BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1837

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of New Facility Direct Access Load	))))))))	OPENING COMMENTS OF NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

The Northwest and Intermountain Power Producers Coalition ("**NIPPC**") submits these opening comments encouraging the Commission to swiftly clarify that new load taking Direct Access service should be exempt from transition charge payment obligations.[1] Doing so is fully within the Commission's discretion, is reasonably easy to implement, will not result in any significant cost shifting, and, most importantly, it is the right thing to do for Oregon.[2]

Summary Recommendations:

- The Commission should exempt all new load from transition charges, unless such new load affirmatively informs the utility of its intention to purchase power from the utility under cost of service rates. One way in which this can be accomplished is that the customer provides notice to the utility at the time of execution of a Master Electric Service Agreement, Electric Service Requirements Agreement, or similar written commitment (generally referred to herein as an "ESRA").[3]

---

[1] For convenience of review, NIPPC's comments are generally organized to be responsive to the questions identified in the November 9, 2017 email circulated by Commission Staff to Parties.

[2] NIPPC's and other parties' previously-filed comments explained that the Commission has the legal authority to exempt new load and the legal limitations on any exemptions. NIPPC's proposals are consistent with the previously articulated legal standard for exempting new loads.

[3] *See*, *e.g.,* PacifiCorp's November 6, 2017 workshop presentation on Forecasting New Loads, included as Attachment 1, page 3 of 6, specifying that PacifiCorp generally completes an Engineering Services Study Agreement, an Engineering Material Procurement Agreement, and a Master Electric Service Agreement prior to initiating any work on new load interconnections.

- New Load should be defined to include:

  (1) all load at a **new meter station** that required execution of an ESRA or similar written commitment; and

  (2) the portion of load at an **existing or upsized meter** where the increase in load is serving new commercial or industrial infrastructure added behind the meter; and is the larger of (a) 10 aMW or (b) 20 percent above the highest two-month period of use during the prior three years.

- The Commission should clarify that utilities can meet their provider of last resort obligations through market-rate purchases for any Direct Access load returning to the system, including any load previously electing New Load Direct Access. Such customers should be eligible to return to standard, cost-of-service rates after three years or such other term as approved by the Commission.

- The New Load Direct Access program should be agnostic with respect to generation type; however, the Commission should recognize that exempting new loads from transition charges will increase Oregon's transition to a green economy and increase renewable resource acquisitions in a way that lowers costs for cost-of-service customers.

- The New Load Direct Access program should not be subject to a cap.

1. The Commission must exercise its discretion and eliminate (or at least significantly reduce) transition charges for new load.

Public policy – and existing law – dictates that the Commission should exercise its discretion to eliminate transition charges for new load. There is no sound basis for new load to pay transition charges in the first instance, and continuation of this policy stymies Oregon's economy. It is also inconsistent with the Commission's statutory obligation to remove barriers to the development of a competitive retail power market.

As the Commission is aware, the Legislature is observing this docket and expecting that the Commission quickly act to eliminate burdensome transition charges from customers bringing new electric load to Oregon.[4] As noted by Senator Beyer, it's time for the Commission to "do

---

[4] In the Senate Business and Transportation work session regarding Senate Bill 979, which would have eliminated transition charges for new load that purchased renewable direct access, Committee Chair Senator Lee Beyer stated

its job" and send a message to companies considering investing in new business in Oregon that the state is supportive of economic development, has mechanisms in place for the acquisition of renewable energy above and beyond state requirements, and will eliminate burdensome and unjustifiable costs standing in the way of new commercial investment.

Nothing in the Direct Access legislation mandates the imposition of transition charges. The law provides that the Commission "may" allow for such charges but does not require they be imposed.[5] Even then, transition charges are limited to specifically-defined "uneconomic utility investments,"[6] which are limited to previously incurred and otherwise unrecoverable investments made by the utility to serve load, and only to the extent such charges are necessary to prevent costs shifts that are "unwarranted."[7] Where a utility has not expressly planned for a load and incurred costs to serve it, no uneconomic utility investments will ever be created and no cost shifting will occur. To the extent there is any residual cost-shifting, such amounts will be minor, and whether such costs shifts are "unwarranted" must be read in conjunction with three important criteria: 1) the public interest in Oregon's economic growth and prosperity from providing a cost-effective opportunity to encourage new investment within the state; 2) the acceleration of renewable energy usage and concomitant greenhouse gas reduction likely to result as customers elect greener sources of power through the Direct Access

---

that he spoke to both the Commission Staff and Commission Chair Hardie and reached the conclusion that the Commission should first be provided an opportunity re-visit direct access. Senator Beyer explained that since SB 1547 passed, things had:

> changed a lot, particularly as you are talking about new load where people [are] coming on and the Commission Chair has assured me that they see that change and want to encourage and be supportive for economic development and of people coming in who are willing to take a look at that and perhaps take a little more supportive look than they have in the past. I think that is good. What I told Commissioner Hardie is that we would let them do their job and if it seemed like they were not going on that way that we would be back in about 8 months and we would take another look at it. So I think the message we want to send to companies that are looking to Oregon as a place to do business and do green power is that we are indeed open for that.

Hearing on S.B. 979 Before the S. Comm. On Business and Transportation, 2017 Leg., 79th Sess. (Or. Apr. 9, 2017).

[5] ORS 757.646(1).

[6] ORS 757.600(31).

[7] ORS 757.607(1).

program; and 3) the Commission's mandatory obligation to eliminate barriers to the development of a competitive retail market. [8]

2. <u>Parameters of new load</u>

Load eligible for the New Load Direct Access program should include all commercial and industrial load, regardless of size or customer, that has not previously been served by the utility unless **(1)** the utility can demonstrate that it expressly planned for such new load; **(2)** it was prudent to plan for such load; and **(3)** the utility can show that it invested in new generation capacity to meet such load. Unless all of these elements are satisfied, load opting for the New Load Direct Access program will not create any uneconomic utility investments nor any costs shifts, and there is no basis whatsoever to impose a transition charge on such load. In addition, the Commission should adopt policies that protect customers that remain on cost of service rates by preventing the utilities from taking action or making plans to serve new loads in a way that could potentially harm customers, especially those without the option to select direct access.

NIPPC proposes the following as the initial definition for new loads:

> (1) **<u>New Meters</u>**: New load includes all load at a new meter that required execution of an ESRA;
>
> (2) **<u>Existing/Upgraded Meters</u>**: New load includes that portion of load at an existing or upsized meter where:
>
> > (**A**) the increase in load is serving new commercial or industrial infrastructure added behind the meter; and
> >
> > (**B**) such increase is the larger of:
> >
> > > (**I**) 10 aMW; or
> > >
> > > (**II**) 20 percent above the highest two-month period of use during the prior three years.

[8] *See* ORS 757.646(1).

As a matter of practical application, NIPPC submits that determining what is, and what is not, new load can be surprisingly simple: have the prospective load make a binding election at the time it initiates discussion with the utility for interconnection or meter facilities. If a customer indicates it desires standard utility cost of service power, the utility can and should plan for that load. If the customer indicates its intent to go directly to Direct Access, by contrast, that load should be considered "new load" and the utility should not plan for it, unless and until that load provides notice to the utility of its intent to "return" to cost of service treatment, using the same notice period that applies for standard Direct Access customers seeking to return to the system.

In the November 6 work session held in this proceeding, the utilities indicated that they have procedural requirements that all new load must undertake prior to the utility engaging in construction of interconnection and/or distribution facilities, including engineering analyses, execution of contracts, etc.[9] For larger loads, this process apparently can take years. The utilities do not appear to plan for a given proposed load addition absent execution of binding agreements. Based on the information provided so far, simply providing prospective load an election opportunity at an early stage will eliminate the substantial bulk of potential load that would require additional utility planning and capital investment in generation facilities and will eliminate creation of any uneconomic utility investment to support load that does not desire standard utility service. NIPPC submits that this one change would resolve most of the concerns with potential cost shifting related to a New Load Direct Access program. Any remaining potential New Load Direct Access will likely be smaller in the aggregate and be within the margin of error of a well-managed plan.

In addition to new load at new meters, new loads at existing facilities should be allowed to choose direct access without payment of transition charges to the extent it is demonstrably new load. NIPPC understands that concerns have been raised about ensuring that ordinary load fluctuations at existing facilities should not be considered new load. NIPPC is also aware that the utilities have raised concerns about tracking and the sometimes fluid nature of smaller

[9] *See Footnote 3, supra.*

commercial loads. To mitigate these concerns, NIPPC is proposing a two-pronged test for new load at existing meters: (1) the customer has added new commercial or industrial infrastructure behind the meter; and (2) the new load must be demonstrably higher than previous loads. With respect to this second aspect, NIPPC recommends that the Commission *initially* adopt the requirement that, to qualify as new load at an existing meter, the load must be at least the greater of 10 aMW or 20 percent above the highest two-month period of use during the prior three years. NIPPC submits that this initial 10 aMW threshold is exceedingly high: It is more than sufficient to ameliorate any concern that such load increase was simply a matter of load fluctuation, and should ensure that only truly new loads at existing facilities, which the utility has not invested in generation capacity to serve, are exempt from transition charges.

Over time, as participants gain experience with the new load program, this initial 10 aMW threshold should be reduced on a specified schedule that allows the utilities to adjust their generation planning and provides opportunities for greater customer participation. NIPPC recommends the Commission establish the reduction schedule in this proceeding or specify that the 10 aMW threshold will be revisited within three years.

3. The Commission can design a New Load Direct Access program that exempts New Load Direct Access customers from transition charges without imposing material costs on other customers.

New load direct access should not create uneconomic utility investment, if utilities prudently plan for future loads. The term "uneconomic utility investments" is expressly defined in the law using past-tense phrasing to specify that "uneconomic" investments, and thus any transition charges to recover such investments, include only investments that were incurred *prior to* a customer's election to leave the utility's cost of service system in favor of Direct Access.[10] The investments in generation infrastructure made to this point by the utilities are made based on the current system load. No cost shifts can possibly occur for load that the utility has not both specifically planned to serve *and* invested in infrastructure in order to serve

[10] ORS 757.600(35) (definition of "uneconomic utility investments"); *see also* ORS 757.600(31) (definition of "transition charge").

such load. NIPPC understands from the Workshop in this docket that utilities generally do not plan for specific large new loads until after execution of an ESRA by a given load, and they certainly do not make commitments to acquire generation resources for such uncommitted new large loads. The utilities further confirmed that if a new customer informed the utility it would move immediately to direct access, the utility would not include the load in its generation planning and would not make any commitments to generation resources. Based on this information, there can be no "uneconomic utility investments" related to the program if adequate notice is provided. To the extent unique circumstances for a given load apply, the impact is likely to be relatively small, and any cost shifts related to such load – if any -- would not be "unwarranted" as we adopt new policies beneficial for Oregon and necessary to remove impediments to development of a competitive retail market.

4. Utilities can adequately plan for New Direct Access Load

Utilities have the ability to adequately plan for New Direct Access Load, but should update some of their modeling assumptions as part of the process. Simply requiring prospective load to make an election in advance of construction of metering facilities will dramatically improve the utility's planning processes. Given that most large facilities take years to develop, the utilities should have ample notice, and ability to plan, around prospective New Load Direct Access growth. Any New Load Direct Access that can be constructed and put in service quickly will almost undoubtedly be smaller customer loads that will not have a significant impact on planning processes. The utilities should anticipate and plan for a portion of these loads, but they would, in the aggregate, be unlikely to create significant differences in anticipated system load. In this regard, as the Commission is aware, one of the major impediments to the growth of a competitive retail power market in Oregon, and the reluctance of some entities to move to direct access, has been the historically high level of transition costs imposed.[11] This creates a

[11] See, e.g., testimony on SB 979 before the Senate Committee on Business and Transportation, April 3, 2017, available at https://olis.leg.state.or.us/liz/2017R1/Committees/SBT/2017-04-03-15-00/SB979/Details.

viscous cycle in utility planning: the utilities do not plan for substantial direct access load growth because load growth has historically been depressed.   To the extent that New Load Direct Access is exempt from transition costs, the utilities should anticipate additional customers will elect that program in the future and adjust their plans accordingly.

5. Allowing new load never before utilizing a utility's system to take New Load Direct Access without transition charges does not impermissibly discriminate against existing customers.

As addressed extensively in NIPPC's September 8, 2017 Initial Brief and October 10, 2017 Reply Brief in this docket, Oregon law does not prohibit utilities from charging different rates to different customers. Instead, the statutes generally prohibit "*undue or unreasonable* preference or advantage to any particular person"[12] and make clear that a "public utility may not charge a customer a rate or an amount for a service that is different from the rate or amount the public utility charges any other customer *for a like and contemporaneous service under substantially similar circumstances*."[13]   New load is factually distinct from existing load, and the utilities are legally permitted to establish charges and surcharges for different customers based on such factual distinctions. As further noted in NIPPC's prior briefs, the Commission also could direct the utilities to create a new customer class and file a new rate schedule applicable to new Direct Access customers.

6. Provider of last resort obligations can be structured to eliminate the risks of cost shifts to the utilities and non-participating customers.

Oregon law directs the Commission to establish terms and conditions for providing default electricity service to nonresidential electricity consumers in an emergency, which conceivably may include failure of an Electricity Service Supplier to meet its contractual obligations. But nothing requires the utility to stand ready to provide such service on a cost of service basis, nor

[12] ORS 757.325(1) (emph. added).
[13] ORS 757.310(2) (emph. added).

to maintain excess generation facilities in rate base "just in case" a Direct Access customer returns to the system. Rather, the law provides that utilities can meet their supplier of last resort obligations to returning Direct Access customers through market-based purchases rather than standing ready to offer cost-of-service rates.[14] A customer electing Direct Access status for new load should be treated in the manner as any returning customer and be entitled to provider of last resort service at market rates, and eligible to return to cost of service rates after a notice period as established by the Commission. NIPPC believes the current notice period of three years currently in place on the Portland General Electric Company ("PGE") system is reasonable and appropriate for this purpose.

By eliminating the need for a utility to maintain a fleet of generation assets "just in case," this mechanism would reduce costs for all utility customers and avoid any cost-shifting issues.

7. What parameters can be placed on the type of new load receiving altered transition adjustment treatment to minimize cost shifting?

NIPPC does not believe that any parameters or limitations need to be placed on New Load Direct Access to minimize cost shifting. However, to provide the Commission and remaining customers the assurance that there are no cost shifts the Commission should consider: (1) establishing a minimum timeframe by which prospective load must notify the utility of its intent to move directly to Direct Access; (2) establishing an express time period for notifying the utility of a desire to return to standard utility service; and (3) clarify that utilities can meet provider of last resort obligations through market-based rate purchases.

NIPPC expressly submits that the Commission should ***not*** impose limitations on the New Load Direct Access program related to source of energy or program size. NIPPC anticipates that the

[14] *See* ORS 757.603(3)(b): "The commission may prohibit or otherwise limit the use of a cost-of-service rate by retail electricity consumers who have been served through direct access, and may limit switching among portfolio options and the cost-of-service rate by residential electricity consumers."

bulk of entities seeking to take advantage of the New Load Direct Access program will likely be interested in obtaining renewable energy products. Indeed, one of the significant benefits that Direct Access can offer to customers is the ability to provide power from a specified renewable source. However, it is not appropriate to limit the New Load Direct Access Program based on type of energy source. This program will help attract business to Oregon, and businesses need the ability to tailor products to meet their business objectives, such as the ability to purchase a hybrid of renewable and thermal power resources that allow for sophisticated price hedging based on weather conditions. Allowing new customers to purchase renewable resources without paying transition charges also will benefit all remaining customers by being early adopters and driving down the cost of renewable resources.

Nor is it appropriate to place any limitations on the program based on the program caps for existing load: the rationale for a cap does not exist. Program caps for existing load leaving the utility system may have historically been appropriate to prevent significant and sudden disruption of the utilities' services as those programs were being established. With respect to New Load Direct Access, by contrast, the utilities will not have invested in generation infrastructure in the first instance; capping the program would put an unnecessary restraint on opportunities for businesses to invest in Oregon. NIPPC further notes that the existing caps, especially for PGE, are already too low and may constrain further development of the competitive retail power market and the Oregon economy. PGE's direct access program has already reached almost 80 percent of its overall cap, with a projection of just 66 aMW available for future customers. [15] This is insufficient room for the addition of multiple new large entities, such as data centers, if the New Load Direct Access Program was subject to the cap.

---

[15] *See* PGE Long-Term Direct Access slides handout, p. 2, from November 6, 2017 Workshop (included as Attachment 2).

I. CONCLUSION

New load coming to Oregon is simply not similarly situated to existing load and does not generate significant (if any) uneconomic utility investments or cost shifts. Discouraging companies from investing in Oregon by making them bear the burden of significant transition costs for decisions that occurred years before they contemplated investing in the state is poor policy that needs to be changed.

Dated this 22nd day of November 2017.

Respectfully submitted,

Carl M Fink

Carl Fink
Blue Planet Energy Law
Suite 200, 628 SW Chestnut Street
Portland, OR 97219
971.266.8940
CMFink@Blueplanetlaw.com

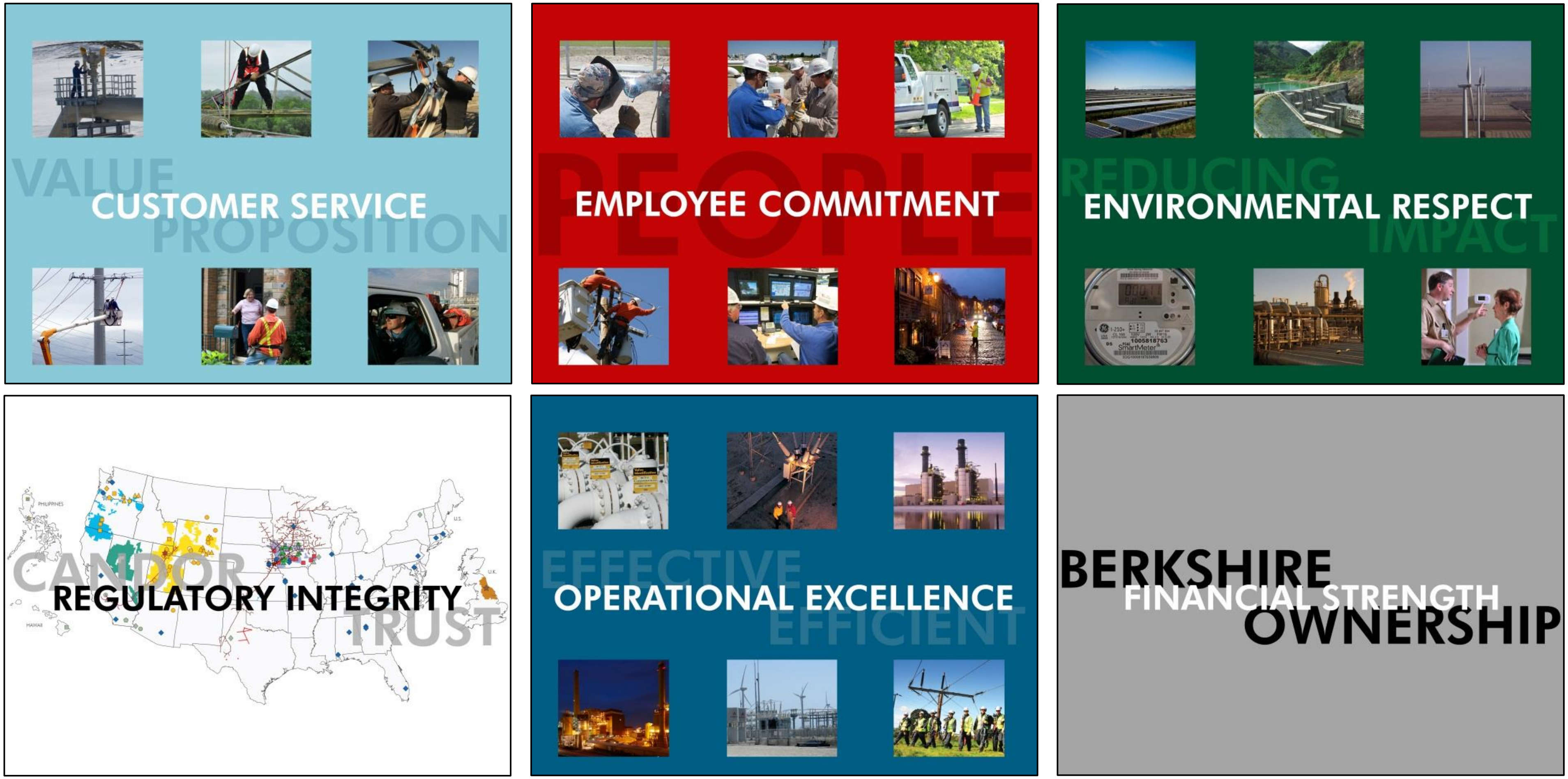
Irion Sanger

Irion A. Sanger
Sanger Law, PC
1117 SE 53rd Avenue
Portland, OR 97215
Telephone: 503-756-7533
Fax: 503-334-2235
irion@sanger-law.com

Of Attorneys for the Northwest and Intermountain Power Producers Coalition

Attachment 1

PacifiCorp’s Forecasting New Loads slides from November 6, 2017 Workshop, Docket UM 1837



PacifiCorp Load Forecasting Overview

November 6, 2017

PacifiCorp Load Forecasting Process

- Annual forecast process begin in March and finalize by June

- Individual Customer Forecast (~20 customers)
  - Relies on customer Regional Business Managers (RBM) input
    - Load forecast group coordinates with RBMs on individual customer forecasts
    - Informed by historical sales, customer input, economic literature & variance analysis
    - The forecast for one direct access customer is modeled using this approach

- Aggregate Customer Forecast (~216,000 customers)
  - Regression based approach
    - Commercial and industrial forecast rely on historical sales data, economic drivers and in the case of the commercial class weather-related variables

- Direct access forecast (~30 customers)
  - Non-individually forecasted direct access customer load are forecasted as simple average of recent direct access customer load

Treatment of Prospective New Load

- Evaluate probability of prospective load occurring
  - Coordinate with RBMs
  - Engineering study status
    - ESSA – Engineering Services Study Agreement
    - EMPA – Engineering Material Procurement Agreement
    - MESA – Master Electric Service Agreement

- Size and timing of new load

- Evaluate projected year-over-year growth in class

- Evaluate if any off-setting load impacts
  - Evaluate year-to-date sales against forecast
  - Determine any declining load projections for other customers with RBMs

Oregon Commercial and Industrial Forecast

Oregon Retail Sales – Megawatt-hours (MWh)		
Year	Commercial	Industrial
2017	5,076,308	1,849,639
2018	5,115,251	1,769,573
2019	5,098,874	1,763,691
2020	5,103,759	1,762,377

*Pacificorp - 2017 Integrated Resource Plan Volume II, Table A.9, page 16

- Oregon Commercial
  - Year-over-year growth of 38,943 MWh projected between 2017 and 2018

- Oregon Industrial
  - Year-over-year decrease of 1,315 MWh between 2019 and 2020

Example 1: New Large Retailer

- Evaluate probability of prospective load:
  - Customer has signed MESA = Very high probability of occurrence

- Size and timing of new load:
  - 1.5 MW at 50% load factor is 6,570 MWh per year. Projected to come on line in 2018

- Year-over-year growth in class forecast:
  - 38,943 MWh increase between 2017 and 2018

- Off-setting load impacts:
  - No known offsetting load projections from other customers in 2018
  - Year-to-date actuals vs. forecast indicate sales are tracking with projections for 2017 and trajectory aligns with 2018 forecast

- The load growth in this example is aligned with the existing forecast projections

Example 2: New Industrial Customer

- Evaluate probability of prospective load:
  - Customer has signed MESA = Very high probability of occurrence
- Size and timing of new load:
  - 15 MW at 80% load factor is 105,120 MWh per year. Projected to come on line in 2020
- Year-over-year growth in class forecast:
  - 1,315 MWh decline between 2019 and 2020
- Off-setting load impacts:
  - No known offsetting load projections from other customers in 2020
- The load growth in this example is above projected sales
  - We would incorporate an individual customer forecast for this projected new load until their actuals are established in our load history

Attachment 2

PGE's Long Term Direct Access Slides from November 6, 2017 Workshop, Docket UM 1837.

PGE Long-Term Direct Access

UM 1837 Workshop
November 6, 2017

Status of PGE LTDA Program

- PGE has provided, on an annual basis, a permanent long-term direct access option with the cessation of transition adjustments after five years since 2003.
- PGE also has provided annually a three-year direct access option since 2005. This option has fixed transition adjustments not subject to update. The three-year option is considered to be consistent with OAR 860-038- 0275(5).
- Eligibility criteria is 250 kW for an account, aggregated to one aMW. Applicable rate schedules are 485, 489, 490, 491, 492, and 495. Transition adjustments are specified in Schedule 129.
- Most recent stipulation in UE 262 covered the service years 2015-2018 (Order 13-459).
- This stipulation provides for the update of Schedule 129 transition adjustments during the five-year transition adjustment period for changes in fixed generation costs. Also, PGE accounts for true-ups to fixed generation costs related to new enrollment in between general rate proceedings (UE 236, Order 12-057).
- The total enrollment is capped at 300 aMW.
- For the five-year option, a return to COS pricing is possible, with either a two or a three year notice, depending on enrollment vintage.
- Current 2018 projected enrollment is approximately 294 accounts and 2,048,702 MWh (234 aMW). All accounts are on the five-year option.

Transition Adjustments/Cost Allocation

- For both the three-and the five-year options, the Schedule 129 transition adjustments reflect the differences between projections of wholesale market prices and tariff energy prices, by rate schedule and delivery voltage for the prescribed period.
- The Schedule 129 transition adjustment payments (or credits) are distributed to all customers during either the Schedule 125 AUT process or the GRC process (~$20 million for 2018).
- Long-term direct access billing determinants are not included when calculating functional generation, transmission, and ancillary service prices. The billing determinants of all customers are used in determining prices related to the other functional categories, therefore distribution and customer service.
- To acknowledge that direct access customers contribute less to PGE's franchise fee obligation to municipalities, direct access customers have a reduced system usage or distribution charge relative to COS customers (UM 1587, Order 12-500).
- PGE is mandated to be the default and emergency default supplier for DA customers regardless of whether they continue to pay transition adjustments (OAR 860-038-0280).