BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Petition for Investigation into Long-Term Direct Access Programs.	)))))))	OPENING COMMENTS OF THE OREGON CITIZENS' UTILITY BOARD

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March 16, 2020

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I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) appreciates the opportunity to comment on the stipulated issues list developed for Phase 1 of Oregon Public Utility Commission (Commission) Docket No. UM 2024, an investigation into issues related to long-term direct access programs. To set the stage for the issues[1] that will be addressed in this proceeding, it is important to consider the historical context of Oregon's direct access program.

Oregon's direct access program grew out of efforts to deregulate the utility system. As CUB discussed in UE 358, Portland General Electric New Load Direct Access docket, Oregon's direct access program was established by SB 1149 in 1999.[2] That bill envisioned a future involving several key elements that have not come to fruition. It assumed that all industrial and commercial customers would purchase their electricity from Electric Service Suppliers (ESS) and they would not have the option of returning to cost-of-service rates. It assumed that utilities would divest of their non-hydro resource. It also assumed that new resources would not be placed in utility rate base to earn a return. However, before the bill was implemented, the California energy crisis began and led to the Western Energy Crisis which led to changes in SB 1149's approach, particularly concerning resource divestment, and the role, size, and purpose of competitive markets. California and Montana pulled back from deregulated energy markets and repealed requirements for utility divestment.

Unlike California and Montana which envisioned a fully deregulated electric marketplace, SB 1149 envisioned an electric utility model that was much like the natural gas model. Large commercial and industrial customers would purchase energy directly from ESSs in the wholesale

[1] UM 2024 – Ruling Granting Motion to Adopt Procedural Schedule (Feb. 21, 2020).
[2] *See* UE 358 - CUB/100/Jenks/page 4-8.

market. Residential and small commercial customers would be served by resources purchased from the competitive wholesale market by the incumbent utility, which was supposed to be tasked with managing the distribution system. However, after the Western Energy Crisis, Oregon pulled back from this vision. Legislation required a cost-of-service option for all customers, though a waiver was allowed. With California and Montana moving back to a traditional, vertically integrated utility model, utilities were now the primary entities investing in new generating resources. The expectation that non-utility investment would provide the resources for a large competitive wholesale market in a manner similar to the natural gas market disappeared. Resource divestment no longer made sense. Oregon joined California and Montana in reverting back to a mostly traditional utility model.

In many respects this docket is asking us to revisit the discussions and decisions of the late 1990s and early 2000s. While CUB believes this is an appropriate time to do so, times have changed since the deregulation debate of the late 1990's. Today, decarbonization is a primary goal of energy regulation. In 2007, Oregon began requiring utility investment in renewable energy to begin the transition to a carbon constrained energy system and in 2016 Oregon required utilities to phase out coal resources.

CUB's comments will address the three broad topics of the issues list: i) the potential costs and benefits associated with direct access; ii) how other states are handling customer choice and wholesale markets for different customer classes; and iii) the interplay with resource adequacy.[3]

II. POTENTIAL BENEFITS AND COSTS OF DIRECT ACCESS

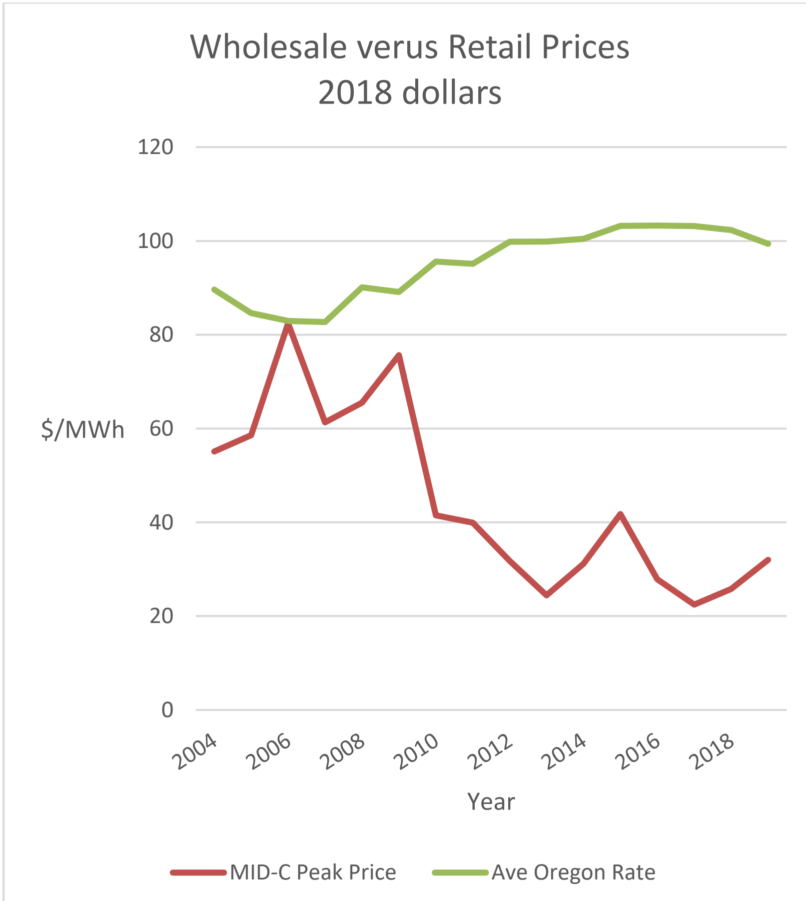
A. The primary benefit is access to energy at its marginal cost.

Well-accepted economic market theory states that in a world of perfect competition the clearing price, or equilibrium price, of a market should be the marginal cost of production. Price is equal to the marginal cost.[4] Marginal cost represents the cost of supplying the next unit. In terms of electricity it represents the cost of fuel and the variable cost of operation and maintenance. For a wind resource, there is no fuel cost and with federal production tax credits the variable cost of operation is negative. It does not represent the fixed cost of generation – the capital cost of construction of the facility.

The primary benefit of direct access to the non-captive customers eligible for the program is the ability to buy power from the wholesale market at a price based on marginal cost and avoid the investment cost of actual resources. The chart below shows that since direct access has been

[3] *Supra* note 1.
[4] Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources, Michael Milligan, Bethany Frew, Kara Clark, and Aaron Bloom. National Renewable Energy Laboratory, December 2017, page 4.

implemented in Oregon, we have seen retail rates rise while we have seen the wholesale market price at Mid-C decline considerably.[5]



Retail rates have slowly risen during the time that direct access has been available. However, peak prices in the wholesale market have fallen dramatically. Retail rates are 19.9% higher than in 2005 while peak wholesale prices are 61.2% lower than 2005. Therefore, while captive customers have had to absorb these retail rate increases, direct access customers have been able to enjoy relatively cheap market power. Because energy costs (as opposed to distribution, transmission, customer service…) make up the bulk of the bills of direct access customers, moving from utility retail rates to wholesale market rates is a financial windfall.[6]

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[5] CUB Attachment A.

[6] For PacifiCorp's Schedule 48, energy costs make up 70% of the bills for secondary voltage customers, 75% for primary voltage customers, and 76 for transmission voltage customers. See UE 374/PAC/Exhibit 1409/page 2.

B. The Market is Flawed.

While the marginal cost of production is the clearing price in the wholesale market, it does not represent the actual cost of producing power because it does not include the fixed capital investment associated with generating plant. This is particularly true of renewable resources. Because the primary marginal cost is fuel, renewable resources have a marginal cost of production of nearly zero – and with the PTC, below zero. This does not mean that power from these facilities are free, it means that once someone has covered the capital cost of the plant, each additional unit of power does not have any significant costs associated with it.

Having a wholesale market operating alongside a monopoly marketplace distorts the wholesale market. The monopoly market allows recovery of the fixed costs of investment in resources. It is this market that drives investment in new generating resources. The wholesale market works well for balancing the monopoly systems. The marginal cost price signal allows monopoly utilities to trade power in the wholesale marketplace and ensure that the least cost resource is being dispatched to serve load. But the price signal in the wholesale market is too low to drive new investment in new resources. Without the monopoly marketplace that is attached to it, the current western wholesale market could not function in the manner it does and would have to be redesigned. State Renewable Portfolio Standards contribute to this by mandating the acquisition of near zero marginal cost resources which depress prices in wholesale markets. All of this makes sense from a perspective of basic market theory. It has also been well documented.

The National Renewable Energy Laboratory (NREL) found that the addition of "near zero marginal cost wind and solar generators" had the following impacts[7]:

- They suppress energy prices;
- They reduce the capacity factors of conventional generators;
- They require additional system flexibility which requires new market designs, greater regional coordination and fair cost allocation.

Lawrence Berkeley National Lab (LBL) worked with NREL on an analysis that shows that renewable resources reduce wholesale electric prices.[8] The Regulatory Assistance Project's (RAP) new cost allocation manual states that the "addition of renewable resources depresses marginal energy costs by adding energy with zero fuel costs (or even negative costs in the case of wind energy with the production tax credit)."[9] Several studies that simulate the impact of renewables in various wholesale markets demonstrate that renewables reduce wholesale market prices.[10]

[7] Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources, Michael Milligan, Bethany Frew, Kara Clark, and Aaron Bloom. National Renewable Energy Laboratory, December 2017, page v-vi.
[8] A Retrospective Analysis of the Benefits and Impact of U.S. Renewable Portfolio Standards, Ryan Wiser, Galen Barbose, Jenny Heeter, Trieu Mai, Lori Bird, Mark Bolinger, Alberta Carpenter, Garvin Heath, David Keyser, Jordan Macknick, Andrew Mills, and Dev Millstein, Lawrence Berkeley National Lab and National Renewable Energy Lab, January 2016.
[9] Electric Cost Allocation For a New Era, Jim Lazar, Paul Chernick and William Marcus, Regulatory Assistance Project, January 2020.
[10] For example, see Simulating the Interaction of a Renewable Portfolio Standard with Electricity and Carbon Markets, Mark C. Thurber, Trevor L. Davis and Frank A. Wolak, The Electricity Journal, 2015.

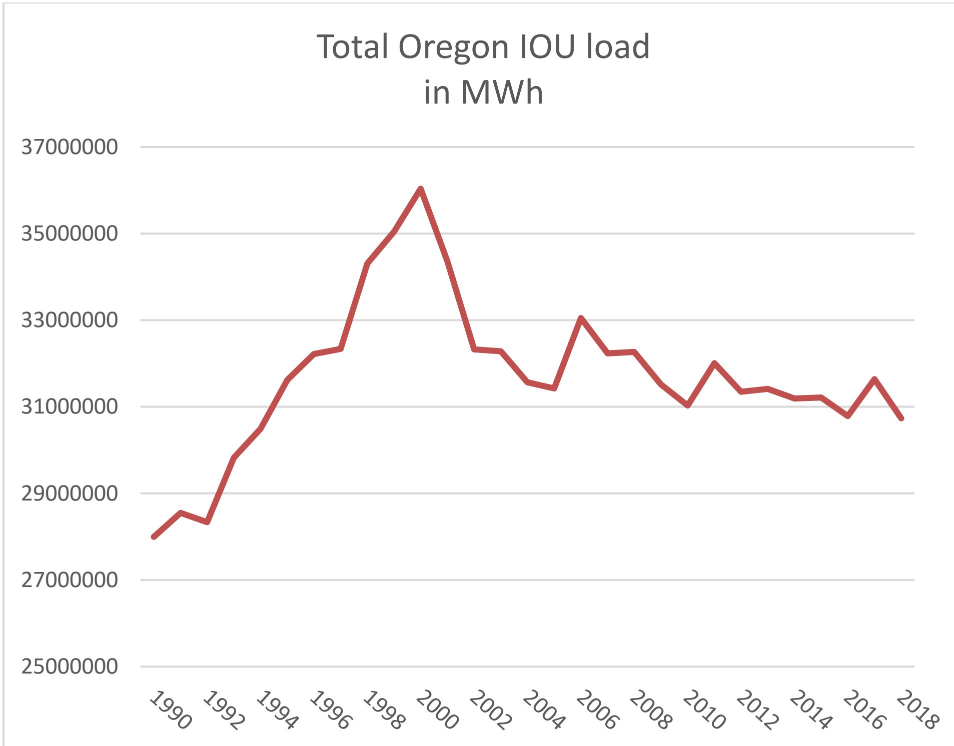
C. The direct access benefits realized by its users are derived from unwarranted cost shifting.

The chart on page 3 shows the difference between wholesale and retail prices. There is no doubt that direct access customers receive substantial benefit when they leave the system to purchase energy on wholesale markets. CUB believes that some of the difference between these two price curves is derived from unwarranted cost shifting. Currently the cost shifting associated with direct access programs is limited due to caps on direct access participation. However, there is pressure to remove the caps which would expand the level of cost shifting onto residential and small business customers.

1. *Shifting of capital costs.*

Because the wholesale market is an energy market only, it does not include the capital costs of generation. These costs are picked up primarily by cost-of-service customers throughout the western US. But these costs are necessary if wholesale market is to be available to serve direct access load.

Some of this is picked up in transition charges, but transition charges are limited to five years for PGE and ten years for PacifiCorp. When SB 1149 was passed to create direct access, utility loads had been growing. There was a general belief that if direct access customers picked up the fixed costs for a period of time, that the system would grow into those abandoned resources. Transitions costs had to cover the time period before the utility load grew into the fixed costs that were being left behind. CUB Attachment B, detailed in the following chart, shows that in the 10 years before SB 1149 passed (1990-1999) Oregon IOU electric demand grew by 25%. In the 10 years after SB 1149 passed (2000-2009) Oregon IOU electric demand shrunk by 13%. In 2018, Oregon IOU load was 15% below 2000 level. Oregon load has not been growing in the manner that SB 1149 contemplated.



For direct access customers who were part of the utility system, their load was included in the planning that led to procurement of the current resource mix. Allowing the capital costs of generating resources to be shifted to other customers after five years is a significant cost shift. Other customers' loads are not growing into these resources. This may not have been anticipated in 1999-2000 when Oregon was developing these programs and the utility's load was growing, but it is clear today.

2. *Cost shifts associated with RPS mandates.*

The RPS was established by the Oregon legislature in 2007 and expanded in 2016. It requires electric utilities to meet a growing portion of their energy supply with new renewable energy. The original law allowed ESSs serving direct access load to use unbundled renewable energy credits (RECs) but limited utilities and their cost of service customers to no more than 20% unbundled RECs for RPS compliance purposes. This established a system where utilities were investing in renewables to meet some of the load of cost-of-service customers, which put downward pressure on price in the wholesale market which is used to serve direct access customers. Simultaneously, the ESS that serve direct access customers could simply purchase unbundled RECs.

This will change somewhat in 2021 when ESS will also be limited in their use of unbundled RECs, though there is a big loophole. The 20% limit on unbundled RECs does not apply to unbundled RECs from Oregon Qualifying Facilities.

While this may seem like it is leveling the playing field, it is not. The installed cost of wind generation fell by 40% between 2009 and 2018[11]. Between 2008 and 2021, utilities were required to invest in renewables to meet RPS obligations when ESS could simply purchase RECs. Those renewables were higher cost than today's renewables. Cost-of-service customers continue to pay for these resources, while direct access customer do not – even though direct access customers benefit from the impact these resources have on the wholesale market and some direct access customers were part of the utilities' load when these investments were planned.

3. *Cost shifting associated with net metering and community solar.*

While net metering and community solar will also put downward pressure on the prices in the wholesale market, this effect will be small due to the relative size of these programs. CUB's concern with these programs is that they are state-mandated programs that direct access customers avoid paying for (bypass) by moving to direct access. Asking residential and small commercial customers to pay for state-mandated programs that are part of Oregon's efforts to reduce carbon emissions while allowing other customers to avoid paying for these programs is unfair and shifts the burden of decarbonization onto small customers.

CUB notes that the recent Executive Order from Governor Brown directs the Commission to:

> Determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's reduction goals.[12]

It is important to recognize that this direction is not limited to cost-of-service customers, but is calling for decarbonization efforts through customer programs, such as the direct access program. Decarbonization is a major policy driver in Oregon utility regulation. The Executive Order makes that clear. But it is a responsibility of all customers, not just cost-of-service customers.

4. *Cost shifting associated with closing coal plants*.

SB 1547 mandated that utilities stop charging Oregon customers for costs associated with coal-fired electricity generation. Even before this requirement, Oregon utilities were beginning to phase out coal. But there are costs associated with closing coal plants. Often, accelerated depreciation is necessary to ensure recovery of the costs of the original investment. In all cases the original capital costs incurred to finance coal plants were done assuming no direct access and that all load in the utility service territory was cost-of-service load. If direct access had not been implemented, the customers currently on direct access would pay their share of the accelerated depreciation. Because of direct access, this cost is shifted to other customers.

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[11] Wind Technologies Market Report, Lawrence Berkeley National Lab, https://emp.lbl.gov/wind-technologies-market-report/
[12] Executive Order No. 20-04, Governor Kate Brown, State of Oregon

Beyond the original investment in the coal plant, closing a coal plant requires decommissioning the plant and the plant site. Traditionally, funds are collected over the life of the plant to ensure that when the plant is closed, funds to cover decommissioning-related costs have already been accumulated. However, it is not clear whether sufficient funds have been collected historically and, if they have, whether current customers may be on the hook for the additional costs. For example, you could have a customer who was served by a plant when it came online in the 1965 but went on direct access in 2005. If new decommissioning studies demonstrate that the utility was under-recovering decommissioning costs from the beginning of the coal plant's life – the direct access customer was undercharged for decommissioning from 1965 to 2005 – the utility will ask current cost-of-service customers to pay additional decommissioning.

5. *Potential cost shifting associated with demand response*.

PGE has invested a significant amount of effort into its Demand Response Test Bed. The NWPPC has identified demand response as a critical resource to meet the reliability needs of the region. Demand response has the potential to deliver benefits to the distribution system, as well as energy and capacity benefits for all customers. CUB is concerned that direct access is a barrier to proper cost allocation because recognizing the energy and capacity benefits could allow direct access customers to escape from paying for a share of these costs, even though they will realize a system benefit.

6. *Cost shifting associated PURPA Qualifying Facilities (QFs).*

Utilities are required to purchase power from QFs if those facilities are priced at or below the utility's avoided cost. While the avoided cost provision is supposed to offer some protection to existing customers to ensure that the QF is not overpriced, QFs are regularly more expensive than other power supply. Since SB 1149 passed, Oregon expects utilities to use competitive bidding before they build or buy new resources, with QFs being the exception. The avoided cost is a forecast from the IRP analysis, but competitive bidding represents a more vigorous competitive process and that competitive process is supposed to reduce the cost of generation. Without direct access, the above-market cost (above-RFP cost) of QFs would be spread across the entire load in the utility's service territory. With direct access the above market cost of QFs are shifted to be the sole responsibility of cost-of-service customers.

7. *Cost shifting associated with energy efficiency*.

Many of the direct access customers are the same customers, who, because of their size (above 1 aMW), are exempt from funding the majority of Oregon energy efficiency programs. The ETO has two funding sources from utilities, the public purpose fund established in SB 1149 and incremental funding from SB 838. Customers above 1 aMW contribute to the first fund, which in 2018 collected $66.8 million from PGE and PacifiCorp customers, but they did not contribute to the second fund, which in 2018 collected $98.3 million. Because SB 1547 mandates that utilities must acquire all cost-effective energy efficiency, this is another state mandate that large customers are able to bypass requiring residential and small commercial customers to make up the difference.

8. *Potential cost shifting associated with Governor's Executive Order*.

The Governor's Executive Order to reduce and regulate greenhouse gas emissions has several elements that could lead to additional cost shifting. The order directs the Commission to "prioritize proceedings and activities that advance decarbonization," "encourage electric companies to support transportation infrastructure" that helps achieve the state's transportation electrification goals, and "address and mitigate" energy burden and other inequities. Will this lead to new programs that direct access customers are allowed to by-pass?

III. HOW OTHER STATES ARE DEALING WITH CUSTOMER CHOICE AND WHOLESALE MARKETS

Most of the country has organized regional markets that require load serving entities to provide sufficient capacity to meet peak needs. PJM is the regional transmission organization (RTO) that operates the power market in the Northeast, and requires loads serving entities to have their own capacity, capacity under contract, capacity from demand response programs or purchase capacity through PJM's capacity Market:

> In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity they purchase from others under contract, through demand response – in which end-use customers reduce their usage in exchange for payment – or with capacity obtained through PJM capacity-market auctions.
>
> PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand three years in the future.[13]

By ensuring all load serving entities provide sufficient capacity, these markets ensure that no customer can use a customer choice program to shift the responsibility to provide capacity onto other customers.

In addition to ensure that acquiring capacity is a requirement of all customers, other states also ensure that customers who participate in customer choice programs are not allowed to by-pass the cost of state mandated programs.

California has customer choice programs that include direct access and Community Choice Aggregation (CCA). California charges them for the generation costs that were incurred to meet their load before they left the system called the Power Charge Indifference Adjustment (PICA -- similar to Oregon's transition charge, but not limited to 5 years). And many of the costs of government required programs are collected as part of the delivery charge. For example, a residential customer being served by Marin Clean Energy (MCE) pays a PICA of 2.769

[13] https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

cents/kWh and a delivery charge of 15.277 cents/kWh, in addition to the energy charges from MCE.[14] The delivery charge, itself, is greater than the full retail rate of any Oregon IOU. Direct access customers also pay a PICA and delivery charges that include non-by-passable charges, through their delivery charges would reflect less use of the distribution system. Finally, in addition to paying for the costs of generation that was built to serve their load, and for the costs of state mandated programs, there is a Resource Adequacy requirement for load serving entities in California.

IV. RESOURCE ADEQUACY (RA)

The western wholesale market is an energy market that sends important price signals that are necessary to dispatch the least lost regional resources. But it is a short-term energy market. In most of the west there is no central grid operator who is ensuring long term reliability by requiring load serving entities to acquire enough forward capacity to ensure a reliable grid – not just meet tomorrow's peak load, but meet load under a variety of conditions over the next few years.

CUB is involved in the Northwest Power Pool's (NWPP) efforts to lead regional discussion towards creating a Resource Adequacy Standard. The NWPP is targeting 2022 as the date to launch a RA program, but whether that date will be met or not is speculative. In addition, NWPP has no regulatory authority.

Any RA requirement on ESSs before 2022 will require moving ahead of the NWPP's plan. CUB has real concerns with waiting for the NWPP. As discussed above, direct access is a very big financial benefit to large customers and part of that benefit is that the costs of capacity are shifted to other customers. But the customers on direct access probably feel that their prices are fair and reasonable and will challenge attempts to increase their costs. Expanding direct access without first getting the costs right only make it harder to get the costs right later.

CUB is an Oregon entity. We do not participate in proceedings in other states. We recognize that many participants in this docket have a great deal of experience in other states where these issues have been dealt with. At this time, CUB is not proposing solutions to the RA challenge. We are eager to see how other parties suggest Oregon move forward with this challenge.

[14] https://www.pge.com/pge_global/common/pdfs/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/mce_rateclasscomparison.pdf

Signed this 16th of March, 2020.

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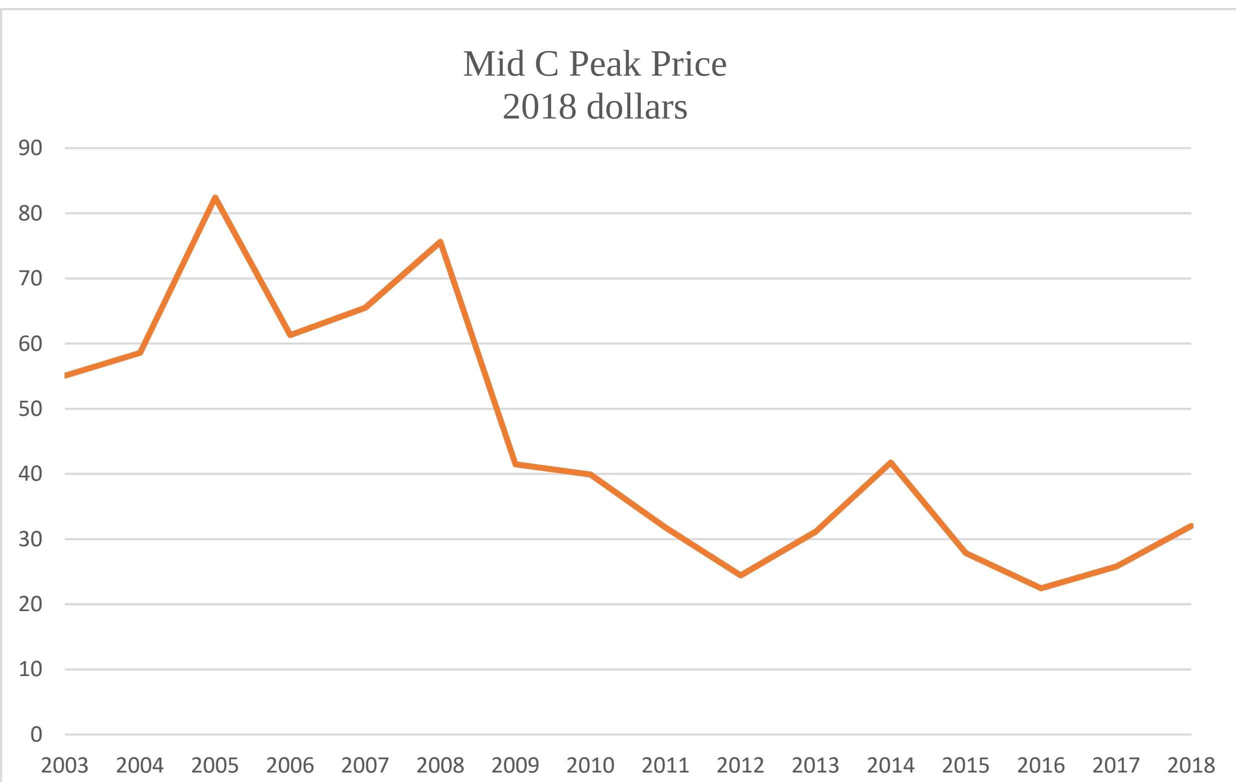
Annual Mid C Peak Price 2003-2018

	Nominal $	2018 $	
2003	40.37	55.09	
2004	44.07	58.58	
2005	64.10	82.42	
2006	49.22	61.31	
2007	54.09	65.51	
2008	64.85	75.63	
2009	35.45	41.49	
2010	34.67	39.92	
2011	28.46	31.77	
2012	22.34	24.43	
2013	28.91	31.16	
2014	39.37	41.76	
2015	26.28	27.84	
2016	21.46	22.45	
2017	25.19	25.78	
2018	32.02	32.02	
Average 2003-2008			*66.42*
Average 2013-2018			*30.16833333*



Year	IOU load	
1990	27,995,169	
1991	28,549,798	
1992	28,332,887	
1993	29,822,639	
1994	30,492,776	
1995	31,619,523	
1996	32,218,805	
1997	32,334,775	
1998	34,310,889	
1999	35,045,835	25%
2000	36,034,749	
2001	34,359,349	
2002	32,324,399	
2003	32,282,141	
2004	31,563,111	
2005	31,422,866	
2006	33,047,876	
2007	32,232,556	
2008	32,264,637	
2009	31,514,314	-13%
2010	31,029,177	
2011	32,008,257	
2012	31,344,390	
2013	31,411,592	
2014	31,192,213	
2015	31,212,875	
2016	30,784,510	
2017	31,636,729	
2018	30,731,768	-15%

Data Source: PUC Utility Factbook