Memorandum

TO: EARTHJUSTICE, ENVIRONMENTAL LAW & POLICY CENTER, AND SIERRA CLUB

FROM: LUCY METZ AND DEVI GLICK

DATE: JANUARY 21, 2026

RE: COST OF CONTINUED OPERATION OF CULLEY UNIT 2 AND SCHAHFER UNITS 17–18 UNDER FEDERAL POWER ACT ORDERS

Executive Summary

Three coal units in Indiana—Culley 2, Schahfer 17, and Schahfer 18—were scheduled to retire at the end of 2025. However, the U.S. Department of Energy (DOE) issued two orders requiring the units to continue operating beyond their planned retirement dates.[1] This is concerning based on both cost and environmental impact.

We find that continued operation of the three units under economic commitment practices will result in net-costs[2] to the plant owners of $229,000 per day or $20.6 million over the initial 90-day order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18. If DOE additionally requires the three units to operate under a must-run commitment status (i.e., to remain online at a minimum dispatch level regardless of whether it is economic to do so), net losses would be even higher at $250,000 per day, or $22.5 million over the initial order period. Under either economic or must-run dispatch, costs will likely be passed on to ratepayers in the region—not taxpayers at large. We calculate these net losses based on the short-term gross costs associated with operating the coal units (fuel, variable operations and maintenance (VOM), and fixed operations and maintenance (FOM) costs) and the energy market revenues the units earn. These calculations assume that Schahfer 18 will be available over the 90-day period, although NIPSCO has stated Schahfer 18 will need repairs that will take longer than the initial 90-day period.

We assume that the units have no capacity value over the order period, based on the timing of MISO capacity auctions and the requirements of the DOE order, as we describe in more detail below.

The estimates above include short-term costs only. If DOE extends the order long-term, we estimate the coal units would require an additional $33.7 million per year in capital expenditures to replace

[1] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.

[2] Net costs refer to gross costs net of MISO market energy revenues.

equipment as it wears out and install environmental controls to maintain compliance with environmental regulations.

Introduction

The Trump Administration's DOE has used authority under Section 202(c) of the Federal Power Act to issue several orders requiring power plants to remain online past their scheduled retirement dates. DOE first took this action with the J.H. Campbell Power Plant, a 1.5 GW coal plant in Michigan, on May 23, 2025. The initial order extended for 90 days. Since then, DOE has continued to issue orders extending the requirement for Campbell; the most recent order goes through mid-February 2026.[3] DOE issued similar orders for Eddystone Generating Station, an oil- and gas-fired power plant in Pennsylvania; Centralia Generating Station, a coal-fired plant in Washington; and Craig Station, a coal-fired plant in Colorado.[4]

Additionally, on December 23, 2025, DOE issued two Section 202(c) orders covering three coal units in Indiana scheduled to retire at the end of 2025: Culley 2, Schahfer 17, and Schahfer 18 (Table 1).[5] In this memo, we estimate the costs of a DOE order forcing Culley 2 and Schahfer 17–18 to remain online and generating electricity after December 31, 2025.

Table 1. Coal units scheduled for retirement

Unit	Location	Nameplate capacity (MW)	Online year	Scheduled retirement date	Owner
Culley 2	Warrick County, IN	103.7	1966	End of year 2025	CenterPoint
Schahfer 17	Jasper County, IN	423.5	1983	End of year 2025	NIPSCO
Schahfer 18	Jasper County, IN	423.5	1986	End of year 2025	NIPSCO

Source: U.S. Energy Information Administration (EIA) Form 860, 2024 release. NIPSCO is the Northern Indiana Public Service Company.

Methodology

We calculate the incremental cost of operating the units over the initial 90 days of the order (i.e., the net loss incurred by the unit owners relative to alternative resources), based on the coal units' short-term costs and energy revenues. Short-term costs include fuel, VOM, and FOM. We assume that in the short term, unit owners will not have time to make additional capital investments in the units. For any

[3] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.

[4] Ibid.

[5] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

units that were not operable as of the start date of the order, unit owners will likely not be able to complete the capital investments necessary to make the unit operable. However, for the sake of this analysis, we assume that each unit is operable for the 90-day period.

We also calculate the energy market revenue that the units generate over the order period. We assume that the units do not have any avoided capacity value, as explained below. We then calculate incremental costs by taking the difference between the gross short-term costs and the energy market revenue.

Finally, we calculate long-term costs if DOE orders the units to remain online for a year or more, including sustaining capital expenditures necessary to replace equipment at end-of-life and maintain environmental compliance.

Short-Term Gross Costs

To calculate short-term gross costs, we first estimate the capacity factors of the units using historical hourly generation data published by the U.S. Environmental Protection Agency.[6] We include two scenarios for capacity factors: one representing economic commitment (Table 3) and the other representing must-run commitment (Table 4 and Table 5):

- In the economic commitment scenario, we assume that the capacity factor of each unit during the term of the DOE order will be consistent with its average capacity factor over the past six years (2020–2025).
- In the must-run scenario, we re-calculate the capacity factor assuming that the units are committed in all hours. In hours when a unit was historically offline, we instead assume that generation never falls below the minimum dispatch level shown in Table 2, except for hours when the plant is in planned or unplanned outage.

We use outage rates, as shown in Table 2, from the North American Reliability Council's (NERC) Generating Availability Data System for coal units of a similar size to Culley 2 and Schahfer 17–18.[7] We then translate both sets of capacity factors into monthly quantities of coal consumption using heat rates from Horizon's National Database.[8] In Table 4, we apply outages evenly throughout the year for simplicity; in reality there would likely be several long planned maintenance outages in the spring and

[6] U.S. Environmental Protection Agency Clean Air Markets Program Data (CAMPD). 2025. Available at: https://campd.epa.gov/data/custom-data-download.

[7] North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures.

[8] More information on Horizon Energy's National Database is available at https://www.horizons-energy.com/encompass/. Data in this dataset is from various sources, including: (1) the U.S. Energy Information Administration, (2) U.S. Environmental Protection Agency, (3) North American Electric Reliability Corporation, (4) Federal Energy Regulatory Commission (FERC), (5) ISO New England, and (6) various trade press announcements.

fall, and then shorter outages scattered randomly throughout the year. In Table 5, we do not apply any outages.

We project coal prices during the order period based on historical coal price data for each unit from the U.S. Energy Information Administration[9] and a year-on-year price trajectory for future years from Horizon's National Database. Because there is no consistent monthly pattern in the historical coal prices, we project fuel prices on an annual basis. We calculate total fuel costs by multiplying monthly coal consumption by fuel price. Finally, we estimate VOM and FOM using unit-specific values from the Horizons National Database.

Table 2. Coal unit parameters

Quantity	**Culley 2**	**Schahfer 17**	**Schahfer 18**
Minimum dispatch (MW)*	50	110	110
Heat rate (MMBtu/MWh)	12	11	11
Percent of hours in planned or unplanned outage	17%	18%	18%
Variable operations and maintenance (2025$/MWh)	$11	$8	$8
Fixed operations and maintenance (2025$/kW-year)	$66	$56	$56
Coal price in 2026 (2025$/MMBtu)	$2.95	$4.55	$4.55

Sources: Horizon's National Database; EIA Form 923, 2020–2024 releases and 2025 release through September 2025; and North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures. To convert FOM costs from $/kW-year to $/MWh, multiply the value shown in the table by 1,000 kW/MW, divide by 8,760 hours/year, and then divide by the capacity factor.
**Note that the minimum dispatch level for Schahfer 17 and 18 differs based on source. We relied on EIA numbers, but looking at hourly CAMPD data, the minimum level looks closer to 160 MW.*

Energy Market Revenue

The coal units receive MISO energy market revenue during hours when they are online. We use market revenue to represent the avoided energy cost of the units—the costs that unit owners would have incurred to replace the energy from the units, if the units had been allowed to retire on schedule. To the extent that a utility would have otherwise relied on a resource that was less costly to operate than market energy, the reported savings would be even larger than what we estimate here. To estimate energy market revenue, we use around-the-clock energy market price projections from CenterPoint and

[9] EIA form 923, 2020–2024 releases and 2025 release through September 2025. Available at: https://www.eia.gov/electricity/data/eia923/.

NIPSCO's most recent integrated resource plans. The price is $43 per MWh (2025$) in 2026 for CenterPoint and $45 per MWh (2025$) for NIPSCO.[10,11]

We assume that the coal units do not have any capacity value, because the DOE orders require that the units "shall not be considered a capacity resource."[12] Additionally, the MISO capacity auction (Planning Resource Action or PRA) for the current planning year, which goes through May 31, 2026, occurred last spring.[13] The coal units were not bid in at this time because they were scheduled to retire. In general, resources that did not participate in the PRA can bid as replacement resources and receive zonal resource credits (ZRC) instead.[14] However, given that the DOE order says the coal units are not considered capacity resources, it seems unlikely they would have the opportunity to earn this revenue.

Short-Term Incremental Costs

We calculate the incremental cost of continued operation of the units by taking the difference between the short-term gross costs and the energy market revenues generated by each unit. The incremental cost represents the net loss that CenterPoint and NIPSCO will likely incur and pass on to their ratepayers because of the DOE order.

Long-Term Costs

In addition to any repairs needed in the near term to restore units to an operable condition, if DOE continues to order the units to operate long term, the units will require additional capital investments to replace equipment components that wear out and maintain compliance with environmental regulations. We estimate sustaining capital expenditures using a Sargent and Lundy survey of U.S. coal plant capital expenditures as a function of unit age.[15] There are no avoidable long-term costs associated with alternative resources.[16]

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[10] CenterPoint Energy. 2025. *2025 Integrated Resource Plan.* Available at: https://www.centerpointenergy.com/en-us/business/services/integrated-resource-plan?sa=in.

[11] NIPSCO. 2024. *Integrated Resource Plan.* Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf.

[12] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

[13] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Appendix K.

[14] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Section 6.4 Replacement Resources.

[15] Sargent & Lundy. 2018. *Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs.* Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[16] There is no evidence that specific fixed or capital costs are being delayed or deferred at other resources as a result of the coal units being kept online.

Results

Short-Term Gross and Incremental Cost Results

The total gross cost to continue operating Culley 2 and Schahfer 17–18 for 90 days past December 23, 2025, is $512,000 per day, assuming economic commitment (Table 3). Over the 90-day initial order period, this adds up to a total gross cost of $46 million, including $4.2 million for Culley 2, $22.8 million for Schahfer 17, and $19.1 million for Schahfer 18. Table 3 shows the breakdown of these costs between fuel, VOM, and FOM.

Over the initial order period, the three units combined receive $25 million in energy market revenue, assuming economic commitment. Revenue is much lower than gross costs over this period, indicating that the unit owners incur net losses because of the DOE order. Continued operation of the plants causes a net loss of $229,000 per day, for a total of $20.6 million over the order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18.

Table 3. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under economic commitment

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	24%	33%	26%	—
Fuel costs (thousands 2025$)	$1,939	$14,586	$11,399	$27,924
VOM (thousands 2025$)	$581	$2,350	$1,837	$4,768
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$4,200	$22,777	$19,077	$46,054
Energy market revenue (thousands 2025$)	($2,326)	($12,964)	($10,131)	($25,421)
Incremental (net) cost (thousands 2025$)	**$1,874**	**$9,814**	**$8,946**	**$20,633**
Gross cost per day (thousands 2025$/day)	**$47**	**$253**	**$212**	**$512**
Incremental (net) cost per day (thousands 2025$/day)	**$21**	**$109**	**$99**	**$229**

Notes: Gross costs are the sum of fuel costs, VOM, and FOM. Incremental costs are equal to gross costs minus energy market revenues.

If DOE additionally requires the three units to operate under a must-run commitment status, gross costs will be higher at $617,000 per day (Table 4). This results in a total gross cost of $56 million over the initial 90-day order period, including $6.6 million for Culley 2, $25.5 million for Schahfer 17, and $23.4 million for Schahfer 18. The higher costs are a result of the increased capacity factors in this scenario, which result in higher fuel and variable operations and maintenance costs. Net losses in this scenario are also higher at $250,000 per day, or $22.5 million over the entire study period. These results, shown in Table 4, assume average planned and unplanned maintenance outages. Table 5 shows must-run results assuming there are no planned or unplanned outages to book-end the results.

Table 4. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment assuming maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	47%	38%	34%	–
Fuel costs (thousands 2025$)	$3,754	$16,960	$15,156	$35,869
VOM (thousands 2025$)	$1,124	$2,733	$2,442	$6,299
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$6,558	$25,534	$23,440	$55,531
Energy market revenue (thousands 2025$)	($4,504)	($15,074)	($13,471)	($33,048)
Incremental (net) cost (thousands 2025$)	**$2,055**	**$10,460**	**$9,969**	**$22,484**
Gross cost per day (thousands 2025$/day)	**$73**	**$284**	**$260**	**$617**
Incremental (net) cost per day (thousands 2025$/day)	**$23**	**$116**	**$111**	**$250**

Table 5. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment without maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	55%	43%	39%	–
Fuel costs (thousands 2025$)	$4,423	$19,089	$17,285	$40,797
VOM (thousands 2025$)	$1,324	$3,076	$2,785	$7,186
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$7,428	$28,006	$25,912	$61,346
Energy market revenue (thousands 2025$)	($5,307)	($16,966)	($15,363)	($37,636)
Incremental (net) cost (thousands 2025$)	**$2,121**	**$11,040**	**$10,549**	**$23,710**
Gross cost per day (thousands 2025$/day)	**$83**	**$311**	**$288**	**$682**
Incremental (net) cost per day (thousands 2025$/day)	**$24**	**$123**	**$117**	**$263**

The Campbell coal plant, which has been operating under a Section 202(c) order since late May 2025, provides a point of comparison for these results. In a recent filing with the U.S. Securities and Exchange Commission, Consumers Energy, the owner of Campbell, reported incurring $164 million of gross costs to keep the plant online from late May through the end of September.[17] This is equivalent to $835 per

[17] Consumers Energy reported that it incurred a net loss of $53 million in the first order period, after applying $67 million in MISO revenues. For the portion of the second 202(c) order period through the end of September 2025, it incurred a net loss of $27 million after applying $17 million in revenue. This implies that total gross costs to operate the plant over both time periods was $164 million. See Consumers Energy Company Form 10-Q for the quarterly period ending September 30, 2025, filed with the U.S. Securities and Exchange Commission (SEC).

MW-day. Table 6 shows the gross cost results for Culley Unit 2 and Schahfer Units 17–18 converted to $/MW-day. Culley and Schahfer would have costs of $450–$598 per MW-day under economic commitment, which is 28–46 percent less than the cost at Campbell. Under must-run commitment (with outages), costs for Culley and Schahfer are in the range of $615–703 per MW-day, 16–26 percent less than the cost at Campbell. This suggests that the cost estimates presented here are conservative.

Table 6. Cost results for Culley and Schahfer converted to $/MW-day

Quantity	Culley 2	Schahfer 17	Schahfer 18
Gross costs under economic commitment (2025$/MW-day)	$450	$598	$501
Gross costs under must run commitment (with outages) (2025$/MW-day)	$703	$670	$615

There are several reasons that the cost to operate a unit beyond its planned retirement date may be higher than the historical cost to operate that unit. For example, plant owners may need to re-hire workers who have already found alternative employment, which can increase labor costs. Fuel costs may also be higher than historical values, especially if plant owners are not able to commit to long-term contracts for coal, given the uncertainty about how long the Section 202(c) order will extend. Additionally, a plant owner may have ramped down maintenance as the expected retirement of the asset approached. This means there may be a backlog of deferred maintenance required at the time the plant is re-started.

Long-Term Cost Results

In the long term, sustaining capital expenditures could add $33.7 million per year to the cost of operating the units, using generic assumptions for annual capital spending as a function of coal unit age (Table 7). If DOE orders the units to operate through 2030, the net present value of sustaining capital expenditures from 2026–2030 would be $156 million, including $18 million for Culley 2, $69 million for Schahfer 17, and $68 million for Schahfer 18. These totals include the annual investment value only and not the total associated revenue requirement (i.e., they do not include the cost of capital). They also do not include the cost of any near-term repairs necessary to make a unit operable. We understand from NIPSCO remarks at a recent Indiana Utility Regulatory Commission forum that Schahfer 18 requires repairs that could take over six months to make it operable again.[18]

Available at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/676cb715-625b-4823-9435-1f928f1880bd.pdf.

[18] David Speakman. WFFT-TV. “Earthjustice warns NIPSO to not pass on coal plant reopening costs to customers.” January 2, 2026. Available at: https://www.wfft.com/news/earthjustice-warns-nipsco-to-not-pass-on-coal-plant-reopening-costs-to-customers/article_5b0fdb80-4310-4328-83cf-5c7947ab6247.html.

Table 7. Estimate of sustaining capital expenditures if units remain online long-term

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Cost in 2026 (thousands 2025$)	$3,957	$14,999	$14,793	$33,749
Net present value of costs 2026–2030 (thousands 2025$)	$18,235	$69,156	$68,218	$155,610

Source: Sargent & Lundy. 2018. Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Net present value calculation uses a discount rate of 7 percent, reflecting a typical nominal discount rate for a regulated utility.

As with the short-term costs, the estimates of sustaining capital expenditures presented here are conservative. Utilities tend to ramp down capital investment ahead of a unit's planned retirement. Utilities may also choose retirement when faced with high environmental compliance costs. This makes it more likely that units such as Culley and Schahfer operating beyond their planned retirement date will require substantial investments to replace aging equipment and ensure continued compliance with environmental regulations, beyond the investments necessary for units of similar age which had not planned to retire.