BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM 2024

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, INVESTIGATION INTO LONG-TERM DIRECT ACCESS PROGRAMS	)	INITIAL COMMENTS OF NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION ON INVESTIGATION INTO LONG-TERM DIRECT ACCESS PROGRAMS

Pursuant to the February 21, 2020 Ruling by the presiding Administrative Law Judge adopting (with modification) the Issues List and Phasing Proposal filed by the Commission Staff on February 18, 2020 in this docket (the "**Phasing Proposal Issues List**"), the Northwest and Intermountain Power Producers Coalition ("**NIPPC**") respectfully provides these initial comments setting forth its perspective[1] on various background and policy issues with respect to the long-term direct access programs in Oregon. NIPPC's initial comments focus on the following issues:

> **First**, NIPPC will address some of the history of the direct access program in Oregon, and the legislative mandate stipulating that the Oregon Public Utility Commission (the "Commission") create programs and policies for a workable competitive power market. This legislative mandate puts to rest the question of whether a functioning competitive energy market is appropriate in Oregon – it makes it clear that the Commission is required to establish a properly-functioning market that embraces competition to the benefit of all Oregon's communities and consumers. NIPPC submits that current Commission policies have not successfully established such a market, and we look forward to discussions that will revamp and improve the competitive market, not impose further restrictions thereon.
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> **Second**, NIPPC will address the potential benefits and potential costs to customers from long term direct access participation, and ways to structure the program within existing statutory constraints to maximize benefits and minimize costs.

[1] NIPPC notes that this docket addresses a wide range of complex and interrelated issues, some of which will require discovery and evidentiary hearings, and some of which are being simultaneously considered in other dockets. Failure by NIPPC to not address a given issue or sub issue herein while providing its initial perspective should not be taken as an indication that such issue or sub issue is not significant, and NIPPC reserves the right to take additional positions, and or respond to positions taken by others, regardless of whether addressed herein.

Third, NIPPC will address whether limits, such as participation thresholds or caps, should be placed on direct access. NIPPC submits that most existing limitations are fundamentally at odds with the statutory mandate placed on the Commission. While such limitations may have been appropriate at the very outset, during nascent development of the direct access program, they are no longer appropriate and now undermine legislative directive.

Fourth, NIPPC will address the interplay between the need for regional resource adequacy, discussions about which are just beginning in the Pacific Northwest, and the direct access market. NIPPC does not take a position in this docket as to the precise form that resource adequacy requirements should take, but NIPPC contends that resource adequacy requirements must be well-defined and apply equally to all load serving entities, and that supply of resource adequacy should be done on a competitive basis.

1. Existing Law Mandates that the Commission Ensure Creation of a Workable Retail Power Market.

Any discussion of direct access must start with the existing legal framework in Oregon. This framework mandates that the Commission facilitate the creation of a competitive retail market for sale of electricity, which is defined to include both energy and generation capacity. The Oregon legislature determined in 1999 that it was in the best interest of the state to allow retail commercial and industrial customers (*i.e.*, nonresidential customers) to purchase their electricity from competitive suppliers through a direct access program. As part of that determination, the legislature gave the Commission a direct statutory mandate to develop policies that eliminate barriers to the development of a competitive retail market structure, mitigate the vertical and horizontal market power of incumbent electric companies, and prohibit preferential treatment (or even the appearance thereof) of generation or market affiliates. Specifically, Oregon law states:

> "(1) The duties, functions and powers of the Public Utility Commission shall include developing policies to eliminate barriers to the development of a competitive retail market structure. The policies shall be designed to mitigate the vertical and horizontal market power of incumbent electric companies, prohibit preferential treatment, or the appearance of such treatment, of generation or market affiliates and determine the electricity services likely to be competitive. The commission may require an electric company acting as an electricity service supplier do so through an affiliate."[2]

[2] OR Laws 1999, ch 865, Section 6(1), and codified in ORS 757.646(1)

The law in Oregon also specifies that "***[a]ll*** retail electricity consumers of an electric company, other than residential electricity consumers, shall be allowed direct access beginning on March 1, 2002." ORS 757.601 (emphasis supplied). More than 20 years later, it is clear that barriers to the development of a competitive market remain, and that "all" customers do not have access to direct access. It is time for the Commission to reform its policies and rules to eliminate the existing limitations on access to direct access, such as thresholds and caps, and eliminate barriers to the development of a competitive retail market. Such reforms should be the focus of this proceeding.

2. **What are the potential benefits and potential costs to customers from long-term direct access participation**?

A. Benefits of Direct Access.

As noted above, the Oregon legislature has already determined that a vibrant competitive retail market is in the best interest of Oregon. As such, NIPPC does not believe there is a need to relitigate why it is important for Oregon to have a more workable direct access market – the legislature has already spoken. Nevertheless, NIPPC submits that the benefits of a competitive power market to market participants, and to the state of Oregon as a whole, are easily identifiable and outweigh any potential costs. Among other things, the existence of a competitive power market allows for numerous benefits:

- Direct access allows customers to choose service that enables them to directly manage their energy costs to meet their business needs and financial goals in ways that are not available under utility cost of service rates;
- Direct access provides opportunities for customers to increase their use of clean energy beyond the state standards to meet their internal environmental improvement and sustainability goals, thus contributing to the achievement of state environmental goals;
- Cost savings created by direct access service allows customers to invest more in their businesses, thus helping to grow the Oregon economy and create jobs;
- Direct access reduces and/or delays the need for expensive additions of capacity into utility rate base and enables a sharing of those obligations with the customers and suppliers in the direct access program;
- Direct access diversifies power supplies needed for resource adequacy;
- Direct access drives significant innovation in the regional energy industry;

- Direct access places competitive pressure on monopoly utilities, which drives energy costs down for everyone.

It is also important to note that the load served under direct access is subject to many of the same charges and obligations that utility customers are subject to. Among other things:

- Direct access customers continue to use and pay for the transmission and distribution systems operated by their incumbent utilities in precisely the same way as bundled customers of the utilities – that is their contribution to the costs of the utility's transmission and distribution system remain the same.
- Direct access customers continue to pay their share of public purposes charges that support specific programs.
- Direct access load is subject to the same Renewable Portfolio Standard ("**RPS**") requirements, and Clean Electricity and Coal Transition Plan ("**Coal to Clean**") requirements as cost of service load served by the incumbent utility.

B. <u>Cost Shifts Resulting From Direct Access -And What To Do About Them</u>

NIPPC submits that issues related to identifying the potential for cost shifts when customers move to direct access – including both the shifts from cost of service customers to direct access customers and from direct access customers to cost of service customers, must be determined *before* addressing the question of how to best design a direct access program in order to eliminate any *undue* cost shifts as direct by the legislature. It is only after we understand what cost shift may occur that we can design appropriate remedies. This is true because a single remedy is not appropriate for diverse cost issues.

As noted above, direct access customers continue to pay their share of costs of the transmission and distribution system owned and operated by the utilities, and their share of all public purpose charges, so there is no cost shift to bundled customers with respect to these items. Similarly, any charge or surcharge, whether required by federal or state mandate or otherwise, that is placed on the transmission and distribution system rates is effectively a non-bypassable charge borne by all customers, whether receiving electricity service through direct access or through the incumbent utility.

NIPPC submits that there are just two categories of issues that could lead to an "undue" level of cost shifting: (1) costs of generation assets – both with respect to excess stranded existing generation assets no longer needed when a customer leaves the utility system for direct access, and the costs savings from avoidance of the need to acquire new generation assets because a customer is no longer purchasing load service from the incumbent utility; and (2) issues related to resource adequacy. We address the first category immediately below, and the second in Section 4.

With respect to generation assets, the legislature has provided very specific direction that departing customers must pay for the stranded costs that their departure creates, and are entitled to the benefit to the extent their departure reduces system costs.[3] NIPPC does not oppose the principle that when a utility has both (i) ***planned to provide capacity*** for a customer and (ii) ***incurred fixed costs that cannot be mitigated*** to serve such customer, the resulting stranded costs should be paid by that exiting customer. In the same way, when a utility is forecasted to be short on capacity, a customer leaving the system enables the utility to avoid or delay acquisition of new capacity – benefiting the remaining cost of service customers.

Existing Oregon law is also very clear that there is no basis to charge the direct access customers for the utility's investments in new generation assets ***after*** the customer has departed utility service and is managing its power procurement separate from the utility. The law also provides that in preventing cost shifting, regulators are to apply a standard of preventing "undue" cost shifting. It is this concept of "undue" cost shifting that needs to be further defined for a successful expansion of direct access.

Finally, NIPPC submits that a key concept to be considered with respect to cost shifting is ensuring the incumbent utility has an express duty to mitigate the impact of any stranded costs. Currently, where a utility has excess capacity due to customers leaving the system in favor of direct access, the utility has the perverse incentive to retain such asset – which is arguably no longer used and useful – to continue earning a regulated rate of return and allocate that financial burden to the departing customers, who no longer need nor want such capacity. If such capacity is truly stranded and has no market value, then it is arguably an "uneconomic utility investment" and it may be appropriate for the utility to recover such costs through transition charges. But in circumstances

[3] The terms "uneconomic utility investments" and "economic utility investments" are both expressly defined in SB 1149 and the implementing statute as investments made by the utility prior to an offer of service under a Direct Access program, not costs that occur after a customer ceased purchasing power from the utilities' generation assets in favor of competitive power markets.

where the utility has a reasonable opportunity to mitigate such transition charges, in whole or in part, without shifting the costs onto cost of service customers, it should have the obligation to do so.

3. Existing limits on direct access should be eliminated.

As described in Section 1, *infra*, Oregon law indisputably specifies that "*all* retail electricity consumers of an electric company, other than residential electricity consumers, shall be allowed direct access beginning on March 1, 2002." ORS 757.601 (emphasis supplied). NIPPC submits that the current limits on eligibility for long term direct access –particularly the caps and thresholds -- are contrary to the clear intent of the legislature and should be eliminated.

With respect to threshold limitations on the size of customers that are eligible for direct access, early justifications for such limitations, such as concerns over administrative burdens, [4] clearly no longer apply. PGE's historic justification for a 1 aMW threshold was "to limit the number of accounts that must be separately tracked, thereby helping to mitigate the administrative burden to PGE."[5] Whether or not this was ever a reasonable rationale to deny smaller customers access to retail power markets, it is not appropriate now with the computer systems available in 2020. PGE itself has offered service under its Variable Renewable Energy Tariff ("VRET") at thresholds of 30 aKW, far below the 1 aMW size threshold for direct access.[6] If PGE can manage the administration of its VRET to customers of that small size, there should be no reason it cannot do so for direct access as well. Moreover, utilities in many other jurisdictions throughout the country are capable of providing direct access to customers of smaller size, so surely there are existing systems and services that can be brought to bear to manage the administration of direct access at smaller customers levels, if necessary. Looking to another industry, telecom companies

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[4] In UE 236, PGE's witness testified as follows:

> Beginning with the 2003 service year, PGE added the option for eligible customers to opt out of Cost-of-Service (COS) energy supply for a minimum five-year period with a pre-specified transition adjustment. Eligibility for this option was and continues to be an enrollment of at least one average megawatt (aMW) with each Point of Delivery (PODID) having a Facility Capacity of at least 250 kW. This eligibility requirement was put into place to limit the number of accounts that must be separately tracked, thereby helping to mitigate the administrative burden to PGE.

UE 236 PGE/100, Cody/3 (Nov. 9, 2011). PGE made the same assertion in its most recent general rate case. UE 335 PGE/1300, Macfarlane-Goodspeed/36-37.

[5] Id.

[6] *See* Portland General Electric Company tariff, Schedule 55, Large Nonresidential Green Energy Affinity Rider.

seem to have no problem separately tracking and invoicing multiple accounts per household or tracking customers as they come and go from the system -- regardless of customer size. There is no longer any reasonable justification for the threshold limitations.

Similarly, the cap on participation in the long-term direct access market is inappropriate and has outlived its usefulness. These caps produce clearly discriminatory results and deny customers the opportunity to access the competitive power market, contrary to law. Claims that caps are necessary to ensure resource adequacy are red herrings. The need for resource adequacy requirements exists whether or not there is direct access and should not be used as the reason to deny customers their lawful right to choose an alternative supplier. If the real concern underlying the need for a cap is the need for sufficient regional resource adequacy, the Commission should establish appropriate resource adequacy policies, as addressed below. Nor does a utility's obligation to act as provider of last resort justify capping direct access participation. Existing regulations already provide a reasonable, workable mechanism to ensure that customers returning to utility service provide adequate notice, and that allow the utilities to meet their supplier of last resort obligations through market purchases. These protections are adequate for the concerns which need to be addressed, especially when coupled with sound resource adequacy policies.

4. The Commission should establish resource adequacy standards applicable to all load serving entities and allow the market to compete to supply necessary capacity.

NIPPC understands the need to ensure resource adequacy standards for all load serving entities, and that this issue is under active discussion in many jurisdictions throughout the Pacific Northwest and throughout the Western Interconnection.[7] NIPPC believes that a regional approach to resource adequacy is key to ensure uniform product definitions, protocols for counting the resource adequacy contributions of various technologies, and related issues because a broad based resource adequacy market will be more efficient, lowering costs for all jurisdictions in the west. NIPPC is not taking a specific position in this docket as to what standards should be adopted, except to note that the standards should apply equally to all load serving entities, with maximum opportunity for all load serving entities to manage the resource adequacy requirements assigned to

[7] NIPPC's Statement on Resource Adequacy submitted to the Northwest Power Pool advisory group is included as Attachment 1 hereto and incorporated herein. This submission sets forth NIPPC's position on resource adequacy issues in greater detail.

it through well-structured markets. It is also important that resource adequacy rules carefully outline if and when it may be appropriate for some resource adequacy requirements to be met through centralized procurement that is done on behalf of all load, and when a load serving entity is entitled to provide its own resource adequacy, whether through self-supply or through purchase of resource adequacy capacity through a competitive marketplace.

5. Conclusion.

NIPPC greatly appreciates the Commission's willingness to undertake a comprehensive review of the Oregon's long term direct access programs. As discussed above, NIPPC believes that the Oregon legislature has clearly mandated development of a competitive retail market structure for electricity, and directed the Commission to eliminate barriers to development of that market. Over the past twenty years, Oregon has gradually moved closer toward a competitive retail market, but the market is far from robust, and many regulatory impediments continue to hinder the marketplace. NIPPC appreciates the opportunity to work with the Commission and interested parties to remove these impediments and move closer to the mandated retail market goals.

Dated this 16th day of March 2020.

Respectfully submitted,

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Northwest & Intermountain Independent Power Producer's (NIPPC) Statement on Resource Adequacy in the Northwest Region

Background

The Northwest is expected to face significant capacity deficits during the 2020-2030 time period. Recent studies by E3 and the Northwest Power and Conservation Council have demonstrated a need for 5,000 megawatts of net new capacity by 2025, growing to as much as 8,000 megawatts by 2030 to maintain reliability.[1] In response, the region's utilities have convened a process through the Northwest Power Pool to investigate the formation of a Regional Resource Adequacy Program.

Statement on Coordinated Planning

The region does not currently have an organized capacity market or consistent process for counting physical capacity. In fact, it has become a common practice for some large utilities to rely on "market purchases" or "front office transactions" to satisfy projected capacity requirements in their Integrated Resource Plans (IRPs). Such market purchases can serve to reduce customer costs by avoiding unnecessary investment as long as there is an adequate supply of available and affordable surplus capacity. If there is a shortage of capacity, however, reliance on financial contracts and risk-hedging instruments that do not involve an identified physical asset or Balancing Authority system commitment, can jeopardize reliable electric service, expose customers to high costs, or both. The magnitude of the capacity deficit forecast for the Northwest is therefore creating pressure on regulators to take action to relieve what is predicted to be a capacity crisis. Region-wide coordinated resource planning is intended to avoid such crises and minimize uneconomic short-term capacity procurement. NIPPC supports the development of a Resource Adequacy obligation that includes capacity demonstration requirements consistent with well-designed capacity-based markets similar to those that have proven to be effective elsewhere.

Statement of Support for Region-wide Capacity Planning

NIPPC supports the development of a "Regional Resource Adequacy Program" and believes that it will provide benefits to electricity consumers by improving the reliability of electricity service and minimizing long-term cost. A broad footprint can reflect the complimentary nature and diversity of a broad set of resources and obtain the benefits of geographic diversity to the economic benefit of ratepayers. NIPPC believes this effort could not only address future regional capacity needs but could also foster regional coordination, establish common metrics, and create tradable products that would further improve regional reliability while increasing market efficiency and decreasing costs. An agreed upon independent planning entity would be needed to determine the annual load serving entity's capacity obligation and the capacity value of the region's assets, for those who voluntarily participate.

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[1] Z. Ming, A. Olson, H. Jiang, M. Mogadali, N. Schlag, 'Resource Adequacy in the Pacific Northwest', *ethree.com*, San Francisco, Energy and Environmental Economics, Inc., March 2019, page 38, https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf (accessed January 20, 2020).

NIPPC Statement on FERC Jurisdiction

NIPPC understands that some Northwest utilities wish to establish a program as quickly as possible due to the looming capacity shortfalls. NIPPC further understands that the region's publicly-owned utilities and federal power marketing agencies wish to minimize FERC jurisdiction over the program. These practical considerations constrain the program design to a voluntary, multilateral compliance obligation in which each state may have differing, potentially conflicting, market rules about the level of capacity required, resource eligibility and capacity counting requirements and compliance requirements that will leave the region's capacity market balkanized and inefficient. A region-wide, formal, capacity procurement obligation that manages reliability on a region-wide basis will facilitate the development of a capacity product that is well-defined and will provide a framework for facilitating market-based transactions that ensure reliability at the lowest possible cost. NIPPC recognizes the practical political constraints in the Northwest region and does not oppose state-based development of the capacity construct in the near-term, but notes the need for a high level of uniformity and coordination among the states for the development of a workable, successful system.

NIPPC Principles for a Regional Resource Adequacy Program, and Specific Program Features

NIPPC offers the following seven principles and associated features for the region's consideration in its development of a "Regional Resource Adequacy Program". NIPPC believes adherence to these principles and features will maximize the benefits of the program to the region.

1. **Reliability:** The Program should assure reliability of electricity service to the region based on industry-standard reliability metrics.
    a. The Program should have binding requirements with meaningful penalties for non-compliance.
    b. The Program should evaluate individual resources based on the contribution they make toward regional resource adequacy, including stand-by generation.
    c. The Program should ensure that each eligible resource is counted once, and none is counted twice.
    d. The Program should appropriately consider the stochastic, variable nature of energy supplies for wind, solar, and hydro resources, including the role of drought years in causing the potential for loss-of-load events in the Northwest.
2. **Efficiency:** The Program design should demonstrate tangible and long-term consumer benefits.
    a. The Program should appropriately consider the effects of diversity and correlation among the region's portfolio of variable energy resources.
    b. The Program should allow for expansion to include or integrate with adjacent regions and market designs, including existing and emerging dispatch markets such as the EIM and EDAM.
3. **Independence:** Determination of need and evaluation of resource eligibility must be overseen by a Program Administrator that is independent of market participants.
    a. The Program Administrator should have independent authority for capacity certification/accreditation ratings, test procedures, and deliverability verification.

4. **Non-discrimination:** The resource evaluation must be technology-neutral and must enable all resources to participate regardless of ownership or location.
    a. The Program should provide for equitable treatment of supply-side and demand-side resources.
5. **Competition:** The Program design should facilitate participation in the program by all regional suppliers and customers, including those that participate in direct access programs.
    a. The Program should facilitate capacity price transparency and product tradability so that competitive entities can manage the risks associated with compliance.
    b. The Program should have well documented and defined processes for participation, multiple contracting options, and published market prices to encourage development of new capacity resources.
    c. The Program should ensure that there is well-formed market oversight to avoid the exercise of market power by either buyers or sellers of capacity resources, and address market power issues if they arise.
    d. The Program should abide by all open access transmission principles and requirements.
6. **Transparency:** The Program Administrator should undertake all calculations as to capacity requirements, resource eligibility, and compliance in a transparent, auditable manner and all information should be public to the maximum extent possible.
    a. The Program Administrator should provide forecasts of each BA's net positions over time.
7. **Practicality:** The Program should not be unduly burdensome to comply with and should be consistent over time.
    a. The Program should have low barriers for entry and exit.
    b. Variable generation, such as intermittent wind and solar, should be expected to be mechanically available during performance periods but should not be subject to a performance requirement. Capacity counting would be based on the historical ability to deliver when peak loads occur.
    c. Due to the regional nature of the Program, a showing of capacity should not include a requirement to hold firm transmission rights. A showing of capacity accompanies an obligation to deliver energy if required.
    d. The Program should leverage existing market institutions as much as possible, e.g., WSPP standard contracts. The capacity obligation should be consistent with other WECC capacity programs such as the resource adequacy construct used by the CAISO.