Unpacking the Cost of 202(c) Orders: Facility-Specific Cost Estimates and Methodological Approach

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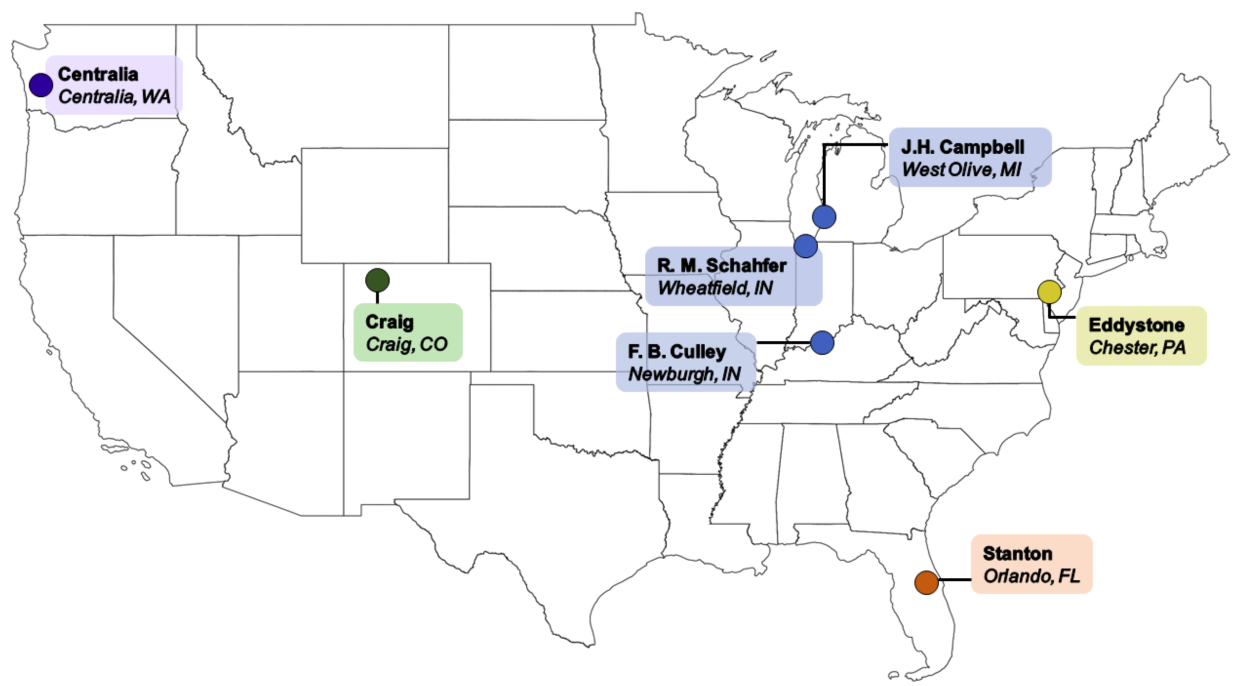
As of today, seven facilities across the U.S. which had previously planned to retire have received 202(c) orders from the U.S. Department of Energy (DOE) forcing the facilities to stay online. The majority (six of the seven) are coal-burning facilities. Conservative estimates from the best available data sources put the cost of keeping these facilities online past their approved retirement dates in the hundreds of millions of dollars, with cost impacts increasing daily.[1] This document provides an in-depth explanation of the facility-level financial impacts caused by these 202(c) orders to date. **This document is a dynamic resource, and will be updated as new or updated information becomes available on facility-specific costs.**



[1] 202C Cost Estimate Calculator, https://www.sierraclub.org/burningmoney

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How do we evaluate estimated costs?

Untangling rate allocation is a difficult and opaque process. There are a number of layers and many actors between an energy generation facility and an individual customer's utility bill. The lack of publicly available data (including publication delays for unit operations and cost recovery filing for operational expenses) creates further challenges for updating cost estimates. This analysis therefore determines, using the best available data for each facility, the 202(c) order costs associated with each facility. We do this by 1) preparing an estimate for the **"gross" (total) daily cost** of continuing to operate targeted facilities, 2) estimating any revenues that targeted facilities were able to recuperate via energy and capacity sales, and 3) subtracting revenues from total cost to determine a **"net" cost,** for which we expect facilities will seek cost recovery.

What exactly does that mean? Put differently, the difference between gross cost and net cost accounts for any revenue that a utility can make on energy sales, offsetting the expenses to operate. The "gross" costs represent the total costs of running the 202(c) plant. However, some generators operating under a 202(c) order are able to sell their electric output into a regional market and thereby defray their costs of complying with the order. This sale of electricity displaces other generators from the market, but does not increase market costs to consumers. To account for this defrayment of costs, our analysis provides the resulting "net" cost estimate, representing the marginal additional costs for which plant operators can be expected to seek reimbursement, most likely from ratepayers. Thus, the "net" cost estimate can be understood as the extra costs that the 202(c) orders impose on ratepayers. So far, the owners of most of the facilities operating under continuous 202(c) orders have already sought permission to charge ratepayers for their net costs. Stanton is the only facility that has yet to file for recovery.

As a final note, where actual cost recovery requests have been filed, our estimate includes all costs that plant owners have incorporated into their reimbursement requests.[2]

Facility-Specific Cost Analysis:

- Michigan: J.H. Campbell (West Olive, MI)
- Pennsylvania: Eddystone (Chester, PA)
- Washington: Centralia (Centralia, WA)
- Indiana: F.B. Culley (Newburgh, IN)
- Indiana: R.M. Schahfer (Wheatfield, IN)
- Colorado: Craig (Craig, CO)
- Florida: Stanton (Orlando, FL)

[2] For example, Consumers Energy has requested that MISO ratepayers reimburse it for the remaining undepreciated net book value of J.H. Campbell Units 1, 2, and 3. In Indiana, the cost for upgrading the Schahfer unit was included in NIPSCO's filing for cost recovery.

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West Olive, Michigan - J.H. Campbell

DOE issued an initial 202(c) order to J.H. Campbell units 1, 2, and 3 on May 23, 2025 for 90 days. The plant has since received five additional orders, for a total of six orders, each lasting 90 days. The plant remains operational pursuant to a 202(c) order to the date of last update.

We derive an approximate daily cost to keep Campbell online using the values reported from two documents: First, Consumers Energy's (the majority owner of Campbell) filing at FERC requesting cost recovery (Cost Recovery Filing of Consumers Energy Company under ER26-1138),[3] which requests reimbursements the first 90 days that the Campbell facility operated under a 202(c) order.[4] And second, Consumers Energy's annual 10-K form prepared for shareholders and filed with the Securities and Exchange Commission (SEC), which discusses the costs it incurred in the 2025 calendar year associated with running the Campbell facility under the 202(c) orders (SEC 2025 financial statement filing).[5]

Together, these filings report a net cost from 202(c) orders of $135 million in the year 2025, starting when the plant was first targeted in May 2025 (here, net cost reflects $290 million in gross costs and $155 million of reported market revenues).[6] **This is equal to an estimated net cost of $605,381 per day to operate the facility's three units for the 223 days[7] in 2025 that the plant was forced to operate.** To then prepare an estimate for the total cost of the J.H. Campbell coal-burning units under 202(c), this daily average is extrapolated across the duration of the subsequent 202(c) order periods, including the year to date in 2026, to derive a reasonable estimate of impacts on customer electric bills. **This results in over $270 million in calculated net costs to customers as of this document's latest update (August 16, 2026).**

[3] Cost Recovery Filing of Consumers Energy Company under ER26-1138, FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260123-5236&optimized=false&sid=2e6441f7-8422-4748-a4f6-002b4db2b283

[4] Consumers Energy has indicated that they might seek recovery for some limited costs associated with the first 202(c) orders in later filings. *See* Cost Recovery Filing of Consumers Energy Company Transmittal Letter at 13-14 ("[T]his cost recovery filing only includes Direct Legal and Consulting Costs incurred through the end of the May 2025 Order Duration Period. Any Direct Legal and Consulting Costs associated with the May 2025 DOE Order but incurred during the August 2025 DOE Order duration period will be presented in a separate cost recovery filing addressing that particular order.").

[5] Consumers Energy Filing to the Securities and Exchange Commission for the fiscal year ending December 31, 2025, filed February 10, 2026, https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115626000004/cms-20251231.htm

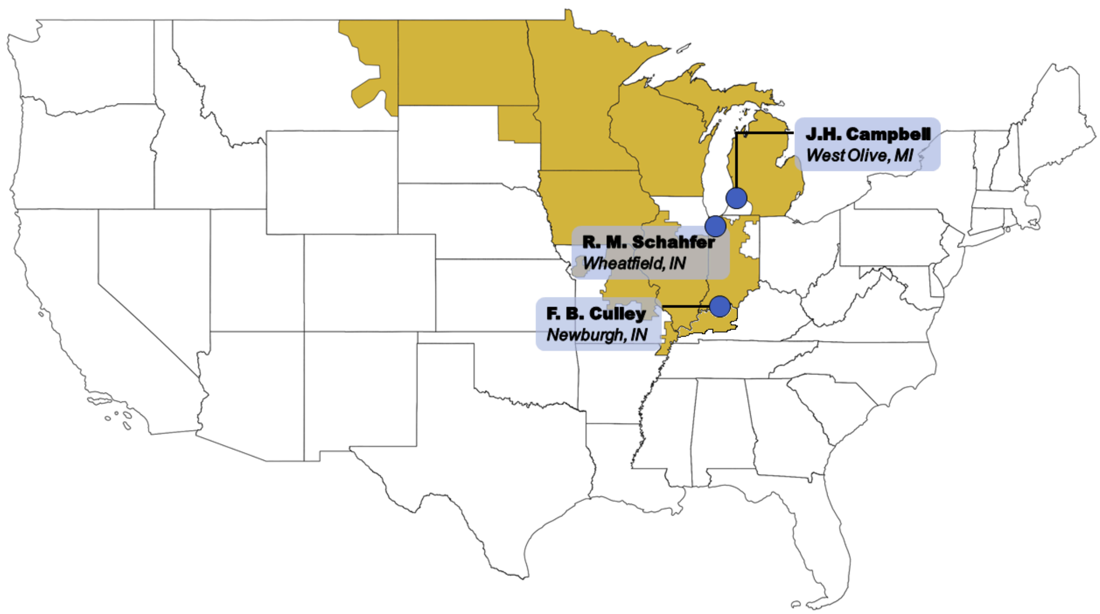
[6] Consumers Energy's cost request includes the remaining undepreciated net book value of Campbell, which it has included based on its determination that such recovery is authorized by Section 202(c); these costs were included because ratepayers across MISO are being asked to pay them.

[7] For the purposes of this analysis, the date at which the plant began operating pursuant to a 202(c) order was not the date the facility was planned to retire (May 31, 2025), but rather the date of the original order (May 23, 2025).

Consumers filed another series of cost recovery dockets on July 30, 2026 with FERC to recover the costs of the second and third 202(c) orders for the units at Campbell.[8] The cost values included within only offer specific costs associated with 3-month periods during 2025. However, the value filed in the 10-K filing offers a more accurate portrayal of the longer-term average cost of keeping the units online, and that estimate is used here instead of the FERC docket filings.

Since the original order, Consumers Energy had sought, and has now received, approval from FERC to charge customers in Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky for the costs of the Campbell plant. The area subject to cost recovery for the facility represents the northern region of the Midcontinent Independent System Operator (MISO) zones 1 through 7 (*the geographic extent of this region is approximated in gold on the map below*).[9]

FERC's approval of Consumers Energy's request foists costs on residents across this region who are also facing additional looming bill increases from 202(c) orders issued to the Cully and Schahfer facilities, both of which have requested to charge customers over the same territory.



[8] FERC docket ER26-3402-000, e-filing on July 30, 2026, see https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260730-5198&sid=cc931659-4a81-48f0-b1b4-cebeb3716a9f for the second order, and FERC docket ER26-3403-000, e-filing on July 30, 2026, see https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260730-5199&sid=cc931659-4a81-48f0-b1b4-cebeb3716a9f for the third order

[9] Order on Complaint re Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc. under EL25-90 et al., FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250815-3095&optimized=false&sid=28f0fe1a-d2c0-4d6d-8176-9e80386b67ac

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Chester, Pennsylvania - Eddystone Generating Station

DOE issued an initial 202(c) order to Eddystone Generating Station units 3 and 4 on May 30, 2025 for 90 days. The plant has since received four additional orders, for a total of five orders, each lasting 90 days. The plant remains operational pursuant to a 202(c) order. **To date, Eddystone is the only non-coal facility to receive any maximum duration 202(c) orders; the facility burns a combination of oil and gas.**

As of May 4, 2026, PJM (the regional grid operator in which Eddystone is operating) has provided public documents detailing the extent of rate recovery under the PJM tariff revisions filed (and approved by FERC) in 2025.[10] Supporting analysis of PJM's filing by the Natural Resources Defense Council (NRDC) found that the filed costs for recovery totaled $8,641,409 over the period from June 1, 2025 through February 28, 2026 (a 272-day period), and equal to $10.2 million since the start of the multiple 202(c) orders through May 3, 2026 (a 336-day period).[11] **This is equal to an average of $30,357 per day in net cost over the duration of all 202(c) orders.**

As NRDC's analysis further reports, the rates provided in the PJM filing were calculated for each month and are therefore not cumulative. This means that the months with $0 Eddystone's energy and ancillary service (AS) revenues fully covered its costs. A number of additional assumptions are built into this analysis, and reflect updates to PJM filings on the cost Eddystone has accumulated over the period of compliance with the ongoing 202(c) orders. Chiefly, January 2026 was revised to zero, likely due to cold weather operations). November 2025 was bifurcated into two rate costs and nearly doubled for the first 25 days of the month. The PJM settlement file lists 'PI costs' in the notes for those days (which likely means Project Improvements). This meaningfully translates to an additional $1.68M in ratepayer charges for capex to keep Eddystone running due to the 202(c) **on top** of what was already being subsidized before the rate true-up.

It's worthwhile to note that at present, the recovery filings that PJM has made public for Eddystone are largely in alignment with the historic operation costs for Eddystone based on 5-year past data made available by S&P. **Using that methodology, the estimated cost using average operating costs for the plant reported by S&P Global over a five year period (from 2020 through 2024, the most recent year with available data).** Over that period, the total annual

[10] 202C Cost Allocation Rates Eddystone, PJM, last updated May 4, 2026, see 202(c) Cost Allocation Rates data file, from https://www.pjm.com/markets-and-operations/billing-settlements-and-credit (or directly at https://www.pjm.com/-/media/DotCom/markets-ops/settlements/eddystone-202c-cost-allocation-rates.xlsx)
[11] Supporting analysis from NRDC (Dana Ammann and Casey Roberts), May 4, 2026, utilizing publicly available data from PJM (see 1)

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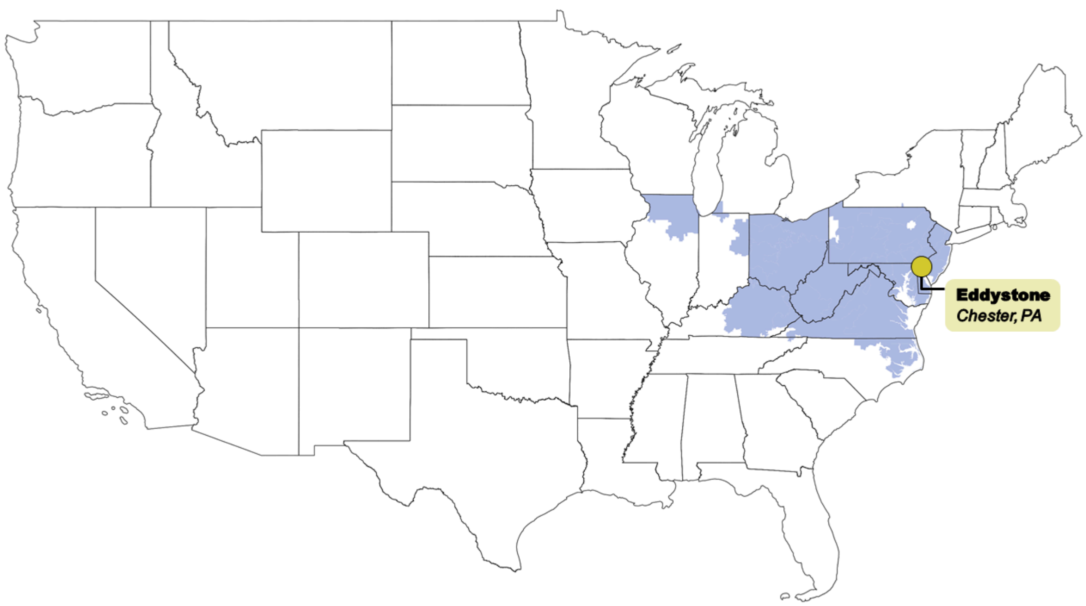
cost of operating the two units ranged from $10.4 million to $16.1 million. Finally, it's important to consider that this is an extraordinarily conservative estimate; any number of things could increase costs incurred from Eddystone's requirement to comply with this order (whether it operates or not). Relatedly, energy prices have an outsized impact on what the continual costs filed for Eddystone's compliance costs for the 202(c) order; as energy prices continue to increase (which in PJM, is the current trend forecast), the cost of compliance is also likely to increase.

As noted, Constellation Energy has secured approval to recover those costs from across all of PJM. PJM is the electric grid operator for the region which spans all or parts of 13 states across the Mid-Atlantic region (IL, IN, OH, MI, KY, WV, PA, NJ, MD, DE, VA, NC, TN) and D.C. (*shown in blue on the map*). The Federal Energy Regulatory Commission (FERC) has granted recovery for at least the first 202(c) order.[12] PJM has since filed to revise their tariff so that subsequent 202(c) order costs are recoverable through the same mechanism, indicating a high likelihood that all PJM customers will foot the bill for all subsequent 202(c) orders.[13]



[12] Order Accepting Tariff Revisions re PJM Interconnection, L.L.C. et al. under ER25-2653 et al., FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250815-3094&optimized=false&sid=28f0fe1a-d2c0-4d6d-8176-9e80386b67ac

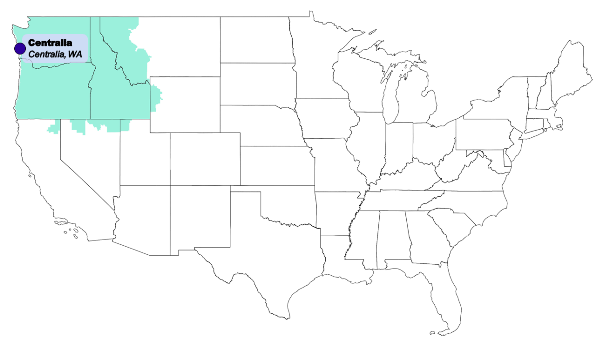
[13] PJM Critical Issue Fast Pass on FPA Section 202(c) Cost Allocation, Education on FPA Section 202(c) and DACC Cost Allocation, CIFP Day 1, Presentation given on June 10, 2025, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-doe-ca/2025/20250610/20250610-item-04-critical-issue-fast-path-doe-202c-cost-allocation-presentation.pdf

Centralia, Washington - Centralia Generating Station

DOE issued an initial 202(c) order to the Centralia Generating Station unit 2 on December 16, 2025 for 90 days. The plant remains operational pursuant to a second 202(c) order that was issued in June 2026 which goes through September 12, 2026. Prior to these orders, the owner, TransAlta, had agreed in 2010 to retire the coal facility in 2025. TransAlta has been preparing for the retirement and replacement of Centralia for the last decade, alongside partners in state government, regional grid operators, labor unions, and environmental advocates.

We derive an approximate daily cost to keep Centralia online using the values reported from TransAlta's filing at FERC requesting cost recovery,[14] which requests reimbursement of $19.8623 million for the fixed cost of keeping the plant operational for the first 90 days that the Centralia facility remained operational under a 202(c) order. **This is equal to an estimated net cost of $220,692 per day just to maintain the facility's ability to operate if called upon.** The order also requests provisional startup and operational fees, but Sierra Club analysts do not believe the plant has actually operated so our estimate ignores these requests so far–this also means **that the plant's gross costs are likely equal to its net costs**. This daily average is extrapolated across the duration of subsequent 202(c) order periods to derive a reasonable estimate of impacts of the Centralia 202(c) orders on customer electric bills, which yields over **$43 million in net costs to customers as of this document's latest update (August 16, 2026).**

In its request for recovery, TransAlta has sought recovery from four grid operators: Bonneville Power Administration (BPA), Gridforce, CAISO, and Powerex. These territories cover areas serving customers in all or parts of Washington, Oregon, Idaho, California, Montana, Wyoming, Nevada, and the Canadian province of British Columbia.[15] Some subset of customers will be impacted. The map at right shows the largest area within Bonneville Power Administration (BPA). However, it is still not entirely clear which subset of customers will be asked to pay, partially because two of the responsible entities (Gridforce and Powerex) are market participants who administer grid services over disparate and unconnected geographic footprints.



[14] Application for Cost Recovery of TransAlta Centralia Generation LLC under ER26-2422, FERC eLibrary, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260430-5425&optimized=false&sid=59be2029-c5ba-4774-bb80-3e88c8a93930.
[15] *Id.*

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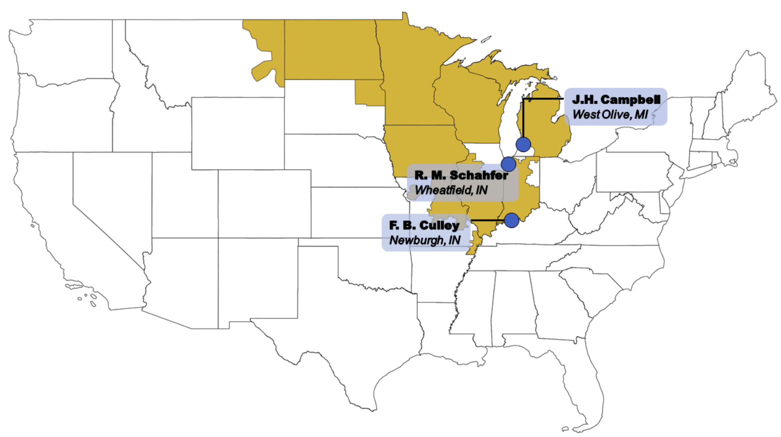
Newburgh, Indiana - F.B. Culley Generating Station

DOE issued an initial 202(c) order to the F.B. Culley Generating Station unit 2 on December 23, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order as of the date of last update, after receiving a second order in March 2026. The F. B. Culley facility is located in Indiana and owned by CenterPoint Energy. While CenterPoint Energy has not publicly posted information on operation costs for Culley Unit 2 while it has been operating pursuant to a 202(c) order, **a January 2026 analysis prepared by Synapse Energy Economics concluded that CenterPoint faces a net costs of approximately $21,000 per day to operate Culley Unit 2.** This amount was derived from an average gross cost of $47,000 per day.[16]

These estimates increase if CenterPoint runs Culley Unit 2 continuously as Consumers has done with Campbell: the facility would then have net costs of up to $24,000 per day, based on gross costs of up to $83,000 per day. These estimates do not include long-term maintenance and any capital costs needed to keep the plant running, which are estimated separately and would significantly increase the overall cost of compliance with ongoing 202(c) orders.

CenterPoint has requested permission from FERC to charge ratepayers across Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Indiana, Illinois, Missouri, and Kentucky (*see gold region approximated on map at right*) for the costs of Culley unit 2. This request would foist costs on residents who already are facing looming bill increases from the Campbell facility (in Michigan) and Schahfer (also in Indiana) subject to 202(c) orders, both of which have requested to charge customers over the same territory.



[16] Lucy Metz and Devi Glick, "Cost of Continued Operation of Culley Unit 2 and Schahfer Units 17–18 Under Federal Power Act Orders," prepared by Synapse Economics, (January 2026) https://www.sierraclub.org/sites/default/files/2026-01/burning-money-synapse-report-on-indiana-orders.pdf

Wheatfield, Indiana - R.M. Schahfer Generating Station

DOE issued an initial 202(c) order to the R.M. Schahfer Generating Station units 17 and 18 on December 23, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order after receiving a third order in June 2026. The R. M. Schahfer facility is located in Indiana and owned by the Northern Indiana Public Service Company (NIPSCO), and is located in Wheatfield, Indiana.

NIPSCO recently filed for permission from FERC to recover expenses associated with the Schahfer facility's costs under the 202(c) order.[17] The filing specifically asked for the depreciation costs plus operating costs for Schahfer for Q1 2026. In the filing, NIPSCO requested recovery of $38,046,241 on the basis of $68,575,699 of expenses, $33,501,717 in revenues, and $146,635 in carrying costs. The $38,046,241 is assumed only to reflect net costs accumulated in 2026 Q1, a duration of 90 days. **This is equal to $422,736 per day**, a value significantly higher than the per day conservative estimate that was prepared by Synapse Energy Economics for the facility, in part because the filing included the costs of rebuilding Unit 18.[18] Per SEC filings, until June 30, NIPSCO has spent $102.2 million to refurbish and run the units, and earned $33.5 million in MISO revenues, leading to a net cost of $363,492 per day. **However, to represent that this rebuild is reflected in cost recovery, it is being included in the estimate here, as well as in the associated cumulative cost tracker.[19]**

In that same filing, a handful of specifics stand out for how the cost recovery from the utility, NIPSCO, is being filed. First, unlike some of the other facilities that have also filed for cost recovery (i.e., J. H. Campbell in Michigan), NIPSCO is filing under the Federal Power Act (FPA) section 205, the section of the act used for filing normal rates. Under 205, FERC needs to respond within 60 days or a rate automatically goes into effect. FERC can add five months to the timer, but after five months the rate goes into effect subject to refund. Second, NIPSCO is also uniquely filing to recover "carrying costs," the short term interest "costs" incurred by the utility reflecting the time between when the utility incurred an expense and when it is allowed to start recovering the expense.[20] Finally, though not a function of the cost recovery per se, NIPSCO

[17] Cost Recovery Filing of Northern Indiana Public Service Company LLC under ER26-3423. Federal Energy Regulatory Commission. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260804-5179. See also, United States Securities and Exchange Commission (SEC), Form 10-Q filing, NiSource, Inc. Filing under Commission file number 001-16189. Available at https://d18rn0p25nwr6d.cloudfront.net/CIK-0001111711/882ac641-c6fa-42dd-ba0a-adba8b6f0a23.pdf

[18] Lucy Metz and Devi Glick, Synapse Energy Economics, "Cost of Continued Operation of Culley Unit 2 and Schahfer Units 17–18 Under Federal Power Act Orders," prepared by Synapse Economics, (January 2026) https://www.sierraclub.org/sites/default/files/2026-01/burning-money-synapse-report-on-indiana-orders.pdf

[19] See SierraClub.org/BurningMoney for the cumulative cost ticker.

[20] Along with that filing, NIPSCO included a comment in one of their submitted testimonies that "In the event that, at the end of the DOE 202(c) Orders, NIPSCO chooses to operate the Impacted Schahfer Units for the benefit of its traditional native load customers, NIPSCO will need to propose a solution to the Commission to address that issue." No other facility under extended issuance of 202(c) order(s) has indicated what they intend to do after the order(s) cease.

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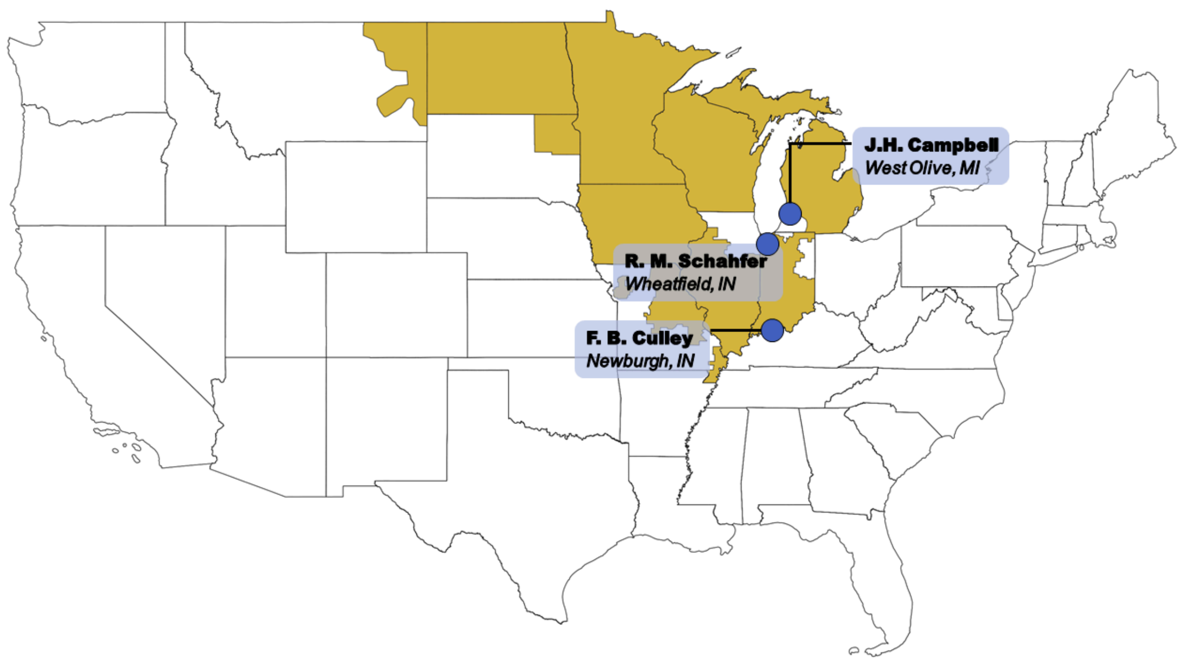
explicitly notes that they are not in environmental compliance, a condition legally permissible under the conditions of a 202(c) order.

We can compare this filing with estimates from a Synapse Energy Economics report that was released January 2026, which did not include the cost rebuild. This analysis estimated the net cost to keep unit 17 operational, but running infrequently. These estimates assume that Schahfer unit 18 incurs only fixed operations and maintenance costs while the turbine is repaired from a unit failure that destroyed one of the turbine blades, rendering it unable to operate, and it is assumed that unit 17 runs only when there are no cheaper generators that could supply energy to the grid.[21] Under these assumptions, the net cost per day of $173,944 was estimated, derived from a gross cost of $317,900 per day.[22] However, if unit 17 were to run continuously, costs would be even higher (concurrent with the updated cost estimate from NIPSCO's own SEC filing). Under these secondary assumptions, the estimate for net costs were upwards of $187,900 per day derived from gross costs of up to $375,900 per day.



[21] NIPSCO's president has estimated that the unit will take six months or longer to repair and "needs to be rebuilt." *See* comments at the IURC 2025 Winter Reliability Forum (Dec. 2, 2025) (video recording available at https://www.youtube.com/live/bCzALF4V45M?si=2pTcsnBZv98Qt2-T&t=3202.

[22] Lucy Metz and Devi Glick, Synapse Energy Economics, "Cost of Continued Operation of Culley Unit 2 and Schahfer Units 17–18 Under Federal Power Act Orders," prepared by Synapse Economics, (January 2026) https://www.sierraclub.org/sites/default/files/2026-01/burning-money-synapse-report-on-indiana-orders.pdf

Craig, Colorado - Craig Generating Station

DOE issued an initial 202(c) order to Craig Generating Station unit 1 on December 30, 2025 for 90 days. The plant remains operational pursuant to a 202(c) order after receiving a third order in June 2026. Prior to the order, the ownership group, led by Tri-State, had announced in January of 2020 that it would transition to new wind and solar projects.[23] Tri-State's CEO at the time said the responses to its request for proposals showed that "*wind and solar energy now comes in prices lower than the cost of generating with any fossil fuel, coal or gas,*" allowing it to close coal plants early without negative rate impacts. Under the utility's "Responsible Energy Plan," Tri-State had expected to be 50% renewable by 2024, and achieve a "70% reduction in CO_2 emissions [for] Colorado wholesale electric sales" by 2030, from 2005 levels.[24] The forced delay to planned retirement has undermined the utility's stated objectives, prompting the utility to pursue legal action against the federal administration's order.[25]

Estimates of the cost to maintain functionality at Craig are now available from initial cost filings from one of the facility's owners, Xcel Energy Colorado. In a June 2026 filing, Xcel stated that their share of the costs to operate Craig Unit 1 in 2026 was over $4 million "to date during 2026."[26] Xcel owns roughly 10% of Craig Units 1 and 2, and costs are allocated among the co-owners in proportion to their ownership share of Craig 1 and 2. For the purposes of this analysis, we extrapolate this cost reporting to other owner shares, resulting in a total estimated cost of $40 million for Craig Unit 1 through June 2026. Presuming this estimate is true to the language of the filing (e.g., "during 2026), this cost would represent costs from January 1st, 2026 through the month of June (June 30th, 2026), a period of 181 days.[27] **This equates to $220,994 per day.**

Unlike the case for other plants, the initial 202(c) order for Craig did not obligate the grid operator to use economic dispatch of the unit, though subsequent orders have required the grid operator to employ economic dispatch of the unit. However, the Southwest Power Pool (SPP), the grid operating region which Tri-State recently joined in April 2026,[28] has only dispatched

[23] "Tri-State will place coal plants with a gigawatt of new wind and solar," Clean Cooperative, February 9, 2020, https://www.cleancooperative.com/news/tri-state-will-replace-coal-plants-with-a-gigawatt-of-new-wind-and-solar
[24] Tri-State Generation and Transmission Association, Overview, Clean Cooperative analysis, 2020, https://www.cleancooperative.com/tristate.html
[25] Tri-State Generation and Transmission Association, Inc., & Platte River Power Authority, Petition for Rehearing, filed Jan. 29, 2026, https://tristate.coop/sites/default/files/PDF/Order%20No.%20202-24-14%20-%20Petition%20for%20Rehearing%20of%20Tri-State%20Generation%20and%20Platte%20River%20-%20FINAL%20COMBINED.pdf
[26] Case Nos. 26-1170, 26-1171, 26-1172, Motion for Leave to Intervene of Public Service Company of Colorado at 5 (D.C. Cir. motion filed July 23, 2026).
[27] Specific language from the filing (see ibid.) reads: "Public Service estimates that its share of the costs to comply with the Department's order has been more than $4 million to date during 2026."
[28] Southwest Power Pool (SPP) Western Expansion, Press Release, SPP, April 1, 2026, available at https://www.spp.org/western-services/rto-expansion/

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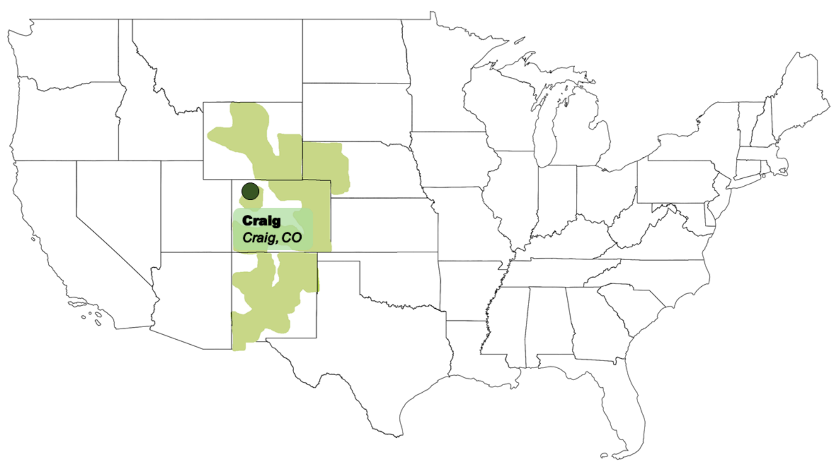
Craig unit 1 a handful of times in 2026.[29] As a result, we assume the plant has not operated, and that **the plant's gross costs are therefore functionally equal to net costs for the purposes of this estimate.**

We can further compare these costs with estimates from the [August 2025 analysis from Grid Strategies](https://www.sierraclub.org/sites/default/files/2025-08/grid-strategies-report.pdf), which calculated an annual gross cost to keep the Craig facility operational of $79,740,475, equal to approximately $218,467 per day.[30] This estimate is consistent with the extrapolated estimate from Xcel's June 2026 reported costs.

Regarding cost recovery, it remains to be seen if the plant owners will file a petition at FERC regarding the method for allocating costs to comply with the 202(c) orders for Craig Unit 1. Thus far, no such petition has been filed at FERC. If filed, it is also not clear who will be asked to pay. DOE attempted to justify the initial order by alleging an emergency existed over a different geographic footprint than the subsequent orders, which focus on the Rocky Mountain Assessment Area. Looking to the service footprint, we know that Tri-State sells power to a number of electric utilities throughout the mountain west (an approximation of the Tri-state footprint shown in green on map below, stretching from Wyoming down through Arizona),[31] and, as noted, joined SPP in April 2026; the other co-owners of Craig Unit cover additional portions of the West. If the co-owners file a petition at FERC, then FERC would decide how to allocate the compliance costs across all or a subset of Western utilities. .



[29] DOE Order No. 202-26-31, The State Of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request at 42 (July 24, 2026). Available at https://www.energy.gov/documents/2026-07-24-co-renewed-craig-petition-rehearing.
Excerpt from RFR reads: "*From the issuance of the Original Order on December 31, 2026, to the date of this request for rehearing, a period of almost seven months, Craig was only called up to run a handful of times, including once for about two weeks in April, which was immediately upon Tri-State and PRPA's entrance to SPP RTO, and for about a week in July. This means that Craig Unit 1 has run for a total of around two weeks in a seven-month period, and mostly at minimum capacity*" (page 42).
[30] https://www.sierraclub.org/sites/default/files/2025-08/grid-strategies-report.pdf
[31] Tri-State Cooperative, Utility Service Territory, https://tristate.coop/

Orlando, Florida - Stanton Energy Station

DOE issued an initial 202(c) order to Stanton Energy Station unit 1 on June 4, 2026 for 90 days. The terms of the order explicitly attribute the need to force Stanton out of retirement to data center development and the energy consumption needs of large load growth and artificial intelligence, citing plans for eight (8) data centers in Florida.[32] This is a notable justification given Florida Governor Ron DeSantis' May 2026 passage of SB484, which aims to protect Florida ratepayers from costs associated with data center development.[33]

Prior to the order, the owner, Orlando Utility Commission (OUC), had been preparing the facility for retirement since the Board formally approved the retirement in December 2021.[34] As of May 2026, just days before the DOE's order was issued, the facility was preparing to enter into what is known as "extended cold shutdown," a period required before final retirement during which the unit is completely non-operational. The decision to move the unit into extended cold shutdown and eventual retirement came with economics in mind. **Preliminary estimates from S&P modeled data put the gross cost of continuing to run the facility at $233,560 per day, equal to $2.70 every second.[35]** This assumes that total annual costs for the facility reflect the average annual cost of the facility over the last five years.

Leading up to the order, OUC had been working for the last five (5) years to prepare for the scheduled retirement. OUC had originally put formal plans in place for the coal units retirement in 2021, the same year they adopted goals to slowly transition their fleet to lower emissions alternatives and phase out coal. The goals were affirmed when, in April 2025, the utility published its ten-year site plan, detailing the purchase of the Osceola Generating Station (OGS), a gas-burning facility that they had purchased within their territory.[36] This purchase, the plan stated, would allow them to retire Stanton with complete confidence that there was sufficient generation to ensure reliability for OUC customers and continue making progress towards OUC's goal to decarbonize by 2050.[37]

[32] Department of Energy, Order No. 202-26-26, issued to the OUC on June 4th, 2026, available at https://www.energy.gov/documents/doe-emergency-order-no-202-26-26

[33] Florida Senate, CS/CS/SB 484: Data Centers, available at https://www.flsenate.gov/Session/Bill/2026/484/?Tab=BillText

[34] LGC Consulting and Energyonline, "OUC's Board Of Commissioners Approves Retirement of Coal Unit 1 and Conversion of Coal Unit 2 to Natural Gas at Stanton Energy Center," December 16, 2021, available at https://energyonline.com/Industry/News.aspx?NewsID=36159&OUC%27s_Board_Of_Commissioners_Approves_Retirement_of_Coal_Unit_1_and_Conversion_of_Coal_Unit_2_to_Natural_Gas_at_Stanton_Energy_Center

[35] S&P Global, Historic Modeled Cost(s) for Stanton Energy Station in Orlando, Florida

[36] Orlando Utilities Commission 2025 Ten-Year Site Plan,. APril 2025, prepared by NFront Consulting, available at https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/Orlando%20Utilities%20Commission.pdf

[37] The plan further spells out interim objectives for decarbonization. "OUC remains committed to meeting the EIRP's objectives, which include increasing solar energy and other renewable resources for electric generation, and reducing carbon dioxide emissions by 50% by 2030 and 75% in 2040 as compared to 2005 levels before reaching Net Zero emissions by 2050."

This is described in language taken directly from the OUC ten-year site plan, last updated April 2025:

"In December 2020 OUC finalized an Electric Integrated Resource Plan ("EIRP"), which provides a roadmap to enable OUC to achieve its goal of Net Zero Carbon by 2050, as well as interim goals of 50% carbon emissions reductions by 2030 and 75% carbon emissions reductions by 2040 as compared to 2005 levels. ***The first major steps outlined to achieve these carbon reduction targets were to convert one coal fired generating unit (Stanton Energy Center Unit 1) to cleaner-burning natural gas no later than 2025, convert the other coal unit (Stanton Energy Center Unit 2) to cleaner-burning natural gas no later than 2027, and install 1,524 MWac of solar and 350 MW of energy storage by 2030."*** [38]

It remains to be seen who will bear the responsibility of the costs associated with this order. Who pays will ultimately be decided by a filing the OUC will make before FERC, which FERC must approve. Possible groups of ratepayers who will pay for Unit 1 include OUC ratepayers alone, ratepayers in Florida Municipal Power Pool (FMPP) footprint, or a region that covers most of the Florida peninsula, SERC's FL-Peninsula region.

[38] The ten-year site plan further speaks to the confidence that OUC had in the determination to retire Stanton without any impacts to systemwide reliability. "*In September 2021, OUC purchased the Osceola Generating Station ("OGS"), which better enables large-scale solar farms by mitigating the intermittency of solar power, the utility's most viable source of renewable energy. The purchase of OGS also allows OUC to place its oldest coal-fired power plant, Stanton Unit 1 located in East Orange County at the utility's Stanton Energy Center ("SEC"), into extended cold shutdown by the end of May 2026 in lieu of converting this unit to cleaner burning natural gas. The OGS purchase further provides OUC an extra layer of resiliency with emergency backup fuel to help prevent power disruption events as seen in Texas in early 2022 and elsewhere in the United States since then.*"