program. After all, even title in fee simple absolute is not free rein to use property in any way. A private property owner possesses not only a bundle of rights but also a bundle of duties to others. Private property may not be used in a way that violates the others' rights, and is restricted by common law doctrines such as nuisance, trespass and negligence. The federal government's use of federal lands is also circumscribed by these common law doctrines—in principle if not as a matter of law per se. These principles abide because although the federal government is insulated from litigation in some instances that would allow others to enforce its obligations or else be liable for damages, and although the federal government has in the discretionary function defense a legal defense that will shut down most if not all lawsuits against it seeking damages for its land and natural resources management decisions, these legal escape-hatches do not obviate the government's duties as proprietor and regulator of the public domain. Moreover, in managing the public lands under its jurisdiction, Interior and BLM act as agents of Congress, executing the laws pursuant to the discretion afforded them under federal legislation.

The remainder of this section addresses the question of whether Interior and BLM have either a duty to mitigate climate change impacts attributable to the coal leasing program's upstream and downstream GHG emissions, or else the discretion to do so.

A. *International Law, Public Trust and Common Law Sources of a Duty to Mitigate Climate Change Impacts*

There are at least four potential sources of the federal government's affirmative duty to mitigate greenhouse gas emissions and associated climate impacts from federal coal: international law, the public trust doctrine, the federal common law of public nuisance, and private nuisance

[15] Kleppe v. New Mexico, 426 U.S. 529, 540 (1976); Gibson v. Choteau, 80 U.S. 92, 99 (1871).
[16] *Kleppe*, 426 U.S. at 540.

under state common law. The discussion that follows illuminates a number of core principles embodied in these sources that ought to guide the federal government as it undertakes its comprehensive review of the federal coal leasing program.

a. International Law

Consistent with the international law principle of *sic utere tuo ut alienum non laedus*, which directs nations to avoid causing significant injuries to the environment of other nations, states in the international community have a duty to address transboundary environmental harms, including those that arise from use of state-owned property and from activities authorized by state action.[17] This principle was recently upheld by the International Court of Justice (ICJ) in the *Pulp Mills* case, where the court noted that it is "every State's obligation not to allow knowingly its territory to be used for acts contrary to the rights of other States."[18] The *Pulp Mills* decision accords with the ICJ's earlier declaration in the *Trail Smelter* case that "no state has the right to use or permit the use of its territory in such a manner as to cause injury . . . in or to the territory of another or of the properties or persons therein, when the case is of serious consequence and the injury is established by clear and convincing evidence."[19] To facilitate compliance with this "no harm" rule there is a "principle of prevention" that requires a state to "use all the means at its disposal in order to avoid activities which take place in its territory, or in any area under its jurisdiction, causing significant damage to the environment of another State."[20]

Climate change plainly falls within the ambit of the "no harm" rule and its corollary obligations. As a technical matter, there is no question that GHGs emitted in the United States contribute to the planetary problem of climate change, injuring property and people in foreign countries. The science is straightforward: CO_2 and the other greenhouse gases become "well-

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[17] *See* RESTATEMENT (THIRD) OF THE FOREIGN RELATIONS LAW OF THE UNITED STATES § 601 (AM. LAW INST. 1987).

[18] Pulp Mills on the River Uruguay (Arg. v. Uru.), Judgment, 2010 I.C.J. 14, ¶ 101 (Apr. 20) (quoting Corfu Channel (U.K. v. Alb.), Judgment, 1949 I.C.J. 4, 22 (Apr. 9)).

[19] Trail Smelter (U.S. v. Can.), 3 R.I.A.A. 1938, 1963 (Trail Smelter Arb. Trib. 1941).

[20] *Pulp Mills*, 2010 I.C.J. 14, ¶ 101 (citing Legality of the Threat or Use of Nuclear Weapons, Advisory Opinion, 1996 I.C.J. 226, ¶ 29 (July 8)).

mixed" in the atmosphere and affect global climate.[21] As the U.S. Environmental Protection Agency (EPA) has explained, "U.S. emissions have climatic effects not only in the United States but in all parts of the world."[22] Moreover, the problem is both historic and prospective. As the IPCC has concluded, "it is extremely likely that human influence has been the dominant cause of the observed warming since the mid-20th century," and that "[c]ontinued emissions of greenhouse gases will cause further warming and changes in all components of the climate system," exacerbating climate change impacts and harms.[23]

The UNFCCC's establishment of climate change mitigation and adaptation obligations for nations party to the Convention concretizes nations' duties under international law. As its overarching purpose, the Convention recognizes that all states share a duty to "prevent dangerous anthropogenic interference with the atmosphere."[24] In the 2010 Cancun Agreements, the Conference of the Parties to the UNFCCC (COP) agreed that, to achieve this goal, they must "hold the increase in global average temperature below 2 °C above pre-industrial levels," and that they should consider strengthening this long-term goal so as to hold the global average temperature increase to 1.5 °C.[25] In the more recent Paris Agreement, the COP strengthened their commitment, committing Parties to "[h]olding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursu[ing] efforts to limit the temperature increase to 1.5 °C above pre-industrial levels."[26]

Among its core principles, the Convention calls on the Parties to "take precautionary measures to anticipate, prevent or minimize the causes of climate change and mitigate its adverse

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[21] *See* Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,536–40 (Dec. 15, 2009); *see also id.* at 66,540 (finding mobile sources comprising 4.3 percent of global greenhouse gas emissions in 2005 to cause or contribute to this pollution). *See generally* ULRICH CUBASCH ET AL., *Introduction* to INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS (Thomas F. Stocker et al. eds., 2013).

[22] U.S. ENVTL. PROT. AGENCY, TECHNICAL SUPPORT DOCUMENT FOR THE ENDANGERMENT AND CAUSE OR CONTRIBUTE FINDINGS FOR GREENHOUSE GASES UNDER SECTION 202(A) OF THE CLEAN AIR ACT 157 (2009).

[23] Lisa V. Alexander et al., *Summary for Policymakers, in* CLIMATE CHANGE 2013, *supra* note 21, at 12, 14.

[24] U.N. Framework Convention on Climate Change art. 2, *adopted* May 9, 1992, 1771 U.N.T.S. 107 [hereinafter UNFCCC].

[25] U.N. Framework Convention on Climate Change, *The Cancun Agreements: Outcome of the Work of the Ad Hoc Working Group on Long-Term Cooperative Action Under the Convention*, U.N. Doc. FCCC/CP/2010/7/Add.1, Dec. 1/CP.16, ¶ 4 (Mar. 25, 2011).

[26] *Paris Agreement*, *supra* note 9, art. 2(1)(a).

effects."[27] Consistent with these goals and principles, the Convention requires all Parties, keeping in mind their common but differentiated responsibilities and capabilities, to design and implement programs containing both mitigation and adaptation measures.[28] Mitigation measures may "cover all relevant sources, sinks and reservoirs of greenhouse gases and adaptation, and comprise all economic sectors."[29] A "reservoir" is defined by the Convention as "a component or components of the climate system where a greenhouse gas or a precursor of a greenhouse gas is stored."[30] Climate change mitigation is most often conceived in relation to reducing emissions from sources such as smokestacks and tailpipes, or else capturing fugitive emissions from landfills and natural resources extraction; management of fossil fuel stocks (or "reservoirs") and accounting for downstream emissions and impacts have not been central to nations' mitigation and adaptation planning to date.[31] However, there is no reason they cannot or should not be. Given the latitude afforded to nations by the UNFCCC and the broad scope of permissible mitigation measures, managing fossil fuel reserves, their upstream and downstream GHG emissions and associated climate change impacts can easily fit within the a nation's program to comply with its duties under international law, including the Nationally Determined Contributions (NDCs) to be developed and employed under the Paris Agreement.[32]

Courts around the world have begun to recognize that international law assigns governments an affirmative duty to mitigate GHG emissions and climate change impacts. In June 2015 the Hague District Court in the Netherlands issued a decision holding that the domestic law

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[27] UNFCCC, *supra* note 24, art. 3(3) (emphasis added).
[28] *Id.* art. 4(1)–(2).
[29] *Id.* art. 3(3).
[30] *Id.* art. 1(7).
[31] *See generally* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, 2006 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES (Simon Eggleston et al. eds., 2006).
[32] *Paris Agreement*, *supra* note 9, art. 4.2. It bears noting, here, that several nations have explicitly referenced coal mining in the submission of their NDCs. *See, e.g.*, *Bangladesh's Intended Nationally Determined Contributions*, UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (Sept. 25, 2015), http://www4.unfccc.int/Submissions/INDC/Published%20Documents/Bangladesh/1/INDC_2015_of_Bangladesh.pdf; *Intended Nationally Determined Contribution of Viet Nam*, UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (Sept. 30, 2015), http://www4.unfccc.int/Submissions/INDC/Published%20Documents/Viet%20Nam/1/VIETNAM'S%20 INDC.pdf.

of that country requires the government to accelerate its emission reduction efforts in order to fulfill a duty of care to its citizens.[33] In reaching its decision, the court cited, though it did not directly apply, various components of international law, including the "no harm" rule, the doctrine of hazardous negligence, the principle of fairness, the precautionary principle, and the sustainability principle embodied in the UNFCCC. In September 2015 an appellate court in Pakistan found that both international law and domestic law required the government to implement its national climate change policy—which included mitigation and adaptation objectives—in order to protect the fundamental rights of its citizens.[34] Cases alleging a violation of fundamental rights as a result of governmental inaction on climate change have been also filed in Belgium[35] and the Philippines.[36] In addition, cases specifically challenging domestic coal policies and their impacts on certain fundamental rights have been filed in Pakistan[37] and, as discussed in the next section, the United States.[38]

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[33] RB-Den Haag [Hague Dist. Ct.] 24 juni 2015, ECLI:NL:RBDHA:2015:7196 (Stichting Urgenda/Nederlanden) [Urgenda Found. v. Netherlands].

[34] Leghari v. Fed'n of Pak., W.P. No. 25501/2015 (Lahore High Ct., Green Bench).

[35] *See* KLIMAATZAAK [CLIMATE CASE], http://klimaatzaak.eu/nl (last visited Sept. 10, 2016) (providing an overview of litigation brought by a nonprofit organization, Klimaatzaak, against the government of Belgium); *see also* Summons to the Ministers of Flanders, Wallonia, Brussels, and the Fed. State of Belg. (April 27, 2015), http://klimaatzaak.eu/wp-content/uploads/2015/04/Dagvaarding.pdf.

[36] *See* Petition submitted by Greenpeace Se. Asia & Phil. Rural Reconstruction Movement to the Comm'n on Human Rights of the Phil. (Sept. 22, 2015), http://www.greenpeace.org/seasia/ph/PageFiles/105904/Climate-Change-and-Human-Rights-Complaint.pdf (asking the Commission to investigate "the human rights implications of climate change and ocean acidification and the resulting rights violations in the Philippines").

[37] *See* Constitution Petition, Ali v. Fed'n of Pak. (SC Apr. 2016), http://elaw.org/system/files/Pakistan%20Climate%20Case-FINAL.pdf (challenging approval of plan to develop coal fields located in the Thar desert region anticipated to increase Pakistani coal production from 4.5 to 60 million metric tons per year).

[38] *See* Complaint, Juliana v. United States, No. 6:15-cv-01517 (D. Or. Aug. 12, 2015). As discussed below, this complaint and other recent cases in the U.S. also allege that federal and state governments have violated their public trust obligation by failing to adequately mitigate the GHG emissions that contribute to climate change. These cases have not yet been successful at compelling government action, but they have resulted in at least one decision holding that the state government (New Mexico) had a public trust responsibility to protect the atmosphere (though the court also found that this responsibility had been met through compliance with the state air quality act), Sanders-Reed v. Martinez, 350 P.3d 1221 (N.M. Ct. App. 2015), and one decision holding that the public trust doctrine required the state to undertake climate action because of impacts to ocean and coastal resources, Foster v. Wash. State Dep't of Ecology, 362 P.3d 959 (Wash. 2015).

b. The Public Trust Doctrine

The public trust doctrine traces its origins to Roman civil law and its legal development to the English common law on public navigation and fishing rights in rivers, oceans and tidelands, but it is not so limited in its scope.[39] It has often been acknowledged, by courts and the government, that the federal government holds title to public lands in trust for current and future generations.[40] However, there is an open question over whether there is a federal public trust *doctrine*, and if so what obligations arise pursuant to that doctrine in regards to the management and administration of public lands, in general, and the federal coal leasing program, in particular, in the the age of climate change.

This question is the subject of ongoing litigation in federal district court in Oregon. In that lawsuit, plaintiffs allege that they are "beneficiaries of rights under the public trust doctrine, rights that are secured by the Ninth Amendment and embodied in the reserved powers doctrines of the Tenth Amendment and the Vesting, Nobility, and Posterity Clauses of the Constitution."[41] According to plaintiffs, these rights include the right to "essential natural resources," including "our country's life-sustaining climate system, which encompasses our atmosphere, waters, oceans, and biosphere."[42] Plaintiffs argue that the federal government has an affirmative, sovereign duty not to "substantially impair" the climate, and that past, present and continued extraction of fossil fuels from federal lands constitute a violation of this duty.[43] The federal government has argued that it is settled law that, as the U.S. Supreme Court has stated, "the public trust doctrine remains a matter of state law,"[44] and that the public trust doctrine is inapplicable to federal lands

[39] Joseph L. Sax, *The Public Trust Doctrine in Natural Resource Law: Effective Judicial Intervention*, 68 MICH. L. REV. 471 (1970).

[40] *See* Shively v. Bowlby, 152 U.S. 1, 57 (1894) ("Upon the acquisition of a territory by the United States, whether by cession from one of the states, or by treaty with a foreign country, or by discovery and settlement, the same title and dominion passed to the United States, for the benefit of the whole people, and *in trust* for the several states to be ultimately created out of the territory.") (emphasis added).

[41] Amended Complaint ¶ 308, *Juliana*, No. 6:15-cv-01517.

[42] *Id.*

[43] *Id.* ¶¶ 309–10.

[44] PPL Montana, LLC v. Montana, 132 S. Ct. 1215, 1235 (2012); *see also* Alec L. *ex rel.* Loortz v. McCarthy, 561 F. App'x 7, 8 (D.C. Cir.) (per curiam), *cert. denied*, 135 S. Ct. 774 (2014) (finding no precedent "standing for the proposition that the public trust doctrine—or claims based upon violations of that doctrine—arise under the Constitution or laws of the United States"); United States v. 32.42 Acres of Land, More or Less, Located in

management. In April 2016, a federal magistrate judge rejected the federal government's argument and recommended that the district court allow the public trust claim to proceed to trial.[45]

Interior and BLM need not await the courts' resolution of this issue to grasp its import. A finding that there is no federal public trust doctrine applicable to federal lands management would not settle the broader question of what the federal government's duties in managing lands it holds in trust for the public are, particularly in regard to foreseeable, if indirect, climate change impacts. Similarly, even if the courts conclude that Supreme Court precedent does not foreclose a federal public trust doctrine claim, and eventually concludes that the continued extraction of fossil fuels from public lands is a violation of this duty, they are in any event unlikely to determine the precise contours of the federal coal leasing program. As the federal magistrate judge in Oregon recognized, "it is not for the courts to say how the trust in resources and the territory shall be administered, that is for Congress to determine."[46] And, as discussed in Sections II.B and IV below, Congress has spoken at length on this topic. In either event—whether the trust obligation be specifically tied to the public trust doctrine or to a more general one—it would be wholly reasonable for a court or the agencies themselves to conclude that Interior and BLM have a duty as trustees of federal lands to provide a proper accounting to the public of environmental externalities associated with the federal coal leasing program, including greenhouse gas emissions and associated climate change impacts, and to mitigate against them.[47]

c. Public Nuisance

The Restatement (Second) of Torts defines a public nuisance as "an unreasonable interference with a right common to the general public."[48] According to the Restatement, an interference may be unreasonable when "the conduct involves a significant interference with the

San Diego Cty., 683 F.3d 1030, 1038 (9th Cir. 2012) (stating that while the equal-footing doctrine is grounded in the Constitution, "the public trust doctrine remains a matter of state law").

[45] Order and Findings & Recommendation at 17–24, *Juliana*, No. 6:15-cv-01517.

[46] *Id.* at 22 (citing Alabama v. Texas, 347 U.S. 272, 273 (1954); United States v. California, 332 U.S. 19, 27 (1947)).

[47] *See* Nevin D. Holmberg & Robert Misso, *Mitigation: Determining the Need*, NAT'L WETLANDS NEWSL., Sept.–Oct. 1986, at 10 (noting the resource mitigation concept to be appropriate given the government's public trust responsibilities, and intrinsic environmental, social and economic values).

[48] RESTATEMENT (SECOND) OF TORTS § 821B (AM. LAW INST. 1979).

public health, the public safety, the public peace, the public comfort or the public convenience,"[49] or else when "the conduct is of a continuing nature or has produced a permanent or long-lasting effect, and, as the actor knows or has reason to know, has a significant effect upon the public right."[50] Where a public nuisance is found, a plaintiff may be able to obtain either injunctive relief or an award of damages. Thus, a landowner may be said to owe a duty to others to not undertake or allow activities that unreasonably interfere with a right common to the general public.

The federal government has not been sued to limit or cease coal leasing under a public nuisance theory. It could be. As a preliminary matter, the federal government may properly be the subject of a federal public nuisance lawsuit.[51] Moreover, the outcome of this claim has not been definitively resolved, despite the U.S. Supreme Court's ruling in *American Electric Power Co. v. Connecticut*[52] and the Ninth Circuit's subsequent decision in *Native Village of Kivalina v. ExxonMobil Corp.*.[53] In *AEP v. Connecticut*, plaintiff states, cities and non-governmental organizations claimed that the CO_2 emissions from four private power companies and the Tennessee Valley Authority contribute to global warming and therefore constitute a public nuisance under federal law, and sought an injunction ordering the companies to lower their emissions. The Supreme Court determined that any existing federal common law cause of action had been displaced by the Clean Air Act, which authorizes EPA to regulate GHG emissions from power plants and other sources.[54] In *Native Village of Kivalina*, the Ninth Circuit extended this holding to a federal public nuisance claim against a number of energy producers—including ExxonMobil, BP, Chevron and other fossil fuel companies—for climate change damages associated with defendants' activities.[55] Notably, plaintiffs in *Native Village of Kivalina* alleged that *direct* emissions associated with the energy companies' operations contributed to climate change—they did not address indirect, or downstream, emissions associated with defendants' extractive activities, such as those that would

[49] *Id.* § 821B(2)(a).

[50] *Id.* § 821B(2)(c).

[51] Michigan v. U.S. Army Corps of Eng'rs, 758 F.3d 892, 901–02 (holding that U.S. Army Corps of Engineers "can be held to account" under federal common law public nuisance if plaintiffs can establish liability).

[52] Am. Elec. Power Co. v. Connecticut, 564 U.S. 410 (2011).

[53] Native Vill. of Kivalina v. ExxonMobil Corp., 696 F.3d 849 (9th Cir. 2012).

[54] *Am. Elec. Power*, 564 U.S. at 424.

[55] *Kivalina*, 696 F.3d at 858.

be at issue in a case against Interior and BLM for coal leasing. The difference being that direct emissions are regulated under the Clean Air Act, while downstream emissions are not.

Without engaging in an extensive analysis of the question, fair reasoning could conclude that a federal common law public nuisance suit against Interior and BLM for climate impacts arising from federal coal would also be found to be displaced by federal legislation, most likely the Federal Land Policy and Management Act and/or the Mineral Leasing Act, which, as discussed further below, grant the agencies the authority to lease—or to not lease—based on numerous factors, including their downstream GHG emissions. Yet, the displacement of the legal claim does not fully resolve the question of whether a duty of care exists, especially in regards to a sovereign landowner. On this point, the most important legal guidance may be garnered from the Second Circuit decision in the *AEP v. Connecticut* litigation. In a portion of the Second Circuit opinion which was not addressed by the Supreme Court, the appellate panel found that problems associated with climate change fall well within the outer limits of public nuisance doctrine.[56] Under this precedent, the federal government's coal leasing program is quite likely contributing to an ongoing public nuisance. Regardless of the likelihood of success in a suit brought against it, as a sovereign landowner the government should undertake efforts to mitigate that nuisance.

d. Private Nuisance

The Restatement (Second) of Torts defines a private nuisance as "a nontrespassory invasion of another's interest in the private use and enjoyment of land."[57] Liability may follow if the complained-of action is the legal cause of the invasion, and the invasion is "either (a) intentional and unreasonable, or (b) unintentional and otherwise actionable under the rules controlling liability for negligent or reckless conduct, or for abnormally dangerous conditions or activities."[58] Thus, a landowner may be said to owe a duty to others to not undertake or allow activities that intentionally and unreasonably interfere with another's private use and enjoyment of land, that unintentionally and negligently or recklessly do so, or else that create abnormally dangerous conditions or comprise abnormally dangerous activities.

[56] Am. Elec. Power. Co. v. EPA, 582 F.3d 309, 331, 349–71 (2d Cir. 2009).
[57] RESTATEMENT (SECOND) OF TORTS § 821D (AM. LAW INST. 1979).
[58] *Id.*

In *Comer v. Murphy Oil USA*, plaintiff property owners alleged that certain power and chemical companies' GHG emissions contributed to climate change, which in turn exacerbated the harmful effects of Hurricane Katrina, constituting a private nuisance (as well as a public nuisance, trespass, negligence, unjust enrichment, fraudulent misrepresentation and civil conspiracy).[59] The case involved a convoluted procedural history, featuring a dismissal in district court, a reversal at the Fifth Circuit, an en banc decision to vacate the reversal due to failure to muster a quorum, plaintiffs' filing a writ of mandamus asking the Supreme Court to reinstate the panel decision, the denial of the writ, plaintiffs' re-filing their case in district court, and dismissal based on res judicata grounds – though not on the merits.[60] For present purposes, the important decision is the first Fifth Circuit decision, in which that court found that plaintiffs had standing to bring an action for private nuisance and that the political question doctrine did not bar such a suit.[61] Salient here, the court found that a diversity suit brought under state common law for damages was materially distinguishable from public nuisance claims brought under federal common law and seeking an injunction.[62] The court did not address the merits of the private nuisance claim, leaving that for a prospective trial.[63]

Though the analyses differ as between public and private nuisance, it may well be that a court would find a private nuisance suit against the federal government on climate change grounds preempted for much the same reasons as a court might find a federal public nuisance suit displaced or a state public nuisance suit preempted.[64] However, as with public nuisance, preemption of the legal claim does not resolve the question of whether a duty of care exists, especially in the case of a sovereign landowner. Here, the question would be whether the federal

[59] Comer v. Murphy Oil USA, 607 F.3d 1049, 1054 (5th Cir. 2010), *petition for writ of mandamus denied sub nom. In re* Comer, 562 U.S. 1133 (2011).

[60] *See* Comer v. Murphy Oil USA, Inc., 839 F. Supp. 2d 849, 855–68 (S.D. Miss. 2012) (dismissing re-filed complaint on preemption, political question, standing, res judicata and collateral estoppel grounds), *aff'd*, 718 F.3d 460 (5th Cir. 2013).

[61] Comer v. Murphy Oil USA, 585 F.3d 855 (5th Cir. 2009).

[62] *Id.* at 879.

[63] *Id.*

[64] *See e.g.*, Comer v. Murphy Oil USA, Inc., 839 F. Supp. 2d 849, 865 (S.D. Miss. 2012), *aff'd*, 718 F.3d 460; *see also* Matthew Morrison & Bryan Stockton, *What's Old Is New Again: State Common-Law Tort Actions Elude Clean Air Act Preemption*, 45 Envtl. L. Rep. (Envtl. Law Inst.) 10,282 (Apr. 2015).

coal leasing program is negligent, reckless, or abnormally dangerous, and the unintentional cause of the invasion of private property. There are strong arguments to be made that continuing to issue new coal leases and to authorize the continued extraction of fossil fuels is, in substance, negligent, or perhaps even reckless or abnormally dangerous, and that causality can be adequately demonstrated.[65] Thus, as above, the federal government in its capacity as a sovereign landowner should undertake efforts to mitigate that private nuisance.

B. *Statutory Sources of a Duty to Mitigate Climate Change Impacts*

The statutes and regulations that govern Interior's management of public lands provide other, and potentially even more forceful, sources for a duty to mitigate upstream and downstream greenhouse gas emissions and associated climate change impacts arising from the federal coal leasing program, and a definite discretion to do so. This section examines key provisions in the Federal Land Policy and Management Act (FLPMA), the Mineral Leasing Act (MLA) and the National Environmental Policy Act (NEPA) that direct and inform Interior and BLM's activities, coal leasing program requirements and environmental review responsibilities, and which either require or authorize mitigation.

a. *FLPMA: The BLM's Organic Act*

According to FLPMA, the BLM must manage public lands for multiple use and sustained yield,[66] must receive "fair market value" for use of public lands,[67] and must avoid "unnecessary or undue degradation of the lands."[68] In addition, BLM must manage public lands "in a manner that will protect the quality of scientific, scenic, historical ecological, environmental, air *and atmospheric*,

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[65] GREENPEACE USA, LEASING COAL, FUELING CLIMATE CHANGE: HOW THE FEDERAL COAL LEASING PROGRAM UNDERMINES PRESIDENT OBAMA'S CLIMATE PLAN (2014); JAYNI FOLEY HEIN & PETER HOWARD, INST. FOR POLICY INTEGRITY, ILLUMINATING THE HIDDEN COSTS OF COAL: HOW THE INTERIOR DEPARTMENT CAN USE ECONOMIC TOOLS TO MODERNIZE THE FEDERAL COAL PROGRAM (2015); DUSTIN MULVANEY ET AL., THE POTENTIAL GREENHOUSE GAS EMISSIONS OF U.S. FEDERAL FOSSIL FUELS (2015); Paul R. Epstein et al., *Full Cost Accounting for the Life Cycle of Coal*, 1219 ANNALS N.Y. ACAD. SCI., Feb. 2011, at 73.

[66] 43 U.S.C. §§ 1701, 1732(a) (2012).

[67] *Id.* § 1701(a)(9).

[68] *Id.* § 1732(b); *see also* Rocky Mountain Oil & Gas Ass'n v. Watt, 696 F.2d 734, 739 (10th Cir. 1982) ("In general, the BLM is to prevent unnecessary or undue degradation of the public lands.").

water resource, and archeological values."[69] When preparing land use plans, the agency must consider present and future uses and the relative scarcity of values, and weigh long-term benefits against short term benefits.[70] Government agencies and other commentators have analyzed how BLM might alter pricing in the coal leasing program to incorporate a price on carbon and obtain "fair market value."[71] The focus, here, in contrast, is on how the multiple use and unnecessary and undue degradation standards implicate a duty to mitigate climate impacts.[72]

Multiple use is defined in FLPMA as:

> the management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; making the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use to conform to changing needs and conditions; the use of some land for less than all of the resources; a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.[73]

The unnecessary or undue degradation requirement is undefined in the statute, but has been defined by BLM in the hardrock mining context to include, among other things, compliance with standards of performance set forth in BLM regulations, with the terms and conditions set

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[69] 43 U.S.C. § 1701(a)(8) (emphasis added).

[70] *Id.* § 1712(c).

[71] U.S. GOV'T ACCOUNTABILITY OFF., GAO-14-140, COAL LEASING: BLM COULD ENHANCE APPRAISAL PROCESS, MORE EXPLICITLY CONSIDER COAL EXPORTS, AND PROVIDE MORE PUBLIC INFORMATION (2013); THE ECONOMICS OF COAL LEASING ON FEDERAL LANDS, *supra* note 7; JAYNI FOLEY HEIN & PETER HOWARD, INST. FOR POLICY INTEGRITY, RECONSIDERING COAL'S FAIR MARKET VALUE: THE SOCIAL COSTS OF COAL PRODUCTION AND THE NEED FOR FISCAL REFORM (2015); OFFICE OF INSPECTOR GEN., U.S. DEP'T OF THE INTERIOR, FINAL EVALUATION REPORT—COAL MANAGEMENT PROGRAM, U.S. DEPARTMENT OF THE INTERIOR (2013); Krupnick et al., *supra* note 7.

[72] The agency's discretion to mitigate impacts is beyond question. As the agency has recognized, "[i]n accordance with FLPMA, the BLM can include mitigation requirements as terms and conditions in the authorizations it issues for appropriate use of public lands." BUREAU OF LAND MGMT., TECHNICAL NOTE: PROCEDURAL GUIDANCE AND FRAMEWORK FOR DEVELOPING SOLAR REGIONAL MITIGATION STRATEGIES 10 (2013).

[73] 43 U.S.C. § 1702(c).

forth in an approved operations plan and with federal and state environmental laws.[74] Notably, standards of performance set forth under these regulations include the prevention of adverse impacts on threatened or endangered species and their habitats,[75] and "mitigation measures specified by BLM to protect public lands."[76] The Secretary has separately defined "undue and unnecessary degradation" in the wilderness study area review context as "impacts greater than those that would normally be expected from an activity being accomplished in compliance with current standards and regulations and based on sound practices, including use of the best reasonably available technology."[77] Courts have held that the Secretary of the Interior has broad discretion to define "undue and unnecessary degradation,"[78] and in application courts routinely uphold land management actions that cause degradation of the public lands, so long as adequate measures are taken to reasonably mitigate the level of degradation to be allowed.[79]

The broad imperatives of the multiple use mandate—including the directive to protect atmospheric values for future generations—and the prohibition against unnecessary and undue degradation each imply a statutory duty to mitigate climate impacts, and plainly confer a great deal of discretion on the agency to do so. Multiple use requires the agency to consider intergenerational equity, authorizes the agency to adapt to changing needs and conditions, and explicitly refuses to require the agency to manage lands in a way that maximizes profitability or short-term economic production. The unnecessary or undue degradation regulations specifically require the use of mitigation measures that will protect threatened or endangered species and the

[74] 43 C.F.R. § 3809.5 (2015).
[75] *Id.* § 3809.420(b)(7).
[76] *Id.* § 3809.420(a)(4).
[77] *Id.* § 3802.0-5(I).
[78] *See* Gardner v. U.S. Bureau of Land Mgmt., 638 F.3d 1217, 1222 (9th Cir. 2011) (stating that section 1732(b) of FLPMA "leaves BLM a great deal of discretion in deciding how to achieve" its goal of preventing unnecessary and undue degradation "because it does not specify precisely how the BLM is to meet [its goal], other than by permitting the BLM to manage public lands by regulation or otherwise" (internal quotation marks and alteration omitted)); Mineral Policy Ctr. v. Norton, 292 F. Supp. 2d 30, 44–45 (D.D.C. 2003).
[79] *See, e.g.*, S. Fork Band Council of W. Shoshone v. U.S. Dep't of the Interior, 588 F.3d 718, 724–25 (9th Cir. 2009) (finding that BLM adequately determined that unnecessary or undue degradation would not occur as a result of mining projects despite finding that some facilities would fail to meet relevant visual impact standards); Theodore Roosevelt Conservation P'ship v. Salazar, 744 F.Supp.2d 151, 158–59 (D.D.C. 2010) (upholding BLM's finding that unnecessary or undue degradation would not occur where development activity was subject to monitoring and mitigation measures, including the concentration of development activity in already-impacted areas).

public lands. As climate change poses significant risks to threatened and endangered species and to the quality of public lands and their value, Interior and BLM would be well within the scope of its regulations in seeking mitigation to avoid, minimize or mitigate against unnecessary or undue degradation.

BLM has itself recognized its obligation and authority under FLPMA to mitigate the off-site impacts of its actions, in guidance going back to at least 2008.[80] As BLM explained then:

> The BLM's authority to address the mitigation of impacts on public lands associated with a use authorization issued by the BLM derives from the Federal Land Policy and Management Act (FLPMA). Additional authority can be found in the statutes governing specific uses of the public lands such as the Mineral Leasing Act. The congressional declaration of policy for FLPMA states that "the public lands be managed in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource and archeological values…." FLPMA §102(a)(8). In addition, the use, occupancy and development of public lands must be regulated by the Secretary through easements, permits, leases, licenses, or other instruments. FLPMA §302(b).

The BLM may take into account actions that are physically removed or that take place at a different location from the immediate project area, either on or off BLM-managed lands, that could serve to protect or preserve BLM resources and values in deciding whether to approve a specific use on the public lands. In some cases, the applicant's offer to undertake certain mitigating actions may be a significant consideration in the BLM's decision. While the BLM does not have the authority to require an applicant to undertake mitigation offsite, the BLM can enforce the terms of a contract in which the applicant agrees to undertake specific mitigating actions offsite in order to receive the BLM's approval of a particular use on the public lands. The BLM may expressly condition its approval of the permit on the applicant's commitment to take those actions, and the BLM may, if necessary, seek appropriate enforcement action to ensure the terms of the contract are met.[81]

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[80] Bureau of Land Mgmt., *Offsite Mitigation,* Instruction Memorandum No. 2008-204 (Sept. 30, 2008) (noting that "BLM has an obligation to approve only land use authorizations that are consistent with its mission and objectives" and that "[t]his may mean that the BLM may be unable to permit certain land use authorizations without appropriate mitigation measures").

[81] *Id.*, attachment 1-1 (addressing the question of BLM's authority to require mitigation).

b. Mineral Leasing Act

Federal coal leasing is principally governed by Section 201 of the Mineral Leasing Act, which authorizes the Secretary of the Interior to "in his discretion, upon the request of any qualified applicant or on his own motion, from time to time, offer such lands for leasing."[82] Today, most coal leasing proceeds by application, rather than through a regional management process.[83] Importantly, the Mineral Leasing Act requires that all coal leasing be done in the public interest.[84] The Secretary of the Interior's interpretive authority is, again, broad: Interior has capacious legal authority to discern what is in the public interest, and how to ensure that coal leases adequately protect it: "The Secretary of the Interior is authorized to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of this chapter."[85]

This broad authority to determine what measures are in the public interest is important, as it relates the question of duty and authority to mitigate back to the historic development of resource mitigation, more generally, and to the history of wetland mitigation, in particular. The earliest manifestations of resource mitigation included mitigation directed at impacts of dams, including construction of fish hatcheries and fish passages,[86] and replacement of lost recreation

[82] 30 U.S.C. § 201 (2012).

[83] See *Coal Operations*, BUREAU OF LAND MGMT., http://www.blm.gov/wo/st/en/prog/energy/coal_and_non-energy.html (last visited Aug. 23, 2016) ("[B]ecause demand for new coal leasing in recent years has been associated with the extension of existing mining operation on authorized federal coal leases, all current leasing is done by application.").

[84] *See, e.g.*, 30 U.S.C. § 201 (directing the Secretary to divide coal leasing into leasing tracts of such size as he finds appropriate and in the public interest); *id.* § 226(m) (permitting the Secretary to authorize and modify cooperative oil and gas leases, so long as he has consent from lessees and the modifications are "necessary or proper to secure the proper protection of the public interest"); *id.* § 208 (permitting the Secretary to authorize the take of coal from public lands without payment if it will "safeguard the public interests"); *id.* § 2015 (permitting the Secretary to authorize consolidation of leases if it is in the public interest); *id.* § 192 (permitting the Secretary to reject bids for oil and gas that is paid as royalty to the United States if accepting the offer would not serve the public interest).

[85] *Id.* § 189. *See also* Arnold v. Morton, 529 F.2d 1101, 1105 (9th Cir. 1976) ("It is quite evident that the Secretary has no obligation to issue any lease on public lands."); WildEarth Guardians v. Salazar, 783 F. Supp. 2d 61, 63 (D.D.C. 2011) (finding that the Secretary is "permitted" but not required to lease particular tracts for coal mining).

[86] Edward T. Laroe, *Wetland Habitat Mitigation: An Historical Overview*, NAT'L WETLANDS NEWSL., Sept.–Oct. 1986, at 9.

days with new facilities, such as fishing piers.[87] With the growth of the environmental movement, the concept re-oriented away from single-species considerations and recreational trade-offs, and expanded to include broader notions of mitigation, including habitat preservation to compensate for habitat destruction; the creation, restoration or enhancement of ecosystem services to replace ones lost to development; and reductions in water and air pollution from existing sources to compensate for new sources.[88] A key turning point in this brief history came in the 1967. The U.S. Army Corps of Engineers (the Corps) had been administering the River and Harbors Act section 10 permit program for decades. Section 10 includes a review that allows the Corps to reject permit applications for work in navigable waters that were shown to be against the public interest. The Corps did not explicitly or regularly include environmental criteria until 1967, when the U.S. Fish and Wildlife Service (FWS) began to insist that the terms of the 1939 Fish and Wildlife Coordination Act required the Corps to consider damage to habitat as part of the public interest review. Since that time, public interest review has regularly included environmental considerations.[89]

Contemporary understandings require a further extension of the public interest analysis to encompass downstream GHG emissions and climate change impacts attributable to them.

c. NEPA: Cross-Cutting Requirements for Impact Assessment and Mitigation

The National Environmental Policy Act, enacted on Earth Day in 1970, is an ambitious statute. Among other things, it makes it a national policy to "create and maintain" a "productive harmony" between "man and nature" and to "fulfill" the obligations imposed by the principle of intergenerational equity.[90] The statute requires the federal government—again, among other things—to "improve and coordinate" its activities in order to better serve as a "trustee of the environment;" to assure "safe, healthful, productive, and esthetically and culturally pleasing surroundings;" to protect against "undesirable and unintended consequences;" and to preserve

[87] Holmberg & Misso, *supra* note 47.
[88] Laroe, *supra* note 86.
[89] Palmer Hough & Morgan Robertson, *Mitigation Under Section 404 of the Clean Water Act: Where It Comes From, What It Means*, 17 WETLANDS ECOLOGY & MGMT. 15, 16–17 (2009).
[90] 42 U.S.C. § 4331(a) (2012).

historic, cultural and natural resources.[91] Each and every one of these goals requires a federal agency to consider the relationship between a proposed action and climate change. In the context of fossil fuel extraction, they require the leasing, licensing or permitting agency to consider reasonably foreseeable upstream and downstream GHG emissions and associated climate impacts.[92]

NEPA delivers on its broad ambitions through the process of environmental impact review. Section 102(2)(C) of the statute requires all federal agencies to prepare a "detailed statement" on the environmental impacts of major federal actions significantly affecting the quality of the human environment.[93] The resulting Environmental Impact Statement (EIS) must discuss: (i) the environmental impact of the proposed action, (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented, (iii) alternatives to the proposed action, (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.[94] Notably, the alternatives analysis required under section 102(2)(C) requires BLM to "rigorously explore and objectively evaluate" an adequate range of alternatives.[95] This evaluation extends to considering more environmentally protective alternatives and mitigation measures.[96] In addition, section 102(2)(E) requires an alternatives analysis for "any proposal which involves unresolved conflicts concerning alternative uses of available resources."[97] And section 102(2)(F) requires federal agencies to take a global view of environmental problems, and, "where consistent with the foreign policy of the United States, lend appropriate support to initiatives, resolutions, and programs designed to maximize international cooperation in anticipating and preventing a decline in the

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[91] *Id.* § 4331(b).

[92] Michael Burger & Jessica Wentz, *Downstream and Upstream Emissions: The Proper Scope of NEPA Review*, ___ HARV. ENVTL. L. REV. ___ (forthcoming 2016) (available at http://web.law.columbia.edu/sites/default/files/microsites/climate-change/downstream_and_upstream_ghg_emissions_-_proper_scope_of_nepa_review.pdf).

[93] 42 U.S.C. § 4332(2)(C).

[94] *Id.*

[95] *See* 40 C.F.R. §§ 1502.14(a), 1508.25(c) (2016).

[96] *See, e.g.*, Kootenai Tribe of Idaho v. Veneman, 313 F.3d 1094, 1122–23 (9th Cir. 2002) (and cases cited therein).

[97] 42 U.S.C. § 4332(2)(E).

quality of mankind's world environment."[98] Moreover, NEPA requires that BLM discuss mitigation measures in the Programmatic EIS.[99]

The Programmatic EIS must fulfill each of these requirements. To do so, it must address (1) the GHG emissions and climate change impacts resulting from the coal leasing program under a range of alternatives, (2) how these alternatives and their comparative emissions and impacts relate to the sustainability of our domestic and planetary socio-ecological systems, (3) whether the extraction and eventual combustion of federal coal in the different alternative scenarios represents an "irreversible and irretrievable commitment[] of resources," (4) whether and how the federal coal leasing program can support the nation's international climate commitments, and (5) mitigation measures.

NEPA defines mitigation as follows:

> (a) Avoiding the impact altogether by not taking a certain action or parts of an action.
>
> (b) Minimizing impacts by limiting the degree or magnitude of the action and its implementation.
>
> (c) Rectifying the impact by repairing, rehabilitating, or restoring the affected environment.
>
> (d) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.
>
> (e) Compensating for the impact by replacing or providing substitute resources or environments.[100]

In 2011, the Council on Environmental Quality (CEQ) issued guidance on the appropriate use of mitigation in the development of environmental impact review documents, including EISs.[101] At the outset, CEQ notes that "[m]itigation is an important mechanism Federal agencies can use to minimize the potential adverse environmental impacts associated with their actions."[102]

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[98] *Id.* § 4332(2)(F).
[99] 40 C.F.R. §§ 1502.14(f), 1502.16(f), (h).
[100] *Id.* § 1508.20.
[101] Final Guidance for Federal Departments and Agencies on the Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact, 76 Fed. Reg. 3843 (Jan. 21, 2011).
[102] *Id.* at 3847.

Importantly, the guidance states that an agency should only look at mitigation measures for which there is legal authority, and resources to ensure monitoring and implementation.[103]

It is often said that NEPA is a procedural, not a substantive, statute. While it is quite likely that this long-standing approach to interpreting the statute misconstrues the original Congressional intent, it is nonetheless, at this point, settled law. Accordingly, it would be difficult to argue that NEPA imposes a substantive requirement that requires Interior and BLM to mitigate climate change impacts associated with upstream and downstream emissions from coal leasing. It does, however, impose a duty to identify, assess and disclose mitigation measures for those impacts. It also anticipates that in order to achieve the statute's broad and ambitious goals mitigation measures—moving along the spectrum from avoidance to compensation—will be adopted and implemented.

III. Common Law Rationale for a Climate Change Impacts Fee as Compensation

The discussion in Part II established that international law, common law principles and statutory requirements imposed by Congress arguably imbue DOI with a legal duty to mitigate the climate change impacts attributable to downstream GHG emissions that are the indirect effects of the federal coal leasing program, and without question confer upon the agency the discretion to do so. This section turns to the question of whether the common law principles that pertain to lessor liability support a prospective decision to compensate for those impacts that cannot be avoided or minimized through imposition of a climate change impact fee.

Climate change impacts from the coal leasing program's downstream GHG emissions will occur in locations, and to persons, both proximate to and remote from a given leased parcel. These impacted locations will include the leased parcel, other public lands and resources under BLM's jurisdiction, other federal lands and resources under Interior's jurisdiction, and private and public property within and outside the United States. For the sake of analysis this section narrows the scope to look at the different theoretical rationales for imposing a climate change impact fee to mitigate for damages to federal property and to other property.

[103] *See, e.g.*, *id.* at 3847–48.

It bears reiterating, here, that this analysis is not intended to serve as a litigation risk screening. The question addressed here is one of principle and duty, not legally enforceable obligations subject to court enforcement. The difficulties involved in proving out a tort case for climate change damages, and the obstacles posed by immunity and discretionary function defenses, have been addressed at length in the scholarly and professional literatures, and do not warrant in-depth review here.[104] However, in considering appropriate forms of mitigation the principles of tenant and lessor liability and the theoretical remedies available may prove useful.

A. *Damages to Federal Property*

It is a general principle of property law that tenants are required to restore leased property to its former condition, or else be subject to termination and/or damages.[105] This principle is integrated into the federal coal leasing program through the Surface Mining Control and Reclamation Act's (SMCRA) bonding and reclamation requirements,[106] and the authority BLM possesses under the Mineral Leasing Act to impose lease conditions it deems appropriate.[107] Although SMCRA does not necessarily accommodate the environmental complexity of climate impacts on leased property attributable to downstream emissions, BLM's authority to impose lease conditions is broad, and liability for damages clauses are not atypical.

Moreover, the federal government owns a vast territory that is exposed and vulnerable to climate change impacts, including national parks, national wildlife refuges, national forests, BLM lands, designated wilderness areas, designated wilderness study areas, roadless areas, military bases, designated historic sites, and so on. Although there may not be a hornbook principle along these lines to cite to, it makes profound sense that a lessor has within its authority the ability to protect its other properties, or to require compensation for impacts to them, from activities it permits on its land.

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104 *See, e.g.*, Michael B. Gerrard & Joseph A. MacDougald, *An Introduction to Climate Change Liability Litigation and a View to the Future*, 20 CONN. INS. L.J. 153 (2013); David Hunter & James Salzman, *Negligence in the Air: The Duty of Care in Climate Change Litigation*, 155 U. PA. L. REV. 1741 (2007); Douglas Kysar, *What Climate Change Can Do About Tort Law*, 41 ENVTL. L. 1 (2011).

105 RESTATEMENT (SECOND) OF PROP.: LANDLORD AND TENANT § 12.2(3) (AM. LAW INST. 1977).

106 *See* 30 U.S.C. § 1259 (2012); 30 C.F.R. pt. 800 (2016).

107 *See* 30 USC § 207(a) ("The lease shall include such other terms and conditions as the Secretary shall determine.").

B. Damages to "Persons Outside of the Land"

The Restatements of Torts and Property make clear that the federal government, as lessor to coal mining companies, could, in principle, be held liable for damages for the climate change impacts associated with downstream GHG emissions.

The Restatement (Second) of Torts states that "A lessor of land is subject to liability for physical harm to persons outside of the land caused by activities of the lessee…if, but only if,: (a) the lessor at the time of the lease consented to such activity or knew that it would be carried on, and (b) the lessor knew or had reason to know that it would unavoidably involve such an unreasonable risk, or that special precautions necessary to safety would not be taken."[108] This tort principle is consistent with the Restatement (Second) of Property Section 18(4), which includes nearly identical language.[109] Indeed, the two are meant to be read together.[110]

The comments from the Restatement (Second) of Property are illuminating. As an example of lessor liability, the Restatement offers the following: "L leases property to T for use as a stone quarry. In the course of operating the quarry, T's blasting operations cause physical harm to a person outside the leased property. If L knows or has reason to know that any such blasting will involve an unreasonable risk of physical harm to those outside the leased property, L is subject to liability to the injured person.[111] What's more, "[t]he liability stated in this section cannot be avoided by a clause in the lease exonerating the landlord from all responsibility or liability."[112]

The standards for lessor liability for nuisance are similar to those for physical harm. The Restatement (Second) of Torts notes that a lessor is subject to liability for nuisance "caused by an activity carried on upon the land while the lease continues and the lessor continues as owner, if the lessor would be liable if he had carried on the activity himself, and (a) at the time of the lease the lessor consents to the activity or knows or has reason to know that it will be carried on, and (b) he then knows or should know that it will necessarily involve or is already causing the nuisance.[113]

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108 RESTATEMENT (SECOND) OF TORTS § 379A (AM. LAW INST. 1979).
109 RESTATEMENT (SECOND) OF PROP.: LANDLORD AND TENANT § 18.4.
110 *Id.* cmt. a.
111 *Id.* cmt. b, illus. 2.
112 *Id.* cmt. d.
113 RESTATEMENT (SECOND) OF TORTS § 837(1).

The principles of lessor liability, then, as inscribed in both domestic tort and property law, put the government on the theoretical hook for damages resulting from the climate impacts to offsite individuals and property attributable to fossil fuel extraction on federal lands. The elements here are easily met: First, the federal government is consenting to the coal mining through the terms of the lease. Second, the federal government is at this time well aware that coal leasing either involves an unreasonable risk (the standard for physical injury) or else that federal coal leasing contributes to the identifiable nuisance of climate change impacts.

C. *Types of Damages*

Damages to federal property, and to the federal estate, provide one type of damages for which the federal government, as owner of the leased land, could seek insurance in the form of a climate change impacts fee. If litigation for off-site damages to other landowners or persons were allowed to proceed, and liability found, the federal government would be potentially liable for a range of damages available under tort and property law. Individuals and their family members have suffered and will continue to suffer a range of personal injuries from climate change, from health effects exacerbated or caused by climate change-altered conditions such as extreme heat and drought to deaths caused by disasters made more likely, more frequent and/or more severe by climate change. Accordingly, damages could in theory be available for wrongful death, medical expenses, future earning capacity/lost wages and pain and suffering. Similarly, climate change impacts on real property are manifold. Damages theoretically available could include restoration costs for damage to land (or perhaps the costs of adaptation of affected land to conditions created by the nuisance of climate change), temporary and permanent damages to land, damages to structures on land, and damage to vegetation. These would be the same sorts of damages the government might seek to insure against in regard to public lands.

IV. Statutory Authority for a Climate Change Impacts Fee as Compensatory Mitigation

The BLM's mission is "[t]o sustain the health, diversity, and productivity of America's public lands for the use and enjoyment of present and future generations."[114] Pursuant to FLPMA's multiple use mandate, the agency pursues this mission by managing public land resources for a variety of uses, including energy development, while protecting a wide array of natural, cultural, and historical resources, including air and atmospheric values, and ensuring that they are passed along to the future. The agency has recognized the realities of climate change and the extraordinary threats it poses to America's public lands.[115] The agency has also recognized its obligation to account for climate change impacts in its decision-making.[116] Moreover, the agency has recognized that compensatory mitigation for unavoidable or residual climate change impacts arising from agency decisions is fully consistent with its broadly stated mission and its multiple use mandate and that it possesses the discretion to require it, and has clarified that doing so is in fact the agency's policy.[117] This section explores how a climate change impact fee for downstream GHG emissions fits within the agency's NEPA obligations and its compensatory mitigation policy.

A. *Compensatory Mitigation under NEPA*

As previously noted, the climate change impacts at issue in this paper are those that occur as a result of GHG emissions both at the coal mine and downstream, when the extracted coal is transported and eventually combusted for its end use. These downstream GHG emissions are considered "indirect effects" under NEPA, and the climate change impacts associated with those emissions are unavoidable or "residual" impacts.

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[114] *About the BLM*, BUREAU OF LAND MGMT., http://www.blm.gov/wo/st/en/info/About_BLM.html (last updated Jan. 26, 2012).

[115] *See* Addressing the Impacts of Climate Change on America's Water, Land, and Other Natural and Cultural Resources, Sec'y of the Interior Order No. 3289 (Sept. 14, 2009).

[116] *See* Improving Mitigation Policies and Practices of the Department of the Interior, Sec'y of the Interior Order No. 3330 (Oct. 31, 2013) [hereinafter SO 3330]; *see also* Bureau of Land Mgmt., *Guidance—Use of Air Emissions Estimating Tools*, Instruction Memorandum No. 2015-020 (Nov. 24, 2014) (announcing availability to BLM of the Greenhouse Gas & Climate Change NEPA (GHGCC-NEPA) toolkit, the Medford District toolkit and the BLM Planning Stage Emissions Inventory (BLM-PSEI) toolkit for estimating GHG emissions).

[117] SO 3330, *supra* note 116; DEP'T OF THE INTERIOR, *Chapter 6: Implementing Mitigation at the Landscape-Scale* (Oct. 23, 2015), *in* DEPARTMENT MANUAL [hereinafter *Mitigation Chapter*].

In undertaking the Programmatic EIS, Interior has at least implicitly recognized that NEPA requires it to to analyze downstream emissions associated with the federal coal leasing program. This conclusion comports with the current trajectory of courts' interpretations of NEPA. Since 2014, there have been five district court decisions regarding the scope of downstream emissions that must be evaluated in NEPA reviews for coal lease modifications and other approvals involving the extraction of coal from federal lands.[118] In four of these cases, district courts in Colorado and Montana determined that the responsible agencies failed to take the requisite "hard look" at downstream emissions from the combustion of the coal.[119] In the fifth case, a district court in Wyoming held that the agency's analysis of downstream emissions was adequate, in part because the agency had already disclosed emissions from coal combustion.[120] Notably, all of the cases have found that there is a sufficient causal connection between the extraction of coal and the downstream greenhouse gas emissions from the processing, transportation, and end-use of the extracted coal. With regards to foreseeability, the courts have often held that agencies have sufficient data and tools to estimate greenhouse gas emissions from the combustion of coal. They have also recognized that tools are available to evaluate how the extraction of coal will influence

[118] Dine Citizens Against Ruining Our Env't v. U.S. Office of Surface Mining Reclamation & Enf't, 82 F. Supp. 3d 1201 (D. Colo. 2015); Wild Earth Guardians v. U.S. Forest Serv., 120 F. Supp. 3d 1237 (D. Wyom. 2015); WildEarth Guardians v. U.S. Office of Surface Mining, Reclamation & Enf't, 104 F. Supp. 3d 1208, 1230 (D. Colo. 2015); Wildearth Guardians v. U.S. Office of Surface Mining, Reclamation & Enf't, No. CV 14-103-BLG-SPW, 2015 WL 6442724 (D. Mont. Oct. 23, 2015), *report and recommendation adopted in part, rejected in part sub nom.* Guardians v. U.S. Office of Surface Mining, Reclamation & Enf't, No. CV 14-103-BLG-SPW, 2016 WL 259285 (D. Mont. Jan. 21, 2016); High Country Conservation Advocates v. U.S. Forest Serv., 52 F. Supp. 3d 1174 (D. Colo. 2014).

[119] *Dine Citizens*, 82 F. Supp. 3d 1201 (finding that DOI's Office of Surface Mining (OSM) must consider downstream emissions from coal combustion); WildEarth Guardians v. United States Office of Surface Mining, Reclamation & Enf't, 104 F. Supp. 3d 1208, 1230 (D. Colo. 2015) (finding that OSM must consider downstream emissions from coal combustion); Wildearth Guardians v. U.S. Office of Surface Mining, Reclamation & Enf't, No. CV 14-103-BLG-SPW, 2015 WL 6442724 (D. Mont. Oct. 23, 2015) (finding that OSM failed to take hard look at environmental impacts when issuing FONSI, including downstream greenhouse gas emissions); *High Country*, 52 F. Supp. 3d 1174 (finding that the Forest Service must consider downstream emissions from coal combustion); *see also* S. Fork Band Council of W. Shoshone v. U.S. Dep't of the Interior, 588 F.3d 718 (9th Cir. 2009) (requiring analysis of downstream emissions from transporting and processing gold in the EIS for a proposed gold mine).

[120] Wild Earth Guardians v. U.S. Forest Serv., 120 F.Supp.3d 1237 (D. Wyom. 2015).

coal markets.[121] These court decisions are fully consistent with CEQ's final guidance on considering climate change in environmental review under NEPA.[122]

As NEPA requires individual coal extraction projects to account for downstream emissions it necessarily requires a programmatic review to account for those same emissions. Indeed, the programmatic review is the better scale at which to analyze potential downstream emissions, in the first instance, as it allows the agency the opportunity to consider the cumulative effects of individual leasing decisions and to craft a program that is consistent with our national climate policy and international climate commitments. Moreover, under NEPA the agency can identify appropriate mitigation measures for these emissions, including compensatory mitigation measures. Greenhouse gas emissions lead inexorably—indirectly, cumulatively—to climate change impacts. NEPA requires that the Programmatic EIS fully disclose such indirect and cumulative impacts and appropriate mitigation measures.[123] Accordingly, the Programmatic EIS must assess mitigation measures in accordance with CEQ's guidance:

> The mitigation measures discussed in an EIS must cover the range of impacts of the proposal. The measures must include such things as design alternatives that would decrease pollution emissions, construction impacts, esthetic intrusion, as well as relocation assistance, possible land use controls that could be enacted, and other possible efforts. Mitigation measures must be considered even for impacts that by themselves would not be considered "significant." Once the proposal itself is considered as a whole to have significant effects, all of its specific effects

[121] Courts have not directly addressed whether GHG emissions from coal transportation and processing are also "reasonably foreseeable" though several cases that have touched on this issue. *See, e.g.*, *Dine Citizens*, 82 F. Supp. 3d at 1213 (noting that transportation-related impacts had already been accounted for in the EIS); Wild Earth Guardians v. U.S. Forest Serv., 120 F. Supp. 3d 1237 (D. Wyom. 2015) (upholding an agency's analysis of downstream emissions, and noting that transportation emissions had been briefly discussed but not quantified); *S. Fork Band Council*, 588 F.3d 718 (requiring analysis of emissions from gold transportation and processing where information was available to calculate those emissions).

[122] Council on Environmental Quality, *Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews*, Memorandum for Heads of Federal Departments and Agencies 13–14, 16 (Aug. 1, 2016), https://www.whitehouse.gov/sites/whitehouse.gov/ files/documents/nepa_final_ghg_guidance.pdf.

[123] *See* U.S. ENVTL. PROT. AGENCY, CONSIDERATION OF CUMULATIVE IMPACTS IN EPA REVIEW OF NEPA DOCUMENTS (1999).

on the environment (whether or not "significant") must be considered, and mitigation measures must be developed where it is feasible to do so.[124]

Thus, NEPA requires that BLM discuss climate change impacts, alternatives that would mitigate those impacts and other mitigation measures, even if the agency determines (presumably based on a market analysis that demonstrates other, potentially worse fossil fuels would substitute for federal coal) that the federal coal leasing program's GHG emissions are not a significant impact, or that the climate change impacts attributable to those emissions are not significant. The overall action undoubtedly has significant effects, and so feasible mitigation measures must be discussed for all impacts. The mitigation measures discussed in the Programmatic EIS should follow the "mitigation hierarchy," discussed further below. The discussion should include measures that would avoid harm (such as requiring coal extracted from public lands be combusted in power plants equipped with carbon capture, utilization and storage technology), those that would lessen harm (such as requiring coal extracted from public lands be combusted at power plants that meet the New Source Performance Standards for coal-fired power plants), as well as those that would compensate for harm.

One might argue that although upstream and downstream emissions are foreseeable effects of coal leases the impacts attributable to those emissions are simply too remote or uncertain to mitigate. Consistent with this view, the BLM could plausibly quantify emissions, identify those emissions as a significant environmental impact and develop a program to minimize those impacts through, for instance, a "net zero" emissions offset program. Such a program would be eminently reasonable, and in theory could be designed to interact with other emissions and emissions credit markets. However, BLM need not limit itself by doing so. The Social Cost of Carbon and the Social Cost of Methane provide valuations to climate change impacts associated with GHG emissions, providing at least one potential basis by which to establish a compensatory mitigation plan that extends beyond emissions offsets. As discussed further in Part V below, a compensatory mitigation plan consistent with NEPA could also include emissions offsets in the form of mitigation banks for carbon sequestration as well as other elements.

[124] Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations, 46 Fed. Reg. 18,026, 18,031 (March 23, 1981) (citing 40 C.F.R. §§ 1502.14(f), 1502.16(h), 1508.14 (2016)).

B. *Departmental Mitigation Policy*

The Department of the Interior and BLM are guided in their approach to mitigation by a number of policy directives and internal guidelines. In November 2015 the Office of the White House issued *Mitigating Impacts on Natural Resources from Development and Encouraging Related Private Investment*, a Presidential Memorandum that announced President Obama's view that the agencies implementing statutes and regulations relating to natural resources management and environmental pollution control can achieve the goals of promoting economic and energy development and protecting environmental values by undertaking "the planning necessary to address harmful impacts on natural resources by avoiding and minimizing impacts, then compensating for impacts that do occur."[125] The Memorandum sets forth four key policies in regards to the present analysis:

- It makes the "mitigation hierarchy" national policy applicable across the natural resource and environmental agencies.
- It recognizes that there are some resources that "are of such irreplaceable character that minimization and compensation measures, while potentially practicable, may not be adequate or appropriate," and therefore impacts should be avoided altogether.
- It establishes a "no net loss" minimum standard for resources that are "important, scarce or sensitive, or wherever doing so is consistent with agency mission and established natural resources objectives."
- It integrates the principles of consistency, durability, additionality and transparency into mitigation policy.

The Presidential Memorandum is consistent with Interior's internal mitigation policies. In Fall 2013, Secretary Jewell released Secretarial Order 3330, *Improving Mitigation Policies and Practices of the Department of the Interior*. Order 3330 directed the Department and each of its bureaus to follow a common set of principles for its mitigation decisions; to use a landscape-scale approach to guide compensatory mitigation efforts; to consider mitigation early in project planning and design;

[125] Mitigating Impacts on Natural Resources From Development and Encouraging Related Private Investment, 80 Fed. Reg. 68,743, 68,743 (Nov. 3, 2015).

to ensure durability, transparency and consistency in mitigation decisions; and to "focus on mitigation efforts that improve the resilience of our Nation's resources in the face of climate change."[126] In walking through the mitigation hierarchy, Secretarial Order 3330 states that "for impacts that cannot be avoided or effectively minimized, the Department should seek ways to offset or compensate for those impacts to ensure the continued resilience and viability of our natural resources over time."[127] Moreover, Order 3330 affirms that "[a]s the Department continues to review development projects and identify associated mitigation, it must consider the effects of climate change and incorporate landscape-level strategies to address these impacts into any mitigation framework."[128] Ultimately, Order 3330 leaves the Department and its bureaus with broad discretion to develop and implement mitigation strategies "through the use of landscape-level planning, banking, in-lieu fee arrangements, or other possible measures," including regional mitigation plans that "address mitigation for multiple resources, such as biological, ecological, cultural, and scenic resources, as well as socioeconomic factors, as appropriate."[129]

On October 23, 2015, Interior released "Landscape-Scale Mitigation Policy," a new chapter in its Departmental Manual, which effectively operationalizes Order 3330.[130] The chapter "establishes Departmental policy and provides guidance to bureaus and offices to best implement mitigation measures associated with legal and regulatory responsibilities and the management of Federal lands, waters, and other natural and cultural resources under the jurisdiction of the Department of the Interior."[131] The purpose of the new policy is to:

> effectively avoid, minimize, and compensate for impacts to Department-managed resources and their values, services, and functions; provide project developers with added predictability, efficient, and timely environmental reviews; improve the resilience of our Nation's resources in the face of climate change; encourage strategic conservation investments in lands and other resources; increase compensatory mitigation effectiveness, durability, transparency, and consistency; and better utilize mitigation measures to help achieve Departmental goals.[132]

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[126] SO 3330, *supra* note 116, § 1.

[127] *Id.* § 2.

[128] *Id.*

[129] *Id.* § 4(a).

[130] *Mitigation Chapter*, *supra* note 117.

[131] *Id.* § 6.1

[132] *Id.*

Different mechanisms for compensatory mitigation—such as in lieu fees, mitigation banks and permittee-responsible measures—are to be held to equivalent standards.[133]

One of the core principles set forth in the Departmental Manual is that mitigation necessitates the identification and promotion of "mitigation measures that help address the effects of climate change and improve the resilience of our Nation's resources and their values, services, and functions."[134] Among the ways the Department and its bureaus can act consistent with this principle is to "[c]onsider greenhouse gas emissions in project design, analysis, and development of alternatives."[135] Other efforts may include protecting habitat, maintaining ecosystem services, slowing the spread of invasive species, protecting and restoring habitats that store carbon and accounting for uncertainty and risk in compensatory mitigation design.[136]

The sum total of the White House and Interior guidance is that BLM can and should assess and potentially implement mitigation measures, which might operate through any number of mechanisms, including lease stipulations and chargeable fees, among other things. The mitigation measure should first seek to avoid GHG emissions and their climate impacts; second, seek to minimize emissions and impacts; and third, compensate for unavoidable impacts, as through a climate change impacts fee.

V. Employing a Climate Change Impacts Fee as a Programmatic Compensatory Mitigation Strategy for the Federal Coal Leasing Program: Design and Technical Issues

This section identifies and discusses some of the key design and technical issues that BLM should address in the course of evaluating the potential of employing a climate change impacts fee. This fee would appear as a compensatory mitigation strategy or plan, consistent with recent agency guidance and practice. As such, it would seek to "compensate for remaining unavoidable impacts after all appropriate and practicable avoidance and minimization measures have been applied, by replacing or providing substitute resources or environments…through the restoration,

[133] *Id.* §§ 6.6(C)(3)(b), 6.7.
[134] *Id.* § 6.6(F).
[135] *Id.* § 6.6(F)(7).
[136] *See id.* § 6.6(F).

establishment, enhancement, or preservation of resources and their values, services, and functions."[137] The intention here is not to set forth a single proposal but to outline an array of considerations and issues for BLM to identify, solicit further comment on and consider in the Programmatic EIS.

There are a number of key questions to address in developing a mitigation framework in any context: 1) Whether to mitigate. 2) When to mitigate. 3) What mitigation should be required. 4) Technical issues surrounding how to mitigate.[138] This section looks at these questions in turn, and concludes by providing a sample analysis, using the framework developed for and employed in the regional compensatory mitigation strategies in BLM's Western Solar Plan.

A. Whether to Mitigate

The question of whether to mitigate was the subject of Part II, where the question was conceived as one of the government's duty and discretion. For the reasons set forth in detail above, BLM has under the common law and federal legislation both a duty to mitigate climate change impacts resulting from upstream and downstream GHG emissions and the discretion to do so. The question has also been broached here as a narrower question of criteria: Are these impacts the sort of impacts for which mitigation, and compensatory mitigation in particular, is appropriate? As discussed in Part IV, under NEPA and Interior's and BLM's compensatory mitigation policies the answer is plainly yes. And, as discussed in Part III, common law doctrines pertaining to lessee and lessor liability reinforce this conclusion.

Moreover, it makes policy sense to require coal lessees to compensate for the unavoidable impacts of their extractive industry in the form of a climate change impacts fee. Indeed, doing so is to the industry's benefit, as compensatory mitigation might allow coal mining companies to continue their existing business, rather than taking more drastic (though arguably necessary) action, such as imposing a permanent moratorium on the issuance of new coal leases. Moreover,

[137] *Id.* § 6.4(C).

[138] *See* Laroe, *supra* note 86, at 9.

this approach would achieve the public benefit, economic efficiency and environmental equity that come with internalizing the external costs of coal extraction.[139]

B. *When to Mitigate*

The question of when to require, or allow, compensatory mitigation will, in this context, bleed into questions of form. A climate change impacts fee could be assigned via BLM's determination of fair market value, as part of the bonus bid, through the rental fee, in a lease stipulation, as part of the royalty rate or potentially in some other form. Each of these potential moments would calculate the fee amount and result in payment and receipt at a different point in the lease process. BLM should consider the pros and cons of calculating and requiring payment at each of these different points.

As a starting point, it may be noted that the mitigation policies set forth by President Obama, Interior and BLM all advocate for advance mitigation where possible, in order to provide certainty to the private sector and to help ensure the effectiveness of compensatory mitigation. Here, however, advance compensatory mitigation could result in over-charging lessees for downstream GHG emissions and climate change impacts. If projected quantities of recoverable coal prove overly optimistic, or if the company's efforts produce less coal than estimated, a fee tied to projected amounts of coal or to acreage would over-charge the lessee. A climate change impacts fee based on actual production, as measured, for instance, on an annual or bi-annual basis, would avoid this scenario. The use of a consistent metric, such as the Social Cost of Carbon and the Social Cost of Methane, which can be readily applied to production, would provide a degree of certainty

[139] Those seeking to challenge a compensatory mitigation regime for federal coal might raise the "perfect substitute" argument. The "perfect substitute" argument posits that the extraction of fossil fuels will not actually cause an increase in consumption, because the same quantity of the fuel would be produced elsewhere and eventually transported and consumed, even if the agency did not approve the proposal at issue. Notably, the Eighth Circuit Court of Appeals explicitly rejected this proposition in relation to a proposed coal rail line, noting that it is "illogical at best" because the "increased availability of inexpensive coal will at the very least make coal a more attractive option to future entrants into the utilities market when compared with other potential fuel sources, such as nuclear power, solar power, or natural gas" and thus the project will "most assuredly affect the nation's long-term demand for coal." Mid States Coal. for Progress v. Surface Transp. Bd., 345 F.3d 520, 549 (8th Cir. 2003). The federal district court in Colorado has also rejected the "perfect substitution" argument in relation to fossil fuel extraction proposals. High Country Conservation Advocates v. U.S. Forest Serv., 52 F. Supp. 3d 1174, 1198 (D. Colo. 2014). *But see* Wild Earth Guardians v. U.S. Forest Serv., 120 F. Supp. 3d 1237 (D. Wyom. 2015).

to the private sector and offer a consistent and transparent programmatic approach to calculating appropriate compensation.

C. *How to Mitigate*

Designing a compensatory mitigation strategy for the federal coal leasing program will require BLM to make two preliminary determinations: how to categorize the atmospheric and other resources adversely affected, and what the appropriate scale for mitigation is. Program design will also require BLM to make a number of more technical decisions, including how to calculate a fee, what types of mitigation mechanisms the fee might be put into and how to manage such mitigation mechanisms. This sub-section seeks to encourage a dialog on a climate change impacts fee by briefly addressing these design questions in turn.

a. Categorization of Federal Coal's Climate Change Impacts

The BLM should consider how to categorize the climate and other natural resources adversely impacted by the federal coal leasing program, as doing so may affect the form and degree of mitigation the agency requires. The Presidential Memorandum *Mitigating Impacts from Natural Resource Development* identifies three types or categories of resources: irreplaceable resources; resources that are important, scarce or sensitive; and other resources managed consistent with an agency's mission and objectives.[140] The preferred means of mitigating impacts on irreplaceable resources is avoidance. For important, scarce or sensitive resources the Presidential Memorandum establishes a minimum "no net loss" standard, and a preference for a "net benefit." The DOI's mitigation policy adopts these categories and standards.[141]

There is an argument to be made that the climate in which human civilization took shape and in which we continue to exist constitutes an irreplaceable resource, and that the appropriate mitigation measure for continued GHG emissions and climate change impacts is avoidance. Irreplaceable resources are those that have been "recognized by legal authorities as requiring particular protection from impacts and that because of their high value or function and unique

[140] Mitigating Impacts on Natural Resources From Development and Encouraging Related Private Investment, 80 Fed. Reg. 68,743, 68,745 (Nov. 3, 2015).
[141] *Mitigation Chapter*, *supra* note 117, § 6.6(b).

character cannot be restored or replaced."[142] Legal authorities—including the UNFCCC and the Clean Air Act—have recognized the need to provide particular protections to the climate. The high value and function of the climate system—to the extent there was ever a real question about it—has been documented by EPA and others,[143] and becomes more and more evident as the increasing extent and severity of climate impacts continue to emerge. What's more, it is entirely unclear that the climate can be restored through technological innovations in direct air capture or geoengineering; clearly, though, it cannot be replaced.

If BLM concludes that the climate is not an irreplaceable resource warranting avoidance to the maximum extent practicable the agency must conclude that it is nonetheless an important and sensitive resource, and that the appropriate mitigation standard is a minimum of no net loss, and preferably a net benefit. There is no other reasonable conclusion—the climate is important. In recent years, due to the quantity of anthropogenic GHG emissions, it has also become sensitive, and it is at serious risk of breaching tipping points that could fundamentally alter life on earth. Pursuant to BLM's policies, the appropriate mitigation for a resource that fits into this category is "a no net loss outcome for impacted resources and their values, services, and functions, or, as required or appropriate, a net benefit in outcomes."[144] This language affords BLM a good deal of discretion in crafting a compensatory mitigation strategy that makes use of a climate change impacts fee. As discussed in Section V.C.d below, the no net loss/net benefit standard could apply directly through an emissions offset requirement, or somewhat more indirectly through fees that would address other "outcomes" related to the "values, services and functions" impacted by the coal leasing program, including through adaptation efforts aimed at increasing resilience by decreasing socioeconomic impacts or funding infrastructure or nature-based adaptations.

b. The Scale of a Compensatory Mitigation Strategy

Secretarial Order 3330 directs Interior and it bureaus to adopt a landscape-scale approach to mitigation. It also requires the Department to "consider the effects of climate change and

[142] Mitigating Impacts, 80 Fed. Reg. at 68, 744.
[143] *See e.g.*, U.S. ENVTL. PROT. AGENCY, CLIMATE CHANGE IN THE UNITED STATES: BENEFITS OF GLOBAL ACTION (2015).
[144] *Mitigation Chapter*, *supra* note 117, § 6.6(B).

incorporate landscape-level strategies to address these impacts into any mitigation framework."[145] The Departmental Manual offers more specific guidance on implementing this directive, and affirms the preference for landscape-scale approaches and landscape-scale plans and strategies for impact mitigation.[146]

The appropriate landscape-scale in which to seek mitigation for climate change impacts is most likely planetary. Interior defines "landscape" as "an area encompassing an interacting mosaic of ecosystems and human systems characterized by a set of common management concerns." [147] A landscape is not geospatially limited; it "is not defined by the size of the area, but rather by the interacting elements that are relevant and meaningful in a management context."[148] The climate is a whole Earth phenomenon, and managing the climate change problem is a fully international affair.

Moreover, the "landscape-scale approach applies the mitigation hierarchy for impacts to resources and their values, services, and functions at the relevant scale, however narrow or broad, necessary to sustain, or otherwise achieve established Departmental goals for those resources and their values, services, and functions."[149] In developing a landscape-scale strategy or plan, BLM is charged with identifying "clear management objectives for targeted resources and their values, services, and functions at landscape-scales, as necessary, including across administrative boundaries, and employ[ing] the landscape-scale approach to identify, evaluate, and communicate how mitigation can best achieve those management objectives."

BLM would have ample room to craft a mitigation program that designates the planet as the appropriate landscape-scale, takes a planetary-scale approach to mitigation and developing planetary-scale mitigation strategies. Most importantly, this approach would empower BLM to directly link the federal coal leasing program's GHG emissions to the United States' international climate commitments and goals. It could also allow BLM to operate in explicit reference to the concept of a carbon budget. At the same time, a planetary-scale approach to mitigation would still

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[145] SO 3330, *supra* note 116, § 2.

[146] *Mitigation Chapter*, *supra* note 117, § 6.6(D), (E).

[147] *Id.* § 6.4(D).

[148] *Id.*

[149] *Id.* § 6.4(E)

preserve the agency's discretion to develop a compensatory mitigation framework that targets national, or even regional, management objectives.

Alternatively, BLM might designate the United States as the appropriate landscape-scale, or even adopt a fully regional approach.

c. Calculating a Climate Change Impacts Fee

The question of what the proper amount to charge for federal coal has been the subject of several economic analyses.[150] This paper does not seek to set any particular amount; rather, the purpose here is to begin to identify fee-related issues Interior and BLM should consider in the environmental review. As noted previously, the Social Cost of Carbon/Social Cost of Methane provides one possible means to calculating a climate change impacts fee. In offering a science-driven metric that provides transparency, consistency and predictability to the private sector and to the American public the Social Cost of Carbon/Social Cost of Methane would be consistent with the United States' existing climate policies, and with the White House and Interior mitigation policies discussed above. In offering a court-tested metric, it provides at least some assurance that the action will survive legal challenge.[151]

However, the Social Cost of Carbon/Social Cost of Methane is also something of a political flashpoint, and need not be taken as the end of the discussion. As noted above, as landowner the federal government possesses the right to recover from its lessee for damages to the leased property and the freedom to insure against damages to its other properties resulting from its lessee's activities, including but not limited to natural and other resources on public lands. In establishing a fee based on the federal government's own expenses, Interior and BLM could seek to calculate the amounts paid out in recent years and expected to be paid out in the future for climate change adaptation and disaster management, and allocate an appropriate percentage to the carbon

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[150] *See* THE ECONOMICS OF COAL LEASING ON FEDERAL LANDS, *supra* note 7; HEADWATERS ECONOMICS, AN ASSESSMENT OF U.S. FEDERAL COAL ROYALTIES: CURRENT ROYALTY STRUCTURE, EFFECTIVE ROYALTY RATES, AND REFORM OPTIONS (2015); VULCAN PHILANTHROPY, FEDERAL COAL LEASING OPTIONS: EFFECTS ON CO2 EMISSIONS AND ENERGY MARKETS (2016); Krupnick et al., *supra* note 7; *see also* Todd Gerarden et al., *Federal Coal Program Reform, the Clean Power Plan, and the Interaction of Upstream and Downstream Climate Policies* (Nat'l Bureau of Econ. Research, Working Paper No. 22,214, 2016).

[151] Zero Zone Inc. v. U.S. Dep't of Energy, 2016 WL 4177217 (7th Cir. 2016). *See also* High Country Conservation Advocates v. U.S. Forest Serv., 52 F. Supp. 3d 1174 (D. Colo. 2014).

being extracted under the lease. This would be a lesser amount than the full Social Cost of Carbon, and may well reflect a percentage of the costs already incorporated into that tool, but it offers an alternative conceptual approach to the establishment of the fee.

Even a decision to to use the Social Cost of Carbon is not the end of the issue. There are other technical questions BLM will inevitably need to consider in deciding not only how to calculate a climate change impacts fee but also what the ultimate fee should be. These include, but are not limited to:

- *How to account for intervening actors*: The extraction of coal from the ground is the beginning, not the end, of the trajectory that results eventually in GHG emissions and associated impacts for which mitigation is warranted. What percentage of the overall cost of the emissions should be allocated to coal production?
- *How to account for regulations on power plants and other coal users:* Assignment of a climate change impacts fee is tantamount to assignment of responsibility for emissions from the fossil fuel. Under the Clean Power Plan and other regulations, downstream emitters are also being "charged" for the use of fossil fuels through regulatory costs. Although there may be sound ecological and equity reasons to charge both coal companies full price for the GHG emissions and climate change impacts associated with their activities there is also a reasonable economic basis for concern about so-called double-counting of emissions. How should a fee be structured to prevent against potential economic inefficiencies and other concerns pertaining to double-counting of emissions?
- *How to account for the different carbon intensity of coal*: Coal located in different regions, and coal located in different places within regions, and coal located in different spots on a leased parcel, might contain different degrees of carbon intensity and/or energy efficiency. To what extent should climate change impact fees be sensitive to these differences, and how should these differences be accounted for?
- *Whether and how to account for historic emissions*: Climate change is already at an advanced stage, due in no small part to the combustion of coal mined in the United States. Should compensatory mitigation for new leases seek to recover costs associated with historic emissions? If so, what percentage of the overall cost should be allocated to new coal production?
- *Whether and how to account for historic costs*: Climate change has already resulted in extraordinary costs incurred by the American public, including but are not limited to disaster recovery costs from events such as Hurricanes Sandy and Katrina, forest fire management costs, and adaptation costs incurred by federal agencies, and emissions that will occur from existing coal leases will only add to those costs. Should

compensatory mitigation for new leases seek to recover costs associated with these historic and locked-in costs? If so, what percentage of the overall cost should be allocated to new coal production?

- *How to account for the impacts different prices will have on different companies, industry sectors, states, tribes, and local communities*: Ultimately, the amount charged through a climate change impacts fee could influence the economics of the coal industry and economic and financial situations of the states, tribes, local communities and individuals engaged with it. How should the agency balance these competing interests and concerns in setting a fee?

d. Permissible Forms and Management of Compensatory Mitigation

Pursuant to agency policy, different mechanisms for compensatory mitigation—such as in lieu fees, mitigation banks and permittee-responsible measures—are to be held to equivalent standards.[152] A climate change impacts fee might be allocated and expended in any of these ways. It could be paid in to the government as an in lieu fee. It could be paid into a government- or privately-managed GHG emissions mitigation bank. Or it could remain with the lessee as a permittee-responsible mitigation requirement. BLM should consider whether to select a preferred form of mitigation, or whether to allow for multiple forms.

An in lieu fee could provide the government with a dedicated fund to expend on programs and projects designed to achieve climate change mitigation or adaptation goals. These funds could go to any number of uses. For instance, the funds could be used to pay for federal adaptation efforts on public lands. The funds could be used to preserve carbon stocks and sinks, or to invest in energy efficiency and renewable energy development. Given the federal government's ownership of extensive carbon resources, a fund created by in lieu fees could be used not only to acquire new stocks or sinks but also to help pay for the impacts of preserving ones already owned by the federal government, such as by increasing community resilience in coal-impacted communities by funding adaptation projects and economic transition programs.

A mitigation bank might be designed to operate in a way similar to those established for wetlands under Section 404 of the Clean Water Act. The bank could be limited to mitigating downstream emissions through sequestration and other offsets. Of course, such a program would

[152] *Mitigation Chapter*, *supra* note 117, §§ 6.6(C)(3)(b), 6.7.

encounter the same technical issues as other GHG emissions offsets programs. BLM must seek to ensure that offsets are real, quantifiable, additional, verifiable and permanent. As with calculating the fee itself, an offsets program may need to designate an appropriate ratio of offsets to emissions. And, BLM should seek to ensure that there is no double-counting of emissions.

D. A Sample Framework for Developing a National Compensatory Mitigation Strategy for the Federal Coal Leasing Program

In considering employing a climate change impacts fee as a compensatory mitigation strategy for the federal coal leasing program BLM will not be starting from scratch. The bureau's Regional Mitigation Strategies for Solar Development provide something of a template. There, BLM committed to seek to avoid and/or minimize adverse impacts associated with solar development on public lands in the American Southwest, and for those impacts that cannot be avoided or minimized develop regional mitigation plans for each solar energy zone analyzed in the Programmatic Environmental Impact Statement for Solar Energy Development in Six Southwestern States (Solar PEIS).[153] The regional mitigation strategies were from the outset authorized to incorporate compensation in the form of funding for identified conservation priorities.[154]

The Regional Mitigation Strategies issued in March 2016 provide further useful detail. Among other things, for instance, the Arizona Regional Mitigation Strategy provides (1) a recommended method for calculating a regional compensatory mitigation fee that can be assessed to developers choosing to contribute to a mitigation fund, and an explanation of how it was calculated for each of the solar energy zones in the state;[155] (2) preliminary information on management of mitigation obligation revenues;[156] and (3) recommended regional compensatory mitigation sites, action(s), and desired outcomes.[157]

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[153] BUREAU OF LAND MGMT., APPROVED RESOURCE MANAGEMENT PLAN AMENDMENTS/RECORD OF DECISION (ROD) FOR SOLAR ENERGY DEVELOPMENT IN SIX SOUTHWESTERN STATES 19 (2012).
[154] *Id.* at 165–68.
[155] BUREAU OF LAND MGMT., REGIONAL MITIGATION STRATEGY FOR THE ARIZONA SOLAR ENERGY ZONES 44–48 (2016).
[156] *Id.* at 49.
[157] *Id.* at 49–53.

There are important differences between BLM's Solar Energy Program and the federal coal leasing program. First, the direct impacts of the Solar Energy Program are, for the most part, to leased lands or areas immediately surrounding them, and indirect effects are largely if not entirely limited to the geographic region or ecoregion and to protected wildlife within it. Second, the limited geographic scope of impacts weighs in favor of mitigation efforts that are similarly situated, and that directly comport with relevant regional management plans. Third, the nature and extent of the impacts and appropriate mitigation, then, are most easily determined on the project-specific level. Climate change, by contrast, has indirect effects that are essentially unbounded. GHGs emitted by coal extracted from federal lands and combusted in the US have the same climate effect as GHGs emitted by coal extracted elsewhere and combusted elsewhere. This likely weighs in favor of a more uniform approach to compensatory mitigation that can be determined at a programmatic level.

Nonetheless, the BLM's approach to developing the regional mitigation strategies for solar energy offers a useful template. Here, the paper adopts the overall approach described in the Final Solar PEIS,[158] and recorded in the BLM Draft Procedural Guidance for Developing Solar Regional Mitigation Strategies, to describe the necessary elements of a climate change impacts fee compensatory mitigation strategy for the federal coal leasing program:

1. *Description of the baseline conditions against which unavoidable impacts are assessed:* BLM should consider comments already submitted and further comments on the appropriate baseline by which to measure GHG emissions and associated climate change impacts. At a minimum, the BLM should establish a baseline condition that accounts for domestic policies and plans aimed at reducing greenhouse gas emissions and dependence on fossil fuels. That is to say, under no circumstance should the the baseline condition correspond with "business-as-usual" trajectories for GHG emissions, but rather trajectories that are consistent with our greenhouse gas reduction targets, and which reflect the effects of current and planned regulations on fossil fuel consumption. Alternatively, the agency might consider setting a carbon budget fully consistent with the international goal of a 2 degree or 1.5 degree limit to global warming.

[158] BUREAU OF LAND MGMT. & U.S. DEP'T OF ENERGY, FINAL PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT (PEIS) FOR SOLAR ENERGY DEVELOPMENT IN SIX SOUTHWESTERN STATES app. A, § A.2.4 (2012).

2. *Assessment of unavoidable impacts:* BLM should consider all GHG emissions resulting from the federal coal leasing program unavoidable impacts. In so doing, the agency should acknowledge that downstream emissions from the transportation, processing and combustion of the resource are indirect effects of the action, and should quantify downstream emissions tied to the estimated amount of coal to be extracted in the alternatives to be analyzed in the Programmatic EIS. BLM can estimate downstream emissions from combustion by multiplying the amount of the resource to be extracted by the CO2 emission factor for the fuel. BLM can also estimate emissions from the transportation and processing of the resource. This inventory of downstream greenhouse gas emissions could be supplemented by a market analysis of how the predicted increase in the supply of fossil fuels will affect prices and consumption vis-à-vis alternative fuel sources. The market analysis should not be used as a substitute for a complete inventory of downstream emissions. Rather, it should serve as a tool for determining whether the proposed action will displace the production and consumption of other fuel sources, thus resulting in a net increase in greenhouse gas emissions that may be less than the gross emissions from downstream processing, transportation and consumption. In other words, the market analysis should inform the agency's understanding of the extent to which the project will actually increase greenhouse gas emissions as compared with the no action baseline.[159]

3. *Identification of unavoidable impacts that warrant mitigation:* As a matter of policy, BLM should identify *all* upstream and downstream emissions as unavoidable impacts that warrant mitigation. The climate is in crisis, and there is literally no room for error if we have any hope of meeting the 1.5 degree or even 2 degree targets.

4. *Method for calculating mitigation fees for unavoidable impacts that warrant mitigation:* Emissions themselves may constitute the unavoidable impact requiring mitigation and the appropriate form of mitigation, in the form of carbon sequestration. The agency should consider how to calculate appropriate emissions offsets on public and private lands. Emissions may also be monetized by looking at their impacts. The Social Cost of Carbon provides one viable method for calculating mitigation fees for unavoidable climate change impacts that warrant mitigation. Another

[159] Resources on downstream emissions calculations are available in Burger & Wentz, *supra* note 92.

approach may be to calculate climate change adaptation and disaster management costs incurred by the federal government and to apportion some responsibility for them to individual coal leases. Other approaches may be available, and should also be considered.

5. *Identification and recommendation of management structure to hold and apply mitigation investment funds:* Climate change impacts fees may be paid in the form of in lieu fees into a government fund or as credits in a government- or privately-owned mitigation bank.

6. *Appropriate mitigation investment locations, objectives and/or actions:* Different investment locations, objectives and actions are available to the government fund and mitigation banks. For example, the government fund may make domestic investments in carbon capture and utilization research; adaptation in coal communities including preparation for climate impacts (wildfire, drought, etc.) as well as economic development for transition away from coal extraction;[160]and investments in carbon sequestration projects in the US and internationally that could provide for net zero emissions. Mitigation banks may make domestic or international investments in carbon sequestration projects.

VI. Conclusion

The programmatic review of the federal coal leasing program will provide a critical opportunity to evaluate the effects of federal coal on climate change and to identify measures that could be implemented to mitigate those effects. The imposition of a climate change impacts fee on federal coal leases is a prime example of a mitigation measure that should be contemplated in the review. This paper presents the policy and legal rationales for introducing such a fee, explains why BLM has ample discretion to pursue this course of action, and highlights some technical questions that warrant further consideration during the environmental review. The paper is thus intended as a starting point for a much more detailed assessment of this important mitigation opportunity.

[160] *See* Bureau of Land Mgmt., National Environmental Policy Act Handbook § 6.8.4 (2008) ("Mitigation measures can be applied to reduce or eliminate adverse effects to biological, physical, or socioeconomic resources. Mitigation may be used to reduce or avoid adverse impacts, whether or not they are significant in nature.").

Center for Western Priorities

UPDATE

June 18, 2015

A Fair Share:

The Case for Updating Oil and Gas Royalties on Our Public Lands

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SUMMARY

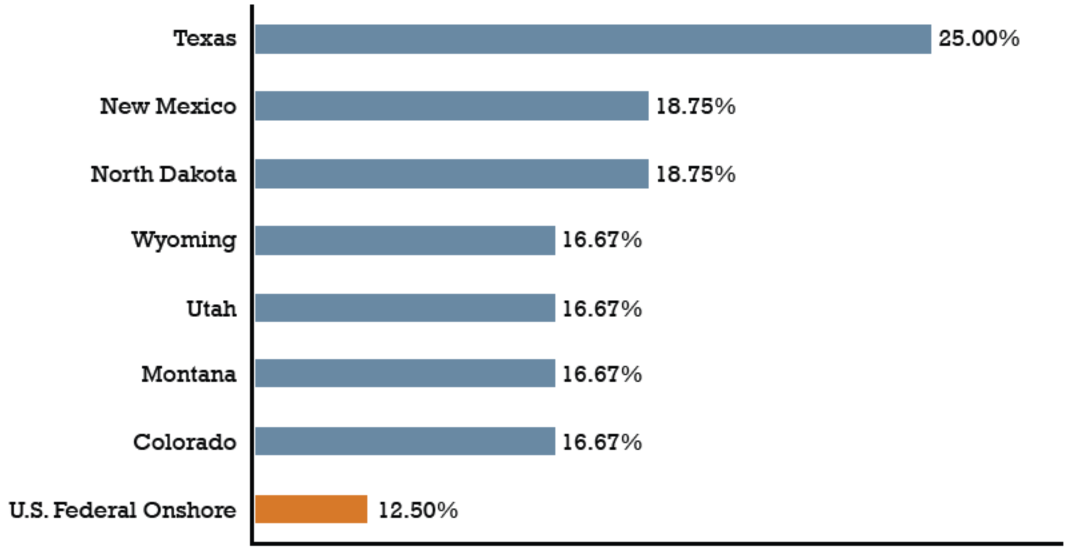
Federal Oil & Gas Royalty Rates are Shortchanging Western States & Taxpayers

Antiquated federal royalty rates for onshore oil and gas development are depriving taxpayers and many Western states of urgently needed revenue that could be used to pay down the national debt, expand access to recreation opportunities, protect public lands, and improve infrastructure strained by oil and gas drilling operations.

The onshore oil and gas royalty rate on U.S. public lands has not been updated since the 1920s, remaining at 12.5 percent.[1] Most oil and gas producing states in the Western United States charge a significantly higher royalty rate than the federal government—typically a rate of 16.67 percent or 18.75 percent—to produce oil and gas on state-owned lands. Texas collects twice the federal rate in royalties.

> By charging royalty rates lower than oil and gas producing Western states, the federal government is leaving revenues on the table and shortchanging taxpayers.

COMPARISON: FEDERAL ONSHORE ROYALTY RATES ARE MUCH LOWER THAN STATE RATES[2]



The royalties that U.S. taxpayers receive from oil and gas production are split between the U.S. Treasury and the states. Our new data show that energy-rich states in the Rocky Mountain West—Colorado, Montana, New Mexico, Utah, and Wyoming—are being deprived of between \$490 million and \$730 million in gross revenues annually because the federal government has failed to modernize royalty rates.

The Bureau of Land Management (BLM)—an agency within the Department of the Interior (DOI)—leases American-owned lands to oil and gas companies. In return, these companies pay royalties to American taxpayers to compensate them for the extraction of their oil and gas resources.

Under this system, oil and gas companies have leases on approximately 34.6 million acres of national public lands.[3] In fiscal year 2014, those leases produced over $3.3 billion in royalty payments.[4] However, the government's failure to update the royalty payment structure costs the states and taxpayers significant revenue each year.

The federal onshore royalty rate must be increased to provide a fair return to states and taxpayers. The law requires the BLM to assess a royalty rate of "not less than" 12.5 percent and the president and the Secretary of the Interior have the executive authority to increase that rate without Congressional action.[5]

After years of contemplating a policy change, DOI and BLM announced in April of 2015 that the agencies would begin to modernize the outdated royalty rate.[6] In announcing the agency's plans, Interior Secretary Sally Jewell said, "It's time to have a candid conversation about whether the American taxpayer is getting the right return for the development of oil and gas resources on public lands."[7]

The time could not be better. Budget cuts in recent years have strained local, state, and federal budgets, creating a significant need to revisit royalty policies on our public lands. And as oil and gas companies continue developing energy resources on national public lands, low royalty rates are shortchanging American taxpayers.

This paper analyzes deficiencies in the federal onshore oil and gas royalty rate and examines opportunities for taxpayers to receive a fair return on energy resources while encouraging the diligent development of federal oil and gas leases and the need for a balanced energy policy.

PUBLIC LANDS AND THE CURRENT ROYALTY STRUCTURE

Public lands are part of our nation's legacy and are an economic driver in the West. These lands contribute to Westerners' quality of life and are a magnet for businesses that create jobs and grow economies. They provide wildlife habitats, sources of drinking water and clean air for towns and cities, and supplies of natural resources including timber, minerals, oil and natural gas.

The BLM, one of the four major federal land management agencies, oversees the 700 million acres of subsurface mineral resources, in addition to managing 245 million surface acres.[8] The BLM is charged with managing these lands for multiple uses, maximizing their benefits to current and future Americans, and striking a balance between land protection and resource development.[9]

When the BLM leases public land to private companies, the companies are obligated to repay the public for the use of the lands, as well as the raw materials like coal, oil, and natural gas that are extracted.

The royalties that companies pay to extract oil and gas from national public lands are an important source of federal revenues. According to a 2010 report by the Government Accountability Office (GAO), royalties from oil and gas development "represent one of the federal government's largest nontax sources of revenue."[10]

Along with royalty payments—which represent the largest source of revenues from oil and gas extraction on national public lands—oil and gas leasing also generates revenues for taxpayers through bonus bids and rental payments.

Royalties: An energy company pays royalties to a landowner—such as the federal government, state government, tribal government, or a private landowner—for the right to extract oil and natural gas from their land. Royalties are assessed as a percentage on the value of the oil or natural gas extracted.[11] Royalty payments contributed 93 percent of all federal onshore oil- and natural gas-related revenues in 2014.[12]

Bonus Bids: Federal oil and gas leases are offered through a competitive bidding process. A company must bid at least $2 per acre to lease national public land, but bids can range much higher.[13] In 2014, bonus bids contributed about 5 percent of all federal onshore oil and natural gas revenues.[14]

Rental Payments: Rentals are paid on oil and gas leases that are not currently in production and therefore the company is not making any royalty payments. Annual rental fees are $1.50 per acre in the first 5 years and $2.00 per acre each year thereafter.[15] In 2014, despite nearly 22 million idle acres of leased land, rental payments accounted for only about one percent of federal onshore oil and natural gas revenues.[16/17] Because rental rates are so low, oil and gas companies are sitting on thousands of leases and millions of acres. Presently, there are nearly 6,000 approved permits, ready for drilling and energy extraction, sitting idle.[18]

FEDERAL AND STATE ROYALTY DISTRIBUTION

Royalties generated on national public lands provide a direct benefit to the states where extraction takes place. The revenues collected are distributed through a formula that returns approximately half of the revenues to the state where drilling occurred—the remainder is deposited into the U.S. Treasury for the benefit of all Americans. The one exception is Alaska, where 90 percent of revenues are returned to the state.[19]

Over the last five years, oil and gas production on federal lands has generated over $15 billion in revenues, a significant portion of which was redistributed to the states where the drilling took place.[20] In FY 2014 alone, the federal government disbursed over $1.6 billion to states where drilling occurs. Because they are major oil and gas producers, significant portion of that amount was distributed to states in the Rocky Mountain West.[21]

Royalty payments distributed to the states are an important source of funds that help alleviate the community and economic impacts of oil and gas development by subsidizing the construction and maintenance of public facilities, like schools and roads.

In Colorado, for instance, federal royalties are distributed to counties, municipalities, and school districts.[22] In Utah, the large majority of federal royalties are dispersed to maintain local highways in communities impacted by energy development and to the state agencies and towns directly affected by oil and gas development.[23]

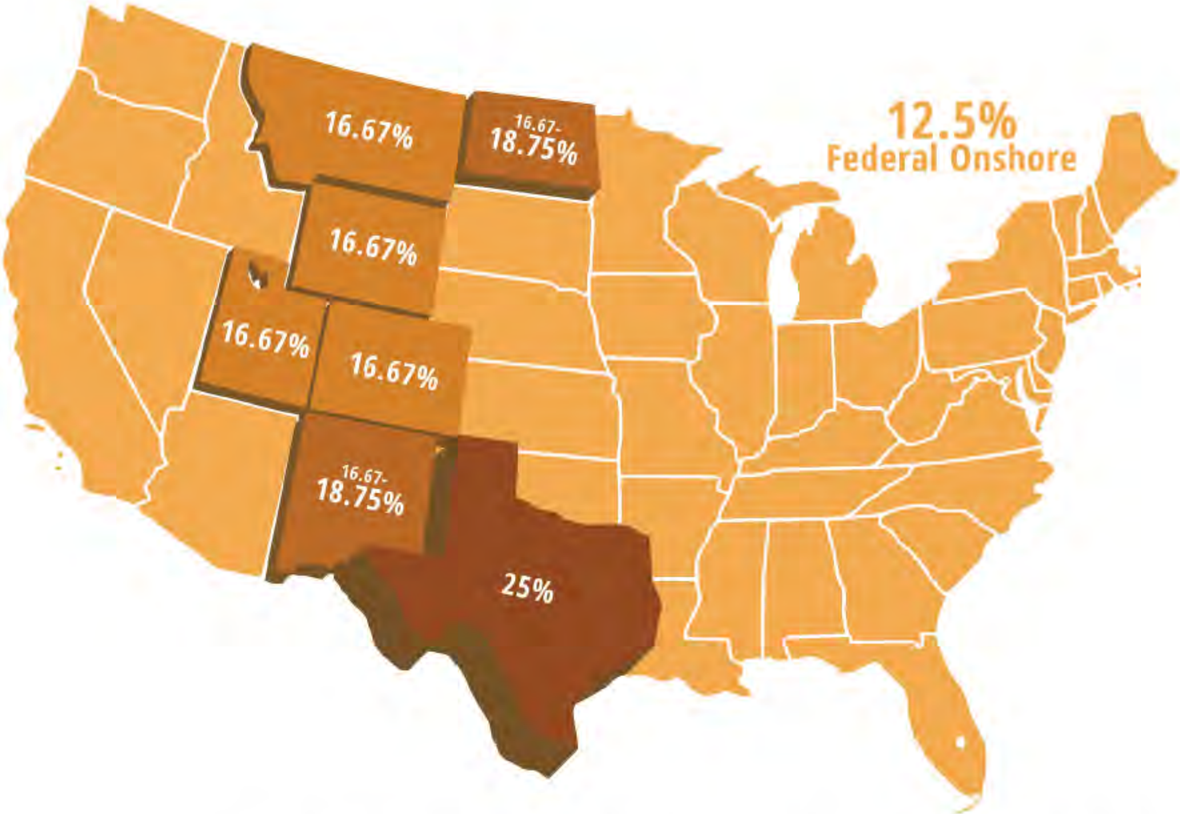
FEDERAL OIL AND GAS ROYALTY DISTRIBUTIONS TO WESTERN STATES, 2014[24]

Colorado	Montana	New Mexico	Utah	Wyoming
$112.6 Million	$16.2 Million	$546.4 Million	$191.5 Million	$542.7 Million

FEDERAL ROYALTY RATES ARE BELOW ROYALTY RATES OF MOST WESTERN STATES

States receive a portion of royalty payments from national public lands, and also assess their own royalties on oil and gas extracted from state owned lands. These lands—mostly state trust lands—were granted by the federal government to states upon their entering the Union.[25]

Our analysis finds that states in the West—where many national public lands are located—charge significantly higher royalty rates to develop oil and gas on state lands. While the federal government charges 12.5 percent on the value of oil and natural gas produced onshore, most Western states charge between 16.67 percent and 18.75 percent. That's anywhere from 33 percent and 50 percent higher than the federal onshore rate. Texas charges a royalty rate of 25 percent, which is twice the federal rate.



North Dakota and New Mexico adjust royalty rates on state lands based on the location of known production areas and the likelihood of discovering oil and gas. New Mexico charges 16.67 percent on more speculative lands and 18.75 percent inside known production areas. Similarly, a 16.67 percent royalty is charged in most of North Dakota, but the state levies an 18.75 percent in the counties lying above the Bakken Formation.

Each of the previous six Department of the Interior budgets called for increasing the onshore rate, but no action has been taken.[26] The current effort by President Obama to modernize royalty rates is not unprecedented. In fact, under President George W. Bush, Interior Secretary Dirk Kempthorne twice increased offshore royalty rates to reflect fair market value: first from 12.5 percent to 16.67 percent, then again to 18.75 percent.[27]

LOST REVENUE DUE TO OUTDATED ROYALTY RATES

The Obama administration's most recent calls for advancing royalty reform include raising the minimum royalty rate, encouraging diligent development, and evaluating other common sense oil and gas management reforms. *The president's most recent budget estimates that reforms would generate $2.5 billion in net revenue to the U.S. taxpayers over the decade.*[33] This number does not include the benefits that state taxpayers would receive.

Our economic analysis reveals how continued royalty stagnation impacts the states and projects how states stand to benefit from modernizing the federal onshore royalty rates.[34] The analysis finds that in 2014 alone, *between $490 and $730 million in additional revenue would have been generated and distributed to states in the Rocky Mountain West*, if royalty rates were increased to 16.67 percent or 18.75 percent.

The two states with the most mineral extraction on national public lands, New Mexico and Wyoming, lost over $190 million each in 2014 because of low federal royalty rates.

INCREASE IN GROSS ROYALTY REVENUE TO WESTERN STATES, 2014

State	Royalty Rate: 16.67%	Royalty Rate: 18.75%
Colorado	$46,192,000	$69,233,000
Montana	$5,736,000	$8,597,000
New Mexico	$190,908,000	$286,133,000
Utah	$53,752,000	$80,563,000
Wyoming	$192,122,000	$287,952,000
Five State Total	$488,710,000	$732,479,000

Assumptions

- The analysis estimates changes in gross revenue and does not consider changes in net revenue from increasing royalty rates.
- The analysis does not consider the changes of higher royalty rates to other tax interactions, like tax loopholes and federal income tax deductions.
- The analysis does not consider the effect of changes to bonus bids or rental rates.
- The analysis does not consider changes in oil and gas production levels.
- The analysis assumes that 50 percent of the revenues flow to the states and 50 percent of the revenues flow into the U.S. Treasury.
- The study assumes that any royalty rate increase would be applied to current leases.

HIGHER RATES DO NOT SIGNIFICANTLY SLOW DRILLING

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The value of oil and gas resources, technology, and geology largely determine when and where it is profitable for a company to drill for oil and gas. Economic data show that small yet fiscally meaningful differences in tax and royalty policy do not significantly affect oil and gas production.[28]

A recent comparative analysis revealed that states with higher oil and gas taxes are not placed at a competitive disadvantage.

Wyoming, for example, has the highest effective tax rate in the West but still remains a national leader in production. At the same time, Montana has among the lowest effective tax rates in an attempt to attract the industry, yet drillers are much more interested in drilling in North Dakota despite the state's relatively higher rates.[29]

Because of Montana's oil and gas tax policy, a new well in Montana will generate $800,000 less for the state than an identical well drilled across the border in North Dakota. Despite this disparity, drilling in North Dakota has boomed as drilling in Montana lags behind. This demonstrates that higher returns to taxpayers are not impacting companies' investment decisions.[30]

POLICY OPTIONS TO ENSURE AMERICANS GET A FAIR SHARE

Both Congress and the administration have options to encourage the diligent development of federal oil and gas leases, while ensuring American taxpayers are receiving a fair return on publicly owned oil and natural gas resources.

Increase Federal Royalties to Mirror Rates Charged by the States

One option to ensure taxpayers receive a fair return is to create parity between federal and state royalties by increasing the minimum federal rate. While the BLM may consider adopting a 25 percent rate—on par with Texas—a more practical approach is to mirror the federal onshore royalty rate with the rates charged by the majority of states. Raising the base royalty rate to 16.67 percent or 18.75 percent for all federal onshore leases will generate significant new revenues for the U.S. Treasury and for oil and gas producing states.

Sliding Scale Based on Oil and Natural Gas Prices

Rather than charging a flat royalty rate, the BLM may consider adopting a variable rate that adjusts with the market price of oil and natural gas. Under this alternative, the royalty rate would rise incrementally as the price for oil and gas increases. For instance, when oil is selling at $50 per barrel, a royalty rate of 16.67 percent could be assessed. If the price reaches $75 per barrel, then the federal government could charge an 18.75 percent rate. And, if the price rises above $100 per barrel, the royalty rate could be set at 22.5 percent. Precise royalty rates and associated fuel prices would be set to maximize taxpayer returns as oil and gas prices rise and fall.

Sliding Scale Based on the Location of Known Resources

The federal government may also consider adopting two royalty rates: a lower rate in areas that are more speculative and a higher rate in known production areas. This is a common policy at the state level—both New Mexico and North Dakota charge a higher rate on lands where oil and gas companies are having the most success.[31] Similarly, the BLM may consider assessing a 16.67 percent rate on speculative lands, while levying a higher rate in more established production areas. This approach provides an incentive to companies exploring for oil and gas in more speculative areas, while ensuring they pay a fair share on lands with known, high quality resources.

Escalating Royalty Rates to Encourage Diligent Development

To incentivize companies to develop oil and gas leases in a timely manner, the federal government could adopt an escalating royalty rate. A company that chooses to hold onto a lease without taking steps to develop would pay a higher royalty rate after production begins. For example, a company that begins producing energy during the first two years of a lease could pay an 18.75 percent royalty rate, while a company that takes longer than five years to begin extraction could pay 22.5 percent.

Increase Rental Rates to Encourage Diligent Development

Current rental rates are too low to discourage companies from stockpiling and sitting on thousands of acres of public land. The federal government could also incentivize diligent development by making it more expensive to leave leased lands idle. Under current rules, sitting on undeveloped leases costs $1.50 per acre during the first five years of a lease and $2.00 per acre during the next five years; a 33 percent increase. The federal government could look towards the states, like Texas, which charges $5 per acre during the first three years of a lease, then $25 per acre for each ensuing year that the lease remains undeveloped; a 500 percent increase.[32]

CONCLUSION

Taxpayers are losing out on significant revenue that could be used to reduce our national debt and alleviate the impacts of oil and gas drilling on communities because the U.S. government charges a decades-old royalty rate on onshore oil and natural gas leases.

After years of inaction, the BLM and DOI are taking steps to ensure Americans receive a fair return from the development of public resources, including adjusting outdated royalty rates, along with considering reforms to low rental rates, minimum bids, and bonding requirements.[35]

While little action has been taken to address the imbalance until now, the issue has not gone wholly unnoticed. The GAO raised concerns in 2008, writing, "Congress and the public are justifiably concerned about whether the federal government is getting a fair return for its energy resources as oil and gas company profits have reached record levels."[36]

Since 2011, each of president Obama's budgets has called for onshore oil and gas royalty reform. The president's fiscal year 2013 budget recommends, "Making administrative changes to federal oil and gas royalties, such as adjusting royalty rates."[37] The BLM's fiscal year 2016 budget calls for royalty reforms, including "evaluating minimum royalty rates for oil, gas, and similar products; [along with] adjusting onshore royalty rates."[38]

Former Interior Secretary Ken Salazar proposed raising onshore royalty rates to 18.75 percent.[39] And in a 2015 speech, current Interior Secretary Sally Jewell called on her agency to "[ensure] that the American taxpayer is getting a fair return for the use of natural resources on public lands."[40]

Given the country's fiscal challenges, it is imperative for the federal government to examine all potential sources of revenue. Updating the royalty rate can help to ensure American and Western state taxpayers are finally receiving a fair return from the development of publicly owned oil and gas resources.

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A Fair Return for the American People: Increasing Oil and Gas Royalties from Federal Lands

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Introduction

For decades, revenues from minerals extracted from federal lands—minerals owned by the American people—have been among the most important non-tax sources of funding for the U.S. government.[1] These revenues have been substantial even though it is widely believed that the federal government shortchanges the public by charging too little for what they sell and collecting even less than they charge. The federal government is charged with returning to the American people fair market value for the sale of these minerals and is found, too often, to have failed to do so.

There are many parts to the federal mineral revenue story—some quite colorful and notorious. In 1922, Secretary of the Interior Albert Fall accepted bribes to award below value, no bid leases to friends for the production of oil at Teapot Dome in Wyoming and two locations in California. Fall distinguished himself by becoming the first sitting Cabinet official to go to jail. In 1980, Charles B. Thomas, an inspector for the U.S. Geological Survey, stopped a tanker truck coming off the Wind River Reservation with stolen oil that bypassed royalty meters. The discovery triggered investigations revealing years or even decades of oil theft from federal and Indian lands—with major losses never fully recovered for the public or tribes. In 2008, Interior Inspector General Earl Devaney issued three reports detailing a "culture of ethical failure" and a culture of "substance abuse and promiscuity" that permeated the oil and gas royalty-in-kind program. He reported on how oil company employees traded gifts, graft, sex, and drugs with Interior staff for sweetheart "royalty-in-kind" oil and gas deals that cost the American public millions of dollars in lost royalties. Interior Secretary Salazar canceled the royalty-in-kind program and reorganized the entire Minerals Management Service out of existence, but no one was criminally prosecuted to the chagrin of the Inspector General.

Scandals are bright, shiny objects that attract momentary attention. Yet, after the headlines and drama of these sensational episodes fade, the thought and consideration given by officials, the press and the public to federal revenues from natural resources also wanes. That failure to pay attention allows a deeper, more consequential scandal—one that has gone on for every minute of every day for decades—to continue with no corrective action taken. That deeper scandal is the failure of the Department of the Interior (Interior) to collect royalties on natural resources produced from federal lands at rates that return fair market value to the American people. In the nearly hundred years Interior has managed federal minerals, it has not

[1] In recent years, federal mineral revenues have been temporarily eclipsed by interest revenues from bonds purchased by the Federal Reserve in the course of its quantitative easing policy designed to pull the economy out of the Great Recession.

changed even once the standard 12.5% royalty that it charges for oil and gas extracted onshore from federal lands. Meanwhile, royalties charged by other owners have increased, including those collected by states for oil and gas from state-owned lands and even by the federal government for offshore deposits. Texas, for example, charges and receives 25% and has done so for thirty years, with 18.75% increasingly a mid-level rate among the largest producing states.

Royalty rates are not a complicated matter. They are simply the price that owners, in this case governments on behalf of their citizens, charge for oil and gas produced. The royalty rate is the same as a homeowner offering to sell a home for a certain price. The federal government, in effect, offers to sell a home for $200,000. In contrast, based on current relative royalty rates, most states close the deal for the identical house between $267,000 to $320,000. Louisiana sells the house for $374,000—and Texas gets $400,000 and has for a long-time.

The question might be asked, "Even if states charge higher prices for oil and gas, are they selling less and reducing production, jobs and economic activity in their states?" The answer is basically no. Economic studies find that even near the highest rates charged by states production would decline by 2% or less—too small to detract from the revenue gains from higher royalty rates. Further, Texas with its highest royalties in the nation remains the largest oil and gas producing state in the nation, with a new boom in production emerging in the Permian Basin within that state.

States are diligent in reviewing and adjusting their royalty rates to ensure their citizens receive a fair return on state minerals. Collectively, they test the marketplace for oil and gas by raising rates and seeing if they secure as much or more production. The states' diligence stands in contrast to Interior's failure to ever test in a hundred years the marketplace for higher rates for onshore oil and gas. Interior has not even established, as the U.S. Government Accountability Office (GAO) has urged it do so, a regular process for continuously reviewing and adjusting the royalty rates for federal oil and gas, which is often produced from the same fields as state oil and gas.

In terms of the practical uses of royalty revenues, achieving a fair return from oil and gas is important to managing the effects of the boom and bust cycles of resource extraction, especially on local communities in rural areas. Those states and communities share in the revenues from federal lands. Shortfalls in royalty collections hamper efforts in those communities to protect public health and safety, repair environmental damage, and diversify their economies for long-term resiliency. Finally, unjustified or improper deficits in federal mineral revenue collections contribute to a combination of reduced public services, higher taxes or increased federal debt.

The failure of Interior to collect royalties at a full and fair market value rate is the real scandal. The best evidence is that at the very least the federal government is giving away to oil and gas companies a third of the royalties that ought to be paid to the American people for onshore production. That is happening every moment of every day for every barrel of oil and cubic foot of natural gas that flows off of federal lands. It is an enormous breach of trust with the American people. For that reason, this report will focus on royalties for onshore oil and gas and the process needed to ensure those royalties are fully and properly collected.

The federal government does deserve credit for increasing federal royalty for offshore production during the Bush Administration. In 2007, royalty rates for deep water oil and gas were increased from 12.5% to 16.67% (to match the existing rate for shallow water production). In 2008, the royalty rate for new offshore leases at all depths was increased to 18.75% where it remains today. The fact that Interior increased offshore royalty rates but has left onshore rates unchanged further highlights Interior's lack of diligence in securing for the public a fair return from onshore oil and gas.

Over the past decade or more, public agencies and non-profit groups have issued several reports evaluating the royalty rate for onshore federal oil and gas. On balance, these studies make a compelling case that Interior should increase the royalty rate for onshore oil and gas above the 12.5% rate and can do so with minimal impact on oil and gas production. The prior studies supporting increases in royalty rates remain fundamentally sound. Beyond updating information to reflect more recent developments, this report does not undertake a new analysis of royalty rates. Instead, it primarily seeks to summarize and refocus attention on the prior findings. In addition, the royalty rate issue will be placed in the context of related issues of determining the proper value of extracted minerals to which the rates are applied. More importantly, in light of continued inaction by Interior in adjusting rates or adequately evaluating potential changes, this report will recommend steps other public officials, agencies and non-profit organizations can undertake to encourage public knowledge and oversight of public mineral revenue issues.

Summary of Findings and Recommendations

This report makes the following findings:

1. States, whose lands are generally held in trust for their public schools, and the federal government have a responsibility to achieve a fair market value return for their citizens on oil and gas produced from their public lands.
2. State governments, collectively, test the market price—the royalty rate—for oil and gas by increasing rates and observing the response in terms of leases secured and oil and gas produced. Thus, state royalty rates reasonably reflect the fair market level for royalties. The federal government has not similarly tested the market price for onshore oil and gas production in over a century, reflecting a lack of diligence in meeting its responsibilities to the public. The untested federal rates are below market value as compared to the market-tested state rates.
3. Federal oversight of natural resource revenue policies and practices is episodic (often prompted by recurring scandals) and fails to regularly engage the broader public. The federal government should establish new mechanisms and procedures to give increased

and continuing attention to these policies and practices with greater opportunities for public participation in the process.

Consistent with the findings above, this report recommends the following actions:

1. As an initial step toward achieving a fair return for the American people, Interior should increase standard royalty rates for new leases for onshore oil production to 18.75% matching both its current offshore royalty rates and the middle range of state royalty rates for onshore oil and gas production. Further changes in the level and structure of federal royalty rates should be considered through the new royalty evaluation process described under items 3, 4, and 5 below. If Interior fails to increase the rate to 18.75%, Congress should adopt that rate by law as the minimum level for new oil and gas leases and mandate Interior to periodically evaluate and report to Congress on potential increases above this minimum.
2. To protect the integrity of natural revenues and prevent royalty payments from being undermined by gaps and loopholes in reporting oil and gas values, Interior should take additional and continuing measures to ensure that oil and gas producers report the full amount and value of their production.
3. Interior should establish, as the GAO has recommended, a continuous process to "evaluate the oil and gas fiscal system as a whole."[2] and review policies through these measures:
   a. Establishing an "Office of Natural Resource Revenue Analysis" to conduct regular and transparent studies of leasing and bid practices, royalty and rental rates, resource measurement practices, valuation policies and methods, and other natural resource revenue topics. The charter and organization of the office should be instituted in a manner the supports the objectivity, independence, and transparency of its work and public participation in its studies and operations.
   b. Reevaluating the level and structure of its natural resource revenue policies as a whole on a periodic schedule. The process should include incorporating lessons learned from state experiences, with specific attention to keeping federal rates at least consistent with the middle range of state rates. The process should also provide opportunities for active public participation in proposed changes prior to formal adoption.
4. Congress should strengthen its oversight of natural resource revenue policy and practices by establishing a Joint Committee on Natural Resource Revenue to conduct studies of natural resource revenue laws, policies and administration. The structure, duties and operations of this new joint committee would be modeled after the Joint Committee on Taxation, with members drawn from the U.S. Senate Energy and Natural Resources Committee and the U.S. House Natural Resources Committee. The joint committee's powers should extend to examining confidential records of returns, disputed cases and other matters necessary to evaluate the effectiveness of Interior's policies and practices.
5. To fulfill the public's right to know what they are being paid for the minerals they own and further strengthen oversight through well-informed public engagement in natural resource

[2] U.S. General Accountability Office, "Oil and Gas Royalties: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment," GAO-08-691, p. 16.

revenue policies, Congress should re-enact transparency laws that require reporting, by lease, of revenues paid, production levels, and mineral values on public lands.

6. As improvements occur in the transparency of federal natural resource revenue systems, state governments should improve the transparency and availability of state natural resource revenue information in a comparable manner.
7. In addition to advocating for substantive improvements in federal royalty policy and administration, non-profit conservation, environmental and public lands management organizations should support increased transparency of natural resource revenue data and evaluate the need for and feasibility of establishing a Natural Resource Policy Center to conduct regular and systematic research on federal and state natural resource revenue policies and administration.

Increasing Royalty Rates for Onshore Oil and Gas Production

From 2007 through 2017, the GAO issued a series of reports focusing on the level and structure of federal oil and gas royalty rates. In its 2008 report, it found that the "inflexibility of royalty rates to change oil and gas prices has cost the federal government billions of dollars in foregone revenues."[3] In the course of its reports, the GAO also noted various comparisons between federal rates and those charged by states and foreign governments.[4] It generally concluded that the federal rates were among the lowest collected. Those comparisons, while not receiving widespread attention, may have had an impact on the increases in offshore federal royalty rates in 2007 and 2008.

The table below compares the royalty rates in major oil and gas producing states.[5] The term "top" royalty rates is used because in some states, slightly lower rates are charged on lower quality, "speculative" deposits. Those deposits are not representative of the primary sources of production in the United States, so the top rates are the most relevant ones for policy purposes. To underscore the regular attention states give to their rates, in the last few years Colorado increased its rate from 16.67% to 20%, and New Mexico increased its top rate from 18.75% to 20%. The following are the current onshore rates in major producing states as compared to the federal onshore rate.

[3] *Id.*, p. 16.

[4] For another state/federal royalty rate comparison, see also: Center for Western Priorities, "A Fair Share: The Case for Updating Oil and Gas Royalties on Our Public Lands," Update, June 18, 2015. Colorado and New Mexico increased their rates since that report was issued.

[5] The practices of two other major, long-term production states, Alaska and California should be noted. California does not appear to have onshore production of oil or gas on state lands because of the limited extent of those lands. Thus, there is not a relevant state royalty rate. Alaska charges a 12.5% royalty for production from its state lands, but it also levies a higher and more extensive structure of state taxes on oil and gas production. Alaska's royalties and taxes combined result in a higher governmental share of revenues than what occurs for the federal onshore rate. Thus, listing Alaska's royalty rate alone would constitute a misleading "apples and oranges" comparison with the other states.

Federal Onshore Royalty Rates Lag Behind State Rates Rates Applicable to New Leases	
Jurisdiction	**Top Rate**
Texas	25%
Louisiana	23.4%
Colorado	20%
New Mexico	20%
North Dakota	18.75%
Montana	16.67%
Utah	16.67%
Wyoming	16.67%
Federal Onshore	12.5%

States exercise a higher-level of diligence than the federal government does regarding royalties from mineral production on their state lands. Fifteen states, predominantly located in the West, retain state lands.[6] Except for Texas, whose public lands derive from its unique history, these state lands were granted at statehood by the federal government for the support of public schools. It is the author's experience that issues regarding earnings from state lands attract greater public interest in these states as compared to the earnings from federal lands. That level of public attention may be attributable, in part, to the direct connection between the revenues from state lands and the budgets of local schools throughout a state.[7] In contrast, federal royalties take a circuitous route through Washington, with about half the revenue returning to the states to be distributed in a variety of ways, not all of which are visible to the public. In addition, state officials and legislators are simply more accessible to the citizens of these fifteen states than federal officials whose responsibilities extend to the entire nation. For these reasons, mineral royalties on state lands get more attention in states than do the same issues for federal lands. That translates into a level of regular and systematic diligence by state officials in managing revenues from state lands that is regrettably absent at the federal level.

States deserve substantial credit for doing a better job than the federal government in securing a return for their citizens from oil and gas produced on public lands. States have tested the market for their oil and gas resources by increasing rates and observing the results. In general, the states discover that higher rates do not reduce production. The GAO has reported this conclusion from state experiences:

> Officials from two state offices we interviewed said that the history of increasing royalty rates for oil and gas production on state lands suggests that increasing the federal

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[6] Souder, Jon and Fairfax, Sally, "The State Trust Lands," The Thoreau Institute. Initially, thirty states owned federal lands, but half of these sold their lands and presumably hold the proceeds in trust for their public schools.

[7] A vivid example of the "state lands for schools" connection is displayed on the website of the Texas General Land Office. See, in particular, the pages associated with "Education" and "Energy" tabs on that site: http://www.glo.texas.gov/glo-education/index.html and http://www.glo.texas.gov/energy/index.html.

> royalty rate would not have a clear impact on production. In particular, officials from Colorado and Texas said that they have raised their state royalty rates without a significant effect on production on state lands. In February 2016, Colorado increased its royalty rate for oil and gas production from 16.67 percent to 20 percent, and, according to state officials, there had been no slowdown in interest in new leases as of August 2016. In fact, Colorado state officials said they were unsure whether the higher royalty rate played much of a role in companies' decision making. Additionally, Texas officials told us that over 30 years ago, Texas began charging a 25-percent royalty for most oil and gas leases on state lands, and this increase has not had a noticeable impact on production or leasing.[8]

Beyond serving their citizens well, state royalty rates provide actual marketplace information on attainable royalty rates. That information is a reasonable guide to setting minimum federal royalty rates.

Proposals to increase royalty rates raise objections from the oil and gas industry that such changes would reduce production. However, there is little evidence to support that viewpoint. In 2017, the GAO reviewed studies on the impact that increasing federal onshore oil and gas royalty rates would have on revenues and production.[9] It noted that a Congressional Budget Office study found that an 18.75% federal onshore rate would raise revenues on federal lands as new leases were granted and placed in production but would likely have only a negligible effect on production. The CBO estimated that, after subtracting payments to states, federal revenue would increase by $200 million in the first 10 years as new production phased in, and more in the subsequent decade.[10] Because states receive nearly half of the federal royalties, the CBO estimate means that total royalty payments would be expected to increase by approximately $400 million over the first decade after the change. A second study by Enegis, LLC, modeled 3 increases in federal royalty rates to 16.67%, 18.75%, and 22.5%. The study found only a small impact on production, ranging from a 0% to a 1.8% decline in oil production across the three scenarios over 25 years, and a 0% to less than a 1.0% decline in natural gas production over the same period. With little or no impact on production, the three scenarios would produce between $125 million and $939 million in additional revenue over 25 years.[11] Raising the federal royalty rates to match the middle-range of state rates will produce revenue with negligible impact on production, jobs and economic activity. An increase of federal royalty rates to 18.75% would represent a modest step forward.

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[8] U.S. General Accountability Office, "Oil, Gas, and Coal Royalties: Raising Federal Rates Could Decrease Production on Federal Lands but Increase Federal Revenue," GAO-17-540, June 2017, pp 21-22.
[9] *Id., pp. 16-23.*
[10] *Id.,* pp. 16 and 22. Recent increases in estimates of future production would appear to make the CBO estimates conservative. New estimates using more current data would be in order.
[11] *Id.,* pp. 16-17 and 22-23.

Similar conclusions arise from a recent major study of the impact of state severance taxes on revenues and oil production.[12] The study modeled four dramatically different severance tax regimes ranging from 0% to 12%, 25%, and 25% with a drilling subsidy. Their overall conclusion was as follows:

> A key result . . . is that oil production is closely linked to the size of the reserve base and is relatively insensitive to changes in oil prices. This outcome, which is broadly consistent with experience in the U.S. oil industry over the past 50 years, leads to the conclusion that severance tax has little effect on production levels and serves mainly to redirect rents earned in the oil industry to the public sector. Thus, increases in severance taxes or a reduction to subsidies provided to the oil and gas industry may lead to rent taxation and therefore have only marginal effects on the drilling and production of oil . . . [13]

What Chakravorty, et. al. found was that even with very high severance taxes of 25% added to the typical public land royalty payments, production of oil is not significantly reduced. The reverse was also true: lower taxes or subsidies for drilling did not produce material increases in production. This outcome also supports a more important conclusion that current royalties are failing to return to their owners what they are owed: the full and fair value of the unproduced resource. In this study, even the highest severance taxes are simply returning a remaining portion of the intrinsic value of the unproduced resource to the public.[14] That is because even the highest taxes added to royalties do not significantly affect production. Producers still receive sufficient after-tax income to cover their costs of production including normal profits, which is the maximum they should receive.

No portion of the value of the unproduced oil and gas should go into excess profits of oil and gas producers over and above their production costs and a normal profit. That is because producers do nothing to create the wealth embodied in the raw, unproduced oil and gas. The multiple studies showing that higher royalty or tax rates can increase revenues without reducing production prove that the current low rates allow oil and gas producers to capture wealth they did not create. The result is that producers unjustly secure excess profits that ultimately benefit the largest shareholders of oil and gas companies and executives whose compensation is tied to stock options.

Current federal royalties are too low to return fair value to the American people who are the owners of this resource. Raising royalties will reclaim wealth that is now improperly gained by oil and gas companies. Higher royalties will not affect production, but will reduce the

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[12] Chakravorty, Ujjayant, et. al. "State Tax Policy and Oil Production: The Role of the Severance Tax and Credits for Drilling Expenses," in Gilbert E. Metcalf, ed., *U.S. Energy Tax Policy*, Cambridge University Press, pp. 305-337.
[13] *Id.,* p. 306.
[14] This sentence and the preceding one translate into less technical terms the quote in the Chakravorty study concerning severance taxes redirecting "rent" from the oil industry to the public. "Economic rent" is supposed to be paid to the original owners for the value of the unproduced oil and gas and not to the oil industry. Thus, the redirection is proper and justified.

excess profits of oil and gas companies and the resulting inflated, unearned income of their major shareholders and top executives. This effect on wealthy shareholders and top executives explains the intensity of corporate lobbying against increases severance taxes and royalties. However, oil and gas lobbying claims that increases in royalties or taxes will decrease production, jobs, and economic activity are not valid. Policies setting royalties below market levels simply subsidize shareholders and executive pay at the expense of the public.

The recent dramatic increase in oil and gas production in the United States also supports the conclusion that the size and nature of a resource deposit and the ability based on current technology to tap that deposit are the real factors that determine output. From 2008 through 2018, crude oil production in the United States essentially doubled. Production has now matched the previous peak in 1970 and is expected to reach even higher, record levels in 2019 and 2020. Indeed, the U.S. is expected to become the world's largest oil producing nation. Natural gas has also boomed. The increased production is largely attributable to fracking technology increasing oil and gas production in both old and new deposits. In particular, fracking led to the development of oil from the Bakken Formation primarily in North Dakota and also Montana. Fracking is also producing huge increases from the redevelopment of the Permian Basin in Texas and New Mexico. All these states charge higher royalties than the federal government, with Texas the highest at twice the federal rate and New Mexico not far behind. The lesson from the history of U.S. oil and gas production is clear. Geology and technology determine the amount of production, not royalty or tax rates.

Interior, by leaving in place for a century a 12.5% royalty rate, has failed the American people and has facilitated the transfer of enormous wealth that belongs to the public to wealthy shareholders and top executives of oil and gas companies. That failure needs to end. The median rate of state royalties in the table above is 19.375%. Increasing the federal onshore rate to 18.75% to match the federal offshore rate would be a conservative first step for Interior to begin doing justice for the American people and the states and communities responsible for responding to and managing the effects of oil and gas production. The rate would apply to new leases issued after the rate change. After this initial rate change, further increases in royalty levels should be thoroughly analyzed and considered with a firm goal of fully guaranteeing that the public is paid the fair market value for unproduced oil and gas.

If Interior fails to increase the rate to 18.75%, Congress should establish by law that rate as the minimum royalty for new oil and gas leases on federal lands. Further, that law should mandate Interior to periodically evaluate and report on Congress on possible increases in rates above this minimum.

There are other proposals for changing royalties such as sliding rate scales in relation to oil and gas prices, the quality or location of the resources, or the timeliness of production undertaken. Consideration of additional rate increases beyond 18.75% and these more sophisticated ideas should occur after the federal policy-making process regarding natural resources revenues is strengthened through improved analysis, oversight, transparency, and public participation in decision-making as recommended later in this report. The time is long since past when Interior should be left with developing royalty policy on its own.

However, before moving on to a discussion of revitalizing and opening up the natural resource policy process, this report will briefly note the need to restore the integrity of the oil and gas royalty base—the quantity and value of the resource to which royalty rates are applied. No amount of royalty rate increases or restructuring can make up for understatements in the amount and value of oil and gas produced.

Restoring the Accuracy and Integrity of the Federal Royalty Base

Royalty payments, especially if rates are increased, can be undermined by gaps, loopholes, and weaknesses in determining the amount and value of oil and gas produced. There are at least three areas of chronic problems that need to be solved if the public is to receive a fair return. Each could be the subject of a report on their own. They will be summarized here simply to note additional issues that need urgent and effective attention. These issues include (a) problems with measurement of oil and gas production, (b) understatement of the value of natural gas through non-arm's length sales and the bundling of deductible and non-deductible costs, and (c) the waste of methane gas through leaks and flaring and the failure to collect royalties on such gas.

The GAO has long identified Interior's management of oil and gas as one of the governmental programs it monitors as a "high risk" of abuse or failure. One of the continuing reasons the GAO classifies the program as a high risk is because it is concerned about deficiencies in Interior's methods of ensuring accuracy in the measurement of natural gas produced for royalty purposes. While the GAO cites some progress made by Interior, that progress is still not sufficient to fully resolve these problems.[15]

In 2007, the Bush Administration's Royalty Policy Committee took note of long-standing issues that non-arm's length sales of natural gas (and also coal) and the bundling of deductible and non-deductible costs created difficulties in valuing natural gas for royalty purposes.[16] These problems include circumstances where companies, by selling gas at below market prices to their captive affiliates, can undervalue the gas in calculating royalties. They also include cases where costs for items that are deductible and non-deductible are bundled together, creating situations where deductions from value can be overstated. Either circumstance results in shortchanging the public.

The Bush committee recommended that Interior remedy these problems by proposing new rules by the end of FY 2008—just nine months after the recommendations were made.

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[15] U.S. General Accountability Office, "High-Risk Series: Progress on Many High-Risk Areas, While Substantial Efforts Needed on Others," February 2017. See p. 141 on deficiencies in the accuracy of measuring natural gas produced.

[16] Subcommittee on Royalty Management, "Report to the Royalty Policy Committee: Mineral Collection from Federal and Indian Lands and the Outer Continental Shelf," U.S. Department of the Interior, December 17, 2007, p. 72-73.

Instead it took nine years for Interior to adopt new rules that tightened up the royalty rules to prevent this loss of revenue by the public. Those rules took effect on January 1, 2017, but were suspended by the Trump Administration in late February 2017 and repealed a few months later. So, these problems of properly accounting for the value of natural gas for royalty purposes continue today.

Perhaps the costliest gap in the oil and gas royalty base occurs with the waste of methane that is flared and vented or leaked in the course of producing oil and gas. Producers not only waste this valuable resource but also fail to pay royalties on it—even though it is part of the minerals extracted. This problem is further aggravated by the fact that methane is a potent greenhouse gas. Interior adopted new rules in 2016 to reduce methane waste and improve the payment of royalties. However, the Trump Administration delayed those rules and then replaced them with weaker standards in 2018. The 2018 rule is estimated to cost the public up to $80 million in lost royalty revenue over ten years.[17]

This and other problems that erode the royalty base and shortchange the public have generally persisted for a long time. As in the case of royalty rates, Interior has not been diligent in correcting these problems. Further, the shield of secrecy surrounding royalty valuation has hampered the ability of Congress and the public to hold Interior accountable for failing to seek or implement solutions that ensure the accuracy and integrity of the federal royalty base. Indeed, the secrecy prevents the public from knowing the extent of revenues it is losing to gaps, loopholes and weaknesses in the royalty system. The secrecy and lack of oversight needs to end.

Achieving Effective Public Oversight of Natural Resource Revenue Policies

The GAO in its reports on federal oil and gas also struck a recurring theme that Interior does not adequately and regularly evaluate the oil and gas fiscal system. It stated,

> Interior does not routinely evaluate the federal oil and gas fiscal system as a whole, monitor what other governments or resource owners worldwide are receiving for their energy resources, or evaluate and compare the attractiveness of the United States for oil and gas investment with that of other oil and gas regions. As a result, Interior cannot assess whether or not there is a proper balance between the attractiveness of federal lands and waters for oil and gas investment and a reasonable assurance that the public is getting an appropriate share of revenues from this investment.[18]

Interior might note in response that at various times it has convened advisory committees on royalty policy including in the Bush Administration and again in the current one. The Bush-era committee was thoroughly focused on details and produced over 100

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[17] Taxpayers for Common Sense, "Issue Brief: Methane Waste on Federal Lands," at https://www.taxpayer.net/article/methane-waste-on-federal-lands .

[18] GAO-08-691*, Supra* at note 3, p. 20.

recommendations, mostly quite valuable as individual pieces. However, the committee's recommendations may have been a case of "missing the forest for the trees." It did not produce the kind of overall assessment of the level and structure of royalty policies that the GAO seems to be recommending.

The Trump Administration's Royalty Policy Committee is still operating. It is subject to criticism of being overbalanced in representing oil, gas and coal producers. Interior's formation of this committee is even subject to an ongoing court challenge. The committee, with little or no expert analysis, recommended reducing the 18.75% offshore royalty rate. That recommendation was then quickly rejected by then-Secretary of the Interior, Ryan Zinke. A final evaluation of this committee is premature until it completes its work. However, there are few signs that it will satisfy the GAO specification as an overall assessment of the oil and gas fiscal system.

The use of advisory committees is episodic and uneven instead of being a process that is continuous and consistent in the scope of analysis, with expertise and knowledge accumulating and improving as it proceeds over time. Further, the administrative staff of Interior typically staffs the episodic reviews through committees. That both interrupts the regular operation of the mineral management function, but also carries the risk of unconscious bias in favor of existing practice.

Thus, it would be better to develop a specific unit in Interior—an Office of Natural Resource Analysis—with the charge of developing a framework for evaluating natural resource revenue policies at three levels: as a whole in its entirety, in its major components and in specific details as needed. At the mid-level of analysis, the office would conduct regular and transparent studies of leasing and bid practices, royalty and rental rates, resource measurement practices, valuation policies and methods, and other natural resource revenue topics. On an established schedule, the office would also conduct a higher-level periodic assessment of the fiscal system as a whole, including the structure and level of royalties as compared to states and other governments. Again, as stated previously, narrow and detailed issues would be examined as they arise. Regardless of the stage or level of analysis, the office would ideally incorporate lessons learned from state experiences, with attention to keeping federal rates at least consistent with the middle range of state rates.

Part of a framework of evaluating natural resource policies will involve the development of consistent series of data and analytical tools that would be continuous but also improved over time. The objective would be to systematically accumulate and improve a body of knowledge and expertise on natural resource revenue policy. That would replace the current process that appears to jump from one episode or policy crisis to another using different tools and information at different times in a disorganized manner.

This office would be charged with working with the public in as open a manner as possible using advisory committees, public workshops and listening sessions and other methods of participation as appropriate. Standards and procedures need to be established to support the independence and objectivity of this office and insulate it from criticism as being subject to undue influence of any kind. The transparency recommendations below would reinforce these efforts.

Congress also needs to strengthen its oversight of Interior's natural resource revenue policies. It should build its own independent capacity to evaluate these policies. It should establish a Joint Committee on Natural Resource Revenue to conduct studies of natural resource revenue laws, policies and administration. The structure, duties and operations of this new joint committee would be modeled after those of the Joint Committee on Taxation. The membership of the joint committee would be bipartisan and drawn from the U.S. Senate Energy and Natural Resources Committee and the U.S. House Natural Resources Committee. The joint committee's powers should extend to examining confidential records of returns, disputed cases and other matters necessary to evaluate the effectiveness of Interior's policies and practices.

Congress should also require an annual report on the natural resource revenue system from Interior. That report would be subject to public hearings by the respective House and Senate Committees. Whether Congress goes further and uses its increased capacity to delve more deeply into revenue issues cannot be guaranteed. However, the process would be improved if Congress would empower the public to engage more effectively in natural resource revenue issues.

Congress should serve the public by providing for greater transparency in royalty information. The American people who own the minerals on federal land are not informed of the amount of royalties they are paid on federal leases or the production amounts and values on which those royalties are based. By keeping this information secret, the public is effectively disenfranchised in the natural resource revenue process. In response to an international movement, the Extractive Industries Transparency Initiative, other nations are providing enhanced royalty and tax information to their citizens. As of today, U.S. citizens can discover how much U.S.-based companies have paid to the government of Nigeria in various taxes and royalties on a project level basis. However, U.S. citizens cannot have access to the same information about the same company payments to the U.S. or state governments on a project or lease basis. That is a disgrace that should be rectified.

Congress actually enacted a law—the bipartisan Cardin-Lugar provisions in the Dodd-Frank Act—requiring disclosure of royalty and lease payments on a detailed basis. It charged the Securities and Exchange Commission (SEC) with developing technical rules to implement that law. The SEC did so, largely only repeating the law itself and adding an administrative reporting process. However, as one the first actions by Congress in 2017, with the support of the new Administration, those largely ministerial rules were overridden by Congress. The law is still on the books, but the disapproval action under the Congressional Review Act now makes it virtually impossible for the SEC to implement it. The Trump Administration then followed this action with a formal removal of the U.S. from the Extractive Industries Transparency Initiative.

Congress should reverse this action and enact new legislation requiring reporting of governmental payments for resource extraction and production amounts and values on a lease-level basis. The public has a right to know what is being paid for the minerals they own and why. Without that information, the public is prevented from effectively participating in natural resource revenue decisions. The policy field is inevitably tilted in favor of oil and gas and other extraction companies to the detriment of the public interest.

Organizations interested in natural resource revenue policy should support this and other transparency measures on a priority basis. States should join in adopting their own improved transparency measures. The result would be to empower the public as the vital means to ensuring accountability by Interior for collecting the full and fair amount of royalties and other revenues for the American people.

Conclusion

For a hundred years, the federal government has shortchanged the American people, Indian tribes, and resource-dependent states and communities by failing to charge royalties at a rate that returns to the public full and fair value for the oil and gas deposits they own. Interior has neglected to evaluate and adjust royalty rates on a regular basis, even though they have an example set for them by state governments on how to do so.

Congress has provided insufficient and uneven oversight to federal minerals management. Worse yet, the federal government has kept secret from the American people information about what they are paid in revenues on each lease and the values and production used to calculate those revenues. The failure of Congress to conduct effective oversight and to provide the public with information necessary for effective participation in federal mineral policy discussions has contributed to the ongoing negligence that plagues the management of federal minerals.

Oil and gas production is rising to record levels in the United States, which means that if royalty rates are left the same, the public will lose even more of the revenue to which it is entitled. Past estimates of increased revenue from raising federal royalty rates are now likely too conservative. Rising production makes it all the more urgent that the federal government increase its rates to a level comparable to state rates.

Beyond that initial increase, the federal government needs to engage in a systematic process of evaluating and adjusting federal mineral revenue policies on regular, diligent and determined basis. Most importantly, Congress needs to welcome the American people into the discussion of federal mineral policies and empower the public to participate through transparent information on the operation and outcomes of current policies. All of this and more are necessary to achieve fiscal justice, accountability and transparency for the American people with respect to the minerals that they own.

Dan R. Bucks is the former Montana Director of Revenue and former Executive Director of the Multistate Tax Commission. The Wilderness Society provided support for the preparation of the report. However, the analysis, judgments, and conclusions of this report are entirely those of the author.

Office Deputy Secretary David J. Hayes
United States Department of the Interior

June 11, 2009

REPORT TO SECRETARY KEN SALAZAR REGARDING THE POTENTIAL LEASING OF 77 PARCELS IN UTAH

On January 17, 2009, a federal district court enjoined the U.S. Department of the Interior from entering into oil and gas leases for 77 parcels in Utah that had been included in a December 19, 2008 auction. The court entered a temporary injunction against the sale of the parcels after concluding that plaintiffs had established "a likelihood of success on the merits" regarding their claims that the proposed lease sales violated the National Environmental Policy Act, the Federal Land Policy and Management Act and the National Historic Preservation Act.[1]

On February 6, 2009, Secretary Ken Salazar concluded that the issues raised by the court, along with other concerns that had been raised about the lease sale, merited a special review.[2] Accordingly, Secretary Salazar directed that the leases be withdrawn and bonus payments be returned to the bidders. He subsequently requested that Deputy Secretary David J. Hayes lead a Departmental team that would evaluate the December lease sale and make recommendations regarding the matter.

This report responds to Secretary Salazar's request. The report is based on a review of the administrative record that accompanied the auction of the 77 parcels; an inspection of the parcels in question via overflight or on-the-ground inspection; interviews of BLM, National Park Service (NPS), and other Interior Department officials who were involved in lease-related decision-making; a listening session with state and local officials and representatives, followed by a public town hall meeting for interested members of the public (held in Vernal, Utah on May 26); and conference calls with industry representatives and conservationists.[3]

The review's findings and recommendations are:

Findings

- The lease sale that BLM's Utah office conducted in the fall of 2008, which culminated in the December 19, 2008 auctioning of 116 parcels, including the 77 parcels that are the focus of this report, deviated in important respects from the normal leasing process:

    - The fall 2008 lease sale began in the customary fashion. On August 1, 2008, BLM informed representatives of the National Park Service of its intent to hold an oil and gas lease sale on November 18, 2008. It identified parcels that were proposed to be included in the sale, and requested input from the NPS "no later than September 5, 2008, in order to address your concerns prior to making a lease recommendation." In a parallel notice provided for BLM field office managers, BLM's State office indicated its intent to provide public notice of lands that would be offered for sale by October 3, 2008. The prior notice that BLM provided to the NPS regarding parcels that it proposed to include in a public lease sale conformed with long-standing BLM/NPS practice.[4] NPS responded to the August 1st pre-notification and provided timely input on the parcels that BLM identified as candidates for the fall oil and gas leasing sale.

    - After soliciting input on the proposed lease sale from the National Park Service, BLM decided to expand the lease sale and delay the public announcement of parcels that were being offered for leasing from October 3, 2008 to November 4, 2008. BLM did not provide the National Park Service its customary opportunity to provide input on the lease sale, even though BLM had decided to greatly expand the lease sale from the 79 parcels that had been suggested in the August 1, 2008 pre-notification to 241 parcels that were announced on November 4, 2008. Among the new parcels added without prior notice to NPS were a number of parcels in the immediate vicinity of three National Park units (Arches National Park; Canyonlands National Park; and Dinosaur National Monument).

    - A third party informed NPS of BLM's action two business days before BLM was scheduled to publicly announce on November 4, 2008 the expanded lease sale. Because it had not received prior notice and an opportunity to discuss the appropriateness of auctioning parcels next to units of the National Park system, NPS requested that BLM defer the late-added parcels from the lease sale until the next quarterly sale so that NPS could have a full opportunity to review and comment on the proposed lease sales. BLM refused to do so.

    - After strong public concern was expressed regarding the proposed sale of many parcels near National Park units for oil and gas development, BLM provided NPS with a belated opportunity to request that parcels be removed from the auction that already had been publicly announced for sale.

- After a short but intensive period of negotiations, BLM agreed to remove parcels that were most objectionable to NPS due to their immediate proximity to Park boundaries.[5] NPS remained concerned about other parcels near the Parks with regard to their potential impacts on viewscapes, soundscapes and regional air quality, but NPS acquiesced with the BLM auction going forward so long as:

  - BLM would recommit in writing to BLM's historic consultation practices with NPS and, in addition, that BLM would provide NPS with advanced notice and an opportunity to consult before allowing exemptions, modifications or waivers to original lease terms.
  - BLM would meet with NPS and develop a plan to address how to address air quality models and "to identify viable modeling/analysis options." NPS made this request because ozone concentrations at Canyonlands National Park "are within about 90% of the current 8-hour ozone National Ambient Air Quality Standard (NAAQS) and may well exceed a new 8-hour standard the Environmental Protection Agency has proposed even without new sources of emissions."[6] (It also should be noted that the U.S. Environmental Protection Agency had expressed concerns to BLM regarding the need for quantitative air quality information regarding oil and gas leasing activity in the region.[7])

- BLM's Utah State Office and NPS' Intermountain Regional Office subsequently entered into a Memorandum of Understanding on May 13, 2009 which memorialized BLM's historic consultation practices with NPS and BLM's commitment to provide NPS with advanced notice and an opportunity to consult before allowing exemptions, modifications or waivers to original lease terms.[8]

- With regard to the air quality issues raised by NPS:

  - On January 15, 2009, a few days before leaving office, Bush Administration appointees representing BLM and the United States Forest Service executed a Memorandum of Understanding which asserted that quantitative air quality analysis would not be "appropriate" when making oil and gas planning decisions, or when undertaking "low-level energy development activity."[9]

  - On February 11, 2009, BLM and NPS officials engaged in a professionally facilitated meeting to address NPS's request to develop a plan for addressing air quality issues in the airsheds surrounding the three National Park units potentially impacted by oil and gas leasing activities. The facilitator described the talks as ending in an "impasse"; no agreement was reached between BLM and NPS regarding whether and/or how to undertake quantitative air quality analysis to cover oil and gas leasing activity in the region.[10]

- Because NPS's jurisdiction is tied to its National Park units, NPS did not address parcels that were proposed for sale and were not in the vicinity of one of its parks. Some of the 77 parcels that were subject to the court's injunction are near other unique and sensitive landscapes, including Nine Mile Canyon, an area that is world renown for its sophisticated, extensive, and potentially fragile rock art, and Desolation Canyon, a deep river canyon that is upstream of the Grand Canyon and one that rivals its beauty.[11]

- The lands associated with the 77 leases in question are covered by three Resource Management Plans ("RMPs") that BLM signed on October 31, 2008, only 4 days before the lease sale was noticed to the public. These RMPs are general planning documents that cover several million acres of public lands in BLM's Moab, Vernal and Price districts (the three RMPs are hereinafter referred to as the "Utah RMPs"). The Utah RMPs had been developed over a period of several years. They include the following features:

    - As a general matter, the Utah RMPs exclude a relatively small proportion of potentially available BLM lands from oil and gas drilling. By way of example, the Utah RMPs provide BLM with the discretion to lease the large majority of lands that it identified as having "wilderness characteristics" for oil and gas development.[12] Likewise, the Utah RMPs provide BLM with the discretion to allow oil and gas development on parcels in the immediate proximity of National Park units and a number of other sensitive landscapes, including lands that have wilderness characteristics, and lands that have other values that may not be consistent with oil and gas development (e.g., hiking, biking, river rafting and other recreational activity that is prevalent in the region). The RMPs identify a menu of potential stipulations that BLM can append to leases to mitigate the environmental impacts associated with oil and gas development of the land.

    - The Utah RMPs are high level planning documents; they do not provide BLM officials with guidance on whether individual parcels should be made available for oil and gas development when such parcels are near National Park units and other sensitive landscapes or when such parcels have wilderness characteristics or other values that may not be consistent with oil and gas development. Guidance from BLM is necessary, given the strong competing values that BLM officials must take into account when making leasing decisions for individual parcels in eastern and southern Utah. The unique canyons and mesas that dominate the landscape in this region and Utah's "red rock" areas are among America's most treasured landscapes.[13] Illustrating the point, Arches National Park attracts more than one million visitors a year, and it is estimated that BLM lands in the vicinity of Arches National Park and Canyonlands National Park attract more than two million recreational visitors per year. On the other hand, extensive oil and gas and related infrastructure development is taking place in some other areas covered by the Utah RMPs. In particular, intensive oil and gas development is occurring in the Uinta Basin, which is primarily covered by the Vernal RMP.

- The Utah RMPs do not model existing air quality in the region or attempt to aggregate, in a quantitative way, the impacts that additional oil and gas leasing may have on air quality in the region. As manifested in the Memorandum of Understanding that was signed by political appointees on January 15, 2009, BLM takes the position that quantitative air quality impacts need not be evaluated until operators request permission to initiate development on specific parcels or, in some cases, when operators develop a concentrated plan of development for a given area. However, individual drilling activities often are exempt from air permitting requirements. BLM does not have a mechanism for evaluating the impact of oil and gas development on air quality in the region, despite the fact that air quality levels for some health-based parameters, such as ozone, are marginal and may be deteriorating.

Recommendations

1. Communication and Cooperation Needs To Be Improved Between BLM and the National Park Service and Other Stakeholders Regarding Leasing Decisions

BLM's decision to auction off oil and gas development rights on lands that are immediately adjacent to some of our nation's most visited and treasured national parks reflects a failure in communication and cooperation between BLM and the National Park Service. Although BLM responded and came to the negotiating table when the National Park Service and the public heavily criticized BLM's decision to lease parcels for oil and gas development on the doorstep of some of Utah's most beautiful national parks, it should not take a public relations melt-down to trigger a meaningful dialogue between the two agencies. Better communication and cooperation is needed between BLM-Utah and Park units in the Intermountain Region. BLM should improve its understanding of the importance of Park values that would be implicated by oil and gas drilling activity occurring alongside the border of and in proximity to a National Park or Monument. This standard should equally apply to BLM managed units of the National Landscape and Conservation System (NCLS). And for its part, it is important that the Park Service understand the need for BLM to evaluate potential multiple uses of BLM lands, in accordance with the Federal Land Policy and Management Act.

Likewise, BLM should seek better communication and cooperation with other stakeholders who have concerns regarding decisions to allow oil and gas development on other sensitive landscapes that have unique values, but which are not near a National Park or Monument, such as Nine Mile Canyon and Desolation Canyon. BLM has its own inherent stewardship responsibilities that should inform its decision-making when evaluating whether to allow commercial development of BLM lands in or near sensitive, treasured landscapes. BLM officials also should be attentive to the input of other stakeholders who seek to protect such lands because of the competing values they represent – whether it be wilderness characteristics associated with the lands, competing recreational interests, or other values.

Some observers may point out that the process of putting together the areas' Resource Management Plans should have provided the opportunity to foster communication and cooperation between BLM and other interested agencies and stakeholders. Because RMPs are high level planning documents, however, they do not make individual leasing decisions for specific parcels; those must be made on a case-by-case basis. As a result, the type of communication and input needed between BLM and the National Park Service regarding potential oil and gas leasing next to National Park units did not occur in the RMP process.

The Utah RMPs illustrate this point. They adopted a broad planning level presumption that the large majority of available BLM lands should potentially be made available for oil and gas development, including lands with wilderness characteristics and lands immediately adjacent to the National Parks. But they did not focus on how BLM officials should weigh competing considerations when deciding, for example, whether to offer or defer a request to nominate a parcel adjacent to Arches National Park or in a wilderness quality area for potential oil and gas development.

Thus, while some proponents argue that the RMP process provided all of the input needed to make individual leasing decisions, that is clearly not the case. Decisions whether to offer specific parcels for oil and gas development must be made on a case-by-case basis, taking into account competing resource values and site-specific circumstances. This decision will be better informed if important stakeholders such as the National Park Service, the State, industry representatives, and other interested organizations are provided a meaningful opportunity for input and dialogue before parcels are announced for public sale. That did not occur here. The new MOU between BLM and NPS should help avoid a repeat of this situation, but we recommend that BLM consider more systematic and bureau-wide initiatives for improving communication and cooperation with important stakeholders when considering what parcels might be offered in potential lease sales.

2. BLM Should Develop Guidance to Assist BLM Officials In Making Parcel-Specific Leasing Decisions

As noted above, BLM has not identified the criteria that BLM officials should apply when deciding whether individual parcels should be made available for oil and gas development. The proximity of such parcels to National Park units, NLCS units and other sensitive landscapes, the fact that parcels may have wilderness characteristics or other values that may not be consistent with oil and gas development, and the relative intensity of existing investments in the immediate area of proposed leasing, including oil and gas drilling activities and related infrastructure, are factors that presumably should have a bearing on leasing decisions for individual parcels.

BLM should develop and issue decision-making criteria that fills this important void and provides a rational basis to better assist BLM officials on how they should weigh competing considerations when deciding whether an individual parcel that is available for leasing as a general matter (e.g, where an RMP would otherwise allow leasing of the parcel in question) should, in fact, be leased and for what purpose(s), given site-specific considerations.[14] The factors that are relevant to individual leasing decisions, such as proximity to special landscapes (including, but not limited to, parks), to wilderness qualities, and to the presence of existing development and infrastructure, among other factors, should be identified by such guidance. New BLM guidance should then suggest approaches for weighing such factors in the decision-making process.

3. It May Be Appropriate to Reinstate Some of the 77 Parcels; Others Should Not Be Leased for Oil and Gas Development

As noted above, site-specific considerations can and should have an important bearing on whether individual leases should be offered for oil and gas development in the context of expansive RMPs, such as those involved here. Because BLM has not developed guidance regarding how site-specific factors should be weighed in determining whether specific parcels should be offered for oil and gas development, managed to protect their wilderness values, or opened up for recreational purposes, the preparers of this report are not in a position to make final determinations regarding the ultimate disposition of the 77 parcels in question.

To address this need, we recommend that the acting BLM Director appoint a multi-disciplinary team of experienced BLM officials who have not been involved in decision-making regarding the 77 parcels in question to make site-specific decisions on whether to reinstate any of the 77 parcels.[15] The BLM team should do its work expeditiously; companies who successfully bid on specific parcels should receive timely feedback on whether they will be able to develop those parcels. In proceeding with this exercise, the BLM team should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

After conducting this evaluation, the BLM team should determine whether: (1) the parcels should be reoffered to the original bidders under the same conditions as previously specified (in which case the winning bidders should have the opportunity to repay their bonus payments and move toward execution of their leases); (2) the parcels should be reoffered for oil and gas development, but under different terms than had been specified in the original offering (in which case the parcels should be subjected to a new auction process); or (3) the parcels should be deferred from leasing.

In connection with the BLM team's review of the 77 parcels, the review team has identified several groupings of parcels that are relevant:

<u>14 Parcels Located Within Already Existing Gas Development And Infrastructure Areas</u>

A set of 14 parcels are located near current production areas that are largely already dedicated to oil and gas development, and which have existing infrastructure to facilitate such development. These factors suggest that reinstatement of the sale of these leases may be appropriate. The BLM team should seek to confirm, on a site-by-site basis, that the stipulations associated with each parcel are adequate, given the specific topographical and locational characteristics of each parcel. As noted above, the BLM team also should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

These parcels are located as follows:

- Central Uinta Basin: parcels 90, 91, 93, 94, 96, 97, 98, 112, 115, 116.

- Southern Uinta Basin: parcels 209, 210, 211, 212.

<u>16 Parcels Located Within More Limited Development Areas</u>

A second set of 16 parcels is located where the intensity of existing production is more limited. The parcels in this second grouping, however, are not near particularly sensitive landscapes and they do not appear to trigger strong concerns regarding recreation or other alternative uses. These factors suggest that reinstatement of the sale of these leases may be appropriate. The BLM team should seek to confirm, on a site-by-site basis, that the stipulations associated with each parcel are adequate, given the specific topographical and locational characteristics of each parcel. As noted above, the BLM team also should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

These parcels are located as follows:

- East of Green River, UT: parcels 159, 187.

- Southeast of Green River, UT: parcels 162, 163, 164, 166, 167, 168, 169, 170, 171, 175.

- South of Green River, UT: parcels 361, 368, 369, 370.

<u>47 Parcels Requiring More Detailed Site-Specific Analysis</u>

The remaining 47 parcels require more detailed site-specific analysis. These parcels fall within three broad categories.

The first category includes parcels that are near two sensitive landscapes that have special cultural and physical attributes: Nine Mile Canyon and Desolation Canyon. Some oil and gas development is beginning to occur in these areas, and parts of the areas are subject to on-going environmental reviews. With regard to Nine Mile Canyon, however, concerns have been raised regarding potential impacts that existing and potential future development on mesas above Nine Mile Canyon may have on the cultural resources in the canyon and on other values associated with the canyon. (BLM has designated Nine Mile Canyon as an "ACEC": an Area of Critical Environmental Concern.) Likewise, Desolation Canyon is a world-class river canyon that has outstanding natural landscape characteristics. Significant acreage in the Desolation Canyon area has been classified as a Wilderness Study Area that is off-limits to oil and gas development.

Additional oil and gas development potentially may be appropriate in both of these areas, but given the special nature of the resources in and around Nine Mile Canyon and Desolation Canyon, a careful, site-specific examination by a the multi-disciplinary BLM team should be undertaken. The BLM team should seek to confirm, on a site-by-site basis, that the stipulations associated with each parcel are adequate, given the specific topographical and locational characteristics of each parcel. The BLM team also should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

The parcels are located as follows:

- Desolation Canyon: parcels 86, 87, 335, 337, 338, 339, 340, 341, 342, 343, 345, 348, 349, 350, 355.

- Nine Mile Canyon: parcels 83, 328, 330, 331, 332.

The second category of the 47 parcels includes six parcels that are in or adjacent to White River Canyon. White River Canyon is a unique landscape. It is located in the highly productive Uinta Basin. Some of the mesas above the canyon have been leased and developed. Additional gas development in the area potentially is appropriate, particularly if new wells can be drilled on already-existing drilling pads, but given the special nature of the White River Canyon area, a careful, site-specific examination by the multi-disciplinary BLM team is appropriate, with special attention given to the stipulations proposed for each parcel. (A number of the parcels have "no surface occupancy" restrictions which would mitigate impacts to the canyon.) In addition, the BLM team should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

The parcels are located as follows:

- White River Canyon: parcels 106, 109, 110, 111, 136, 137.

The third category of the 47 parcels includes parcels that are in the Moab region, in an area of limited existing oil and gas development, of potentially high recreational values, and within a ten mile radius of Arches National Park or Canyonlands National Park. As explained below, while we do not believe that all leasing activity should be delayed pending the completion of the air quality analyses that are recommended below, parcels that are close to national parks or monuments (the parcels here are in a band that is only 5 to 10 miles from these national park units) should receive heightened scrutiny because their development could more immediately impact air quality in the nearby parks.

The sole additional parcel is in the northern portion of the Vernal area, adjacent to Dinosaur National Monument. Although that parcel is on land that already has been disturbed, there is very limited oil and gas development in the area and the immediacy of the parcel to the National Monument recommends it for a more deliberative review by the BLM team.

The BLM team also should review protests that have been lodged against each of the parcels in question and address those protests when making its final decisions.

To summarize, the parcels that fall into this category include:

- West of Arches National Park: parcels 174, 176, 177, 180, 181, 182, 183, 184, 185, 186, 196, 197.

- East of Arches National Park: parcel 242.

- East of Canyonlands National Park: parcels 201, 202, 203, 205, 206, 207, 208.

- West of Dinosaur National Monument: parcel 101.

4. Air Quality Analysis

The National Park Service's and the Environmental Protection Agency's concerns about the lack of robust quantitative air quality data and analysis regarding baseline conditions, and the potential contributions that additional oil and gas development may have on air quality in the region, appear to be well-founded. While some analyses of air quality issues have been undertaken in the areas covered by the Utah RMPs and others are underway, attention to the issue remains both limited and fragmented.

We recommend that BLM move forward with a comprehensive air quality strategy for the region, in consultation with the National Park Service, the Environmental Protection Agency, and state officials. The comprehensive strategy should include:

- An analysis of whether and, if so what, additional monitoring is needed in the Utah RMP areas to adequately characterize air quality in the region for key parameters.

- A plan to install and maintain any additional monitoring stations, in cooperation with other agencies and interested stakeholders.
- The initiation of a programmatic air quality environmental impact statement that will analyze current air quality in the Utah RMP areas, and will model the impacts that alternative development scenarios may have on air quality in the areas. Questions regarding the geographic area or areas that should be the subject of such programmatic analyses should be determined through the EIS scoping process.

We recognize that the court relied on the absence of quantitative air modeling in granting a temporary restraining order against execution of the 77 parcels at issue here. The court acted in the context of BLM's unwillingness to make any commitment to undertake quantitative air quality analyses for any leasing activity. As noted above, this report is recommending that BLM initiate a comprehensive air quality analysis for the region. As the BLM team reviews individual leasing decisions, it should evaluate whether the approval of some of the leases for oil and gas development can go forward without waiting for the completion of the comprehensive air analysis. Factors that may be relevant in that regard include whether the parcels are in areas where extensive oil and gas production already is occurring; the nature of the stipulations attached to leases which may minimize air impacts; the proximity of the parcels to areas that may be most sensitive to potential air impacts (e.g., Nine Mile Canyon, Desolation Canyon, and the three National Park units); and the availability of relevant air quality analysis pertaining to the areas in question. (In that regard, we understand that some air quality analytical work is underway in connection with the West Tavaputs EIS process; it may have relevance to the air quality questions associated with Nine Mile Canyon and Desolation Canyon. Also, we understand that an industry-sponsored Uinta Basin study is nearing completion; it also may have some relevance to some of the parcels).

Endnotes

1 More specifically, the court concluded that "[b]y not engaging in quantitative ozone dispersion modeling," BLM was "unable to assess the concentration of pollution in the air and therefore cannot adequately measure those pollutants which are expressed in ambient concentrations." The court continued: "Thus, the plaintiffs have made the requisite likelihood of success showing as to their NEPA claim . . . BLM cannot rely on EISs that lack air pollution and ozone level statistics." Similarly, the court determined that plaintiffs made a showing of success on the merits for their National Historic Preservation Act and Federal Land Policy and Management Act)(FLMPA) claims because BLM's failure to take into account the effect of air pollution on areas outside of Nine Mile Canyon made it unable to determine if the lease sale had the potential "to cause effects on historic properties."

2 As explained in the Secretary's February 6 memorandum to the BLM State Director: "There has been considerable controversy surrounding this lease sale, including questions about the degree of coordination between the BLM and other Federal agencies, including the National Park Service, and the adequacy of the environmental review and analysis performed in connection with certain parcels as well as the underlying Resource Management Plans. On January 17, 2009, a Federal district court issued a Temporary Restraining Order enjoining issuance of oil and gas leases for 77 of the parcels offered. Given the concerns raised about the adequacy of the consideration given to important values many members of the public associate with these 77 parcels, such as sensitive landscapes and cultural resources, and my belief that the issues raised merit further review, I am directing you to withdraw the 77 parcels that were

covered by the January 17, 2009, Temporary Restraining Order from further consideration in this lease sale."

3 In addition to Deputy Secretary Hayes, the review team included Acting BLM Director Mike Pool and Acting National Park Service Director Dan Wenk. Messrs. Pool and Wenk contributed to the findings and recommendations, but Mr. Hayes, as the team leader, has adopted the findings and recommendations as his own.

4 This practice had been memorialized in a Memorandum of Understanding executed in 1993. The MOU had expired, but the practice continued to be followed on a routine basis, as illustrated by the August pre-notification of the proposed fall lease sale.

5 *See* Attachment A (the attached maps show, in blue, the parcels adjacent to the National Park units that were publicly announced for auction, but which were removed prior to the auction after NPS strongly objected and public attention was drawn to proposed oil and gas development immediately adjacent to the parks).

6 *See generally* Attachment B (Memorandum from Regional Director, Intermountain Region, NPS to Director, Utah State Office, BLM (Nov. 25, 2008)).

7 *See* Attachment C.

8 *See* Attachment D.

9 *See* Attachment E.

10 The facilitator's report on the February 11, 2009 meeting is not attached; it is captioned as "protected from disclosure: deliberative process, attorney-client communication."

11 See Attachment F (map depicting the location of the 77 parcels at issue).

12 The Moab RMP identified 266,471 acres as having wilderness characteristics, but it did not "select" the large majority of that acreage (218,724) to be managed for their wilderness characteristics. *See* Moab RMP at page 28. Likewise, the Vernal RMP identified 277,596 acres as having wilderness characteristics, but it did not select the majority of that acreage (171,418 acres) to be managed for their wilderness characteristics. The Price RMP identified 937,440 acres as having wilderness characteristics, but it did not select the large majority of that acreage (840,330 acres) to be managed for their wilderness characteristics.

13 A large number of protests are being lodged against leasing decisions in this area. By way of example, a significant concentration of protests have been lodged against proposed leases on BLM lands that are west of Arches National Park. Many of these lands have compelling landscape characteristics and are heavily used for recreational purposes.

14 The Mineral Leasing Act provides that all lands subject to the MLA "which are known or believed to contain oil or gas deposits *may* be leased by the Secretary [of the Interior]." 30 U.S.C. 226(a)(emphasis added). The Supreme Court has held that the MLA gives the Secretary broad discretion not to offer an oil and gas tract for leasing. *Udall v. Tallman*, 380 U.S. 1,4 (1965). More recently, the U.S. Court of Appeals for the Ninth Circuit has held that refusing to issue leases is a legitimate exercise of the Secretary's discretion under the MLA. *Bob Marshall Alliance v. Hodel*, 852 F.2d 1223, 123-40 (9th Cir. 1988). *See also Marathon Oil Co. v. Babbitt*, 966 F. Supp. 1024 (D. Colo. 1997), *aff'd*, 1999 U.S. App. LEXIS 123 (10th Cir.), The IBLA has expressly held that lands identified for oil and gas leasing in an RMP are open for permissible uses, and thus BLM has no duty to offer them for lease, even when BLM has received a pre-sale non-competitive offer to lease. *Richard D. Sawyer*, 160 IBLA 158, 163 (2003).

[15] We also are recommending that the acting Director of the National Park Service identify NPS officials who will be made available to work with the BLM team with regard to evaluating potential impacts that leasing activity may have on National Park units. As with the BLM team, these individuals should not have had prior involvement in this matter.

Office of
INSPECTOR GENERAL
U.S. Department of the Interior

Evaluation of Bureau of Land Management's Oil and Gas Lease Auction Process

Report No. CR-EV-BLM-0002-2009

August 2009

United States Department of the Interior

OFFICE OF INSPECTOR GENERAL
Washington, DC 20240

AUG 26 2009

Memorandum

To: Robert V. Abbey
Director, Bureau of Land Management

From: Mary L. Kendall Mary L. Kendall
Acting Inspector General

Subject: Evaluation Report of Bureau of Land Management's Oil and Gas Lease Auction Process (Report No. CR-EV-BLM-0002-2009)

This memorandum transmits our report detailing the results of our evaluation of the Bureau of Land Management's (BLM) oil and gas lease auction process. Our review was prompted by a highly publicized incident in which an individual who, in an act of environmental protest, disrupted a BLM lease auction by bidding for parcels without the intent or ability to pay for or develop the leases.

We focused on BLM's implemented and proposed revised measures to its lease auction process as a result of the incident and obtained information on other federal and state auction processes to identify practices that could improve or enhance BLM's lease auction process.

We found that BLM took swift action to initiate improvements to the lease auction process after the incident by drafting an Instruction Memorandum with new measures designed to reduce the likelihood of individuals participating in auctions without the intent to complete their purchase. Although the new measures should reduce the risks associated with bad-faith bidders, we are recommending additional steps to further minimize the risks of fraudulent bidders and improve the lease auction process.

We ask that you inform us of your course of action within 30 days. Should you have any questions about this report, please do not hesitate to contact me at 202-208-5745.

Attachment

cc: Assistant Secretary, Land and Minerals Management

Introduction

In December 2008, in an act of environmental protest, an individual exploited the Bureau of Land Management's (BLM) oil and gas lease auction program by bidding for parcels without the intent or ability to pay for or develop the leases. The individual won 14 parcels totaling $1.8 million in lease revenue.

In April 2009, the individual was indicted by a federal grand jury for violation of the Federal Onshore Oil and Gas Leasing Reform Act of 1987 for knowingly interfering with the competitive bidding process and knowingly making a false and fraudulent statement when he completed and signed a bidder registration form.

In response to the incident, we initiated an evaluation of BLM's lease auction process. We concentrated our efforts on three main areas:

- assessing BLM's implemented and proposed changes to the lease auction process as a result of the incident;
- reviewing BLM's Internet lease auction pilot program; and
- obtaining information on other federal and state auction processes to identify practices that could improve or enhance BLM's lease auction process.

We conducted our evaluation work in accordance with the Quality Standards for Inspections issued by the President's Council on Integrity and Efficiency.

Background

BLM's Oil and Gas Leasing Program

The Mineral Leasing Act of 1920 (MLA), as amended, authorizes leasing of federal lands for development of oil and gas resources. The MLA requires each BLM state office to conduct quarterly oil and gas lease sales by oral bidding where eligible lands are available. It also establishes the minimum bonus bid[1] of $2 per acre. Parcels unsold at the oral auctions are available noncompetitively starting the day after the sale.

The Code of Federal Regulations (43 C.F.R. § 3120.5-2) requires winning bidders to pay the first year's rental ($1.50 per acre), a processing fee ($140), and the minimum bonus bid ($2 per acre) the day of the lease sale. Any additional bonus over the $2 per acre is due within 10 working days of the sale; failure to make this payment will result in the forfeiture of the

[1] Bonus bid refers to the minimum bid amount of $2 an acre and any amounts bid over the $2.

initial deposit and rejection of the bid. The only requirements outlined in the CFR for bidder qualification are that the bidder must be a U.S. citizen or an alien stockholder in a corporation organized under state or federal law, and 18 years of age or older.

The oral lease auction represents a small fraction of the entire leasing process, described in Appendix 1. BLM's Division of Fluid Minerals manages the leasing program at the national level, providing guidance to its state offices. BLM's "Oil and Gas Adjudication Handbook - Competitive Leases" (H-3120-1) is the written guidance for conducting the lease sales.

BLM has received nearly $1.2 billion dollars in bonus bid revenue from the sale of over 14,000 leases from 2004 through 2008.[2] The majority of leases and the resulting revenue come from the western states of New Mexico, Wyoming, Colorado, Utah, and Montana.

WHAT WE FOUND

• • •

*For the purpose of this evaluation, individuals or companies defaulting on winning bids are referred to as **bid-walkers** and separated into two categories: bad-faith and non-paying bidders.*

*An individual or company that bids with ulterior motives and no intention of paying, exemplifies a **bad-faith bidder**.*

*A **non-paying bidder** is an individual or company that defaults without malfeasance; the most prevalent reason cited was insufficient funds.*

The effect of both bad-faith and non-paying bidders is the disruption of the lease auction process.

• • •

We found that BLM did not view bid-walkers as a significant threat to the lease auction program and had few deterrents in place to limit the risk of occurrence. BLM's lease auctions are designed to maximize bidder participation by providing easy access for prospective bidders. This open process results in a higher risk that individuals with hidden agendas may participate in the auction and cause disruption.

According to BLM's records, in the last 5 years, there were 35 bid-walkers who defaulted on 152 of the approximately 14,000 parcels sold. We estimated the monetary loss[3] to be $3.4 million which is less than 1 percent of the nearly $1.2 billion in lease auction revenue. Non-monetary considerations associated with bid-walkers include delays in issuing federal leases and in developing the Nation's energy resources, fairness to other bidding parties, and disruption of BLM's lease auction process.

To date, the occurrence of bad-faith bidders has been rare, with only two known cases in the last 5 years. However, there is growing concern that lease auctions may become a forum for future protests due to the publicity of the Utah incident.

[2] Alaska is governed by different laws and therefore excluded from the statistics.

[3] Monetary impact to BLM reflects bonus bid revenue lost or gained upon resale and the loss of rental revenue.

We found that prior to the Utah incident BLM did not have adequate measures to deter bid-walkers from disrupting oil and gas lease auctions. Specifically:

- BLM did not publicize that there are criminal and civil penalties associated with the fraudulent actions of a bidder.

- BLM did not clarify the liability incurred by the winning bidder for the monies due the day of sale.

- BLM did not have a policy requiring verification of identification for lease bidders.

- BLM did not have a formalized billing and collection process for bid-walkers. BLM state offices were inconsistent in their efforts to collect unpaid amounts due on the day of sale.

- Some BLM state officials were not familiar with the BLM Handbook requirement to ban potential bidders who defaulted three times in a single state. Also, the Handbook was unclear about whether the three defaults were represented by parcels or by lease sales. We identified instances in which bidders were allowed to participate in subsequent sales after defaulting on more than three parcels.

- BLM did not track bid-walkers and, thus, did not implement the bid-walker ban as required in its Handbook.

BLM Actions to Improve the Process

The Utah incident set in motion BLM's internal assessment of its auction process and controls. BLM's Division of Fluid Minerals drafted an Instruction Memorandum (IM), "Measures to Better Safeguard Competitive Oil and Gas Lease Auctions," planned to be issued this summer. The draft IM includes the following short-term measures.

- Requires BLM to centrally track bid-walkers and distribute reports to BLM state offices prior to lease sales.

- Requires changes to the pre-sale lease auction process to include: (1) verification of a government issued identification for all bidders, (2) prevention of persons or companies with an outstanding balance from registering to bid, and (3) clarification of the debt created by a winning bid in the opening oral remarks at lease auctions.

- Requires changes to the post-sale process including: (1) issuing a bill through BLM's Collection and Billing System to those individuals or companies that do not pay the amount of money due the day of the sale and (2) mandating rejection of any bid for which any payment is not paid as required.

- Amends the Bidder Registration Form and the Notice of Competitive Oil and Gas Lease Sale to incorporate the changes above and to inform bidders of their responsibilities.

During the course of our evaluation, BLM state offices were directed by the Division of Fluid Minerals to immediately implement the provisions in the draft IM.

Although the above actions should reduce the risks associated with bid-walkers, the IM did not emphasize the criminal penalties associated with bad-faith bidding by specifically citing imprisonment and fines, or include the citation and the language from 30 U.S.C. Section 195(a) and (b) in the Bidder Registration Form and the Notice of Competitive Oil and Gas Lease Sale. This Section makes it unlawful to organize or participate in any scheme to defeat provisions of the mineral leasing regulations punishable by a fine of not more than $500,000, imprisonment of not more than 5 years, or both. Also, the IM did not contain provisions for banning repetitive bid-walkers.

Furthermore, the IM does not provide the detailed procedures required to effectively implement the short term measures. In order for the IM to be effective, specific procedures need to be developed and distributed throughout the Bureau, thereby providing guidance to the field and consistency in implementation. For example, the IM does not specify acceptable forms of government issued identification and does not define the roles and responsibilities related to the distribution and maintenance of the list of non-responsible persons or companies.

In BLM's deliberation of proposed controls, requiring proof of financial capacity was considered, but not included as a proposed measure. BLM cited staffing constraints and costs exceeding the benefits as reasons for not implementing proof of financial capacity. We agree that requiring proof of financial capacity may not be warranted at this time; however, it may need to be considered in the future if the occurrence of bid-walkers increases.

The draft IM clarifies that a winning bid creates a debt to the U.S. for the amount due the day of sale. BLM plans to recommend to the Department a proposed regulation to clearly establish that a winning bid creates a debt for the *entire* amount of the bonus bid. This requirement would not only increase the level of commitment required of bidders, but also the penalty for defaulting, thereby further reducing the risk of bid-walkers.

INTERNET AUCTION PROCESS

In the Fiscal Year 2008 Consolidated Appropriations Act, Congress directed BLM to pilot an Internet lease auction as an alternative to the oral auctions required by the MLA. BLM's Colorado State Office was selected as the location for the pilot. In September 2009, 38 parcels will be available for bid on BLM's Oil and Gas Lease Internet Auction Pilot System.

Bidders will be allowed to pre-register from 60 days before the auction to the day of auction. Potential bidders will have to submit a credit card to validate identity only. A deposit or credit card authorization will not be required.

The Internet leasing auction presents potential benefits such as increased bidder participation and accessibility; savings to bidders; electronic verification of disqualified bidders; additional identification and financial verification through pre-registration and pre-certification; the potential for nationwide bidding instead of individual state auctions; and the capture of lease auction data for analysis, planning, and reporting.

The Internet leasing auction, however, also presents new risks. For example, this method allows for potential anonymous participation in the auction process increasing the risk of fraudulent bidding. Even though a credit card will be required for bidders to pre-register in order to verify identity, it would not preclude an individual from using a stolen or unauthorized credit card. As with any Internet accessible system, the risk for cyber attacks also exists. BLM reports that the pilot system will comply with all aspects of the National Institute of Standards and Technology's Special Publications and Certification and Accreditation of Federal Information Systems. We did not attempt to validate this assertion.

The Internet leasing auction is a promising prospect for BLM in the evolution of its oil and gas leasing process. For BLM to fully implement the Internet leasing auction concept, however, Congress will need to amend the MLA to eliminate the requirement for oral auctions.

AUCTION PROCESS COMPARISON

We obtained information on other federal and state lease programs to identify promising auction practices and bidding methods. We reviewed state oil and gas lease auction programs that were similar to BLM's. Specifically, we selected New Mexico, Colorado, and Wyoming. We also considered other programs that conduct auctions of natural resources or other products including BLM's timber, coal, and geothermal programs; Minerals Management Service's (MMS) Offshore Energy and Minerals Management (MMS-OEMM) oil and gas program; Federal Communications Commission (FCC); and MMS' Royalty-In-Kind (RIK) program (for pre-qualification only). See Appendix 2 for a summary of the leasing practices identified.

The following are several processes identified that are different from BLM's current lease auction program:

- **Sealed Bidding.** The State of New Mexico, MMS-OEMM, BLM Alaska, and BLM coal and timber programs use the sealed bid method. A representative from the State of New Mexico said that the bonus income generated is higher than when holding an oral auction. All the agencies above required a certain percentage of the bid as an upfront bid deposit. Due to the oral auction requirements in the MLA, BLM is not currently allowed to auction parcels with this method.

- **Pre-registration.** MMS-OEMM requires a certified statement indicating the state in which the company is registered, if it is authorized to hold a mineral lease, and a list of authorized officers in order to submit bids. Once approved, MMS will issue a qualification approval letter containing a unique MMS qualification number that can be used on all future lease auction sales. FCC also requires pre-registration of potential bidders.

- **Internet Auction.** Internet-based auctions offer the potential for increased participation given the ease of accessibility. The FCC is the only agency we found conducting auctions via the Internet. BLM has initiated a pilot program to develop and test the feasibility of conducting future auctions via the Internet.

- **Bid-walker Ban.** The State of Wyoming will ban a bid-walker from auction participation for 1 year. If the party participates after 1 year, Wyoming will require full payment with certified funds the day of the sale. Although Wyoming has an auction law allowing it to sue for the money due, a Wyoming official stated that barring the bidder has a greater, immediate impact.

- **Amount Due on the Day of the Sale.** The States of New Mexico and Colorado require full payment the day of the sale. Increasing the amount due on the day of sale is more consistent with similar oil and gas leasing programs. This also increases the penalty for those individuals or companies who default on winning bids.

- **Bid Deposits.** MMS-OEMM, BLM coal, BLM Alaska, and the State of New Mexico require partial or full payment of the bonus bid with the submission of the bid. These organizations all conduct sealed or written bid auctions. None of the oral auctions reviewed required a bid deposit.

- **Pre-qualify Bidders.** RIK and FCC are the only organizations we identified that verified financial capacity prior to the lease auction. The FCC expends a large effort in pre-qualifying bidders to determine the bidder's financial capacity. FCC and RIK pre-qualification, and the absence of such requirements in oil and gas leasing programs, suggests that pre-qualification may be more appropriate for more expensive lease acquisitions. BLM onshore lease parcels can be as small as 40 acres, for which a bidder can acquire the lease for a minimum of $280.

- **Oral Auction Initiated with Written Bid.** BLM timber auction sales require the bidders to complete a written bid and submit a certified funds deposit of 10 percent of the written bid. The written bid has to be at least the minimum amount established by BLM. The oral auction begins with the highest written bid. The highest oral bidder will be the successful bidder.

Through our evaluation, we concluded that other auction methods such as sealed bids and Internet-based, could provide BLM some benefits such as increased revenues or streamlined processes. BLM is precluded, however, from employing alternative auction methods until the oral requirement is removed from the MLA.

Implementing BLM's short term measures outlined in the IM, as well as our recommendations outlined below, may not completely eliminate bid-walkers, but will add extra levels of control to minimize the risk of occurrence.

The possibility for increased bad-faith participants in BLM's lease auction process may be affected by the outcome of the pending prosecution of the individual in Utah. If the individual is convicted, the severity of the penalties associated with that conviction will be crucial to reinforcing the implemented measures and serve as a major deterrent to future bad-faith bidders. If he is acquitted, the absence of consequences for such actions may encourage similar incidents such as the one in Utah and require BLM to reassess its controls.

RECOMMENDATIONS

We recommend the Director, BLM:

1. Amend the Draft IM to include the following provisions:

    a) Emphasize the criminal penalties associated with the statutes cited in the Bidder Registration Form and the Notice of Competitive Oil and Gas Lease Sale by specifically stating prison and monetary penalties.

    b) Include the citation and the language from 30 U.S.C. Section 195(a) and (b) in the Bidder Registration Form and the Notice of Competitive Oil and Gas Lease Sale which makes it unlawful to organize or participate in any scheme to defeat provisions of the mineral leasing regulations punishable by a fine of not more than $500,000, imprisonment of not more than 5 years, or both.

    c) Establish a nationwide ban that prohibits a person or company from all lease sales after repetitive defaults. This would expand the existing statewide ban included in the BLM Handbook (H-3120-1, Competitive Leases) which states, "Any entity who forfeits the right of issuance of a lease (failure to submit the remaining monies due) totaling three times in the _(Name)_ State Office, shall be prohibited from bidding at any future sale in this State." In developing a ban policy, BLM should (1) clarify in its nationwide ban whether three defaults represents sales or parcels; (2) expand the ban to include default on monies due the day of sale; and (3) consider a ban for a certain period of time for a single default, such as the State of Wyoming's 1 year bid-walker ban.

2. Develop and distribute supplemental guidance on implementing the IM throughout the Bureau and update the BLM Handbook (H-3120-1, Competitive Leases) to incorporate the new guidance as soon as possible.

3. If BLM does not implement the policy to make the entire bonus bid a debt to the U.S., BLM should increase the amount due on the day of sale from $2 per acre to a specified percentage (e.g. 20 percent) of the bonus bid to be determined by BLM.

4. Conduct an analysis to determine which auction process is best suited for oil and gas leases including oral, sealed, and Internet bidding.

5. Work with Congress to revise or amend the Mineral Leasing Act of 1920 to eliminate the requirement for quarterly oral auctions and allow for alternative auction processes, e.g., sealed bid or Internet.

BLM Oil and Gas Lease Auction Process

Expressions of Interest
Parcels are nominated to state BLM offices for lease consideration.

EXPRESSIONS OF INTEREST: Parcels can be nominated from expressions of interest by private entities or by BLM under special conditions. Also, parcels can be reintroduced from deferred lands list (parcels put on hold pending further evaluation for compliance with Resource Management Plan (RMP) or ongoing protest).

Adjudication
BLM identifies if parcels are available based on current RMP – forwarded to Field Offices for DNA.

ADJUDICATION: The BLM state office identifies the parcel is available for leasing based on the RMP in place. Potential parcels are forwarded to respective field offices for review by an interdisciplinary team, including the surface management agency. Field office issues a recommendation for leasing and DNA (Determination of NEPA Adequacy).

Preparation of BLM Sales Notice
Proposed list issued 45 days prior to sale. Initiates the 30 day protest period. Allows 2 weeks to review protests. Addendums are issued for changes to the parcels to be offered at the lease auction.

PREPARATION: BLM state offices review recommendations from field offices and notes the stipulations recommended for each parcel. A list of proposed parcels is developed 45 days prior to the scheduled lease sale. This allows the requisite time to allow protests and resolve any issues. Addendums are regularly issued to inform bidders of changes leading up to the auction. Unresolved protests may result in deferring the parcels for future potential sale (deferred lands list).

Lease Sale
Bidders register for lease sale. Oral auction held to sell available leases. Winning bidders make required payment by close of business – additional bonus paid within 10 business days. Leases not awarded available non-competitively.

LEASE SALE: Lease sales are conducted orally on a quarterly schedule as required by statutes. Bidders must be American citizens of legal age (18) to bid on leases. A bidder registration form is used to identify eligible bidders at lease auction - there are no financial requirements. Winning bidders must submit payment for minimum bonus ($2 per acre), 1st year's rental, and $140 administrative fee the day of the sale. Additional bonus payment is due within 10 business days. Leases not awarded at auction are available non-competitively the day after the sale for up to 2 years.

Lease Issuance
Leases are issued 30-60 days after the lease sale pending review of any protests and appeals. Lease is effective only when issued by authorizing BLM officer. Refunds provided for leases withdrawn.

LEASE ISSUANCE: Resolution of appeals / protests and payment are required prior to issuance of the lease. Winning bid and full payment does **not** result in effective lease – must be issued by the authorizing officer. Leases withdrawn after payment will result in refund to the winning bidder. Subsequent to issuance of lease, the lessee obtains the right to explore and drill for, extract, remove, and dispose of deposits of oil and gas found on the lease. Leases are valid for 10 years or as long as there is at least one producing well.

COMPARISON OF AUCTION PRACTICES

Entity	Type of Auction	How Often are Auctions Held	Financial Pre-Qualification	Financial Requirement to Bid	Required to Register Before Day of Sale	Required to Register Day of Sale	Bid Deposit	Amount Due Day of Sale	Remainder Due	Track Bid-Walkers
BLM Onshore	**Oral**	**Quarterly**	**No**	**No**	**No**	**Yes**	**No**	**$1.50/acre rent, $2 minimum bonus, and $140 processing fee**	**10 working days**	**No**
Other Onshore Oil & Gas Agencies										
BLM AK	Sealed	Once/2-yrs	No	No	Yes	No	Yes	1/5 of sealed bonus bid	15 days after receipt of the lease	No
State of CO	Oral	Monthly	No	No	No	Yes	No	1st year rental, bonus, and processing fee	Total due day of sale	No
State of NM	Sealed/ Oral	Monthly	No	No	Yes	No	Yes	Bonus and $30 application fee	Total due day of sale	No
State of WY	Oral	3 Times/Yr	No	No	No	Yes	Yes	$1/Acre min bonus, $1/acre rental, filing fee, and $0.12/Acre advertising fee	10 days from date of sale	No
Other DOI Programs										
BLM Coal	Sealed/ Application	Varies	No	No	No	Yes	Yes	1/5 of bid	4-annual installments	No
BLM Timber	Sealed/ Oral	Varies	No	No	No	Yes	Yes	10% of appraisal price	20% due end of 1st year; 40% end of 2nd year; balance prior to expiration of contract	Yes
BLM Geothermal	Oral	Every two years	No	No	No	Yes	Yes	20% of bonus bid, 1st year's rental, and processing fee	15 calendar days after the sale	No
MS RIK	*	*	Yes	Yes	Yes	*	*	*	*	*
MMS-OEMM	Sealed	Varies	No	No	Yes	N/A	Yes	1/5 of cash bonus	Remaining 4/5 and total first year's rental due within a prescribed time.	No
Other Auction Entities										
FCC	Internet	4 to 6 months	Yes	Yes	Yes	N/A	Yes	Covered by deposit	10 working days	Yes

*For MMS-RIK, we only obtained information regarding pre-qualification.

Report Fraud, Waste, Abuse, and Mismanagement

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