TAXPAYERS for COMMON SENSE

REPORT

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# Understanding Federal Coal Subsidies



Coal Mine in West Virginia
Photo by spiritofamerica, Adobe

## Executive Summary

The federal government has subsidized the production of coal since as early as 1932, when companies were allowed to deduct a portion of their income to help recover initial capital investments—also known as the percentage depletion allowance. To date, coal is still supported by taxpayers through the tax code, favorable federal coal leasing policies, taxpayer-backed public health liabilities, and direct federal spending. From early 20th-century tax preferences to modern-day Department of Energy (DOE) research programs, federal policy has consistently helped reduce the cost of coal production and consumption for close to a century.

**Preferential Tax Treatment**

Starting as early as 1932, provisions in the U.S. tax code have allowed coal companies to pay less through special credits, deductions, refunds, and other preferential tax treatment.

**Favorable Leasing Policies**

Outdated policies have left taxpayers without a fair return on the development of publicly owned coal and exposed to costly cleanup liabilities.

**Taxpayer-backed Public Health Liabilities**

A safety net for the public health costs associated with coal mining has turned into a permanent taxpayer-backed subsidy. Taxpayers could be on the hook for up to $27 billion by FY2050 in health benefit payouts because coal companies have failed to cover these costs.

**DOE Direct Spending and Loan Guarantees**

Grants and Treasury-backed loan guarantees for “clean coal” projects have cost taxpayers billions with little to show for it.

## Coal Production in the U.S.

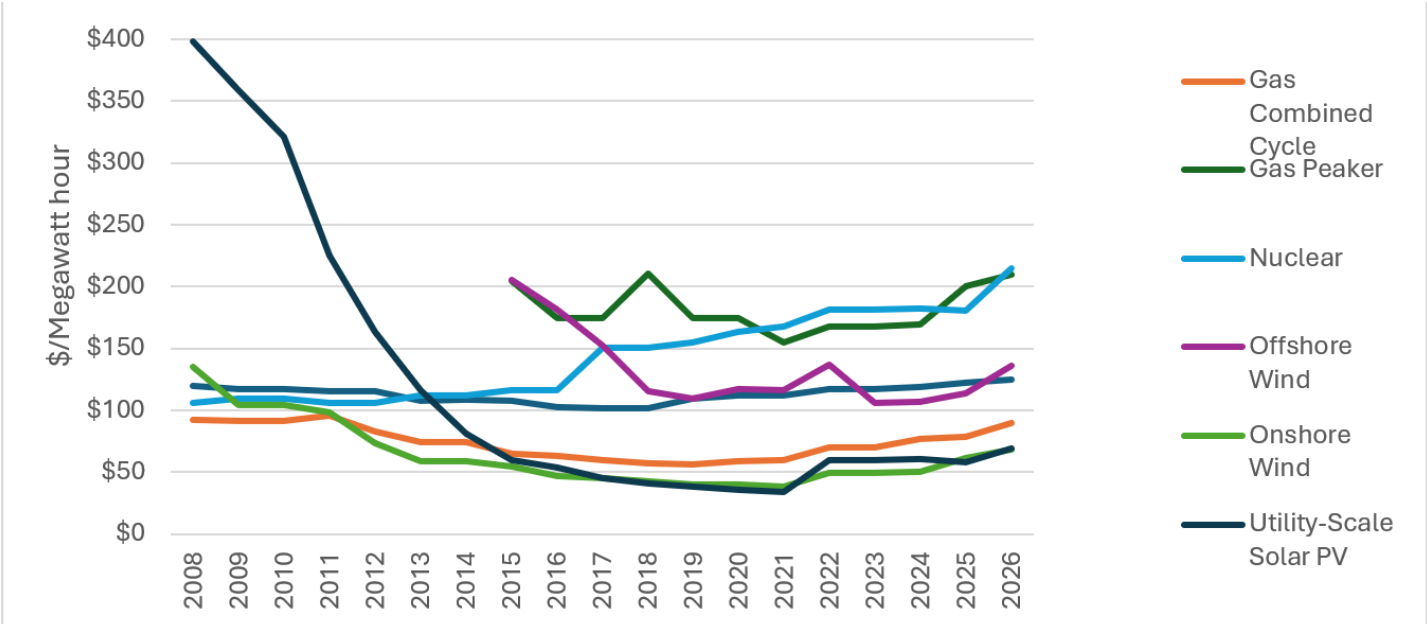
Starting in the early 19th century, coal became a foundational component of America's energy mix. Commercial production scaled rapidly alongside industrialization, supplying power for railroads, steel production, and early electric utilities. By the turn of the 20th century, coal had cemented its position as the nation's leading energy source. While coal's share of total U.S. energy reached its height in the mid-20th century, coal still accounted for close to half of domestic electricity generation well into the 2000s.[1]

After reaching its peak in 2008, U.S. coal production began a long decline. During this time, the U.S. energy landscape has shifted dramatically. When hydraulic fracturing sharply lowered natural gas prices in the early 2000s,[2] coal lost both its cost advantage and its position as the nation's primary fuel source for electricity generation. Renewable energy also became much cheaper to install and deploy.[3] From 2000 to 2022, coal lost market share as natural gas generation nearly tripled and renewable output grew roughly twenty-fold. Throughout the 2010s and 2020s, uncompetitive operating costs and growing emissions-reduction goals accelerated that shift, prompting utilities to retire older coal plants and replace them with natural gas and renewable energy.

These market trends reflect an undeniable economic reality—the lack of price competitiveness is the main driver of coal's decline, not a sudden withdrawal of subsidies or uniquely unfavorable policies.

- **Coal experienced sustained decline in the 2010s and 2020s**: Lower natural gas prices and increasingly cheaper renewable energy significantly undercut coal's competitiveness over the last two decades. As coal lost market share, both natural gas and renewables experienced significant growth.
- **Federal subsidies have increased taxpayer and consumer costs without changing the long-term economic outlook for coal**: They artificially lower producer costs, boosts industry profits, and increases costs for taxpayers without acknowledging the structural shift in the energy market.

**Figure 1. Levelized Cost of Energy, 2008-2026**




Source: Annual benchmark of the unsubsidized levelized cost of energy ($/MWh) for utility-scale renewable and conventional generation technologies, from Lazard's LCOE Analysis series (v1.0–v19.0, 2008–2026).

Coal's challenge is the lack of demand, not insufficient production capacity. The United States retains ample coal reserves and existing mining infrastructure, yet domestic coal consumption has fallen year over year.[4] Subsidizing production in the absence of demand does not create a sustainable market; they artificially lower producer costs, boosts industry profits, and increases costs for taxpayers without acknowledging the structural shift in the energy market.

## Historical and Longstanding Taxpayer Subsidies for Coal

Historically, the U.S. federal government has subsidized coal mainly through preferential tax treatment, favorable federal coal leasing policies, DOE coal research and development and other programs that fund R&D, provide grants, or offer subsidized loans. These subsidies carry direct and indirect fiscal consequences for taxpayers and roughly fall into three categories:

- **Foregone revenues**, including policies that reduce tax receipts and lost government revenue from the development of federally owned coal leases.
- **Direct spending**, typically through appropriations for research, development, demonstration and other programs, or the issuance of tax credits that can be claimed as direct cash payments.
- **Below-market credit subsidy and taxpayer backstop of other liabilities**. Taxpayers can be left responsible for cleanup liabilities if a coal company goes bankrupt, loan guarantees if companies default, and the public health costs and climate-related liabilities associated with emissions.

## Preferential Tax Treatment

Preferential tax treatment for the coal industry has been embedded in the tax code for nearly a century, beginning in 1932 when the federal government allowed coal companies to deduct a portion of their income to recoup initial

**Figure 2. Select Coal and Coal-Related Preferential Tax Provisions**

| Tax Provision | Year Established | Description |
|---|---|---|
| Percentage depletion allowance | 1932 | Can deduct 10% of gross income from resource production. |
| Expensing of exploration and development costs | 1951 | Can expense 70% of their costs from surface strip mining exploration and development and amortize the remaining 30% over five years. |
| Qualifying advanced coal project credit | 2005 | Provides a 15% tax credit for advanced coal technologies. |
| Qualifying gasification project credit | 2005 | Provides a 20% tax credit for coal gasification projects using integrated gasification combined cycle technology. |
| Carbon Oxide Sequestration Tax Credit | 2008 | Provides up to $180 for every metric ton of carbon oxide captured and used or stored. |
| Advanced Manufacturing Production Tax Credit | 2022* | Provides a 2.5% tax credit for metallurgical coal used in steelmaking. |

*The Advanced Manufacturing Production Tax Credit was established by the Inflation Reduction Act (P.L. 117-169) but amended in 2025 by the One Big Beautiful Bill Act (P.L. 119-21) to allow metallurgical coal to qualify.

capital investments. The early 2000s also saw another wave of clean coal investment tax incentives and, as recently as 2025, Congress further expanded tax subsidies for the coal industry by allowing coal used in steelmaking to qualify for the existing Advanced Manufacturing Production Tax Credit.

### *1900s: Old Tax Subsidies Meant to Encourage a Growing Industry Continue to This Day*

The oldest tax subsidy for the coal industry—percentage depletion allowance (PDA)—was written into the tax code in 1932. PDA allows coal producers to deduct 10% of gross income from resource production. PDA nominally allows companies to reduce their taxes to recoup investments in new mines but, in practice, functions as an ongoing production subsidy for as long as the mine generates income. Coal companies can continue to claim the PDA deduction even after their total depletion claimed exceeds the original cost of investment, meaning that taxpayers end up subsidizing their day-to-day operations.

Another longstanding coal tax subsidy is the expensing of exploration and development costs. This provision allows coal companies to expense the costs of ascertaining the location, quality, or quantity of a deposit, as well as the costs of development for extraction once the deposit is discovered. This immediate expensing is a subsidy because it deviates from the standard cost depletion method, which typically spreads the cost of tangible assets over their useful lives. Coal companies can expense 70% of their costs from surface strip mining exploration and development and amortize the remaining 30% over five years. Expensing of mine development was established in 1951 and expensing of mine exploration in 1966.[5]

Other prominent longstanding coal tax subsidies include capital gains treatment for royalties on coal, which was established in 1951 and allows qualifying royalty income from coal to be treated as capital gains rather than ordinary income, resulting in lower tax rates, and exclusion of special benefits for disabled coal miners, established in 1977, which allows coal companies to deduct payments made to disabled miners out of the Black Lung Trust Fund from their taxable income. For a more comprehensive list of coal tax preferential treatments and tax credits, see Appendix A.

### *2000s: "Clean Coal" Subsidies Fail to Accomplish Goals, Cost Taxpayers*

The 2000s saw a wave of new tax credits created to incentivize the adoption and deployment of "clean coal," as both Congress and the Administrations at the time pursued policies that promoted clean coal carbon capture and storage (CCS) technologies in an effort to reinvent coal to be cleaner and more competitive against natural gas. Enacted under the Energy Policy Act of 2005 (EPACT 2005) and expanded in the Energy Improvement and Extension Act of 2008 (Division B of EESA), Section 48A (the Qualifying Advanced Coal Project Credit) and Section 48B (the Qualifying Gasification Project Credit) offer federal investment tax credits to offset the capital costs of coal-based power and gasification projects.[6]

Section 48A targets coal-fired electricity generation facilities—including new builds as well as retrofits of existing plants. Congress authorized a total of $2.55 billion for Section 48A credits:

- EPACT 2005 authorized $1.3 billion for 48A, providing a 20% investment tax credit for integrated gasification combined cycle (IGCC) projects and a 15% credit for other advanced coal-based generation technologies.
- EESA 2008 authorized $1.25 billion for 48A and expanded the credit to provide a 30% tax credit for qualified investments for both IGCC and non-IGCC advanced coal projects.

Section 48B similarly provides investment tax credits for qualifying gasification projects serving electricity generation or industrial applications. Congress initially authorized



Kingston power plant in Roane County, Tennessee
Photo by bilalol, Adobe

up to $350 million under EPACT 2005 for 48B, which provided a 20% tax credit for qualifying investments. Another $250 million was authorized under EESA 2008 at a 30% rate for projects capturing and sequestering at least 75% of their $CO_2$ emissions—bringing total authorized credits to $600 million.[7]

### *2010s: Expanded Carbon Capture and Storage Incentives a Boon for Coal Operators*

One of the most expensive tax credits—although not specifically designed for the coal industry, but heavily benefits coal plants with CCS equipment—was also established during the 2000s period of heavy incentivization of CCS adoption and deployment. The Carbon Oxide Sequestration Tax Credit, most commonly referred to as 45Q, was significantly expanded in the 2010s. Initially only available for the first 75 million tons of carbon dioxide captured and stored, the Bipartisan Budget Act of 2018 removed this cap on 45Q, increased the credit amount, and allowed credit recipients to claim the credit for 12 years.

Although many types of carbon-emitting facilities can install CCS equipment to capture their own emissions and qualify for 45Q, at the time of its creation the credit was anticipated to provide additional subsidies to many DOE-funded clean coal projects that integrated CCS equipment. The credit has since been expanded and extended multiple times.

### *2020s: Congress Maintains and Expands Coal Tax Subsidies*

45Q remains one of the most lucrative tax credits for coal and other fossil fuel facilities. Most recently expanded by the One Big Beautiful Bill Act (OBBBA), 45Q now provides up to $180 for every metric ton of carbon oxide captured and sequestered. The U.S. Treasury estimated the credit would cost taxpayers $36.2 billion from FY2024 through FY2033.[8]

One of the most recent tax subsidies added for the coal industry is the amended advanced manufacturing production credit, Section 45X. OBBBA added metallurgical coal to the list of qualified critical minerals under Section 45X, making producers eligible for a 2.5% tax credit through 2029. Other critical minerals remain eligible for a 10% credit through 2030, with the credit phasing down to 0% after 2033.

## Favorable Federal Leasing Policies

The federal government manages a significant share of total U.S. coal reserves, particularly in western states. Montana and Wyoming, where the federal government owns a large amount of public land, together account for 37% of U.S. coal reserves.[9] All coal produced in Wyoming, the nation's top coal producing state, is extracted from federal lands, and more than one third of the coal produced in Montana, the fifth largest coal producing state, comes from federal lands.[10]

For decades, instead of generating a fair return for taxpayers on publicly owned coal, the federal coal leasing program has favored the coal industry at the expense of taxpayers. Noncompetitive lease sales, outdated royalty rates, weak valuation practices, and inadequate bonding requirements have left taxpayers without a fair return on publicly owned coal

and exposed them to costly cleanup liabilities.

- **Not So Fair Market Value Calculations:** The Bureau of Land Management's estimate of fair market value (FMV) serves as the benchmark for evaluating lease sale bids. A lack of transparency limits public oversight and accountability for FMV determinations that directly affect taxpayer revenues.
- **Limited Competition:** In almost all cases, only a single company submits a bid at auction, typically the company that nominated the tract. The absence of meaningful competition increases the likelihood that taxpayers will receive less than full market value for publicly owned coal resources.
- **Low and Often Reduced Royalty Rates:** Coal royalty rates have long lagged behind the rates charged for other federally owned energy resources, including onshore and offshore oil and gas. The already low royalty rates are often reduced. Between 1992 and 2013, BLM approved 30 royalty rate reductions, reducing revenue by an estimated $294 million.
- **Undervaluation:** Coal companies use sales between affiliated companies to undervalue federal coal and reduce royalty payments.
- **High Cleanup Liabilities:** Financial assurances that coal operators have to submit to ensure cleanup after operation have too often fallen short of actual cleanup costs. As a result, taxpayers are forced to pick up the cleanup tab.

## *Outdated and Below-Market Coal Leasing Policies Shortchange Taxpayers*

The Bureau of Land Management (BLM) within the Department of the Interior (DOI) manages the federal coal leasing program, covering approximately 570 million acres of federal coal mineral estate.[11]

BLM auctions off plots of federal land for coal leases, giving lessees the right to develop and produce coal, which they in turn sell for profit.[12] In return for the extraction of publicly owned coal from federal lands, taxpayers should, in theory, receive fair compensation through competitive lease bids, rental payments for the use of federal land for nonproducing leases, royalties based on the value of coal produced, and other minor fees. From FY2015 through FY2024, the program generated $5.8 billion for federal and state taxpayers,[13] with revenues split between the federal treasury and the state where the coal is mined.[14]

However, taxpayers have been shortchanged for decades due to limited competition, opaque valuation practices, and royalty rates that fail to reflect market value. Weak bonding requirements have further exposed taxpayers to cleanup liabilities that should be borne by the industry profiting from coal production.

### *Not So Fair Market Value Calculations*

The Federal Coal Leasing Amendments Act of 1976 requires DOI to conduct competitive coal lease sales and prohibits the acceptance of bids below fair market value. BLM's estimate of fair market value (FMV) serves as the benchmark for evaluating lease sale bids. If the sealed bid submitted by a private company undervalues the coal tract, it will be rejected. As a result, accurately estimating FMV is essential to ensuring taxpayers receive a fair return.

However, the data and methodology BLM uses to calculate FMV are not publicly available, and company bids are submitted under seal. This lack of transparency limits public oversight and accountability for FMV determinations that directly affect taxpayer revenues.

### *Limited Competition*

DOI has effectively circumvented the intent of the competitive leasing requirement through the Lease By Application (LBA) system. Under the LBA process, a private company identifies and nominates a specific coal tract for leasing. BLM reviews the application and, if land use and development requirements are met, prepares an Environmental Assessment (EA) or Environmental Impact Statement (EIS) and

solicits public comment. Once the EA or EIS process is complete, BLM publishes a notice of lease sale in the Federal Register. Before the sale, BLM estimates the tract's FMV and the value of the coal it contains. Companies then submit sealed bids to BLM for the lease.

In almost all cases, only a single company submits a bid, typically the company that nominated the tract. The absence of meaningful competition undermines the leasing process and increases the likelihood that taxpayers will receive less than full market value for publicly owned coal resources.

### *Low Royalty Rates That Often Get Further Reduced*

Companies producing coal from federal leases pay royalties based on the value of the coal they extract. Royalties may be assessed on a cents per ton basis but are more commonly charged as an ad valorem percentage of the coal's value.

In 1979, BLM set the royalty rate at the statutory minimum of 12.5% for surface mined coal and 8% for underground coal. These rates remained unchanged until 2025, when Congress reduced the royalty rate for both new and existing federal coal leases to 7% through September 30, 2034. Coal royalty rates have long lagged behind the rates charged for other federally owned energy resources, including onshore and offshore oil and gas. The recent reduction in the royalty rate is expected to further reduce taxpayer revenues.

In Wyoming, which produces the most federal coal,[15] the state's official budget forecaster estimates the change will reduce Wyoming's share of federal mineral royalty revenue by roughly $50 million annually, while federal taxpayers will lose roughly another $50 million.[16]

Taxpayer losses are further compounded by royalty rate reductions approved administratively. BLM has broad discretion to reduce royalty rates and has exercised that authority frequently.[17] Between 1992 and 2013, the agency approved 30 separate royalty rate reductions, reducing royalty payments by an estimated $294 million, according to Headwaters Economics.[18]

### *Undervaluation of Federal Coal*

Valuation of extracted coal is another key component of the royalty collection system and directly affects the amount of revenue taxpayers receive. Companies can exploit weaknesses in the valuation system to reduce royalty payments and increase profits.

The Office of Natural Resources Revenue (ONRR) generally relies on arm's length transactions, sales between unrelated parties, to determine the market value of federal coal. Determining market value becomes more difficult when coal is sold between affiliated companies through non-arm's length, or captive sales. Critics have long argued that coal companies use captive sales to undervalue federal coal and reduce royalty payments.



Powder River Basin, Wyoming
Photo by RobertCoy, Adobe

The prevalence of these transactions has amplified those concerns. In Wyoming, the Energy Information Administration reported that 39% of coal produced in 2023 was sold through captive transactions.[19]

ONRR attempted to address this issue through a rule requiring companies to use prices established in transactions between unrelated parties when calculating royalty value. However, the rule was later repealed. As a result, taxpayers have yet to receive fair valuation and royalty collection on publicly owned coal extracted from federal lands.

### *Weak Bonding Requirements and Cleanup Liabilities*

To prevent taxpayers from paying for the cleanup ("reclamation") of abandoned coal mines, coal companies must demonstrate that they can cover reclamation costs by providing some type of financial assurance, or a "bond," before they begin mining. One accepted form of financial assurance is a self-bond, which is backed solely by the financial strength of the coal operator and its ability to cover future reclamation costs. In 2017, regulatory authorities reported that self-bonds accounted for $1.2 billion, or roughly 12% of all bonds posted by coal companies.[20]

A wave of coal company bankruptcies exposed serious weaknesses in federal reclamation bonding requirements, particularly self-bonding. Large coal companies have used the financial statements of subsidiaries to prove they have the assets available to cover reclamation costs even as the financial condition of the parent company deteriorates. When those companies carry substantial debt or declare bankruptcy, reclamation liabilities may ultimately fall to the federal government. Moreover, the same assets used to demonstrate the financial health of a subsidiary for self-bonding purposes are often pledged as collateral for the parent company's debt. As a result, creditors may have a claim on those assets while federal agencies do not.

The Government Accountability Office found that the Office of Surface Mining Reclamation and Enforcement (OSMRE) and state regulators responsible for reclamation often struggle to determine whether an operator is financially healthy enough to qualify for self-bonding and to require replacement bonds when conditions deteriorate.[21] Between July 2007 and June 2016, 22% of forfeited financial assurances fell short of covering reclamation costs, while the adequacy of another 26% remains unresolved.[22] Current coal bonding requirements should be strengthened to prevent companies from exploiting these loopholes and to protect taxpayers from bearing reclamation liabilities.

## Taxpayer-subsidized Public Health Costs

In addition to environmental cleanup liabilities left by coal companies, federal taxpayers have also borne significant public health costs associated with coal mining. Chief among these is the federal program that compensates miners suffering from coal workers' pneumoconiosis, commonly known as black lung disease, which is caused by prolonged inhalation of coal dust. Over time, structural weaknesses in the program's financing—combined with industry bankruptcies and declining coal production—have resulted in substantial taxpayer exposure through federal borrowing and debt forgiveness.

- **Shifting Industry Liabilities to Taxpayers:** Established in 1977 to make coal companies finance miners' health costs, the Black Lung Disability Trust Fund has failed as a safety net and has forced taxpayers to absorb the liabilities when operators failed to cover them.
- **Chronic Deficits Funded by Treasury Borrowing:** Coal excise tax revenues have failed to cover benefit payments nearly every year since 1979, leaving the fund reliant on continuous borrowing from the U.S. Treasury to stay solvent.
- **Repeated Bailouts:** Rather than requiring the coal industry to cover its shortfalls, Congress has repeatedly stepped in with direct relief—forgiving five years of loan

interest in the late 1980s and wiping out roughly $6.5 billion in Trust Fund debt in 2008.

- **Growing Long-Term Taxpayer Exposure:** Even with higher excise tax rates made permanent in 2022, declining coal production and ongoing bankruptcies are expected to increase the Trust Fund's deficit. The Government Accountability Office projects that the fund could owe taxpayers between $15 billion and $27 billion by FY2050.

### *Coal Companies Fail to Cover Liabilities, More Costs Fall to Taxpayers*

Congress first established a federal compensation framework in the Federal Coal Mine Health and Safety Act of 1969, creating a program to provide disability and survivor benefits to coal miners and their families affected by black lung disease. The original framework envisioned a cooperative system involving both federal and state governments. Congress then enacted the Black Lung Benefits Act of 1972 to establish federal standards for state workers' compensation programs covering coal workers' pneumoconiosis.

State systems were required to meet these standards and obtain approval from the U.S. Department of Labor. If a state system failed to meet federal standards, individual coal operators would be responsible for paying benefits to affected miners. In cases where no responsible operator could be identified, or where an operator was unable to pay because of bankruptcy or other financial distress, the federal government would cover the benefits. In practice, however, no state workers' compensation system has ever met the federal standards established under the law. As a result, responsibility for paying claims has frequently fallen either to coal operators directly or to the federal government when operators could not meet their obligations.

Initially, federal black lung benefits were paid from general Treasury revenues. As claims grew and operators increasingly failed to



Coal mound and conveyor belt at Charleston, WV
Photo by Kristina Blokhin

cover their liabilities, Congress created a dedicated financing mechanism through the Black Lung Benefits Revenue Act of 1977. The legislation established the Black Lung Disability Trust Fund, financed through an excise tax on coal production set at $0.50 per ton for underground coal and $0.25 per ton for surface coal, capped at 2% of the coal's sales price. The intent was to ensure that the coal industry, rather than taxpayers, would finance compensation for the occupational health harms associated with coal mining.

### *Benefit Payments Surpass Excise Tax Revenues*

Despite the dedicated excise tax, Trust Fund revenues proved insufficient to cover benefit payments. As a result, the fund began borrowing from the U.S. Treasury soon after its creation and has operated with deficits nearly every year since 1979.[23] Congress increased the coal excise tax several times in an attempt to close the funding gap. In 1981, Congress doubled the tax to $1.00/ton for underground coal and $0.50/ton for surface coal, capped at 4% of the sales price. In 1985, the excise tax was temporarily increased again to $1.10/ton for underground coal and $0.55/ton for surface coal, capped at 4.4% of the sales price. These higher rates were subsequently extended in 1987 and again in 2008.

Even with these higher rates, the Trust Fund continued accumulating debt because benefit payments exceeded revenues. To slow the growth of that debt, Congress enacted a five-year interest forgiveness period on Treasury loans from 1985 to 1990. When Congress extended the higher excise tax rates again in 2008, it also forgave approximately $6.5 billion in Trust Fund debt and restructured the remaining obligations. This reduced total debt owed to taxpayers from $10.4 billion in FY2008 to $6.2 billion in FY2009. Although the restructuring lowered the outstanding balance, the program continued relying on borrowing from the Treasury because benefit payments still exceeded excise tax revenues.

The higher excise tax rates extended in 2008 expired on January 1, 2019, after which the tax temporarily reverted to its original 1977 levels for one year. Congress subsequently enacted two one-year extensions through the FY2020 and FY2021 appropriations bills before permanently restoring the higher rates in the Inflation Reduction Act of 2022 (IRA). According to the Joint Committee on Taxation, the permanent extension is expected to reduce the federal budget deficit by roughly $1.16 billion over ten years.[24]

### *Federal Costs Projected to Climb*

Despite these reforms, Trust Fund expenditures have consistently exceeded revenues, requiring continued borrowing from the Treasury's general fund. While outstanding debt declined from roughly $10.4 billion in 2008 to approximately $4.5 billion in FY2019, long-term projections indicate continued fiscal pressure due to declining coal production, coal company bankruptcies, and interest obligations on existing debt.[25]

Based on current projections, the Government Accountability Office estimates the Trust Fund could owe between $15 billion and $27 billion to taxpayers by FY2050, depending on future coal production levels and the number of beneficiaries.[26] While the permanent extension of higher excise tax rates under the Inflation Reduction Act reduces some fiscal exposure, structural declines in coal production and ongoing health liabilities mean the Trust Fund may continue relying on federal borrowing for decades.

## Golden Fleece: Coal to Kaiserslautern

Another way taxpayers subsidize coal that is perhaps less obvious than tax preferences or direct spending is through how the federal government procures fuel sources. Directing the Department of Defense (DOD) to buy coal from Pennsylvania to power a U.S. base in Kaiserslautern, Germany—or in short, coal to Kaiserslautern—was awarded the Golden Fleece award by TCS in 2015 to highlight this egregiously wasteful spending.

Starting in 1961, Pennsylvania lawmakers pressured—and later statutorily required—the Department of Defense to buy declining, high-cost Pennsylvania anthracite coal and ship it across the Atlantic to heat U.S. military bases in Germany, barring the military from switching to cheaper fuels. Even after Congress allowed most European bases to modernize, this legislative carve-out kept DOD hauling Pennsylvania coal 4,000 miles to Kaiserslautern for more than half a century. A 1989 study by the Departments of Defense, State, and Commerce found no economic justification for the mandate, which cost taxpayers more than $1.1 billion in extra heating expenses between 1962 and 1988 alone.[27]

With the Administration's EO issued in 2025 ordering DOD to secure long-term power purchase agreements with domestic coal plants, taxpayers might once again be on the hook to pay for the same costly mistake. Using military procurement to manufacture demand for structurally uncompetitive coal will saddle taxpayers with above-market electricity costs, divert dollars to prop up a declining industry, and lock in expensive, long-term contracts while crowding out cheaper, more efficient energy options.

## DOE Grants and Loan Guarantees

Department of Energy (DOE) subsidies for coal started as early as 1984 when the Clean Coal Technology program was established. Since then, DOE's support for coal—either through direct support for research and development (R&D) or financing assistance like loan guarantees—has mostly focused on "capturing" emissions from coal facilities. These DOE R&D and demonstration programs have cost taxpayers billions with little to show for it, as most projects have failed or were abandoned. However, recent Administration actions have shifted the focus from carbon capture to building new coal plants and prolonging the life of existing ones.

- **Decades of DOE R&D Support with Limited Demonstrative Success:** DOE started funding clean coal programs as early as the 1980s, with the biggest wave of funding from the stimulus package passed in 2009 appropriating carbon capture programs $3.4 billion. Coal-specific projects were awarded $2.7 billion of that funding yet did not exhaust all of it because most projects were cancelled or eventually abandoned.
- **Recent Influx of Funding on top of Sustained Annual Appropriations Heightens Risks for Taxpayers:** From FY2010 to FY2026, Congress appropriated $7.2 billion in annual appropriations to DOE coal and/or CCS programs. The Infrastructure Investment and Jobs Act additionally provided $12.1 billion for FY2022-FY2026. Recent Administrative actions have repurposed about $1.2 billion of this funding to build new coal plants and upgrade, retrofit, and extend the life of old plants instead of using it on CCS as Congress intended.
- **Treasury-Backed Loan Guarantees:** DOE's loan guarantee program has historically supported financing for risky projects that exposed taxpayers to financial risks that private investors are unwilling to take on. A new $250 billion loan guarantee authority would amplify that risk for taxpayers. To date, DOE has already committed $3.2 billion under the new authority for coal and coal-related projects.

### *Decades of DOE Clean Coal & CCS Support*

Clean coal programs can be traced back to 1984, when the Clean Coal Technology (CCT) program was started under a now defunct government corporation. The program received generous funding throughout the 1990s but stopped funding new projects in 1994.[28]

In 1997, DOE officially began funding coal and clean coal RD&D through the Office of Fossil Energy.[29] To accelerate the deployment of CCS, the Bush Administration's FY2002 budget outlined more than $2 billion in spending over 10 years for a restructured CCT program, known as the Clean Coal Power Initiative (CCPI). The CCPI was launched in 2002 to provide direct subsidies to demonstration projects through cost-sharing agreements between DOE and industry. There were three rounds of funding through the CCPI:

- Round 1 (2003) – for "advanced coal-based power generation and efficiency, environmental and economic improvements."
- Round 2 (2004) – for "focused on gasification, mercury-control and carbon dioxide ($CO_2$) sequestration."
- Round 3 (2009) – for "$CO_2$ capture and sequestration/beneficial reuse ($CO_2$ EOR)."

In 2003, the Bush Administration announced plans to construct the world's first clean coal power plant using CCS technologies, known as FutureGen. The plant was to be managed through a public-private partnership between DOE and the FutureGen Industrial Alliance, a coalition of power producers from around the world formed to support the project. DOE would cover 76% of the cost, while the FutureGen Alliance would provide the remaining 24%. Congress appropriated $174 million for FutureGen between FY2004 and FY2008. However, DOE spent only $42 million on the project between FY2005 and FY2010.[30] In 2008, DOE canceled funding for FutureGen because of rising construction costs, effectively terminating the project. But in 2010, the Obama Administration revived the project and reintroduced it as FutureGen 2.0, which

consisted of two demonstration projects—a power plant and a pipeline and storage project.

By the late 2000s, CCPI, FutureGen 2.0, and the Industrial Carbon Capture and Storage (ICCS) program were the three primary CCS initiatives funded by DOE. While CCPI and FutureGen 2.0 funding are geared towards coal plants, the ICCS program supported projects in the non-power plant industrial sector. In 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), also known as the stimulus bill. Nearly $3.4 billion in stimulus funding was directed specifically to DOE-supported CCS demonstration projects:

- $850 million for Round 3 of CCPI, awarded to six projects.
- $1.52 billion for the ICCS program, part of which funded three ICCS demonstration projects in 2010.
- $1 billion for two FutureGen 2.0 demonstration projects.

Authority to spend ARRA funds expired on September 30, 2015. By that deadline, DOE had spent roughly $2 billion of the $3.4 billion allocated for CCS projects. [31]The remaining $1.4 billion went unspent because recipients withdrew from projects or DOE terminated them. The largest portion of the unspent funding, $795 million, had been designated for FutureGen 2.0, which DOE suspended in February 2015 because of escalating construction costs.[32]

**Figure 3. CCS Demonstration Projects Selected by DOE**

| | Project | DOE original award amount ($, million) | Funded Thru |
|---|---|---|---|
| Coal | American Electric Power | 334 | (CCPI 3) |
| | Basin Electric | 100 | (CCPI 3) |
| | FutureGen 2.0 Power Plant | 1,000 | (ARRA) |
| | FutureGen 2.0 Pipeline and Storage | | (ARRA) |
| | Hydrogen Energy California | 408 | (CCPI 3) |
| | Petra Nova | 167 | (CCPI 3) |
| | Southern Company Services (Plant Barry) | 295 | (CCPI 3) |
| | Summit Texas Clean Energy | 450 | (CCPI 3) |
| **Coal CCS Total** | | 2,754 | |

Source: Taxpayers for Common Sense, "Pricey and Problematic: Carbon Capture and Storage Remains Elusive Despite Decades of Taxpayer Subsidies," https://www.taxpayer.net/energy-natural-resources/pricey-and-problematic/

In total, coal CCS projects were awarded $2.75 billion through ARRA, although the actual amount of money obligated was much less because most projects were cancelled or never got built.

## FutureGen and FutureGen 2.0

Proposed by the Bush administration in 2003, FutureGen was a multibillion-dollar DOE initiative to build the world's first zero-emissions coal plant in Mattoon, Illinois. The plant would produce hydrogen and electricity and capture its emissions with CCS. After scrapping the original plant in 2010 due to cost overruns, DOE pivoted to "FutureGen 2.0," committing $1 billion in 2009 stimulus funds toward an estimated $1.4 billion retrofit of a 64-year-old power plant in Meredosia, Illinois. The plant would build a 150-mile $CO_2$ pipeline designed to sequester more than 1.3 million tons of carbon dioxide annually. The revised plan quickly stalled: Ameren, the project sponsor, withdrew and shut down the Meredosia plant in 2011, as local landowners opposed the pipeline and storage site over property value and contamination concerns. FutureGen 2.0 was ultimately abandoned after failing to finalize procurement and construction agreements or attract sufficient private financing—after DOE had already spent more than $200 million on the effort.

### *Poor Taxpayer Return from Investments*

Despite decades of extensive federal investment in CCS and the huge influx of funding in 2009, the results have been largely disappointing. In 2021, the Government Accountability Office (GAO) examined 11 CCS demonstration projects funded through Round 3 of CCPI and ARRA, including eight coal CCS projects. GAO found that coal demonstration projects were particularly unsuccessful, partially due to DOE mismanagement but more importantly because of poor economic prospects. Only one of the eight coal projects funded by DOE was built and eventually entered operation but soon shut down in May 2020 because of low oil prices.[33]

**Figure 4. Status of DOE-funded Coal CCS Demonstration Projects**

| CCS Program | Project | Project outcome | Final phase entered | DOE funding totals ($) |
|---|---|---|---|---|
| Coal | American Electric Power | Withdrawn | Definition | 16,880,268 |
| | Basin Electric | Withdrawn | None | 0 |
| | FutureGen 2.0 Power Plant | Terminated | Design | 116,666,759 |
| | FutureGen 2.0 Pipeline and Storage | Terminated | Design | 83,857,100 |
| | Hydrogen Energy California | Terminated | Definition | 153,428,898 |
| | Petra Nova | Completed (Shut down in 2020) | Operations | 195,132,425 |
| | Southern Company Services (Plant Barry) | Withdrawn | None | 0 |
| | Summit Texas Clean Energy | Terminated | Definition | 117,876,707 |
| **Coal CCS Total** | | | | **683,842,157** |

Source: GAO-22-105111. Table 1

GAO found that DOE's inconsistent project selection and rushed funding negotiations drove significant waste across coal CCS programs. Expedited negotiations resulted in conditional agreements that undermined DOE's ability to enforce basic requirements like procurement contracts, and the agency violated its own risk-mitigation policies for four failed coal projects: two FutureGen 2.0 projects, Hydrogen Energy California, and Summit Texas Clean Energy. When those projects missed milestones, DOE failed to terminate funding; instead, it cut sponsor cost-share requirements, shifted money from later development phases, and accelerated ARRA disbursements. As a result, DOE spent $300 million more than planned on projects that were never completed.

### *Additional Boost for CCS and Coal in Recent Years*

Despite this lack of demonstrable success of federally funded coal CCS projects, recent legislation significantly expanded RD&D programs and provided another major influx of funding. The Energy Act of 2020, passed as a part of the Consolidated Appropriations Act of 2021 (P.L. 116–260), authorized $6.365 billion for RD&D programs from FY2021 through FY2025,[34] including the following:

- $2.6 billion for six commercial scale demonstration projects (natural gas, coal, and industrial)
- $1 billion for large scale pilot projects
- $910 million for DOE R&D programs
- $200 million for front end engineering and design programs for CCUS
- $800 million for large scale carbon storage validation and testing
- $125 million for carbon capture test centers
- $283 million for carbon utilization programs
- $447 million for carbon removal

The CHIPS and Science Act (P.L. 117-167) additionally created the carbon storage research and geologic computational science initiative and authorized $300 million for FY2022-FY2027. The bill authorized another $4 billion "to carry out carbon removal research, development, and demonstration activities." Neither the Energy Act of 2020 nor the CHIPS Act appropriated the authorized amounts. The biggest influx of funding for CCS in recent years comes from the Infrastructure Investment and Jobs Act (IIJA, P.L. 117-58), enacted in November 2021. IIJA further increased funding authorizations for CCS programs already established under the Energy Act of 2020 and created several new programs, including:

- $2.537 billion for CCS demonstration projects
- $100 million for front end engineering and design of CCUS transport infrastructure
- $2.5 billion for carbon storage validation and testing
- $2.1 billion for carbon dioxide transportation infrastructure financing and innovation
- $937 million for large scale CCS pilot projects
- $310 million for carbon utilization
- $3.5 billion for regional direct air capture (DAC) hubs under the carbon removal program
- $115 million for a carbon removal prize competition

IIJA appropriated the full authorized amount for the programs listed above, totaling around $12.1 billion in supplemental appropriations for CCS programs from FY2022 to FY2026.

Aside from big spending packages such as ARRA and IIJA, Congress provides annual appropriations to DOE's Office of Fossil Energy and Carbon Management (FECM, recently renamed to Office of Fossil Energy) to support CCS programs. Congress provided roughly $7.2 billion (in nominal dollars) in annual appropriations for DOE's CCS programs from FY2010 to FY2026. For detailed annual appropriations data, see Appendix B.

However, recent Administrative actions have doubled down on more direct subsidies for coal plants without real requirement or commitment to tie funding with capturing emissions as Congress intended. The Administration has repurposed up to $700 million worth of IIJA funds originally intended for CCS demonstration projects and instead awarded the money to projects that would build new coal plants and upgrade, retrofit, or extend the life of existing ones.

And through the Defense Production Act (DPA) authority—a Korean War-era authority created to ensure supply production—DOE gave away $500 million to subsidize 11 coal plants. DOE even invoked Federal Power Act authority to issue emergency orders to retiring coal plants, forcing them to continue operation past planned retirement even though these plants are becoming too old, too expensive and unsafe to operate, and are set to be replaced by plants powered by other energy sources.

Heavy subsidization despite unfavorable market conditions and poor economic outlook has had a long history of failure, given DOE's own records, and would only cost taxpayers billions more if the Administration continues down the path.

### *High-Risk and Low-Return Treasury-Backed Loan Guarantees*

In addition to directly funding RD&D programs, DOE supports the early commercialization of advanced technologies, including renewable energy, nuclear power, and advanced fossil fuel technologies, through the Title XVII Section 1703 loan guarantee program, named after the section in which the program was authorized in the Energy Policy Act of 2005. Loan guarantees, as the name suggests, commit the federal government to repay lenders if borrowers default on their loans.

In the 2008 Omnibus Appropriations Act, Congress provided $6 billion in Section 1703 loan guarantee authority for coal-based power generation and industrial gasification projects incorporating carbon capture and storage or other beneficial uses of carbon, as well as $2 billion for advanced coal gasification projects.[35] No loan guarantees have been issued to clean coal projects since enactment of Section 1703 and over $8 billion worth of loan authority remains available.

In addition to existing lending authority, the Inflation Reduction Act (IRA) created a new, time limited $250 billion Title XVII loan authority under Section 1706, Energy Infrastructure Reinvestment Financing, for projects that:

(1) retool, repower, repurpose, or replace energy infrastructure that has ceased operations; or

(2) enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or anthropogenic greenhouse gas emissions.

However, OBBBA amended Section 1706 to have the program offer financing for electricity supply that would at time intervals "maintain or enhance grid reliability" instead, which generally refers to coal and nuclear power. DOE has already awarded a combined $3.2 billion to coal-related projects.

Unfortunately for taxpayers, the track record for DOE loan guarantees is not pretty, either. DOE's Title XVII program has repeatedly backed risky, capital-intensive projects with inadequate taxpayer protections. In one instance, DOE guaranteed up to $12 billion for the Vogtle 3 and 4 nuclear reactors—a project that ran over six years behind schedule, exceeded its budget by over $14 billion, triggered partner credit downgrades, and drove Westinghouse into bankruptcy in 2017. Even so, DOE assessed the credit subsidy cost at $0, effectively treating loans for the project as risk-free.

Taxpayers should not be asked to back risky projects that cannot secure private financing, especially for coal projects that are likely to already struggle in the current energy market. With an unprecedented $250 billion in loan authority, Section 1706 could potentially expose taxpayers to a sky-high tab that we cannot afford.

## Conclusion

For nearly a century, the federal government has subsidized the production of coal through preferential treatment in the tax code, favorable federal leasing policies, the Black Lung Disability Trust Fund, and direct federal spending and loan guarantees in DOE Clean Coal and Coal R&D Programs. This market intervention has cost taxpayers billions of dollars without tangible, positive results.

To halt the ongoing waste of taxpayer and ratepayer funds while ensuring that all Americans have access to reliable and affordable energy, we need to pivot away from an energy agenda that favors high-cost energy sectors with long-term liabilities over cost-effective ones that reduce taxpayer risks.



Giant mining truck hauling coal at the Eagle Butte mine, Wyoming
Photo by RobertCoy, Adobe

# Appendix A. Detailed Coal and Coal-Related Preferential Tax Provisions

| Tax Subsidy | U.S.C. | Description | Year in Effect |
|---|---|---|---|
| Percentage depletion allowance | 26 U.S. Code §613 | Established in 1932,[36] percentage depletion allowance (PDA) allows coal producers to deduct 10% of gross income from resource production. PDA nominally allows companies to reduce their taxes to recoup investments in new mines but, in practice, functions as an ongoing production subsidy for as long as the mine generates income. Coal companies can continue to claim the PDA deduction even after their total depletion claimed exceeds the original cost of investment, meaning that taxpayers end up subsidizing their day-to-day operations. | 1932 – Now |
| Expensing of exploration and development costs | 26 U.S. Code §617(a) | This provision allows coal companies to expense the costs of ascertaining the location, quality, or quantity of a deposit, as well as the costs of development for extraction once the deposit is discovered. This immediate expensing is a subsidy because it deviates from the standard cost depletion method, which typically spreads the cost of tangible assets over their useful lives. Coal companies can expense 70% of their costs from surface strip mining exploration and development and amortize the remaining 30% over five years. Expensing of mine development was established in 1951 and expensing of mine exploration in 1966.[37] | 1951(development) – Now<br>1966 (exploration) |
| Capital gains treatment for royalties on coal | 26 U.S. Code §631(c) | Established by the Revenue Act of 1951, this provision allows qualifying royalty income from coal to be treated as capital gains rather than ordinary income, resulting in lower tax rates. However, coal companies choosing to benefit from this provision are barred from taking the percentage depletion allowance.[38] | 1951 – Now |
| Accelerated amortization of air pollution control equipment | 26 U.S. Code §169 | This tax credit was established in the Energy Policy Act of 2005. It accelerates the amortization period for air pollution controls for coal plants to 84 months and applies to plants placed in service after April 11, 2005.[39] | 2005 – Now |

| Tax Subsidy | U.S.C. | Description | Year in Effect |
|---|---|---|---|
| Exclusion of interest on energy facility bonds | 26 U.S. Code §142 | Established by the Revenue Expenditure and Control Act of 1968, this provision allows interest on bonds used to finance certain energy facilities to be deducted from gross income. Such bonds may be issued for: electricity generation, natural gas provision, district heating systems, environmental facilities, and dam projects.[40] This tax break benefits coal power generation as well as many other fuels. | 1968 – Now |
| Exclusion of special benefits for disabled coal miners | 26 U.S. Code §192 | Under the Black Lung Benefits Revenue Act of 1977,[41] payments made by coal producers to disabled miners out of the Black Lung Trust Fund can be deducted from taxable income. | 1978 – Now |
| Partial expensing for advanced mine safety equipment | 26 U.S. Code §179E | Under the Tax Relief and Health Care Act of 2006, coal companies are allowed to expense up to 50% of mine safety equipment for underground mines. | 2006 – 2017 |
| Tax credits for investment in clean coal technologies | 26 U.S. Code §48A and §48B | The tax credits for clean coal technologies were established in the Energy Policy Act of 2005. Technologies may include industrial gasification or integrated gasification combined cycle projects. Section 48B provides a 20% tax credit for coal gasification projects using integrated gasification combined cycle technology and Section 48A provides a 15% tax credit for other advanced coal technologies. These credits were extended in the American Recovery and Reinvestment Act of 2009. | 2005 – no fixed sunset with allocation cap |
| Special rules for refund of coal excise taxes | 26 U.S. Code §4121 | Certain coal producers are eligible for refunds of coal excise taxes paid after 1990. The excise tax rate is $1.10/ton of underground coal and $0.55/ton of surface coal. Coal exporters get a subsidy of $0.825/ton of exported coal. | 2008 (applies retroactively to coal exports from Oct 1990–Oct 2008, with claims due Nov 3, 2008) |
| Credit for production of nonconventional fuels | 26 U.S. Code §45K | The nonconventional fuel production credit provides a credit for entities selling qualified fuels, such as coalbed methane, tight formation gas, or synthetic fuels from coal, to unrelated persons. The credit is $3.00/barrel of oil equivalent, adjusted for inflation, and applies to qualified fuel production from facilities placed in service before 1998. The credit phases out if the reference price of oil exceeds certain inflation adjusted thresholds, starting at $23.50 per barrel. | 1980 – 2008 |

| Tax Subsidy | U.S.C. | Description | Year in Effect |
|---|---|---|---|
| Advanced manufacturing production credit | 26 U.S.C. §45X | The One Big Beautiful Bill Act (OBBBA) added metallurgical coal to the list of qualified critical minerals under Section 45X, making producers eligible for a 2.5% tax credit through 2029. Other critical minerals remain eligible for a 10% credit through 2030, with the credit phasing down to 0% after 2033. | 2022 – Now |
| Advanced energy project credit | 26 U.S.C. §48C | Established in 2009 and expanded in the Inflation Reduction Act of 2022, Section 48C provides a credit for eligible energy projects, including but not limited to industrial technology designed to reduce GHG emissions and "processing, refining, or recycling of critical materials." | 2009 – no fixed sunset, allocation capped |
| Mine Rescue Training Credit | 26 U.S.C. §45N | Established in 2006, the credit provides 20% for mine rescue training expenditures made by coal companies, with a maximum of $10,000 per mine rescue team employee. The credit expired after 2021. | 2006 – 2021 |
| Refined Coal Tax Credit | 26 U.S.C. §45(e)(8) | Established in 2004, the credit provides $4.375 per ton of refined coal, adjusted annually for inflation, and reaching $7.38 per ton in 2021, produced and sold during the 10-year period, following a facility's placement in service. Producers claimed $8.7 billion in credits between 2010 and 2019.[42] The credit phased out if the reference price of fuel used as feedstock exceeded certain inflation-adjusted thresholds, starting at $8.75. The credit expired after 2021. | 2004 – 2021 |
| Carbon Oxide Sequestration Tax Credit | 26 U.S.C. §45Q | The carbon oxide sequestration credit, commonly known as 45Q, was created in 2008 to encourage the adoption of carbon capture and sequestration (CCS) technologies. Although many types of carbon-emitting facilities can install CCS equipment to capture their own emissions and qualify for 45Q, at the time of its creation the credit was anticipated to provide additional subsidies to many DOE-funded clean coal projects that integrated CCS equipment. The credit has since been expanded and extended multiple times, most recently by OBBBA, and now provides up to $180 for every metric ton of carbon oxide captured and sequestered. | 2008 – Now |

# Appendix B. Annual Appropriations for DOE Office of Fossil Energy Program Areas, FY2010-FY2026 (nominal $ in thousands)

| Coal/CCS Programs | FY 2010 | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Carbon Capture | - | 58,703 | 66,986 | 63,725 | 92,000 | 88,000 | 101,000 | 101,000 | 100,671 |
| Carbon Dioxide Rei | - | - | - | - | - | - | - | - | - |
| Carbon Utilization | - | - | - | - | - | - | - | - | - |
| Carbon Storage | - | 120,912 | 112,208 | 106,745 | 108,766 | 100,000 | 106,000 | 95,300 | 98,096 |
| Advanced Energy a | - | 168,627 | 97,169 | 92,438 | 99,500 | 103,000 | 105,000 | 105,000 | 112,000 |
| Cross-Cutting Research | - | 41,446 | 47,946 | 45,618 | 41,925 | 49,000 | 50,000 | 45,500 | 58,350 |
| Mineral Sustainability | - | - | - | - | - | - | - | - | - |
| Supercritical CO2 Technology | - | - | - | - | - | 10,000 | 15,000 | 24,000 | 24,000 |
| NETL Coal R&D | - | | 35,011 | 33,338 | 50,011 | 50,000 | 53,000 | 53,000 | 53,000 |
| Transformatioal Coal Pilots | - | - | - | - | - | - | - | 50,000 | 35,000 |
| **Total** | **393,485** | **389,688** | **359,320** | **341,864** | **392,202** | **400,000** | **430,000** | **473,800** | **481,117** |

| Coal/CCS Programs | FY 2019 | FY 2020 | FY 2021 | FY 2022 | FY 2023 | FY 2024 | FY 2025 | FY 2026 | FY2010-FY2026 Total |
|---|---|---|---|---|---|---|---|---|---|
| Carbon Capture | 100,671 | 117,800 | 86,300 | 99,000 | 135,000 | 127,500 | 127,500 | 75,000 | 1,540,856 |
| Carbon Dioxide Rei | - | - | 40,000 | 49,000 | 70,000 | 70,000 | 70,000 | 45,000 | 344,000 |
| Carbon Utilization | - | - | 23,000 | 29,000 | 50,000 | 52,500 | 52,500 | 50,000 | 257,000 |
| Carbon Storage | 98,096 | 100,000 | 79,000 | 97,000 | 110,000 | 93,000 | 93,000 | 59,000 | 1,577,123 |
| Advanced Energy a | 129,683 | 120,000 | 108,100 | 94,000 | - | 85,000 | 85,000 | 80,000 | 1,584,517 |
| Cross-Cutting Research | 56,350 | 56,000 | 32,900 | 33,000 | - | - | - | - | 558,035 |
| Mineral Sustainability | - | - | 53,000 | 53,000 | 54,000 | - | - | - | 160,000 |
| Supercritical CO2 Technology | 22,430 | 16,000 | 14,500 | 15,000 | 95,000 | - | - | - | 235,930 |
| NETL Coal R&D | 54,000 | 61,000 | - | - | - | - | - | - | 442,360 |
| Transformatioal Coal Pilots | 25,000 | 20,000 | 10,000 | - | - | - | - | - | 140,000 |
| **Total** | **486,230** | **490,800** | **446,800** | **469,000** | **514,000** | **428,000** | **428,000** | **309,000** | **7,233,306** |

Source: CRS, "Carbon Capture and Sequestration (CCS) in the United States," https://www.congress.gov/crs-product/R44902 and TCS compilation of annual appropriations.

Note: Appropriation totals before FY2012 reflect total funding for coal programs. After FY2012, DOE reorganized its budget reporting and no longer differentiates between coal and other fossil fuels, so CCS program totals include mostly coal programs but include CCS spending on other types of fossil fuels as well.

# Endnotes

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