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June 23, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2024 Transition Adjustment Mechanism.
Docket No. UE 420

Dear Filing Center:

Please find enclosed the redacted Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 105) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's Opening Testimony contains Protected Information that is being handled in accordance with Order No. 16-128. The confidential version of Exhibit AWEC/100 has been encrypted with 7-zip software and is being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served **Confidential Exhibit AWEC/100** upon the parties shown below by sharing an encrypted copy via electronic mail.

Dated this 23rd day of June, 2023.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u>
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2024 Transition Adjustment Mechanism.	)
	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

June 23, 2023

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EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in **Exhibit AWEC/101**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp dba Pacific Power ("PacifiCorp").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's 2024 Transition Adjustment Mechanism ("TAM") filing, including its $2.642 billion forecast of total-company Net Power Costs ("NPC") for calendar year 2024, which PacifiCorp calculated using the AURORAxmp ("AURORA") production cost model.[1] Including production tax credits ("PTCs") and other out-of-model adjustments, PacifiCorp has forecast a $2,361,354,814 total-company TAM revenue requirement, representing a $664,194,130 or 39.1% Oregon-allocated increase compared to the 2023 TAM.[2] Further, the proportion of system costs being allocated to Oregon are also increasing. Relative to the 2023 TAM, Oregon loads have increased by [redacted]%. Correspondingly, Oregon's share of system costs has increased from 24.9% to 28.5% using the

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[1] PAC/101, Mitchell/1:35.
[2] *Id.* at 1:41.

System Energy factor, and 26.0% to 28.7% using the System Generation ("SG") allocation factor.[3] These changes are significant, and the cost and policy implications of these dramatic changes need to be better understood. However, PacifiCorp only mentions them in passing.[4]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are detailed in Table 1, below, followed by brief descriptions of each issue.

Table 1
AWEC Recommended TAM Adjustments
(Whole Dollars)

		Total Company	Oregon Allocated
Filed TAM Revenues		**2,361,354,814**	**674,321,365**
A1	AURORA Model Version	(3,674,464)	(1,054,623)
A2	Hub Demands	(12,510,434)	(3,590,670)
A3	DA/RT Adjustment	(17,068,137)	(4,898,795)
A4	APS Short-Term Trans.	(7,937,458)	(2,278,162)
A5	Washington CCA	(72,970,628)	(20,943,596)
A6	Ozone Transport Rule	(202,475,788)	(58,113,398)
A7	PTC Rate	(2,707,340)	(777,045)
Total Adjustments		**(319,344,249)**	**(91,656,290)**
Adjusted		**2,042,010,565**	**582,665,075**

AURORA Model Version: I recommend PacifiCorp use the more recent AURORA version 14.2.1052.

Hub Demands: I recommend that hub demands, formerly known as market caps, be modeled consistent with the Commission's decision in Docket No. UE 390 (the 2022 TAM), Order 21-379.

[3] *Id.*
[4] PAC/100, Mitchell/6:16-21.

Day-ahead / Real-time Adjustment ("DA/RT"): I recommend that the DA/RT adjustment be modeled using only the outboard adjustment to sales and purchase prices.

Arizona Public Service ("APS") Short-Term Transmission: I recommend that uneconomic short-term transmission to Palo Verde be removed from AURORA.

Washington Climate Commitment Act ("CCA"): I recommend that Washington CCA compliance costs be removed from NPC.

Ozone Transport Rule: I recommend that Ozone Transport Rule costs be removed from NPC based on the final rule, which does not apply to Wyoming and is under legal review by the US District Court for application within Utah.

Production Tax Credit ("PTC") Rate: I recommend that the PTC rate be increased to 30 cents per kWh, consistent with inflationary trends expected through the end of 2023.

II. AURORA MODEL VERSION

Q. WHY HAVE YOU MADE AN ADJUSTMENT UPDATING AURORA TO VERSION 14.2.1052?

A. Energy Exemplar provides periodic updates to the AURORA model every few months. These updates generally include changes and improvements to the modeling environment and the model's algorithms. When preparing my analysis, I used AURORA version 14.2.1052, while PacifiCorp used version 14.2.1034 in preparing their initial filing. The analysis produced by version 14.2.1052 resulted in a $3,674,464 lower total-company NPC when using the more recent, updated version, compared with the version PacifiCorp employed. The difference is likely attributable to algorithmic improvements to the model in the newer version, although it is possible that some of the difference may be attributable to the different system architecture of my computer versus PacifiCorp's. Since the model is being run on different computers with different processors, there is the potential for the model algorithms to produce different results.

In either case, I recommend NPC be updated based on the results my model calculated, resulting in a $1,054,623 reduction to Oregon-allocated NPC.

III. HUB DEMANDS

Q. WHAT ARE HUB DEMAND LIMITS?

A. Hub demand limits in AURORA are the modeling assumption roughly analogous to the market caps modeling parameter included in the GRID model. Market caps were a specific modeling parameter programed into GRID to address alleged over optimization of the model algorithm at certain illiquid market hubs. The parameter established a hard limit on the maximum volume of sales that could be made at a market in any hour. The AURORA model, on the other hand, contains no specific modeling parameter limiting the volume of off-system sales, as GRID did. In fact, the AURORA model lacks capability to evaluate off-system sales altogether; the AURORA model was designed to simulate a regional dispatch, not a closed system dispatch as GRID was designed to do. It is only by means of complicated modeling workarounds that PacifiCorp was able to incorporate off-system sales and a closed system dispatch in AURORA. The workaround, which involved displacement of fictionalized loads at each market hub, will not fully be evaluated here, although it is likely that there are issues with this workaround. Nevertheless, when implementing this workaround, PacifiCorp limited the volume of fictional loads used to simulate off-system sales included in an AURORA table called "Hub Demand." This was done with the objective of duplicating market caps, although the approach was subject to modifications relative to the Commission-approved method for modeling market caps. Because the AURORA model does not optimize sales and purchases in the same way as the GRID model, it also produced different results.

Q. WHAT METHOD HAS THE PUBLIC UTILITY COMMISSION OF OREGON ("COMMISSION") APPROVED FOR MARKET CAPS?

A. Since implementation, market caps have been a controversial modeling assumption. Since the TAM began, the Commission has approved various methods for implementing market caps. The most recent method was approved in Docket No. UE 390 (the 2022 TAM), which established market caps based on the "third-quartile" approach Staff proposed.[5] Basically, the approach was to average the two highest monthly sales levels, both for heavy-load-hours and light-load-hours, over a four-year period.

Q. DID MARKET CAPS APPLY TO ALL MARKET HUBS?

A. No. The approved method was limited to illiquid market hubs, including the California-Oregon Border, Four Corners, Mead, and Mona. Highly liquid exchanges for power exist at the Mid-Columbia and Palo Verde markets. This negated the need for a market cap adjustment to those markets, which had not been subject to market caps since the 2015 TAM.[6] While I was unable to find a specific discussion of these markets in the 2015 TAM filing, **Exhibit AWEC/102** contains an excerpt from a then-contemporaneous Wyoming general rate case discussing the removal of market caps from the Mid-Columbia and Palo Verde markets. I can confirm based on my involvement in past TAM proceedings that PacifiCorp had similarly removed market caps from the Mid-Columbia and Palo Verde markets in the TAM at that time.

Q. DID PACIFICORP USE THE COMMISSION-APPROVED MARKET CAP METHOD FOR THE HUB DEMAND LIMITS IN AURORA?

A. No. Rather than using the "third-quartile" approach from the 2022 TAM, PacifiCorp used the four-year average approach, which the Commission rejected in the 2022 TAM. Further, hub

[5] Docket No. UE 390, Order 21-379, at 28 (Nov. 1, 2021).
[6] *See, e.g.*, Exhibit AWEC/102.

demand limits were added back in for the liquid Mid-Columbia and Palo Verde markets. While similar changes were also made in the 2023 TAM, this issue was resolved through a black-box adjustment via stipulation. The changes in the hub demand limits relative to the approved market cap method were never fully evaluated or resolved.

Q. WHAT IS YOUR RECOMMENDATION?

A. Lacking compelling justification otherwise, I recommend using the Commission-approved method for the hub demand limits (i.e., market caps), including the third-quartile approach and excluding the liquid Mid-Columbia and Palo Verde market hubs. Notwithstanding, continued use of a market caps assumption in AURORA altogether, needs to be evaluated. Accordingly, I recommend the continued use of market caps in AURORA be subject to further review and analysis in the 2025 TAM filing. Specifically, I recommend that the Commission require PacifiCorp to evaluate alternatives to the current method, including an approach which eliminates market caps, as well as an approach based on the 75th percentile of hourly sales.

Q. WHY DO YOU RECOMMEND EVALUATING AN APPROACH BASED ON THE 75TH PERCENTILE OF HOURLY SALES?

A. Using an average to set a maximum level of sales has the inherent result of producing a sales value that is less than the historical average. This is the main problem with PacifiCorp's use of average market caps. The third quartile approach the Commission approved recognized this by setting the maximum sales above the average, such that the result is more in line with the four-year average and actual sales capability. The method, however, relies on monthly values over the four-year period. It results in only four values being considered in the summary statistic. A similar analysis with hourly data – for example, evaluating the third-quartile sales level of all heavy-load-hours in June – will establish a larger sample size and a resulting value that is more reflective of the actual ability of PacifiCorp to make sales at individual markets. While I did not have the proper data to perform this analysis, evaluating this approach in the next TAM proceeding as a part of a holistic review of market caps would be appropriate.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Reverting to the Commission-approved method results in a $12,510,434 reduction to total-company NPC, with $3,590,670 allocated to Oregon.

IV. DAY-AHEAD / REAL-TIME ADJUSTMENT

Q. WHAT IS THE DA/RT ADJUSTMENT?

A. The DA/RT adjustment was a modeling adjustment made to the GRID model that adjusts the costs and revenues of system market purchases and sales relative to average monthly prices. The objective of the adjustment is to produce costs and benefits of market purchases and sales that are similar to the costs and benefits recognized historically. In GRID, PacifiCorp implemented two modifications to its modeling for the DA/RT adjustment. First, it modeled a spread between hourly sales and purchase prices in the GRID model itself. Second, it included an outboard adjustment to tie the impact of the modeled DA/RT adjustment to be equal to the historical impact of the DA/RT adjustment. With this second step, the first step became perfunctory, except to the extent that it modified the way thermal plants were dispatched. The detailed mechanics of the adjustment have been discussed extensively in prior dockets and will not necessarily be evaluated here. In AURORA, however, PacifiCorp has adopted similar modeling—both in-model price spreads, and an outboard adjustment tying to the historical average—albeit subject to different model limitations and algorithms.

Q. IS A DA/RT ADJUSTMENT NECESSARY IN AURORA?

A Not necessarily. The DA/RT adjustment was implemented to address a shortcoming in the GRID model. It has not been established that the AURORA model has the same limitations as the GRID model necessitating the DA/RT adjustment. Importantly, the two models use entirely different approaches to calculate dispatch. The GRID model calculated a transmission-constrained, least-cost dispatch using an hourly linear program. Although less is known about its proprietary algorithms, the AURORA model dispatch does not contain the same level of optimization as GRID. Unlike GRID, AURORA is based on merit-order dispatch, meaning it simply dispatches the lowest cost resources necessary to meet zonal load requirements. This approach works in a regional dispatch, where there are no external market sales or transfers into or out of the region that must be optimized. It does not necessarily solve for the optimal level of dispatch necessary for making market purchase and sales transactions, however. As a result of this limitation, the sales and purchases being made by AURORA are not optimized to the same degree as they were for GRID, raising the question of whether the DA/RT adjustment continues to be appropriate.

Q. HOW DOES AURORA MARKET DISPATCH COMPARE WITH HISTORICAL AVERAGES?

A. Use of the DA/RT adjustment in AURORA is producing the opposite effect that it did with the GRID model. In AURORA, it results in a modeled DA/RT adjustment value of $[redacted], which was $[redacted] greater than the $[redacted] historical average DA/RT adjustment. In comparison, I performed a separate model run with the DA/RT adjustment removed. It produced a DA/RT adjustment value that was $[redacted] less than the historical average. Thus, in AURORA, eliminating the in-model DA/RT adjustment resulted in a more accurate system dispatch relative to the historical average. Of course, these differences are otherwise offset in the second step of the DA/RT adjustment, the outboard adjustment which ties the modeled DA/RT impacts to the historical average. The only difference between the two scenarios studied is therefore the efficiency of thermal dispatch and since my alternative analysis produced results that were more consistent with the historical averages, it also produced a more accurate thermal dispatch.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given that the AURORA model is not optimizing purchases and sales in the same way as the GRID model, I recommend removing the in-model DA/RT adjustment, while retaining the outboard adjustment. The impact of this recommendation results in a $17,068,137 reduction to total-company NPC, with $4,898,795 allocated to Oregon.

V. APS SHORT-TERM FIRM TRANSMISSION

Q. PLEASE DISCUSS PACIFICORP'S ABILITY TO TRANSACT AT THE PALO VERDE MARKET.

A. Following the closure of the Cholla coal-fired power plant, PacifiCorp's long-term transmission with APS expired. These expiring rights included all of PacifiCorp's firm transmission rights to and from the Palo Verde market hub. Notwithstanding the expiration, PacifiCorp has continued to transact in the Palo Verde market by purchasing short-term firm transmission from APS. Most of these transactions, however, have been driven by an exchange agreement with the Public Service Company of Colorado ("PSCo"), which also is now expired. The PSCo Exchange delivered a material volume of physical power to the Palo Verde market and, given that PacifiCorp no longer had transmission access to the hub, PacifiCorp was required to either sell the power into the market or wheel it back to their balancing area using APS short-term firm transmission.

Q. WHAT SHORT-TERM FIRM TRANSMISSION DOES PACIFICORP MODEL WITH APS?

A. PacifiCorp includes $[redacted] of short-term firm wheeling expenses from APS in the Forecast Period. This value was calculated based on actual wheeling transactions over the 12-month period ending June 2022. Given the expiration of the PSCo Exchange, however, the historical pattern of wheeling transactions at Palo Verde is not necessarily relevant for setting rates on a going forward basis.

Q. HOW DOES PACIFICORP MODEL THE TRANSMISSION CAPABILITY GENERATED FROM THESE TRANSACTIONS?

A. PacifiCorp models APS short-term firm transmission based on a historical four-year average. Thus, in any hour, the model is allowed to transact up to, but not exceed, the historical, four-year average level. Like average market caps, the inherent result of using an average level to set the maximum value is short-term transmission capability that is less than the historical average. Thus, not only is there a disconnect between the time frames of when the transmission capability and wheeling expenses are measured—12 months versus 48 months—, the use of an average results in modeled short-term firm transmission capability that is less than the historical amounts otherwise being paid for in rates. It is typical, for example, for short-term transmission to be purchased opportunistically based on market conditions, not based on a flat average over a year.

Q. ARE THERE ECONOMIC BENEFITS IN USING SHORT-TERM FIRM TRANSMISSION TO ACCESS THE PALO VERDE MARKET IN AURORA?

A. No. I performed a model scenario evaluating the cost of removing short-term transmission access to the Palo Verde market. The result of the study was a $45,740 reduction to total-company NPC, even before considering the wheeling cost of the associated transmission to the Palo Verde market. That is, having access to the Palo Verde market is more expensive than not. This result is unintuitive and an indication that the modeling approach PacifiCorp developed is sub-optimal. If sales and purchases were being appropriately optimized, the addition of transmission capability to a market would never result in a higher NPC.

Q. HOW DO YOU PROPOSE TO ADDRESS THIS PROBLEM?

A. The issue surrounding the Palo Verde market may be indicative of a more significant flaw in the AURORA model workarounds that PacifiCorp has adopted to simulate a closed-system dispatch, though I have not fully evaluated the magnitude or extent of this flaw. Further study of this anomaly is necessary to conclude that the AURORA model dispatch is being appropriately optimized under PacifiCorp's modeling workarounds. For purposes of this testimony, I propose removing both the short-term wheeling cost and the associated transmission to Palo Verde from the AURORA model. The result is a $7,937,458 reduction to total-company NPC, with $2,278,162 allocated to Oregon.

VI. WASHINGTON CCA

Q. WHAT IS THE WASHINGTON CLIMATE COMMITMENT ACT?

A. The Washington CCA was passed by the Washington State Legislature in 2021. Among other things, the CCA established a "cap and invest" program, which requires certain covered entities to purchase compliance instruments administered by the Washington Department of

Ecology ("Ecology") in connection with carbon emissions from emitting resources, including electric generating facilities such as Chehalis.

Q. WHAT COSTS HAS PACIFICORP FORECAST FOR THE WASHINGTON CCA?

A. PacifiCorp has modeled an allowances cost adder for generation from the Chehalis gas-fired generating facility associated with the output allocated to states other than Washington. The impact of this assumption was a $72,970,628 increase to NPC on a total-company basis, with approximately $20,431,776 allocated to Oregon customers.

Q. IS IT REASONABLE FOR OREGON CUSTOMERS TO PAY THESE COSTS?

A. No. Complex legal issues arise with respect to the imposition of generation taxes and regulations that impact interstate commerce. Such legal issues will not be addressed here. They will be reserved for legal briefing. Based upon the advice of counsel, however, the facts support a conclusion that the Washington CCA, as applied to interstate generators such as Chehalis, is discriminatory towards Oregon ratepayers, and therefore, is not a permissible cost to include in the TAM.

Q. WHAT COSTS ARE ASSOCIATED WITH THE WASHINGTON CCA CAP AND INVEST PROGRAM?

A. Covered facilities must purchase carbon allowances that cover emissions associated with the facility based on the compliance obligation established by Ecology. However, Washington utilities subject to Washington's Clean Energy Transformation Act ("CETA") are allocated "no-cost" allowances that can be assigned to covered facilities (i.e., generators such as Chehalis). Utilities can use no-cost allowances to cover their compliance obligations, or they can auction the no-cost allowances. The revenues generated from the consignment to auction of no-cost allowances is unknown until the auction takes place because it depends on an auction process and prices in secondary markets. Notwithstanding, the supply of the allowances is controlled entirely by Ecology and the proceeds from all allowance sales, except for no-cost allowances provided for the benefit of in-state electric service customers, are paid to Washington State.

Q. IS THE WASHINGTON CCA APPLIED THE SAME TO IN-STATE AND OUT-OF-STATE ELECTRIC SERVICE PROVIDERS?

A. No. A key provision of the Washington CCA is that it provides no-cost allowances to electric service companies that are subject to CETA to offset the "cost burden" of complying with the CCA, which only serve to benefit Washington ratepayers. The cost burden of the program is calculated by Ecology using Washington, utility-specific demand and supply forecasts. These no-cost allowances are described in response to AWEC Data Requests 38 through 42, attached as **Exhibit AWEC/103.** No-cost allowances are not provided to electric service companies for the cost burden of compliance for retail service provided outside of Washington. In other words, PacifiCorp's Oregon customers are paying CCA compliance costs that are not equally applicable to PacifiCorp's Washington customers.

Q. WHAT IS THE MAGNITUDE OF THE COSTS ASSOCIATED WITH THE WASHINGTON CCA?

A. PacifiCorp models the Washington CCA as a $[redacted]/MWh increase to the cost of generating power from Chehalis. Absent the CCA, cost of power from Chehalis would otherwise be $[redacted]/MWh in 2024. Thus, the Washington CCA increases the cost of Chehalis by [redacted]%. This is a significant cost increase on the output of Chehalis. It is also an order of magnitude greater than generation taxes imposed by other states, such as the $1.00/MWh Wyoming wind tax, which impacts both in-state and out-of-state power uses.

Q. DOES OREGON HAVE ITS OWN POLICIES FOR DEALING WITH THE CARBON EMISSIONS FROM THE ELECTRIC UTILITY SECTOR?

A. Yes. Oregon investor-owned utilities are subject to both the Renewable Portfolio Standard and HB 2021, both of which are intended to reduce carbon emissions from electricity generation used to serve Oregon retail customers, the costs of which are borne by Oregon ratepayers. HB 2021 specifically creates clean energy targets applicable to investor-owned utilities like PacifiCorp and requires them to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers to 100 percent below baseline emissions levels by 2040. Notably, the requirements of HB 2021 are more aggressive than those in CETA, which forms the basis for the allocation of no-cost allowances to Washington utilities.

Q. WHAT DO YOU RECOMMEND?

A. Considering the foregoing, and subject to further legal analysis in briefing, I recommend that the Washington CCA allowance costs identified above be removed from the TAM.

VII. OZONE TRANSPORT RULES

Q. WHAT ARE THE OZONE TRANSPORT RULES?

A. The Ozone Transport rules were published by the Environmental Protection Agency ("EPA") on June 5, 2023. Among other things, the rules were designed to reduce the amount of ozone-forming emissions of nitrogen oxides. Under the rule, electric generators are required to follow specific state implementation plans designed to limit nitrogen oxide emissions. These plans were implemented for 22 different states, including Utah. A fact sheet on the program is attached as **Exhibit AWEC/104.**

Q. HOW DID PACIFICORP MODEL THE RULE?

A. It modeled the ozone transport rule as an annual limit on the amount of nitrogen oxide emissions from gas and coal facilities in both Utah and Wyoming, although the rule only applies to the months of May through September.

Q. IS PACIFICORP'S MODELING CONSISTENT WITH THE FINAL RULE?

A. No. Foremost, Wyoming was not subject to the final rule issued by the EPA. Further, PacifiCorp's approach of using an annual emissions limit is not consistent with the rule, which applies to the months of May through September.

Q. IS THE RULE BEING CHALLENGED?

A. The rules have been challenged and stayed in several jurisdictions.[7] Further, while an implementation plan has been proposed for Utah, a lawsuit filed on June 20, 2023 requests review of the rule.[8] Thus, the likelihood that the new rule will apply to Utah in 2024 is unknown, as it is possible that the implementation plan for Utah will be modified, overturned, or delayed by the pending lawsuit.

Q. WHAT DO YOU RECOMMEND?

A. Given that it is now known that the Ozone Transport Rule will not apply to Wyoming and the uncertainty surrounding Utah's implementation plan, I recommend removing PacifiCorp's Ozone Transport Rule modeling from AURORA. This adjustment reduces total-company NPC by $202,475,788, or $58,113,398 on an Oregon-allocated basis.

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[7] *See Texas v. United States EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898 (5th Cir. May 1, 2023).

[8] *See State of Utah v. United States EPA*, U.S. Court of Appeals for the District of Columbia Circuit, Petition for Review (June 20, 2023) *available at*: https://attorneygeneral.utah.gov/wp-content/uploads/2023/06/2023-06-20-Utah-DC-Petition-for-Review-of-FIP-1.pdf.

VIII. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRODUCTION TAX CREDIT RATE.

A. In its initial filing in this proceeding, PacifiCorp forecast a PTC rate of [redacted] cents per kWh. As I demonstrate in **Exhibit AWEC/105**, however, the PTC rate, which is set annually based on an index of inflation, will likely increase to 3.0 cents per kWh in 2024, and in no circumstance will the 2024 PTC rate be less than 2.9 cents per kWh. My recommendation is to use a 3.0 cents per kWh rate in this filing, which results in a $2,707,340 reduction to TAM revenues.

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The detailed mechanics of the PTC rate were discussed in my Opening Testimony in UE 390 (the "2022 TAM").[9] As noted in that testimony, the IRS adjusts the PTC rate each year by applying an inflation adjustment factor. The inflation adjustment factor is an indexed value calculated based on the GDP implicit price deflator, an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. The Bureau of Economic Analysis publishes the GDP implicit price deflator each quarter, and from that information, the expected GDP implicit price deflator value for calendar year 2023, which will be used to establish the 2024 PTC rate, can be assessed.

Q. DID THE INFLATION REDUCTION ACT IMPACT THE CALCULATION OF THE PTC?

A. While the Inflation Reduction Act ("IRA") imposes a new PTC rate for new renewable resources placed into service after December 31, 2021, the PTC rate calculation for resources placed into service prior to that date did not change. The IRA PTC rate for new resources is

[9] Docket No. UE 390, AWEC/100, Mullins/3:4-20.

approximately the same as the PTC rate for non-IRA resources, except that it is adjusted in smaller increments, using a slightly different formula. The PTC rate for post-2021 resources applies to repowered Foote Creek II-IV, although I did not prepare a similar analysis forecasting the PTC rate for those resources.

Q. HOW DID YOU FORECAST THE PTC RATE FOR 2024?

A. In **Exhibit AWEC/105**, I perform a forecast of the PTC rate for 2024 using the same analysis I presented in the 2022 TAM. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for the first quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 3.13% on an annualized basis for the remainder of 2023. Given recent indications, it is likely that inflation will exceed this level for the remainder of the year. For example, the annualized inflation rate for April 2023 inflation was 4.9%.[10] Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

10 U.S. Department of Labor, Bureau of Labor Statistics, *Consumer Price Index April 2023* (May 10, 2023) *available at*: https://www.bls.gov/news.release/archives/cpi_05102023.htm.

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EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

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MW Analytics is the professional practice of Bradley Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the western United States. Since starting MW Analytics in 2013, Mr. Mullins has sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, rate development, and new resource additions. MW Analytics also assists clients through informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory and other energy consulting services.

Education

- Master of Accounting, Tax Emphasis, University of Utah
- Bachelor of Finance, University of Utah
- Bachelor of Accounting, University of Utah

Relevant Prior Experience

PacifiCorp, Portland, OR: Net Power Cost Consultant 2010 – 2013

- Analyst involved in power cost modeling and forecasting
- Responsible for preparing power cost forecasts, supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations

Deloitte, San Jose, CA: Tax Senior 2007 – 2009

- Staff accountant responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients
- Joined to national tax practice specializing research and development tax credit studies

Recent Regulatory Appearances

Docket	Party	Topics
In re the Application of Avista Corporation dba Avista Utilities Requesting Authority To Revise Its Natural Gas Book Depreciation Rates And Deferred Accounting, Or.PUC Docket No UM 2277.	Alliance of Western Energy Consumers	Depreciation
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Natural Disaster Protection Plan, PUC Nv. Docket No. 23-03003	Caesars Enterprise Services, LLC; MGM Resorts International; Wynn Las Vegas, LLC; and Smart Energy Alliance	Wildfire Mitigation
In re NW Natural Gas Corporation, d.b.a NW Natural Renewable Natural Gas Adjustment Mechanism - Dakota City, Or.PUC Docket No UG 462.	Alliance of Western Energy Consumers	Revenue Requirement
In re Portland General Electric Company Request for a General Rate Revision, Or. PUC UE 416.	Alliance of Western Energy Consumers	Power Costs / Revenue Requirement

Docket	Party	Topics
In re the Application of Intermountain Gas Company for Authority to Increase Its Rates and Charges for Natural Gas Service in the State of Idaho, Id.PUC Case No. INT-G-22-07.	Alliance of Western Energy Consumers	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2021 Joint Integrated Resource Plan, PUC Nv. Docket No. 22-11032.	Caesars Enterprise Services, LLC; MGM Resorts International; Nevada Resorts Association	Resource Planning
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the Third Amendment to its 2021 Joint Integrated Resource Plan., PUC Nv. Docket No. 22-09006.	Caesars Enterprise Services, LLC; MGM Resorts International; Nevada Resorts Association	Transportation Electrification
In re Portland General Electric Company, Advice No. 22-18 New Schedule 151 Wildfire Mitigation Cost Recovery, Or.PUC Docket No. UE 412.	Alliance of Western Energy Consumers	Regulatory Accounting
In re PacifiCorp, Automatic Adjustment Clause for Wildfire Protection Plan Costs, Or.PUC Docket No. UE 407.	Alliance of Western Energy Consumers	Regulatory Accounting
In re Portland General Electric Company, Application for Authority to Amortize Deferred Amounts Related to 2020 and 2021 Wildfire and Ice Storm Emergency Events, Or.PUC Docket No. UE 408.	Alliance of Western Energy Consumers	Regulatory Accounting
In re PacifiCorp 2021 Power Cost Adjustment Mechanism, Or.PUC Docket No. UE 404.	Alliance of Western Energy Consumers	Power Cost Deferral
In re Portland General Electric Company, 2021 Annual Power Cost Variance Mechanism, Or. PUC UE 406	Alliance of Western Energy Consumers	Power Cost Deferral
In re Portland General Electric Company, Application Regarding Amortization of Boardman Deferral, Or.PUC Docket No. UE 410.	Alliance of Western Energy Consumers	Regulatory Accounting
In re the application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 22-06014.	Smart Energy Alliance and Caesars Enterprise Services, LLC	Revenue Requirement
In re the Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications Ut.PSC Docket No. 22-057-03.	Nucor Steel-Utah	Cost of Service, Rate Spread and Rate Design
In re Joint Application of Nevada Power Company d/b/a NV Energy ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC") for approval to merge into a single corporate entity, to transfer Certificates of Public Convenience and Necessity ("CPC") 685 Sub 20, 688, and 688 Sub 6 from SPPC to NPC, and to consolidate generation assets, PUC Nv. Docket No. 22-03028.	Wynn Las Vegas, LLC and Smart Energy Alliance	Merger
In re Puget Sound Energy Requests for a General Rate Revision, Wa.UTC Docket. UE-220026 (cons.).	Alliance of Western Energy Consumers	Revenue Requirement
In re Northwest Natural Gas Company, dba, NW Natural, Updated Depreciation Study Pursuant to OAR 860-027-0350, Or.PUC Docket No. UM 2214	Alliance of Western Energy Consumers	Power Cost Modeling

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In the Matter of	)
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EXHIBIT AWEC/102

EXCERPT OF DIRECT TESTIMONY OF GREGORY DUVALL
IN WYOMING DOCKET 20000-446-ER-14

REDACTED
Docket No. 20000-___-ER-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED Direct Testimony of Gregory N. Duvall

March 2014

Q. What are the terms of the transactions entered into by the Company as a result of the 2012 Gas RFP?

A. In August 2013 the Company executed two [redacted] contracts with J. Aron for a total volume of [redacted] Confidential copies of the executed contracts are provided as part of the filing requirements accompanying the Company's case. Prices are structured to be aligned with market prices at the time the transactions were entered into, [redacted]

Q. Why is it in the public interest for the Commission to approve these transactions as prudent long-term contracts?

A. It is in the public interest because of the dramatic fall in forward natural gas prices down from their 2008 apex, and because the Company utilized a robust competitive procurement solicitation process to identify the least-cost products to hedge a small percentage of the Company's future natural gas requirements with a variety of product types and terms.

GRID Modeling Improvements

Q. Has the Company modified its modeling to address any contested issues from the 2011 GRC?

A. Yes. In response to issues raised by parties in the Company's past cases, the Company refined the following inputs to GRID:

- *Market Capacity* - Sales restrictions on the Mid-Columbia and Palo Verde markets have been removed. The remaining markets continue to be limited by caps on wholesale sales based on the four-year average historical short term firm transactions, broken down by market, month and hour class. The Company's market capacity methodology is discussed in further detail later in my testimony.

- *"Must Run" Gas Plant Operation* - The 2012 Wind Study did not have resource-specific reserve requirements for Currant Creek and the Gadsby combustion turbines so these plants are now dispatched based on economics, rather than forced online to provide reserves. The 2012 Wind Study and its impact on integration costs in this case are discussed later in my testimony.
- *Chehalis Reserves* - As mentioned previously, the transmission system upgrades necessary to dynamically transfer the Chehalis plant into PACW were completed in November 2013. As a result, the Chehalis plant is now modeled with reserve-carrying capability throughout the test period.
- *Hydro Forced Outage Rates* - In the current case, the availability of hydro units with storage capability has been normalized to reflect forced outage levels by making a flat percentage reduction in capacity across all hours of the period, a method similar to that used for thermal units. The reductions to plant capacity are based on the outages from the same 48-month historical period used for thermal plants in this case. An additional adjustment to reflect energy lost due to forced outages is made to hydro generation based on historical measurements which began in January 2011. Adjusting for lost energy based on historical measurements captures the flexibility of hydro projects with storage capability to shift generation around outages, while accounting for the operating constraints that may prevent such shifts under certain circumstances.

the wind shaping methodology and how it improves the accuracy of NPC modeling are provided later in my testimony.

- *Integration Costs* - The Company's wind integration costs are now based on the 2012 Wind Study released in April 2013 as Appendix H to the Company's 2013 Integrated Resource Plan.[3] The 2012 Wind Study indicates that the estimated cost of wind integration has declined, primarily because of lower forecast natural gas and power market prices. Further details regarding integration costs in the test period are provided later in my testimony.
- *CAISO Fees* - Since January 1, 2013, when California's carbon cap and trade program took effect, electricity imported into California results in a carbon emissions allowance obligation. As a result, the Company has not sold power to the CAISO since that time. Previously, the Company included CAISO sales volumes and wheeling expense based on the 12-month historical period. To align with the recent change in operating practice, the sales volumes and associated wheeling expense have been removed from the test period in this case.

GRID Modeling Improvements - Market Capacity

Q. Please explain why the Company specifies market capacity limits, a.k.a. market caps, in GRID.

A. The GRID model automatically assumes unlimited market depth bound only by the Company's transmission constraints for system balancing sales and purchases; it does not account for load requirements, market illiquidity, or price elasticity that

[3] www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf.

would not allow the Company to make sales at a static forecast market price. The Company's transmission access to a market point limits its ability to sell its generation in that market; similarly, counterparties' demand for purchases is limited by their transmission access and their own load and resource balance. Without market caps, the GRID model has no constraints to reflect counterparties' inability to make economic transactions. Furthermore, because forecasted market prices are a static input into GRID, as long as there is available transmission capacity the GRID model will buy power at a market with a low price and sell power at a market with a high price, artificially reducing the modeled net power costs. Consequently, market caps have been an input to GRID since its inception, and the current method for calculating the caps was put in place in the Company's 2010 general rate case, Docket No. 20000-384-ER-10. In the current case, the Company has removed the market caps from the Mid-Columbia and Palo Verde markets.

Q. How are the market caps calculated?

A. For each market with a capacity limit in place, the allowable level of wholesale sales is specified for all hours based on a four-year historical average of both spot and short-term firm wholesale sales transactions, aggregated by month and HLH/LLH periods. In this case the four-year historical average has been updated to the period ending June 2013.

Q. Please further explain the static assumptions of market prices in GRID.

A. The Company's official forward price curve ("OFPC") produces an hourly price that remains static in GRID in each hour, regardless of the changes in load and resource balance. The driving force behind market prices in real-time is based on the dispatch cost of additional generation; therefore, an increase in load or reduction in resources will require that higher cost resources be dispatched, or vice versa. In reality, prices are impacted by changes in the loads and resources of all market participants, including the Company. Without market caps the GRID model will overestimate sales revenues as it continues to make sales at the static hourly market price, even though additional sales would push market prices down.

Q. Why has the Company removed the market caps from the Mid-Columbia and Palo Verde markets?

A. Market caps have been challenged in the past several general rate cases where parties have argued to remove all market caps. The Company proposes to remove market caps at Mid-Columbia and Palo Verde as a compromise position since these two markets are the most liquid market points to which the Company has access. These markets have many participants and are often used to balance the Company's load and resource position on a forward basis. This is not the case with the other market hubs in GRID. As a result, the Company's historical sales at the Mid-Columbia and Palo Verde markets may be more strongly aligned with the Company's resource position, rather than the position of the other counterparties in the market, as would be the case in the other market hubs modeled in GRID.

Furthermore, the short-term firm sales volume upon which market caps are based has been declining over time which has lowered the market caps. In past cases, the caps at the Mid-Columbia and Palo Verde markets exceeded the transmission capability and forward transaction position at these markets in all hours and had no impact on the model outcome. With the updated historical volume, the caps at these two markets would be lower than the transmission capability and forward transaction position and would restrict the GRID model's ability to transact at these two most liquid markets, counter to operational reality.

With the caps on Mid-Columbia and Palo Verde removed, the GRID model has more flexibility to sell in these markets, better reflecting the Company's actual operating potential.

Q. Did the Company change the calculation of the market caps for the remaining four markets modeled in GRID?

A. No. The market caps remain intact for the COB, Four Corners, Mona, and Mead markets. These markets are less liquid and the GRID model must continue to have constraints on the transactions that can occur at these markets. As discussed above, GRID will assume unlimited market depth at a static price if market caps are not in place.

GRID Modeling Improvements - Wind Generation Shape

Q. Please explain how the Company models wind generation in GRID.

A. Total energy from wind generation is included in GRID based on a "P50" forecast. A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than actual output. Typically such a forecast is developed by a third party for an individual wind project by combining wind speed measurements taken prior to the project being constructed with a detailed model of turbine locations and performance characteristics. The projected

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EXHIBIT AWEC/103

PACIFICORP RESPONSES TO DISCOVERY REQUESTS

UE 420 / PacifiCorp
June 2, 2023
AWEC Data Request 038

AWEC Data Request 038

Please provide transaction level details of each WA CCA allowance sales or purchase transaction that PacifiCorp has made since the WA CCA was enacted. For each transaction, please specify the purpose of the CCA allowance purchase or sale (i.e. whether the transaction was for a specific generating unit, market transactions, or some other purpose).

Response to AWEC Data Request 038

PacifiCorp objects to this request as outside the scope of this proceeding, requesting information that could subject the Company to violations in another jurisdiction, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, the Company responds as follows:

Consistent with Washington Administrative Code (WAC) 173-446-317 (2)(e), PacifiCorp cannot disclose bidding information including bid price or quantity.

UE 420 / PacifiCorp
June 2, 2023
AWEC Data Request 039

AWEC Data Request 039

Please identify the total amount of free WA CCA allowances that PacifiCorp has been awarded to date.

Response to AWEC Data Request 039

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

Consistent with the schedule published by the Washington State Department of Ecology, PacifiCorp has been awarded 2,489,384 no-cost allowances to-date.

https://apps.ecology.wa.gov/publications/documents/2302031.pdf

UE 420 / PacifiCorp
June 2, 2023
AWEC Data Request 040

AWEC Data Request 040

Please specify the total amount of free allowances that PacifiCorp expects to receive by year through 2026.

Response to AWEC Data Request 040

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

The Washington State Department of Ecology issued a summary of initial allowance allocations to electric utilities for 2023 through 2026.

https://apps.ecology.wa.gov/publications/documents/2302031.pdf

The forecast provided in the table below was submitted to and approved by the Washington Utilities and Transportation Commission (WUTC) at Order 01 in Docket UE-220789.

2023	2024	2025	2026
2,489,384	2,206,442	1,951,113	1,052,210

UE 420 / PacifiCorp
June 2, 2023
AWEC Data Request 041

AWEC Data Request 041

Please provide the forecast system dispatch calculations that were used to calculate the free allowance awards to PacifiCorp by the Washington Department of Ecology.

Response to AWEC Data Request 041

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

The Climate Commitment Act (CCA) allows electric utilities that are subject to the Clean Energy Transformation Act (CETA) to receive no-cost allowances to mitigate the cost burden of the program on its Washington retail electric customers. Washington Administrative Code (WAC) 173-446-230 specifies that the Washington State Department of Ecology will use utility-specific four-year demand and resource supply forecasts to determine the cost burden effect and the allocation of no-cost allowances to each electric utility. That forecast, and methodology description, based on PacifiCorp's Clean Energy Implementation Plan (CEIP), PacifiCorp's Integrated Resource Plan (IRP), and the Washington Inter-Jurisdictional Allocation Methodology (WIJAM)), was filed in Docket UE-220789 and approved by the Washington Utilities and Transportation Commission (WUTC) in Order UE-220789 Order 01.

UE 420 / PacifiCorp
June 2, 2023
AWEC Data Request 042

AWEC Data Request 042

If approved by the Washington Utilities and Transportation Commission, will the conversion of Jim Bridger 1 & 2 to a gas fired resource increase the amount of free allowances awarded by the Washington Department of Ecology? Please explain.

Response to AWEC Data Request 042

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

No- cost allowances are awarded commensurate with emissions associated with resources allocated to Washington retail customers. Theoretically, if a unit were converted to a lower-emitting technology and remained allocated to customers at the same rate, the number of no-cost allowances would decrease.

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EXHIBIT AWEC/104

EPA FACT SHEET ON OZONE TRANSPORT RULE

EPA's "Good Neighbor" Plan Cuts Ozone Pollution – Overview Fact Sheet

EPA's final Good Neighbor Plan for the 2015 ozone NAAQS will improve air quality, saving lives and improving public health in smog-affected communities across the United States. This final rule, which requires emissions reductions from power plants and industrial sources that pollute across state lines, delivers substantial health benefits using proven, cost-effective control technologies and strategies.

Summary of Action

On March 15, 2023, the U.S. Environmental Protection Agency (EPA) issued its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NO_X) from power plants and industrial facilities. This action will save thousands of lives and result in cleaner air and better health for millions of people living in downwind communities.

The Good Neighbor Plan ensures that 23 states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining EPA's health-based air quality standard for ground-level ozone (or "smog"), known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS), in downwind states.

The final Good Neighbor Plan ensures that emissions reductions will happen as quickly as possible and be aligned with Clean Air Act deadlines for states to achieve the 2015 ozone NAAQS – which vary according to the severity of nonattainment.

- The initial phase of NO_X emissions reductions takes effect as soon as possible prior to the August 3, 2024 attainment date for areas classified as Moderate nonattainment.
- Further emissions reductions phase in at the beginning of the 2026 ozone season to coincide with the August 3, 2027 attainment date for Serious nonattainment areas.

The Final Rule Includes a Combination of Approaches to Reduce Ozone Pollution:

NO_X Allowance Trading Program for Fossil Fuel-Fired Power Plants in 22 States
Beginning in the 2023 ozone season, EPA will include power plants in 22 states in a revised and strengthened Group 3 Cross-State Air Pollution Rule (CSAPR) ozone season trading program. To achieve emissions reductions as soon as possible, EPA is setting the initial control stringency based on the level of reductions achievable through immediately available measures, including consistently operating emissions controls already installed at power plants.

In order to achieve the remaining needed emissions reductions from power plants, the final rule sets emissions budgets that decline over time based on the level of reductions achievable through phased installation of state-of-the-art emissions controls at power plants starting in 2024. Building on the long and successful track record of EPA's CSAPR ozone season trading program, this program will secure significant reductions in ozone-forming pollution while providing power plants operational flexibility they need to continue providing reliable and affordable electric service. The final rule's 2027 budget for power plants reflects a 50% reduction from 2021 ozone season NOx emissions levels.

The final rule includes additional features that promote consistent operation of emissions controls to enhance public health and environmental protection for the affected downwind regions and will also benefit local communities:

- A backstop daily emissions rate in the form of a 3-for-1 allowance surrender for emissions from large coal-fired units that exceed a protective daily NO_X emissions rate. This backstop would take effect in 2024 for units with existing controls and one year after installation for units installing new controls, but no later than 2030;
- Annually recalibrating the size of the emissions allowance bank to maintain strong long-term incentives to reduce NO_X pollution;
- Annually updating emissions budgets starting in 2030 to account for changes in power generation, including new retirements, new units, and changing operation. Updating budgets may start as early as 2026 if the updated budget amount is higher than the state emissions budgets established by the final rule for 2026-2029.

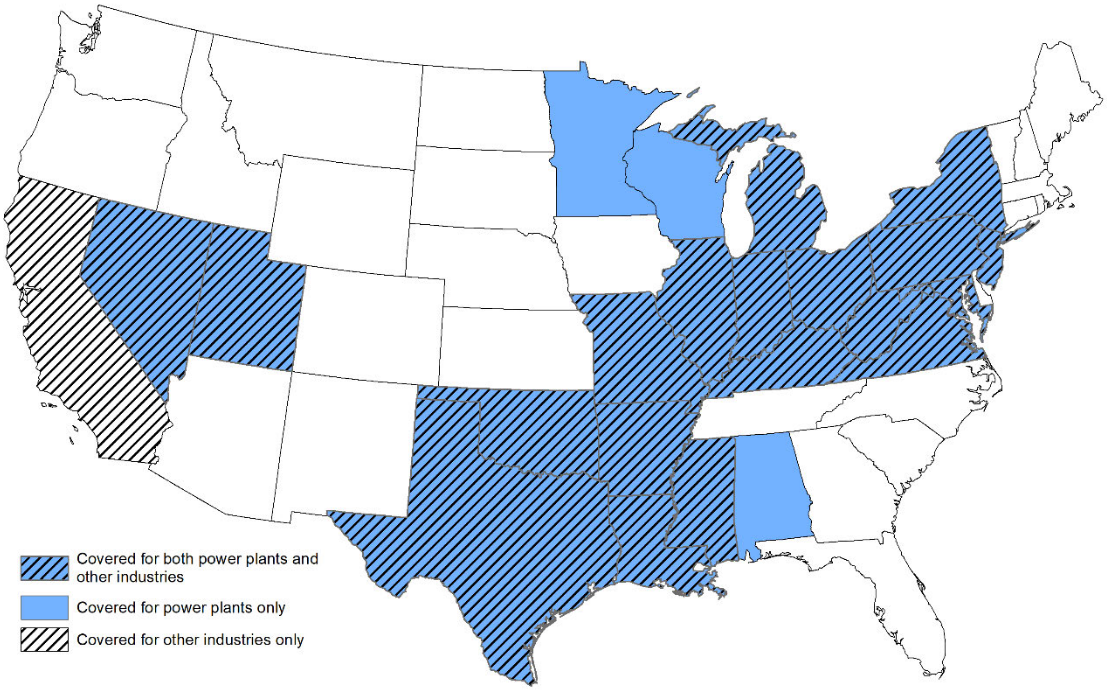
NO_X Emissions Standards for Nine Large Industries in 20 States

Beginning in the 2026 ozone season, EPA is setting enforceable NO_X emissions control requirements for existing and new emissions sources in industries that are estimated to have significant impacts on downwind air quality and the ability to install cost-effective pollution controls. These standards would collectively achieve an approximately 15% reduction in NOx emissions from 2019 ozone season, point source emissions. The reduction in NOx emissions comes from the following types of emissions sources:

- reciprocating internal combustion engines in **Pipeline Transportation of Natural Gas**;
- kilns in **Cement and Cement Product Manufacturing**;
- reheat furnaces in **Iron and Steel Mills and Ferroalloy Manufacturing**;
- furnaces in **Glass and Glass Product Manufacturing**;
- boilers in **Iron and Steel Mills and Ferroalloy Manufacturing**, **Metal Ore Mining**, **Basic Chemical Manufacturing**, **Petroleum and Coal Products Manufacturing**, and **Pulp, Paper, and Paperboard Mills**; and
- combustors and incinerators in **Solid Waste Combustors or Incinerators**.

These industry-specific requirements reflect proven, cost-effective pollution reduction measures that are consistent with standards that sources in downwind states, and throughout the country, have long implemented. With EPA's approval, individual facilities may be eligible for a one year compliance extension. If specific additional criteria are met, EPA may grant additional compliance extensions of up to two more years.

Map of States Covered by the Final Good Neighbor Plan



Since proposal, EPA updated its air quality modeling based on stakeholder input providing improved emissions data and recommendations to improve model performance. EPA's final Good Neighbor Plan relies upon the Agency's most recent air quality modeling data identifying:

- areas expected to have trouble attaining and maintaining the 2015 standards in 2023 and 2026, and
- contributions from upwind states causing downwind ozone problems.

Applying EPA's longstanding, court-affirmed 4-step framework to this information, the final Good Neighbor Plan determines that 23 states must achieve additional reductions in NO_X pollution to fully resolve their outstanding Good Neighbor obligations for the 2015 ozone NAAQS.

EPA's updated modeling analysis for 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico, may be significantly contributing to nonattainment or maintenance in downwind sites. EPA intends to undertake additional assessment of its modeling for these states and will determine if it is necessary to address Good Neighbor obligations for these states in future action(s).

EPA's updated modeling analysis confirms that Delaware is not significantly contributing to downwind ozone air quality problems. The Agency is withdrawing the proposed error correction and the proposed Good Neighbor Plan for Delaware. In addition, EPA is deferring final action on the Agency's proposed Good Neighbor Plans for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis.

EPA's Good Neighbor Plan Would Substantially Reduce Summertime Ozone Levels

EPA estimates that the final Good Neighbor Plan will reduce ozone forming NO_X emissions from the 23 significantly contributing upwind states by approximately 70,000 tons during the 2026 ozone season (May 1 – September 30) compared to a business-as-usual scenario.

About 25,000 tons will come from fossil fuel-fired power plants -- reducing their ozone season NO_X emissions. The additional 45,000 tons of NO_X emissions reductions would come from the other covered industrial sources. These reductions will improve air quality for millions of people across the country.

The final Good Neighbor Plan will also reduce other harmful pollutants from power plants. In 2026 alone, EPA estimates that annual sulfur dioxide emissions will drop by 29,000 tons, annual fine particle emissions by 1,000 tons, and annual carbon dioxide emissions by 16 million metric tons.

Protecting Communities

EPA's final Good Neighbor Plan will reduce ozone across the U.S. with a focus on areas struggling to attain and maintain the 2015 ozone standards.

Program enhancements, including the daily backstop emissions rates for large power plants and program coverage for both existing and future power plant and industrial sources, will achieve air quality benefits in downwind communities that suffer a disproportionate burden from ozone pollution.

Human Health and Environmental Benefits of Reducing Ozone Far Exceed Costs

In the year 2026, the final Good Neighbor Plan will prevent up to 1,300 premature deaths, reduce hospital and emergency room visits for thousands of people with asthma and other respiratory problems, help keep hundreds of thousands of children and adults from missing school and work due to respiratory illness, and decrease asthma symptoms for millions of Americans. For each year from 2027 through 2042, EPA estimates the benefits will be approximately as large as in 2026, although the annual benefits decline slightly over time based on EPA's projection that the health status of the population will improve over this period.

The benefits that EPA could quantify for the final Good Neighbor Plan far outweigh the costs. EPA estimates the benefits in 2026 will be $4.3 billion and could be as much as $15 billion (2016$, 3 percent discount rate). In 2026, the net benefits of this final rule – after accounting for the costs of compliance – are estimated to be $3.7 billion and could be as much as $14 billion (2016$, 3 percent discount rate). EPA estimates that the net present value of this rule over the period from 2023 to 2042, after taking into account compliance costs, is $200 billion (2016$, 3 percent discount rate).

In addition, the emissions reductions projected from the final Good Neighbor Plan will result in a broad range of unquantified benefits, including improving visibility in national and state parks and increasing protection for sensitive ecosystems, coastal waters and estuaries, and forests.

To more fully understand the impacts of this rule, EPA evaluated the effects the Good Neighbor Plan would have on minority populations, low-income populations and/or tribal nations. Our analysis shows that the Good Neighbor Plan will lower ozone and fine particle concentrations in many areas, providing broadly shared benefits for people of color and low-income households.

The cost of achieving these reductions is estimated to be approximately $910 million annually over the period 2023 to 2042 (2016$, 3% discount rate), a fraction of the estimated value of the benefits. As noted above, the final emissions reduction requirements are also based on cost-effective, well-demonstrated pollution control measures that many states have been implementing for years. EPA projects that the final rule will not have a significant impact on small businesses, and that once fully implemented the Good Neighbor Plan will increase the overall costs of electricity production by only slightly more than 1 percent.

The Good Neighbor Plan Preserves Industry's Ability to Deliver Reliable Electricity

The Agency made several adjustments to the proposed emissions reduction requirements for power plants – reflecting input received from grid operators across the country and other stakeholders – to ensure that the power sector can continue to deliver reliable electricity while also achieving cleaner and healthier air. These changes are designed to provide owners and operators of power plants with the operational flexibility and predictability needed to ensure electric system reliability, particularly in the early years of the program. For more detail, see the fact sheet: The Good Neighbor Plan and Reliable Electricity

Background

The Clean Air Act requires states to submit a State Implementation Plan (SIP) that provides for the implementation, maintenance, and enforcement of each primary or secondary NAAQS. Each state must make this new SIP submission within 3 years after promulgation of a new or revised NAAQS. A key Clean Air Act requirement for these SIPs, known as the "Good Neighbor" provision, is that they ensure that sources within the state do not contribute significantly to nonattainment or interfere with maintenance of any NAAQS in other states.

Where EPA finds that a state has not submitted a Good Neighbor SIP, or if the EPA disapproves the SIP submission, within two years, the EPA must issue a Federal Implementation Plan (FIP) to assure downwind states are protected.

EPA is continuing its efforts since the 1990s to implement Good Neighbor requirements, including through rules such as the NO_X SIP Call (1998), the Clean Air Interstate Rule (2005), the Cross-State Air Pollution Rule (CSAPR, 2011), and updates to the CSAPR rule issued in 2016 and 2021. These prior rules successfully addressed less protective ozone NAAQS set in earlier years.

As in its prior interstate transport rules, EPA has employed a longstanding, court-affirmed 4-step framework to identify downwind receptors that are expected to have problems attaining or maintaining the NAAQS, determine which states contribute significantly to these downwind air quality problems, and identify available pollution reduction measures and enforceable requirements necessary to meet the Clean Air Act's Good Neighbor requirements.

More Information

Interested parties can download a copy of the final Good Neighbor Plan from EPA's website at the following address: https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

Today's action and other background information are also available electronically at https://www.regulations.gov, EPA's electronic public docket and comment system.

For more information about the final action:

- For general questions about the rule, please contact Liz Selbst, Office of Air Quality Planning and Standards, at Selbst.elizabeth@epa.gov.
- For questions about regulatory requirements for power sector sources, please contact Beth Murray, Office of Atmospheric Protection, at Murray.beth@epa.gov.
- For questions about regulatory requirements for industrial sources, please contact Dylan Mataway-Novak, Office of Air Quality Planning and Standards, at Mataway-novak.dylan@epa.gov.

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EXHIBIT AWEC/105

PRODUCTION TAX CREDIT RATE FORECAST FOR 2024

PTC Inflation Adjustment Factor Calculations and PTC Rate Forecast

	Year	GDP Implicit Price Deflator						Inflation Adjustment Factor			PTC
		Q1	**Q2**	**Q3**	**Q4**	**AVG.**	**1992**	**Calculated**	**Actual**	**Delta**	**Rate**
	1992	119.80	120.60	121.20	121.80	120.90	120.90	1.0000	1.0000	-	1.5
	1993	123.30	124.00	124.50	124.90	124.20	120.90	1.0273	1.0273	-	1.5
	1994	125.00	125.90	126.50	126.90	126.10	120.90	1.0430	1.0430	-	1.6
	1995	106.70	107.30	107.80	108.30	107.50	100.00	1.0750	1.0750	-	1.6
	1996	109.00	109.50	109.90	110.30	109.70	100.00	1.0970	1.0970	-	1.6
	1997	111.71	112.22	112.62	113.05	112.40	100.00	1.1240	1.1240	-	1.7
	1998	112.32	112.56	112.84	113.04	112.69	100.00	1.1269	1.1269	-	1.7
	1999	103.83	104.19	104.46	104.98	104.37	91.70	1.1382	1.1382	-	1.7
	2000	106.10	106.73	107.15	107.65	106.91	91.84	1.1641	1.1641	-	1.7
	2001	108.65	109.21	109.82	109.75	109.36	91.84	1.1908	1.1908	-	1.8
	2002	110.14	110.48	110.76	111.21	110.65	91.84	1.2048	1.2048	-	1.8
	2003	105.15	105.43	105.85	106.16	105.65	86.39	1.2230	1.2230	-	1.8
	2004	107.25	108.09	108.48	109.06	108.22	86.39	1.2528	1.2528	-	1.9
	2005	110.91	111.62	112.53	113.49	112.14	86.39	1.2981	1.2981	-	1.9
	2006	114.95	115.89	116.42	116.89	116.04	86.39	1.3433	1.3433	-	2.0
	2007	118.75	119.52	119.83	120.61	119.68	86.39	1.3854	1.3854	-	2.1
	2008	121.51	121.89	123.06	123.21	122.42	86.39	1.4171	1.4171	-	2.1
	2009	109.69	109.69	109.78	109.88	109.76	76.53	1.4342	1.4342	-	2.2
	2010	109.95	110.49	111.05	111.15	110.66	76.53	1.4459	1.4459	-	2.2
	2011	112.40	113.12	113.84	114.08	113.36	76.60	1.4799	1.4799	-	2.2
	2012	114.60	115.04	115.81	116.07	115.38	76.60	1.5063	1.5063	-	2.3
	2013	106.11	106.26	106.78	107.20	106.59	70.64	1.5088	1.5088	-	2.3
	2014	107.66	108.23	108.60	108.64	108.28	70.57	1.5344	1.5336	0.00	2.3
	2015	109.10	109.67	110.03	110.29	109.77	70.57	1.5555	1.5556	(0.00)	2.3
	2016	110.63	111.26	111.65	112.21	111.44	70.57	1.5791	1.5792	(0.00)	2.4
	2017	112.75	113.03	113.61	114.27	113.42	70.57	1.6072	1.6072	-	2.4
	2018	109.37	110.27	110.68	111.22	110.38	67.33	1.6396	1.6396	-	2.5
	2019	111.47	112.19	112.66	113.04	112.34	67.33	1.6686	1.6687	(0.00)	2.5
	2020	113.42	112.82	113.84	114.37	113.63	67.33	1.6877	1.6878	(0.00)	2.5
	2021	116.12	117.92	119.71	121.71	118.37	67.28	1.7594	1.7593	0.00	2.6
	2022	124.17	126.91	128.27	129.51	127.21	67.28	1.8909			2.8
2024 Forecast	2023	130.787	*131.7986*	*132.818*	*133.8454*	*132.3123*	67.28	1.9667			***3.00***
		0.99%	*0.77%*	*0.77%*	*0.77%*	3.13%					
Zero Inflation	2023	129.508	*129.508*	*129.508*	*129.508*	*129.508*	0.00	1.9250			***2.90***
		0%	*0%*	*0%*	*0%*	0.0%					