Noble Americas Exhibit 100
Witness: Kevin C. Higgins

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

In the Matter of PacifiCorp, dba	**)**	
Pacific Power	**)**	**Docket No. UE-296**
2016 Transition Adjustment	**)**	
Mechanism	**)**	

REDACTED

Opening Testimony of Kevin C. Higgins

on behalf of

Noble Americas Energy Solutions LLC

June 29, 2015

OPENING TESTIMONY OF KEVIN C. HIGGINS

<u>Introduction</u>

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this phase of the proceeding?

A. My testimony is being sponsored by Noble Americas Energy Solutions LLC ("Noble Solutions"). Noble Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico. Noble Solutions serves more than 15,000 retail customer sites nationwide, with an aggregate load in excess of 4,500 MW. Noble Solutions' retail customers are located in the service territories of 55 utilities. In Oregon, Noble Solutions is currently serving customers in Portland General Electric's service territory and PacifiCorp's territory.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before this Commission?

A. Yes. I have testified in twenty-one prior proceedings in Oregon, including six PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM), UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM). I have also participated in six PacifiCorp general rate cases, UE 263 (2013), UE 246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147 (2003), as well as the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

In addition, I have testified in five PGE general rate cases, UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008) and UE 180 (2006); the PGE Opt-Out case, UE 236 (2012); and the PGE restructuring proceeding, UE 115 (2001).

Most recently, I have filed testimony in Phase II of the Investigation into Qualifying Facility Contracting and Pricing, UM 1610 (2015).

Q. Have you participated in any workshop processes sponsored by this Commission?

A. Yes. In 2003, I was an active participant on behalf of Fred Meyer Stores in the collaborative process initiated by the Commission to examine direct access issues in Oregon, UM-1081. More recently, in 2012, I participated in drafting comments on behalf of Noble Solutions as part of UM-1587, the Commission's investigation of issues relating to direct access.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 185 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also prepared affidavits that have been filed with the Federal Energy Regulatory Commission.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the calculation of the Schedule 294, 295, and 296 transition adjustments, as well as issues pertaining to Direct Access Service Requests ("DASRs") for Schedule 296. As this 2016 TAM represents the initial implementation of Schedule 296, which applies to customers selecting the recently-approved five-year opt-out, my testimony addresses certain aspects of the

Schedule 296 calculation that were not addressed in Commission Order No. 15-060, which established PacifiCorp's five-year opt-out in UE 267.

Q. What are the primary conclusions and recommendations in your testimony?

A. I offer the following primary conclusions and recommendations:

- The Schedule 294, 295 and 296 transition adjustments should be adjusted to reflect the value of freed-up Renewable Energy Certificates ("RECs"). Otherwise, direct access customers will unreasonably pay for Renewable Portfolio Standard ("RPS")-related resources twice: once from their Electricity Service Supplier ("ESS") and a second time from PacifiCorp, which banks the RECs paid for by direct access customers for future use by cost-of-service customers.
- In calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should <u>not</u> be escalated in Years 6 through 10 as proposed by PacifiCorp. Rather, Schedule 200 costs used in this calculation should decline each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.
- PacifiCorp's proposal for handling a DASR that arrives after the 13-business-day advance deadline for a customer to start the five-year opt-out program on January 1 is to deny participation in the program for a full year. This approach, which is unstated in the tariff, is unreasonable.

Instead, the customer should have the option to enter the five-year program by paying PacifiCorp all applicable five-year opt-out charges that would have applied between January 1 and the effective date of the DASR in excess of the amount that the customer is charged by PacifiCorp under the default participation in Schedule 220 during that period.

<u>The Transition Adjustment and Ongoing Valuation</u>

Q. What is the purpose of retail direct access and transition adjustments under Oregon's direct access law?

A. Under a retail direct access program, the direct access customer continues to use the utility's distribution system but does not use the utility as its power supplier, but instead obtains energy from another supplier. Oregon's direct access law was initially enacted in 1999. In its findings supporting the legislation, the legislative assembly declared that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable."[1] The direct access law requires that all nonresidential retail customers be allowed direct access to competitive markets by purchasing generation services from Commission-certified electricity service suppliers ("ESS").[2] The law requires the Commission to implement rates that charge or

[1] Or. Laws 1999, Ch. 865.
[2] *See* ORS 757.600(6), (16), -601(1), -649(1)(a).

credit the direct access customer an amount that prevents "unwarranted shifting of costs."[3]

Q. By way of background, please summarize the status of direct access in PacifiCorp's service territory.

A. Thirteen years after the statutory implementation of direct access in Oregon, the direct access program in PacifiCorp's service territory remains at very low participation levels. In my opinion, this low level of participation is due in large part to a transition adjustment regime that results in a negative value proposition for participating customers. Shopping participation levels in 2014 were only 1.4% of eligible shopping load, far below the 14.4% participation rate in the Portland General Electric ("PGE") territory.[4] Oregon businesses continue to face material barriers to acquiring market-priced power in PacifiCorp's territory, despite the proximity to major wholesale trading hubs, and despite the plain objectives of the Oregon Legislature in enacting direct access legislation in 1999.[5]

Prior to the 2016 shopping year, customers in the PacifiCorp territory have had a choice between one-year and three-year programs, pursuant to which the direct access customer pays the ESS for generation supply and continues to pay PacifiCorp for Schedule 200 generation costs subject to the transition adjustment. At the conclusion of the one-year or three-year term the customer returns to cost-

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3 ORS 757.607(1), (2).

4 Source: Oregon Public Utilities Commission, Status Report: Oregon Electric Industry Restructuring (July 2014). See Exhibit Noble Solutions/101, Higgins 1.

5 ORS 757.601(1) provides 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."

of-service or elects a new one-year or three-year term. Under this regime, the customer never stops paying for PacifiCorp's generation resources.

One potential remedy for this situation is the implementation of the five-year opt-out program that allows customers to migrate to 100% market prices for generation services without any remaining obligations to compensate the interconnected electric utility for generation resources it has acquired for bundled customers, similar to what PGE has implemented. The Commission determined to adopt such a program for PacifiCorp in Order No. 12-500. In that order, the Commission ordered PacifiCorp to file a tariff for a five-year opt out program that allows a qualified customer to go to direct access and pay transition charges for the next five years, and then to be no longer subject to transition adjustments. After the conclusion of payments of five years of transition adjustments under the program, the customer will only pay the interconnected electric utility for distribution delivery service. However, as I will discuss below, the structure of the new PacifiCorp five-year opt-out approved by the Commission in UE 267 exacerbates the negative value proposition found in the Company's one-year and three-year programs currently in effect. Consequently, despite the inherent appeal of a five-year opt-out program, populating the five-year opt-out program approved for PacifiCorp will be very challenging. This proceeding is the first time that the Commission will approve the rates applied under the new five-year opt-out program, and thus presents an opportunity to ensure that those rates are just and reasonable for the Schedule 296 five-year opt-out customers.

In this testimony, I propose a small change to the calculation of the Schedule 294, 295 and 296 transition adjustments, as well two refinements to the Consumer Opt-Out charge proposed for Schedule 296. Although these small changes will provide incremental improvements to the economics of direct access, by themselves, they will be insufficient to overcome the underlying negative value proposition embedded in the algebra of the PacifiCorp shopping program. Nevertheless, these changes should be adopted because they are reasonable.

Q. What is your understanding of the purpose of the transition adjustment?

A. The purpose of the transition adjustment is to provide the appropriate credit or charge for customers who choose direct access service. The transition adjustment is applied either through Schedule 294, Schedule 295, or Schedule 296. Schedule 294 is applied to customers who choose a one-year direct access option, Schedule 295 is applied to customers who choose a three-year direct access option, and Schedule 296 will be applied to customers who select the new five-year opt-out that was recently authorized in UE-267.

PacifiCorp's transition adjustment calculation is a form of Ongoing Valuation as prescribed in OAR 860-038-0140. According to OAR 860-038-0005(42):

> Ongoing Valuation means the process of determining transition costs or benefits for a generation asset by comparing the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period.

The logical premise behind Ongoing Valuation is to credit or charge direct access customers the difference between market prices and cost-of-service rates. The design logic in this approach places customers in an economically "break even" position with respect to the choice of direct access service; that is, if market prices are below cost-of-service rates at the time the transition adjustment is calculated, the direct access customer is charged the difference via the transition adjustment. Conversely, if market prices are *above* cost-of-service rates, the direct access customer is *credited* the difference via the transition adjustment.

The corollary to this design logic is that it holds non-participating customers harmless, as the utility, which buys and sells billions of kilowatt-hours over the course of a year, should be able to dispose of the energy freed up by direct access through market transactions. In the case of PacifiCorp, the transition adjustment analysis consists of evaluating the impact of 25 MW of direct access load on a 10,000 MW system in the calculation of Schedules 294 and 295, and 50 MW of direct access load in the calculation of Schedule 296.

Q. Please explain how direct access can be viable if the design logic of Ongoing Valuation places direct access customers in an economically break even position.

A. For customers who attempt to select direct access service on a year-to-year basis, the Ongoing Valuation approach indeed makes direct access a tenuous value proposition. A one-year direct access selection may be economically viable in certain circumstances, such as, for example, if some market movement occurs during the shopping window, after the transition adjustment has been set. Alternatively, some customers may have a strong corporate preference for participating in the market, despite the barrier of contending with a "break even" transition adjustment design. But in general, the year-to-year "break even" model is not particularly attractive for customers. In Oregon, the only direct access program that has shown signs of sustained success is PGE's five-year opt-out program, in which customers pay PGE's Ongoing Valuation transition adjustment for five years, and then migrate fully to market prices (with no further transition adjustments). As I noted above, pursuant to the Commission's order in UE-267, PacifiCorp is also implementing a five-year opt-out program effective January 1, 2016, although the design of its transition adjustment differs in some important respects from PGE, as will be discussed later in my testimony.

<u>Calculation of the One-Year and Three-Year Transition Adjustments (Schedules 294 and 295)</u>

Q. How is PacifiCorp's transition adjustment mechanism for Schedules 294 and 295 calculated?

A. PacifiCorp's transition adjustment charges (or credits) direct access customers the difference between PacifiCorp's net power cost (as reflected in Schedule 201) and the estimated market value of the electricity that is freed up when a customer chooses direct access service.[6] This is calculated by subtracting the former from the latter, after adjusting the latter for line losses to reflect its value at the point of retail delivery. If the result is a positive number, the difference is applied as a credit to the direct access customer. If the result is a

[6] Direct access customers in PacifiCorp's service territory already pay for the Company's fixed generation costs through Schedule 200. Thus, the transition adjustment is calculated by subtracting *net power costs* from the value of freed-up energy rather than subtracting *total generation costs* from the value of freed-up energy. Calculating the transition adjustment in this manner is logically equivalent to subtracting total generation costs from the value of freed-up energy while *not* charging direct access customers for Schedule 200.

negative number, the difference is applied as a charge to the direct access customer.

Q. If Schedule 294 or 295 is a credit, does that mean that PacifiCorp's generation costs are less expensive than the market and that direct access customers are being paid to leave cost-of-service rates?

A. No. PacifiCorp direct access customers must continue to pay for the Company's fixed generation costs through Schedule 200. A Schedule 294 credit simply means that the Company's *net power costs* are less than market prices. Only if the Schedule 294 credit were greater than the Schedule 200 charge could it be accurate to state that direct access customers were being "paid" to leave cost-of-service rates. That is far from the case today. For example, PacifiCorp's sample 2016 Schedule 294 rate for Schedule 48 customers is an average credit of $7.87/MWh during Heavy Load Hours and an average credit of $3.35/MWh during Light Load Hours, while the average Schedule 200 charge for these customers is $26.47/MWh.[7] Thus, the Schedule 200 charge is far greater than the transition adjustment credit, meaning that the direct access customer makes a net payment to PacifiCorp for generation resources that the customer does not use.

Q. Please continue with your explanation of how PacifiCorp's Schedule 294 and 295 transition adjustment mechanism is calculated.

A. The transition adjustment is calculated using PacifiCorp's GRID model. According to PacifiCorp's tariff, the estimated market value of the electricity that

[7] Sources: The average Schedule 294 credits are derived from PacifiCorp's Response to TAM Support Set 3. See Exhibit Noble Solutions/102, Higgins/17 for the relevant source material. The average Schedule 200 rate for 2014 is provided in the Confidential Attachment to PacifiCorp's Response to Noble Solutions Data Request 1.7. This is included in Exhibit Noble Solutions/102, Higgins/4. PacifiCorp consented to my use of this figure as non-confidential in this testimony.

is freed up when a customer chooses direct access service is determined by running two system simulations – one simulation with PacifiCorp serving the direct access load and one simulation with the Company not serving the direct access load. At the present time, for the Schedule 294 one-year and Schedule 295 three-year programs, these simulations are run assuming direct access occurs in 25 MW decrements, which are shaped using the load shape of the rate schedule being analyzed for purposes of determining its Schedule 294 or 295 credit (charge). The difference between the two scenarios is used to calculate the impact on PacifiCorp's total system, which is then used to determine the "weighted market value of the energy" freed up due to direct access.[8] The weighted market value of the energy is then compared to the customer's price under Schedule 201 to determine the Schedule 294 or 295 credit (charge).

Q. Does PacifiCorp's Ongoing Valuation calculations for Schedules 294 and 295 result in a "break even" proposition for customers?

A. No. As I have explained in Docket UE 264, this approach does not adhere strictly to the definition of Ongoing Valuation articulated in OAR 860-038-0005(42). Ongoing Valuation requires that transition costs or benefits for a generation asset be determined by comparing the value of the asset output at projected *market prices* to an estimate of the revenue requirement of the asset. PacifiCorp's use of the GRID model to calculate transition costs does not produce a valuation based exclusively on projected market prices as required in the OAR, but a valuation that is based on a blend of market prices and thermal generation

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[8] *See* PacifiCorp Tariff, Schedule 294, p. 1.

costs. Because the incremental cost of PacifiCorp's thermal generation is typically less than market prices, blending market prices and the Company's thermal costs invariably produces a lower valuation of freed-up energy than would occur if market prices alone were used for this purpose. Because the value of freed-up energy is a credit against the cost-of-service price for direct access customers in the calculation of Schedules 294 and 295, using a lower price for this purpose increases the transition adjustment charge (or alternatively, reduces the transition adjustment credit), all other things being equal. Indeed, because shopping customers must pay market prices for power, if the value of freed-up energy used in the calculation of the transition adjustment is less than the actual market price direct access customers pay, then it creates a negative value proposition for year-to-year shoppers rather than the break-even proposition inherent in the logic of Ongoing Valuation.

Q. Have refinements been developed to mitigate the impact of including thermal costs in the calculation of Schedules 294 and 295?

A. Yes. In UE-199 (2009 TAM), a Stipulation approved by the Commission in Order No. 08-543 modified the valuation of the thermal generation assumed to be backed down due to direct access by providing for a partial weighting using market prices. Specifically, the parties agreed as follows:

> 15. <u>Transition Adjustment</u>: The Parties agree to modify the calculation of the Transition Adjustment for direct access in two ways: (1) the Company will relax the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to determine the value of the freed up power; and (2) any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. The monthly COB and

> Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanisms will remain in effect.

The partial weighting using market prices was implemented pursuant to the second provision quoted above. While this provision mitigates the negative value proposition faced by direct access customers in the PacifiCorp territory, it does not eliminate it, as I demonstrated in UE 264.

Q. Has this second provision been applied continuously since its initial adoption in UE-199?

A. Yes. PacifiCorp has continued to apply this provision in each TAM proceeding since it was initiated in 2009 and continues to apply it in the 2016 TAM.[9]

Q. Are you recommending any changes in this docket regarding continued reliance on the GRID model for calculating the transition adjustment?

A. No. In Docket UE 264, to address the problem of negative bias in the calculation of the PacifiCorp TAM, I recommended abandoning the use of the GRID model for determining the market value of energy freed-up by direct access and instead calculating this value directly based on the utility's forward price curve used for projecting its net power costs, just as PGE does. I also recommended recognizing a BPA Point-to-Point transmission credit to remedy a structural impediment to the pricing of direct access service associated with the need for an ESS to obtain wheeling from BPA to reach the PacifiCorp service territory from the Mid-C trading hub.

[9] PacifiCorp Response to Noble Solutions Data Request 1.1, included in Exhibit Noble Solutions/102, Higgins/1.

Although I continue to believe these modifications are appropriate, I am not advocating for these changes in this proceeding because neither were adopted by the Commission in UE 264.

Q. Are you recommending any other changes to the Schedule 294 and 295 TAM calculations?

A. Yes. I recommend that the calculation be modified to capture the effects of Oregon's RPS on the transition adjustment.

Q. Please explain.

A. The Oregon RPS is applicable to both cost-of-service and direct access customers. When direct access customers purchase power from an ESS, the energy provided by the ESS must meet RPS requirements, which at present require that 15% of supply come from qualifying renewable electricity when serving in the PacifiCorp territory.[10] At the same time, direct access customers pay for the renewable energy that PacifiCorp has acquired to meet the RPS for its cost-of-service customers. In paying both the ESS and PacifiCorp for RPS power, direct access customers are paying twice to meet RPS requirements.

Q. How do direct access customers pay PacifiCorp for RPS requirements?

A. PacifiCorp recovers its RPS-related costs both through Schedule 200, through which the fixed costs of utility-owned renewable generation are recovered, and Schedule 201, through which power purchases of RPS-eligible resources are recovered. [11] As I discussed above, direct access customers are charged directly for Schedule 200 and also pay for the difference between

[10] ORS 469A.052, 469A.065. This percentage increases to 20% in 2020 and 25% in 2025.
[11] See PacifiCorp Response to Noble Solutions Data Request 1.11, included in Exhibit Noble Solutions, Higgins/7.

Schedule 201 costs and the value of the freed-up power, as calculated through the transition adjustment calculation.

Q. When a customer switches to direct access and acquires its RPS resources from its ESS, what happens to PacifiCorp's RPS requirement?

A. When a customer switches to direct access, PacifiCorp's RPS obligation is reduced proportionately. According to the Company, the freed-up RECs are banked for future use.[12]

Q. Are direct access customers compensated for the value of the RECs procured to serve their load by PacifiCorp or otherwise allowed to recognize the benefits of those RECs PacifiCorp procured on their behalf prior to the direct access election?

A. No.

Q. Do you believe the status quo is reasonable?

A. No. It is not reasonable for direct access customers to be required to pay twice to meet the RPS requirements, and effectively subsidize the cost of RECs that are banked for future use by cost-of-service customers.

Q. What remedy do you recommend to address this concern?

A. PacifiCorp actively sells RECs that are not required to meet state RPS requirements. The revenues from these sales are credited to customers in non-RPS states such as Utah and Wyoming, and the valuations of the REC sales are reported in those states in the ordinary course of ratemaking. The sold RECs are classified by PacifiCorp in these proceedings in these other states either as

[12] See Exhibit Noble Solutions/102, Higgins/8, containing PacifiCorp Response to Noble Solutions Data Request 1.12.

"structured" or "unstructured," depending on their attributes, which correspond generally to the "bundled" and "unbundled" attributes recognized in the Oregon RPS.[13] Since an ESS can acquire unbundled RECs to meet its Oregon RPS obligations, I recommend that the average price of unstructured RECs that are projected to be sold in the current year be used as the basis for valuing the RECs that are freed-up by a direct access customer. Thus, in this case, unstructured REC prices for 2014 would be used to set the valuation for the 2016 TAM.

Q. What was the average value of unstructured RECs sold by PacifiCorp in 2014?

A. According to filings made by the Company in Utah, the average value of unstructured RECs in 2014 was [CONFIDENTIAL] [redacted] [CONFIDENTIAL].[14]

Q. How would this adjustment work mechanically?

A. The price of unstructured RECs, prorated for the proportion of resources that must be RPS-eligible (i.e., 15% at the current time), should be added to the weighted average market price of energy freed-up by direct access. So, for example, in this case, PacifiCorp has provided workpapers for a sample Schedule 294 calculation for Schedule 48 customers which indicate that the weighted average market price of freed-up energy during HLH (measured at sales) is $31.89/MWH.[15] My adjustment would be in the form of an adder to this price

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[13] A bundled REC includes the underlying electricity for which the REC was issued, whereas an unbundled REC does not. *See* ORS 469.A.005 (3), (12).

[14] Source: Calculated using PacifiCorp Confidential Response to Noble Solutions Data Request 3.22, included in Confidential Exhibit Noble Solutions 103, Higgins/1-5.

[15] Source: PacifiCorp's Response to TAM Support Set 3 CONF, included in Confidential Noble Solutions Exhibit/103, Higgins/6. Although some of the inputs used in the derivation of this value are confidential, the average value itself is not confidential.

that is equal to the 2014 average price of unstructured RECs multiplied by 15 percent.

Q. Why do you recommend using the *average* unstructured REC price rather than the price set in the most recent unstructured REC sale?

A. The price set in the most recent REC sale would reflect the confidential terms of an individual transaction. By using an average price during the year, it would avoid revealing the terms of any one transaction.

Q. Have you queried PacifiCorp regarding the possible recognition of the value of freed-up RECs in the transition adjustment?

A. Yes. PacifiCorp was asked in discovery whether the Company believed that such a recognition would be appropriate. In response, PacifiCorp indicated that the Company did not support recognizing the freed-up value of RECs in the transition adjustment, as communicated in the following response:

NAES Data Request 1.13
Does the Company agree that the calculation of the Schedule 294, 295, and 296 transition adjustments do not reflect the value of RECs that are freed-up as a result of direct access? Does the Company believe it is appropriate to adjust the transition adjustment calculation to reflect the freeing-up of RECs due to direct access? If not, please explain the basis for the Company’s response.

Response to NAES Data Request 1.13
The calculation of the Schedule 294, 295, and 296 transition adjustments accurately reflects the fact that election of direct access service by a customer does not result in “freed-up” renewable energy credits (RECs). Under Oregon’s Renewable Portfolio Standard (RPS), unlimited banking of RECs is allowed. Thus, if the Company’s retail load is lowered as the result of a customer electing direct access service, RECs that may have otherwise been necessary if the customer did not elect direct access are retained in the Company’s REC bank for use towards RPS compliance in future years.

Q. Why is it reasonable to credit direct access customers with the value of freed-up RECs if those RECs are banked for future use?

A. The migration of a customer to direct access causes PacifiCorp's RPS obligation to be reduced and the RPS obligation to the ESS provider to be increased in the same amount. The fact that PacifiCorp chooses to bank the freed-up RECs rather than sell them to an ESS that has picked up the direct access load or another party is not reasonable grounds for failing to recognize the value of the freed-up RECs in the TAM calculation. In the calculation of the TAM, great pains are taken to avoid any subsidization of direct access customers by cost-of-service customers. Equal care should be exercised in the counter direction. Direct access customers should not be expected to pay twice for RPS-eligible power: once from their ESS and a second time to underwrite the cost of banking RECs for future use by cost-of-service customers.

<u>Calculation of the Five-Year Transition Adjustment (Schedule 296)</u>

Q. How is PacifiCorp's transition adjustment mechanism for Schedule 296 proposed to be calculated?

A. PacifiCorp's sample calculation of Schedule 296 is provided in a Confidential Attachment in Response to Noble Solutions Data Request 1.7. This calculation was prepared in connection with UE-267, and the Company notes that the calculation has not been updated for this case. I have provided a non-confidential excerpt from this data response that summarizes PacifiCorp's sample calculation in Exhibit Noble Solutions/102, Higgins/3-4.

Schedule 296 consists of two major parts: (1) a five-year transition adjustment component that structurally is nearly identical to the calculation of the

Schedule 294 and 295 transition adjustments, and (2) a Consumer Opt-Out component, which brings forward into Years 1 through 5 the projected Schedule 200 costs for Years 6 through 10, net of projected net power costs savings attributed to the departed opt-out load.

In addition to the Schedule 296 charge, the customer must also pay PacifiCorp the base Schedule 200 charge for the five years, which may be updated in each rate case during that period.

From the effective date of the opt-out election forward, the customer also pays charges for the generation and delivery that the customer will use to serve its load, which includes payments to an ESS for the generation and to PacifiCorp for delivery service under an applicable delivery service tariff.

Q. Does Schedule 296 result in a negative value proposition for customers during the five-year opt-out period?

A. Yes. The negative value proposition derives from two sources. The first source is a result of calculating the transition adjustment using the GRID model, further exacerbated by the absence of a credit for BPA PTP transmission, as I noted above in relation to Schedules 294 and 295 and previously discussed in detail in UE 264 and UE 267. The second source is the Consumer Opt-Out charge, which brings forward projected costs from Years 6 through 10 and recovers them in Years 1 through 5. It is self-evident that *even if* the transition adjustment itself were a break even proposition (as intended per the Ongoing Valuation approach) the addition of costs from future years to an otherwise break even transition adjustment would create a negative value proposition in the amount of the additional charge, i.e., in the amount of the Consumer Opt-Out charge itself.

So, for example, according to PacifiCorp's sample calculation, in Year 1 of the five-year opt-out, a Schedule 48 customer would pay an average of $26.98/MWh for Schedule 200, while receiving a Transition Adjustment credit of $9.01/MWh, for a net charge of $17.97/MWh, prior to considering the Consumer Opt-Out charge.[16] Conceptually, under ongoing valuation, this $17.97/MWh charge is *intended* to produce a "break-even" value proposition for the direct access customer relative to cost-of-service rates, after taking into account the customer's purchase of market power. But, in addition, the five-year opt-out customer would pay a Consumer Opt-Out charge of $5.75/MWh.

Q. You indicated that, structurally, the five-year transition adjustment component of Schedule 296 is nearly identical to the calculation of the Schedule 294 and 295 transition adjustments. In what ways does it differ from the Schedule 294 and 295 calculation?

A. Aside from the obvious fact that it is calculated for five years (instead of one or three), the transition adjustment component of Schedule 296 is calculated assuming 50 MW of direct access load rather than 25 MW, as is assumed for Schedules 294 and 295. The five-year opt-out customers will also pay Schedule 200 rates for each of the first five years of the opt-out period. In this manner, Schedule 296 is comparable to Schedule 294. Schedule 295 is slightly different, in that three-year opt-out customers pay for *projected* Schedule 200 costs, rather than contemporaneous Schedule 200 costs. Otherwise, the Schedule 296

[16] As noted above, this information is presented in Exhibit Noble Solutions 102, Higgins/4.

transition adjustment component is calculated in a manner that is identical to the Schedule 294 and 295 transition adjustments.

Q. In your opinion, should the transition adjustment component of Schedule 296 be adjusted to reflect the value of freed-up RECs, as you propose for Schedules 294 and 295?

A. Yes. The rationale for recognizing this value in Schedule 296 is the same as for Schedules 294 and 295. In the case of Schedule 296, the REC valuation should be updated annually for Year 1 through Year 5 and should reflect the then-current proportion of RPS-eligible resources that is required.

In addition, for Years 6 through 10, a projected value for freed-up RECs should be included as a credit in the calculation of the Consumer Opt-Out charge. For purposes of the 2016 TAM, I recommend using the 2014 REC value for this purpose, combined with the relevant RPS requirement percentage.

Q. Regarding the Consumer Opt-Out charge, do you have any other recommendations to the Commission concerning how that rate is calculated as Schedule 296 is implemented for the first time?

A. Yes. In UE 267, PacifiCorp provided an illustrative example of the calculation. In that docket, I recommended against adoption of the Consumer Opt-Out charge in its entirety. However, the Consumer Opt-Out charge was nevertheless approved by the Commission. In Order 15 195, denying the motion of Noble Solutions and other parties for clarification or reconsideration, the Commission noted that, “As PacifiCorp notes, if in the future the joint parties believe that they have new evidence or arguments demonstrating that the customer opt-out charge is unjust or unreasonable, they may seek our review at time."[17] I believe that some refinements to the Opt-Out charge calculation are necessary in this case for the rate to be just and reasonable.

Q. Please proceed. What refinements to the calculation of the Consumer Opt-Out charge are appropriate?

A. Two refinements are appropriate. Currently, I understand that PacifiCorp proposes that the Consumer Opt-Out charge be calculated based on projected Schedule 200 costs for Years 6 through 10. Under PacifiCorp's proposal, these projected costs are simply current Schedule 200 rates escalated at an assumed rate of inflation. However, it is not reasonable for Schedule 200 costs to be escalated for Years 6 through 10 as part of this calculation, because the five-year opt-out customer will have already departed cost-of-service rates five years prior, and *incremental* fixed generation costs incurred during Years 6 through 10 should not be incurred on the departed customer's behalf. Rather, the opt-out charge for Years 6 through 10 should be limited to the generation investment that had been built for the departed customer's benefit. At the maximum, this would extend to the five year planning horizon following the customer's departure (i.e., Years 1 through 5 of the opt-out period).

Q. What is your first recommendation related to Schedule 200 charges for years six through 10?

A. My first refinement to the Consumer Opt-Out charge is that Schedule 200 costs should not be escalated in Years 6 through 10; since incremental generation expenditures are not incurred on departed customers' behalves, it is not

[17] Order 15 195 at 2-3.

reasonable to assume increased Schedule 200 costs for departing customers beyond the projected Year 5 Schedule 200 price.

Q. What is your second proposal related to Schedule 200 charges for years six through 10?

A. The second refinement is an extension of this argument. Not only should Schedule 200 costs not be escalated for the purpose of determining the Consumer Opt-Out charge, these costs should in fact *decline* each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of increased accumulated depreciation and amortization. That is, as I just discussed, the portfolio of generation resources acquired to meet the departed customer's load should not be increased after Year 5. Once the portfolio of assets is "frozen" for the purposes of this calculation, the revenue the Company earns from its return on these assets properly will decline each year as a portion of those assets is depreciated and amortized. This treatment is consistent with basic ratemaking principles, which provide that a utility's return is earned on its net plant, reflecting the removal of accumulated depreciation and amortization from rate base. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.

Q. Have you estimated how much Schedule 200 should decline from Year 6 through Year 10 in the calculation of the Consumer Opt-Out charge?

A. Yes. The Schedule 200 entry should decline by approximately 2.36% per year from Years 6 through 10. The return component is approximately 28.2% of the Schedule 200 revenue requirement and annual depreciation and amortization of production plant is approximately 8.38% of production rate base. This means that, absent new additions to rate base, the existing production rate base (and return on that rate base) shrinks by about 8.38% per year. Since the return component is about 28.2% of the Schedule 200 revenue requirement, the annual reduction in return revenues of 8.36% translates into a reduction in overall Schedule 200 revenue requirement of 2.36% per year (i.e., 8.38% x 28.2%).

Q. Have you calculated the effects of your two recommended refinements to the Consumer Opt-Out charge related to the inclusion of Schedule 200 costs projected for years six through 10 on the sample Schedule 296 calculation provided by PacifiCorp?

A. Yes. As shown in Exhibit Noble Solutions/104, Higgins/2-3,these refinements reduce the sample Consumer Opt-Out charge $8.24/MWh to $5.56/MWh for Schedule 30-S and from $5.75/MWh to $3.26/MWh for Schedule 48-P.

Q. Please summarize your recommendations concerning refinements to the Schedule 296 calculation in this proceeding.

A. First, the transition adjustment component of Schedule 296 and the Consumer Opt-Out charge should be adjusted to reflect the value of freed-up RECs. Second, in calculating the Consumer Opt-Out charge, Schedule 200 costs should not be escalated in Years 6 through 10. Rather, Schedule 200 costs used in this calculation should decline each year from Year 6 through Year 10 to reflect the decline in the Company’s return on generation rate base attributable to the departed customer's load, due to the effects of increased accumulated depreciation. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.

<u>Treatment of Late DASRs</u>

Q. Please explain timing issues that can arise in submitting a Direct Access Service Request.

A. The Commission's administrative rules provide that an ESS may not provide service to a retail customer without a written contract or electronic authorization between the customer and the ESS and the submission by the ESS of a Direct Access Service Request (DASR) to the electric company (here, PacifiCorp) to switch such customer from its then-current supplier to the ESS. The DASR must contain all information required by the electric company's direct access tariff to effect the switching of such customer's supplier.[18] The rules further state the electric company must provide the ESS with acceptance or rejection of the DASR within three business days, and the ESS must obtain the electric company's acceptance of the DASR at least 10 business days prior to service from the ESS.[19]

After a PacifiCorp customer elects to purchase from an ESS in the election window beginning in November, direct access service under the one-year, three-year, and five-year opt-out programs commences on January 1 of the following year. Thus, if one assumes that PacifiCorp will take the maximum time allowed, the ESS must submit the DASR to PacifiCorp at least 13 business days prior to

[18] OAR 860-038-445(2).
[19] OAR 860-038-0445(8), (9).

January 1. If the Company does not receive the DASR at least 13 business days in advance of January 1, the ESS may not be able to begin serving the customer on that date, which raises questions as to how to treat the customer during the interim and after the DASR becomes effective.

Q. Could you calculate the cut-off date that is 13 business days prior to January 1 in this year to demonstrate?

A. Yes. Under Oregon law, the only weekday in December that is a legal holiday and thus not a business day is Christmas Day on December 25.[20] Thus, in this year, if we assume PacifiCorp will exercise its right to require the full 13 business days prior to moving the customer to service by the ESS, the ESS must submit the DASR by December 14, 2015. If PacifiCorp receives the DASR after December 14, 2015, there is ambiguity as to how the customer will be treated.

This potential issue is amplified under the new five-year opt-out program where Order No. 15-060 states that the election window commences on November 15 each year and extends three weeks thereafter. In this year, the election window commences on Sunday, November 15, 2015, and extends for three weeks thereafter until Sunday, December 3, 2015. If the election window closes on the next business day, December 4, 2015, the ESS and the customer will have only until December 14, 2015, to submit the DASR to PacifiCorp.

Q. Do you have any documents demonstrating how PacifiCorp has treated a late DASR in the past and how PacifiCorp proposes to do so going forward?

A. Yes. I have prepared Exhibit Noble Solutions/105, which contains PacifiCorp's responses to data requests in this proceeding on this topic.

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[20] ORS 187.010(1).

Q. How has PacifiCorp treated late DASRs in the past?

A. In response to Noble Solutions Data Request 2.17, PacifiCorp indicated that there are eleven past instances in which a customer elected to participate in the one-year or three-year opt-out program during the election window, but PacifiCorp received the customer's DASR after the cut-off date that allowed the customer to begin service from the ESS on January 1. In each instance, PacifiCorp indicates that the customers were placed on Schedule 220 (standard offer supply services) and the one-year opt-out Schedule 294 as of January 1. Once the Company received, accepted and processed the DASR, it placed the customer on its elected direct access schedule (700 series) and the transition adjustment rate Schedule, 294 (one-year opt-out) or 295 (three-year opt-out). PacifiCorp treated each of these customers the same way, honoring their direct access election to the one-year or three-year program after activating the late DASR on a date after January 1.

Q. How does PacifiCorp propose to treat a late DASR on a going forward basis?

A. Through its responses to several data requests contained in Exhibit Noble Solutions/105, PacifiCorp indicated that it intends to continue to honor the direct access election of customers who elect the one-year and three-year programs in the event of a late DASR.

However, PacifiCorp maintains that it will not honor the direct access election of a customer who elects the five-year program in the event of a late DASR. PacifiCorp maintains that if a DASR is not received and accepted in time for service commencing January 1, then the customer is no longer eligible for the five-year opt-out program in that year. PacifiCorp proposes to notify the consumer that a DASR was not received in time to place them on the five-year program and upon receipt of a DASR they will be placed on the one-year opt-out program. If a DASR is not received for the consumer at all, PacifiCorp proposes to leave the consumer on Standard Offer Schedule 220 for the year. The Company states that the customer will not be allowed to return to cost-based service for that year except through the returning service provisions of Schedule 201.

Thus, even if the DASR is only one day late, the customer's choice to elect the new five-year program will be thwarted, and the customer will only be able to re-enroll in that program by again electing the program during the election window commencing on the next November 15.

Q. Is PacifiCorp's differential treatment for the five-year opt-out program described clearly in any of PacifiCorp's Commission-approved tariffs or rules?

A. Not that I am aware of. When asked to identify the tariff or rule upon which PacifiCorp bases its position, PacifiCorp pointed to its Schedule 296 at pages 1 and 3, which indicate that the rates shown are for service commencing on January 1 in the applicable year. PacifiCorp also pointed to its Rule 21.VI.C.2, which states that the Company "may reject a DASR if . . . the requested effective date is less than 13 business days after the date the DASR is submitted."

However, the language in Schedule 296 is consistent with the terms set forth Schedules 294 and 295, both of which contain statements that the rates are applicable for a service period commencing on January 1 in the applicable year, and Rule 21.VI.C.2 makes no distinctions for the five-year program. PacifiCorp pointed to no other tariffs or rules indicating that in the event of a late DASR for a customer that elected the five-year program, the Company will unilaterally place the customer in the one-year program once it processes the late DASR.

Q. Was this issue addressed by the Commission in the order implementing the five-year opt-out program in docket UE 267?

A. No. The Commission's order did not address this issue. The order adopted PacifiCorp's proposal for a three-week window commencing on November 15, without addressing what happens if the DASR is not received at least 13 business days prior to the date of service. The UE 267 compliance filing tariff does not address the issue either, and thus no party commented on the issue in the compliance filing. PacifiCorp's reply testimony in docket UE 267 proposed the treatment that PacifiCorp proposed in this docket, but no party had an opportunity to respond to PacifiCorp's reply testimony and the Commission's order did not endorse PacifiCorp's proposal to deny a customer its choice to participate in the five-year program as a result of a late DASR.

Q. Has PacifiCorp provided any basis for different treatment for the five-year program as opposed to how it has treated this issue in the one-year and three-year programs?

A. Based upon PacifiCorp's responses to Noble Solutions' data requests 1.16(a) and 2.18(c), I understand PacifiCorp's position to be that allowing the customer to start the five-year program late without also extending the end of the five-year period during which it pays all applicable opt-out charges would allow the customer to avoid paying part of the total five-year exit fee charges.

Q. Do you think this concern warrants denying the customer's choice to participate in the five-year program?

A. No. There are alternatives PacifiCorp could implement that would allow the customer to remain in the five-year program that it elected while also addressing PacifiCorp's concern that the customer pay the full five-years' charges owed to PacifiCorp. I agree it is reasonable to place the customer on Schedule 220 during the period between January 1 and the effective date of the late DASR. However, the customer should have the option to remain in the five-year program by paying PacifiCorp all applicable five-year opt-out charges that would have applied between January 1 and the effective date of the DASR in excess of the amount that the customer is charged by PacifiCorp under the default participation in Schedule 220 during that period. I recommend that the Commission order PacifiCorp to implement its rules and tariffs in this manner to ensure that customers who elect the five-year opt-out program are not subjected to differential treatment and that PacifiCorp will take reasonable steps to honor the customer's election of retail choice.

Q. Does this conclude your opening testimony?

A. Yes, it does.

Status Report

Oregon Electric Industry Restructuring
(July, 2014)

Portfolio Options*	PGE	PP&L
Fixed Renewable	10,640	11,351
Renewable Usage	94,247	32,227
Habitat		4,308
Habitat Rider***	8,621	
Time-of-use	2,623	1,552
Eligible Customers	823,982	555,747**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of January 1, 2014.
*** Habitat Rider is available to existing renewable customers only, and should not be included in calculation of total renewable enrollment numbers.

Direct Access and Standard Offer Service

Certified Electricity Service Suppliers: 5
Registered Electricity Service Aggregators: 10

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	81.6%	4.0%	14.4%
PP&L	98.4%	0.2%	1.4%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Electric Rates and Planning
(503) 378-6917

NAES Data Request 1.1

Section 15 of the TAM Stipulation dated September 4, 2008 in UE-199 provides that in the calculation of the Schedule 294 transition adjustment, monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. Section 15 further provides that the monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. Please confirm that PacifiCorp has used the calculation described above in calculating the Sample Schedule 294 Transition Adjustments for Schedules 30 and 48 filed in UE-296.

Response to NAES Data Request 1.1

PacifiCorp confirms that the calculation of the Sample Schedule 294 Transition Adjustment for Schedules 30 and 48 was calculated consistent with the calculation methodology set forth in Section 15 of the TAM Stipulation in UE 199. For details on the calculations, please refer to the confidential work papers provided with the Company's response to TAM Support Set 3; specifically those work papers beginning with "15-M."

NAES Data Request 1.7

Please provide sample calculations and supporting work papers for Schedule 296 (transition adjustments and opt-out charge) that would be applicable to Schedule 30-Secondary customers and Schedule 48-Primary customers.

Response to NAES Data Request 1.7

Please refer to Confidential Attachment NAES 1.7, which provides a sample calculation for Schedule 296. Note: the Company has not yet prepared calculations or work papers corresponding to the forecast period in the current case.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

Non-Confidential Excerpt from Confidential Attachment NAES 1.7, Sch 30 (Pri-Sec)

Exhibit PAC 401
Schedule 30
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=23.32-15.09
2015	$27.57	$35.41	($7.84)	-	$28.95	-	$8.24
2016	$28.18	$35.80	($7.62)	-	$29.50	-	$8.24
2017	$28.14	$36.53	($8.39)	-	$30.06	-	$8.24
2018	$28.53	$38.31	($9.78)	-	$30.63	-	$8.24
2019	$28.81	$40.44	($11.63)	-	$31.21	-	$8.24
2020	$29.85	$45.50		($15.65)		$31.80	
2021	$32.21	$50.27		($18.06)		$32.40	
2022	$32.90	$56.91		($24.01)		$33.02	
2023	$33.70	$58.59		($24.89)		$33.65	
2024	$34.07	$59.92		($25.85)		$34.29	
10-Year Net Present Value (1)				($61.60)		$95.23	$33.63
5-year Nominal Levelized Payment				($15.09)		$23.32	$8.24

Notes:
(1) 2015 through 2024 using a 7.154% Discount Rate
(2) Losses at 8.56%

Non-Confidential Excerpt from Confidential Attachment NAES 1.7, Sch4748 (Pri-Sec-Trans)

Exhibit PAC 401
Schedule 47/48
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=21.73-15.98
2015	$26.08	$35.09	($9.01)	-	$26.98	-	$5.75
2016	$26.66	$35.48	($8.82)	-	$27.49	-	$5.75
2017	$26.62	$36.20	($9.58)	-	$28.01	-	$5.75
2018	$26.99	$37.96	($10.97)	-	$28.54	-	$5.75
2019	$27.26	$40.08	($12.82)	-	$29.08	-	$5.75
2020	$28.24	$45.09		($16.85)		$29.63	
2021	$30.48	$49.81		($19.33)		$30.19	
2022	$31.13	$56.39		($25.26)		$30.76	
2023	$31.89	$58.06		($26.17)		$31.34	
2024	$32.24	$59.37		($27.13)		$31.94	
10-Year Net Present Value (1)				($65.23)		$88.72	$23.49
5-year Nominal Levelized Payment				($15.98)		$21.73	$5.75

Notes:
(1) 2015 through 2024 using a 7.154% Discount Rate
(2) Losses at 7.58%

NAES Data Request 1.8

In calculating the Schedule 296 opt-out charge:

(a) Please explain the assumptions the Company intends to use regarding Schedule 200 fixed generation costs for the period 2021-2025.

(b) What was the amount of Oregon rate base included in determining Schedule 200 in the Company's most recent Oregon general rate case?

(c) What was the amount of Oregon accumulated depreciation included in rate base that was included in determining Schedule 200 in the Company's most recent Oregon general rate case?

(d) Please explain how the Schedule 296 opt-out charge takes account of projected changes in accumulated depreciation for the period 2021-2025.

(e) Please provide the Company's best estimate of the projected annual accumulated depreciation included in Schedule 200 for each year from 2015 through 2025.

Response to NAES Data Request 1.8

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

(a) As explained in the opening testimony of Gregory N. Duvall, PAC/200, Duvall/5-6, in UE 267, the Schedule 200 costs are based on the Schedule 200 rates in effect at the time of the calculation for the opt-out charge, escalated at an annual average rate of inflation.

(b) Based on the Company's jurisdictional allocation model (JAM) from the settlement in UE-263, Oregon rate base related to production activities was $1,662,452,363.

(c) Based on the Company's JAM from the settlement in UE-263, Oregon accumulated depreciation related to production activities was ($1,071,361,045).

(d) See the response to (a) above.

(e) The Company does not forecast forward annual depreciation included in Schedule 200.

NAES Data Request 1.9

Does the GRID model capture changes in fixed generation costs when projecting the generation cost of future periods or must changes in fixed generation cost be estimated external to the GRID model? If the Company maintains that the GRID model captures changes in fixed generation costs, please explain and show where in the model this is reflected.

Response to NAES Data Request 1.9

The Generation and Regulation Initiative Decision Tool (GRID) and the Company's net power costs (NPC) forecast do not include fixed generation costs. Rates for fixed generation costs are established in general rate cases.

NAES Data Request 1.11

Are the costs of renewable resources used by the Company to meet its Renewable Portfolio Standard requirements included in Schedule 200? If not, please explain how these costs are recovered by the Company from Oregon ratepayers.

Response to NAES Data Request 1.11

Schedule 200 includes costs associated with all utility-owned resources, including renewable resources that may be eligible for use towards compliance with Oregon's RPS. Renewable resources acquired under power purchase agreements (PPA) are included in Schedule 201.

NAES Data Request 1.12

When Oregon customers select direct access service does that reduce the Renewable Energy Credits ("RECs") that the Company needs to meet its Oregon Renewable Portfolio Standard requirements? If not, please explain why not.

Response to NAES Data Request 1.12

When Oregon customers select direct access service, that customer's load is no longer included in the total amount of retail load used to determine the Company's compliance obligation under the Oregon Renewable Portfolio Standard (RPS). Oregon's RPS allows for unlimited banking of renewable energy credits (RECs). Thus, if the Company's retail load is lowered as the result of a customer electing direct access service, RECs that may have otherwise been necessary if the customer did not elect direct access are retained in the Company's REC bank for use towards RPS compliance in future years.

NAES Data Request 1.13

Does the Company agree that the calculation of the Schedule 294, 295, and 296 transition adjustments do not reflect the value of RECs that are freed-up as a result of direct access? Does the Company believe it is appropriate to adjust the transition adjustment calculation to reflect the freeing-up of RECs due to direct access? If not, please explain the basis for the Company's response.

Response to NAES Data Request 1.13

The calculation of the Schedule 294, 295, and 296 transition adjustments accurately reflects the fact that election of direct access service by a customer does not result in "freed-up" renewable energy credits (RECs). Under Oregon's Renewable Portfolio Standard (RPS), unlimited banking of RECs is allowed. Thus, if the Company's retail load is lowered as the result of a customer electing direct access service, RECs that may have otherwise been necessary if the customer did not elect direct access are retained in the Company's REC bank for use towards RPS compliance in future years.

NAES Data Request 3.22

Please provide the documents, work papers, and all other information supporting the valuation of the Company's REC sales, as provided in Utah PSC Docket No. 15-035-27. Please note that Noble Solutions has already requested this material in request 1.14. PacifiCorp's response to Noble Solutions data request 1.14 was non-responsive in that it narrowed the request to a request for valuation of *Oregon* RECs, while the request contained no such qualifier and instead asked that PacifiCorp provide valuations for sales of the Company's RECs. Noble Solutions therefore requests expedited treatment of this request.

Response to NAES Data Request 3.22

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Confidential Attachment NAES 3.22. This confidential attachment provides the confidential exhibits to the Direct Testimony of Company witness, Bruce W. Griswold in the Company's Schedule 98 Renewable Energy Credits (REC) Balancing Account (RBA) application, submitted to the Public Service Commission of Utah (UPSC) on March 16, 2015 (Docket No. 15-035-27). Also included is the Company's 1st Supplemental response to DPU Data Request 2.1, which updated the forecast REC sales for November 2014 and December 2014 with actual REC sales. These sales are from RECs in excess of the Company's compliance and / or regulatory obligations. Most of the REC sales were completed through request for proposals (RFP) whereby the transactions are awarded based on price competition relative to the REC product(s) of interest. The REC valuation is determined by the price a willing buyer pays.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

NAES Data Request 4.23

Follow-up to PacifiCorp Response to Noble Solutions No. 1.8.
a. Please provide the work papers and models supporting the derivation of the production rate base that were used to determine Schedule 200 rates in the compliance filing in Docket UE-263.
b. Please show the derivation of the $1,662,452,363 rate base number in Response to Noble Solutions Data Request No. 1.8.b.

Response to NAES Data Request 4.23

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

a. Provided as Attachment NAES 4.23 are rate design workpapers based on the stipulation and final order in docket UE 263 which show the calculation of the final effective Schedule 200 rates from that docket.

b. Please refer to the table below for the derivation:

Functionalized Production Plant	3,267,355,470
Rate Base Deductions	(1,604,903,107)
Total Production Rate Base	1,662,452,363

Excerpt from Attachment NAES 4.23, Functionalized Revenue 1202

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2014

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services1	$20,335	$20,000	$20,000	$25,445
	System Usage T&A & Sch2012		$4,149	$4,149	$4,088
	System Usage Sch 2003		$3,968	$3,968	$3,873
	Distribution	$258,310	$259,893	$259,893	$248,958
	Other Adjustments	$4,573	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$150,780	$164,052	$164,052	$160,795
	Generation Energy - Net Power Costs (Sch 201)	$153,561	$151,532	$153,561	$153,561
	Total	$587,558	$603,595	$605,623	$596,721
Schedule 23, Small General Service					
	Transmission & Ancillary Services1	$3,974	$4,023	$4,023	$4,965
	System Usage T&A & Sch2012		$827	$827	$804
	System Usage Sch 2003		$792	$792	$771
	Distribution	$49,749	$50,403	$50,403	$48,098
	Other Adjustments	$870	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$29,852	$33,387	$33,387	$32,561
	Generation Energy - Net Power Costs (Sch 201)	$30,398	$30,839	$30,398	$30,398
	Total	$114,843	$120,271	$119,830	$117,596
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services1	$7,401	$7,250	$7,250	$9,846
	System Usage T&A & Sch2012		$1,536	$1,536	$1,540
	System Usage Sch 2003		$1,470	$1,470	$1,481
	Distribution	$49,364	$47,043	$47,043	$44,791
	Other Adjustments	$1,652	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$55,601	$59,969	$59,969	$60,358
	Generation Energy - Net Power Costs (Sch 201)	$56,624	$55,393	$56,624	$56,624
	Total	$170,642	$172,660	$173,892	$174,640
Primary Voltage					
	Transmission & Ancillary Services1	$69	$61	$61	$83
	System Usage T&A & Sch2012		$13	$13	$13
	System Usage Sch 2003		$13	$13	$13
	Distribution	$470	$493	$493	$467
	Other Adjustments	$15	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$502	$535	$535	$531
	Generation Energy - Net Power Costs (Sch 201)	$511	$494	$511	$511
	Total	$1,567	$1,610	$1,627	$1,619
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services1	$4,238	$4,309	$4,309	$5,844
	System Usage T&A & Sch2012		$908	$908	$872
	System Usage Sch 2003		$874	$874	$835
	Distribution	$22,408	$23,007	$23,007	$20,336
	Other Adjustments	$923	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$33,594	$37,146	$37,146	$35,442
	Generation Energy - Net Power Costs (Sch 201)	$34,187	$34,311	$34,187	$34,187
	Total	$95,350	$100,556	$100,431	$97,517
Primary Voltage					
	Transmission & Ancillary Services1	$307	$321	$321	$437
	System Usage T&A & Sch2012		$65	$65	$62
	System Usage Sch 2003		$63	$63	$60
	Distribution	$1,616	$1,727	$1,727	$1,503
	Other Adjustments	$66	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,425	$2,688	$2,688	$2,566
	Generation Energy - Net Power Costs (Sch 201)	$2,477	$2,483	$2,477	$2,477
	Total	$6,891	$7,346	$7,340	$7,106

Excerpt from Attachment NAES 4.23, Functionalized Revenue 1202

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2014

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services1	$678	$661	$661	$847
	System Usage T&A & Sch2012		$171	$171	$176
	System Usage Sch 2003		$167	$167	$171
	Distribution	$11,957	$11,482	$11,482	$11,616
	Other Adjustments	$157	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$6,305	$6,670	$6,670	$6,847
	Generation Energy - Net Power Costs (Sch 201)	$6,421	$6,161	$6,421	$6,421
	Total	$25,518	$25,312	$25,572	$26,078
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services1	$1,997	$2,022	$2,022	$2,758
	System Usage T&A & Sch2012		$419	$419	$397
	System Usage Sch 2003		$403	$403	$386
	Distribution	$9,885	$9,923	$9,923	$8,653
	Other Adjustments	$430	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$15,363	$17,244	$17,244	$16,389
	Generation Energy - Net Power Costs (Sch 201)	$15,615	$15,928	$15,615	$15,615
	Total	$43,291	$45,938	$45,626	$44,198
Primary Voltage					
	Transmission & Ancillary Services1	$4,796	$5,051	$5,051	$6,842
	System Usage T&A & Sch2012		$1,048	$1,048	$1,254
	System Usage Sch 2003		$1,009	$1,009	$933
	Distribution	$19,794	$20,823	$20,823	$17,225
	Other Adjustments	$1,023	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$38,878	$44,071	$44,071	$40,715
	Generation Energy - Net Power Costs (Sch 201)	$39,611	$40,708	$39,611	$39,611
	Total	$104,101	$112,709	$111,613	$106,580
Transmission Voltage					
	Transmission & Ancillary Services1	$2,275	$2,210	$2,210	$2,953
	System Usage T&A & Sch2012		$529	$529	$506
	System Usage Sch 2003		$517	$517	$473
	Distribution	$7,475	$7,162	$7,162	$6,625
	Other Adjustments	$488	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$19,667	$22,138	$22,138	$20,295
	Generation Energy - Net Power Costs (Sch 201)	$19,980	$20,448	$19,980	$19,980
	Total	$49,885	$53,004	$52,535	$50,832
Schedules 51, 53, 54, Lighting3					
Secondary Voltage					
	Transmission & Ancillary Services1	$14	$13	$13	$16
	System Usage T&A & Sch2012		$11	$11	$10
	System Usage Sch 2003		$11	$11	$10
	Distribution	$1,654	$1,823	$1,823	$1,713
	Other Adjustments	$2	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$439	$483	$483	$455
	Generation Energy - Net Power Costs (Sch 201)	$448	$446	$448	$448
	Total	$2,557	$2,786	$2,788	$2,652
TOTAL		**$1,202,203**	**$1,245,787**	**$1,246,878**	**$1,225,539**
Additional Rate Schedules					
	Employee discount	($457)		($464)	($464)
	Schedule 47	$11,485		$11,737	$11,737
	Lighting 15, 50, 513, 52	$3,405		$3,528	$3,528
Total Oregon		**$1,216,636**		**$1,261,679**	**$1,240,339**
			Revenue Increase	**$45,042**	**$23,703**

1Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.
2Includes the portion of Franchise & Energy Supplier Taxes which are associated with rates not paid by Direct Access consumers - Transmission & Ancillary Services and Generation Energy - Net Power Costs.
3Includes the portion of Franchise & Energy Supplier Taxes which are associated Generation Energy - Other (non-NPC) revenues.
4Cost of Service study includes only certain lamp types under Schedule 51.

NAES Data Request 4.24

Please confirm that the tax gross up factor at the conclusion of the Docket UE-263 was 1.661. If this is incorrect, please provide the correct tax gross up factor for the conclusion of that case.

Response to NAES Data Request 4.24

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

The net to gross bump up rate used for calculating the price change required for the requested return in docket UE 263 was 166.11 percent.

NAES Data Request 4.25

Please provide the Schedule 200 revenue requirement incorporated into the compliance filing in docket UE-263. Please provide all models and work papers supporting this response with formulas intact.

Response to NAES Data Request 4.25

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

The Function1149 tab is based on the requirements for functionalization for cost of service. This tab is only used for Oregon filings. This tab determines the revenue requirement for each of the unbundled service categories required by OAR 860-038-0200. Please refer to Attachment NAES 4.25.

Excerpt from Attachment NAES 4.25, Function1149, p. 1.

2010 PROTOCOL
Year End
RESULTS OF OPERATIONS SUMMARY

	2010 PROTOCOL Description of Account Summary:	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
1	General Business Revenues	1,219,531,704	729,208,138	149,254,434	252,606,176	10,667,409	12,161,007	25,755,131	18,546,371
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	124,030,465	124,030,465	-	-	-	-	-	-
5	Other Operating Revenues	39,567,427	26,993,269	12,726,916	5,324,890	(10,667,409)	4,516,005	274,849	398,907
6	Total Operating Revenues	1,383,129,596	880,231,872	161,981,350	257,931,066	0	16,677,012	26,029,980	18,945,278
7									
8	Operating Expenses:								
9	Steam Production	291,940,990	291,940,990	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	10,668,181	10,668,181	-	-	-	-	-	-
12	Other Power Supply	274,185,141	274,185,141	-	-	-	-	-	-
13	ECD	(8,792,171)	(8,792,171)	-	-	-	-	-	-
14	Transmission	52,930,053	226,487	52,703,565	-	-	-	-	-
15	Distribution	69,008,481	-	-	63,631,180	-	-	5,377,301	-
16	Customer Accounts	35,090,928	4,226,740	777,810	1,238,546	0	11,006,210	11,058,918	6,680,266
17	Customer Service	3,901,521	-	-	1,690,794	-	-	-	2,210,728
18	Sales	-	-	-	-	-	-	-	-
19	Administrative & General	45,703,437	10,277,034	3,797,048	24,128,146	-	1,292,143	2,350,364	3,858,703
20									
21	Total O & M Expenses	774,636,562	582,732,402	57,278,423	90,688,665	0	12,298,353	18,786,583	12,749,698
22									
23	Depreciation	209,513,302	131,584,643	26,523,684	47,433,678	-	594,118	2,516,741	860,438
24	Amortization Expense	14,529,658	7,654,167	1,085,932	1,677,232	-	1,469,723	935,325	1,707,279
25	Taxes Other Than Income	67,770,290	18,716,840	7,557,520	40,379,524	0	227,194	545,656	306,183
26	Income Taxes - Federal	27,176,921	(17,572,948)	11,062,398	23,902,199	0	550,040	1,270,637	546,966
27	Income Taxes - State	4,912,522	(160,293)	1,503,191	3,247,902	0	74,741	172,658	74,323
28	Income Taxes - Def Net	44,337,342	36,077,059	12,182,192	(3,908,757)	-	105,717	(495,582)	376,714
29	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
30	Misc Revenue & Expense	(90,219)	(88,949)	(4,640)	3,263	-	-	107	-
31									
32	Total Operating Expenses	1,142,786,377	758,942,922	117,188,699	203,423,705	0	15,319,886	23,732,125	16,621,600
33									
34	Operating Revenue for Return	240,343,219	121,288,951	44,792,651	54,507,361	0	1,357,126	2,297,856	2,323,677
35									
36	Rate Base:								
37	Electric Plant in Service	6,675,127,527	3,113,078,803	1,370,453,837	2,008,643,372	-	37,301,056	94,215,705	51,434,753
38	Plant Held for Future Use	-	-	-	-	-	-	-	-
39	Misc Deferred Debits	25,541,078	16,981,682	6,959,848	693,298	-	125,389	259,900	520,960
40	Elec Plant Acq Adj	10,072,737	10,072,737	-	-	-	-	-	-
41	Nuclear Fuel	-	-	-	-	-	-	-	-
42	Prepayments	7,197,975	3,390,280	571,559	1,388,169	-	298,068	516,382	1,033,518
43	Fuel Stock	60,471,050	60,471,050	-	-	-	-	-	-
44	Material & Supplies	58,580,887	49,389,284	379,862	8,528,265	-	-	283,476	-
45	Working Capital	28,970,032	13,971,635	2,299,218	6,857,113	0	1,054,381	1,784,784	3,002,901
46	Weatherization Loans	(1,219)	-	-	(1,219)	-	-	-	-
47	Miscellaneous Rate Base	-	-	-	-	-	-	-	-
48									
49	Total Electric Plant	6,865,960,066	3,267,355,470	1,380,664,323	2,026,108,998	0	38,778,894	97,060,249	55,992,133
50									
51	Rate Base Deductions:								
52	Accum Prov For Depr	(2,359,864,735)	(1,071,361,045)	(353,708,507)	(888,632,526)	-	(3,236,187)	(38,543,989)	(4,382,481)
53	Accum Prov For Amort	(152,115,135)	(47,522,779)	(6,706,833)	(28,981,026)	-	(24,848,769)	(15,832,708)	(28,223,019)
54	Accum Def Income Taxes	(1,014,614,465)	(480,770,285)	(211,583,182)	(303,812,957)	-	(2,519,845)	(12,351,324)	(3,576,872)
55	Unamortized ITC	(593,249)	(214,763)	(29,300)	(148,758)	-	(32,321)	(55,965)	(112,143)
56	Customer Adv for Const	(5,758,640)	-	(3,822,938)	(1,870,973)	-	-	(64,729)	-
57	Customer Service Deposits	-	-	-	-	-	-	-	-
58	Misc. Rate Base Deductions	(8,073,647)	(5,034,235)	(212,288)	(1,365,016)	-	(234,174)	(415,420)	(812,514)
59									
60	Total Rate Base Deductions	(3,541,019,871)	(1,604,903,107)	(576,063,048)	(1,224,811,256)	-	(30,871,296)	(67,264,134)	(37,107,030)
61									
62	Total Rate Base	3,324,940,195	1,662,452,363	804,601,275	801,297,741	1	7,907,598	29,796,115	18,885,103
63									
64	Return on Rate Base	7.228%	7.296%	5.567%	6.802%	7.028%	17.162%	7.712%	12.304%
65									
66	Return on Equity	9.046%	9.176%	5.858%	8.229%	8.662%	28.113%	9.974%	18.789%
67									
68	100 Basis Points in Equity:	17,322,938	8,661,377	4,191,973	4,174,761	0	41,199	155,238	98,391
69	Revenue Requirement Impact	27,918,159	13,958,931	6,755,907	6,728,168	0	66,397	250,186	158,570
70	Rate Base Decrease	(223,536,280)	(110,804,848)	(68,855,618)	(57,005,893)	(0)	(232,980)	(1,885,571)	(767,167)

Excerpt from TAM Support Set 3, 15-M - ORTAM16w_Transition Adjustment Summary

One-Year Option - Transition Adjustments (cents/kWh)

Initial Filing UE-296 - Sample Calculations

	2016			
	30/730 Secondary		48/748 Primary	
	HLH	LLH	HLH	LLH
Jan-16	-0.643	-0.542	-0.883	-0.708
Feb-16	-0.302	-0.076	-0.500	-0.287
Mar-16	-0.349	-0.020	-0.554	-0.263
Apr-16	0.163	-0.292	-0.013	-0.439
May-16	0.275	0.360	0.069	0.177
Jun-16	0.121	0.767	-0.115	0.573
Jul-16	-0.942	-0.646	-1.180	-0.736
Aug-16	-1.811	-0.516	-2.042	-0.662
Sep-16	-0.923	-0.249	-1.103	-0.478
Oct-16	-0.672	-0.295	-0.473	-0.506
Nov-16	-0.592	0.203	-1.052	-0.014
Dec-16	-1.322	-0.508	-1.600	-0.681

[Confidential Exhibit Noble Solutions 103

Withheld from Public Filing]

Derivation of Return Component in Sch. 200
in PacifiCorp 2013 Rate Case, Docket UE-263

Line			Source
1	Approved Rate of Return on Rate Base	7.621%	Docket UE-263 Order13-474, Appendix A (Stipulation, p. 4 of 39).
2	Oregon Production Rate Base Included in Sch. 200	$ 1,662,452,363	PacifiCorp Response to NAES DR. No. 4.23.
3	Return on Production Rate Base Included in Sch. 200	$ 126,695,495	= Ln. 1 x Ln. 2
4	Tax Gross-Up Factor	1.6611	PacifiCorp Response to NAES DR. No. 4.24.
5	Revenue Requirement Impact of Return on Production Rate Base	$ 210,456,137	= Ln. 3 x Ln. 4
6	Total Unbundled Oregon Production Revenue Requirement	$ 747,123,482	PacifiCorp Response to NAES DR No. 4.23.
7	Percentage of Return Component in Production Revenue Requirement	28.2%	= Ln. 5 ÷ Ln. 6
8	Annual Oregon Production Depreciation/Amortization Exp.	$ 139,238,810	Pacificorp Response to NAES DR No. 4.25.
9	Annual Deprecation/Amortization Exp. as Pct. of Rate Base	8.38%	= Ln. 8 ÷ Ln. 2
10	Annual Depreciation Impact on Production Return Component	**2.36%**	= Ln. 7 x Ln. 9

Noble Solutions
Schedule 30
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply*		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=20.64-15.09
2015	$27.57	$35.41	($7.84)	-	$28.95	-	$5.56
2016	$28.18	$35.80	($7.62)	-	$29.50	-	$5.56
2017	$28.14	$36.53	($8.39)	-	$30.06	-	$5.56
2018	$28.53	$38.31	($9.78)	-	$30.63	-	$5.56
2019	$28.81	$40.44	($11.63)	-	$31.21	-	$5.56
2020	$29.85	$45.50		($15.65)		$30.47	
2021	$32.21	$50.27		($18.06)		$29.75	
2022	$32.90	$56.91		($24.01)		$29.05	
2023	$33.70	$58.59		($24.89)		$28.36	
2024	$34.07	$59.92		($25.85)		$27.69	
10-Year Net Present Value (1)				($61.60)		$84.29	$22.69
5-year Nominal Levelized Payment				($15.09)		$20.64	$5.56

Notes:
(1) 2015 through 2024 using a 7.154% Discount Rate
(2) Losses at 8.56%

* Data Source: For 2015 - 2019, see PacifiCorp Response to NAES DR No. 1.7 (Included in Noble Solutions Exhibit 102, pp. 2-4).

Noble Solutions
Schedule 47/48
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation ($/MWh)

Year	Schedule 201 - Net Power Costs in Rates	NPC Impact of 50 aMW Leaving System	Transition Adjustment		Schedule 200 - Base Supply*		Consumer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=19.24-15.98
2015	$26.08	$35.09	($9.01)	-	$26.98	-	$3.26
2016	$26.66	$35.48	($8.82)	-	$27.49	-	$3.26
2017	$26.62	$36.20	($9.58)	-	$28.01	-	$3.26
2018	$26.99	$37.96	($10.97)	-	$28.54	-	$3.26
2019	$27.26	$40.08	($12.82)	-	$29.08	-	$3.26
2020	$28.24	$45.09		($16.85)		$28.39	
2021	$30.48	$49.81		($19.33)		$27.72	
2022	$31.13	$56.39		($25.26)		$27.07	
2023	$31.89	$58.06		($26.17)		$26.43	
2024	$32.24	$59.37		($27.13)		$25.81	
10-Year Net Present Value (1)				($65.23)		$78.54	$13.31
5-year Nominal Levelized Payment				($15.98)		$19.24	$3.26

Notes:
(1) 2015 through 2024 using a 7.154% Discount Rate
(2) Losses at 7.58%

* Data Source: For 2015 - 2019, see PacifiCorp Response to NAES DR No. 1.7 (Included in Noble Solutions Exhibit 102, pp. 2-4).

NAES Data Request 1.16

Reference UE 267 PAC/300, Steward/11:20 – 12:6, stating:

> Service under Schedule 296 requires the customer to take supply service from an ESS. If the customer opts out, but the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, the Company proposes that the customer's opt-out election revert to the one-year program, Schedule 294. This means that the customer would be placed on Schedule 220, Standard Offer Supply Service, until a DASR is received. If a DASR is received, then the customer would be moved to Schedule 294, consistent with the tariff. The customer would have the ability to elect a Schedule 296 opt-out the following November, at which point the five-year transition would begin (assuming that the overall program cap has not been reached).

(a) Does the Company agree that a more reasonable solution to the problem identified is to place the customer on the Schedule 296, five-year program commencing on February 1, 2016? If not, please explain why not.

(b) Please explain which tariff supports the proposal to reject the customer’s election to the five-year opt-out program on Schedule 296 and to place the customer on Schedule 294, which the customer did not elect.

(c) Please explain which Commission order supports the proposal to reject the customer’s election to the five-year opt-out program on Schedule 296 and to place the customer on Schedule 294, which the customer did not elect.

(d) Please identify the date in December 2015, by which the Company believes it must receive the DASR in order “to allow the ESS to provide service beginning on January 1.” Please identify the Commission order, rule, or tariff identifying this date, or otherwise explain PacifiCorp’s basis for this date.

Response to NAES Data Request 1.16

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

(a) No. The Schedule 296, five-year program rates are designed based on a consumer taking service under the program for a full five-calendar-year term at the end of which they will no longer be subject to Transition Adjustments, the Consumer Opt-

Out Charge, or charges under Schedule 200, Base Supply Service. Service beginning after January 1 but still ending within the five-calendar-year rate period would result in less than a full five-year term and could encourage consumers to delay the submission of the Direct Access Service Request (DASR) to avoid rates under Schedule 296. A five-year term beginning on a date other than January 1 and not tied to calendar years would not correspond to the annual Transition Adjustment and Consumer Opt-Out Charge rates calculated for the tariff.

(b) Schedules 296 and Rule 21 support the rejection of the consumer's election to the five-year opt-out program on Schedule 296. Schedule 296, page 1 indicates that the Transition Adjustments and Consumer Opt-Out Charge will be applicable for the five-year enrollment period which is shown on page 3 of the tariff in terms of calendar years. Additionally, Schedule 296, page 3 indicates that the rates shown are "Adjustments for Consumers Electing This Option for Service Beginning January 1, 2016." Rule 21.VI.C.2 states that the Company may reject a DASR if "the requested effective date is less than 13 business days after the date the DASR is submitted."

Consistent with Schedule 220, when a consumer elects to remove themself from cost-based service during the open enrollment window, they are placed on Schedule 220, Standard Offer Supply Service, until the Company is properly notified of the consumer's election of direct access by a DASR. Standard Offer Supply Service is considered Default Supply service per OAR 860-038-0280.

If a DASR is not received and accepted in time for service commencing January 1, then the consumer is no longer eligible for the five-year opt-out program in that year as described in (a) above. If the Company subsequently receives a DASR for that consumer, the default is to allow the consumer to take service from the ESS in that year through the one-year direct access program which is available to the consumer for a starting date after January 1. In such a case, the consumer will be notified that a DASR was not received in time to place them on the five-year opt-out and upon receipt of a DASR they will be placed on the one-year opt out. If a DASR is not received for the consumer, the consumer will remain on Standard Offer for the year. The Consumer will not be allowed to return to cost-based service for that year except through the returning service provisions of Schedule 201.

(c) Please refer to Order No. 15-060 approving the Company's five-year opt out program. The testimony of Joelle Steward regarding the treatment of five-year opt out consumers for whom a DASR is not received in time for commencement of service on January 1 was not disputed in the docket.

(d) The Company must receive the DASR by December 14, 2015 to allow the ESS to provide service beginning on January 1, 2016. The date is 13 business days prior to the requested effective date of service. The Company's Rule 21.VI.C.2 2 states that the Company may reject a DASR if "the requested effective date is less than 13 business days after the date the DASR is submitted." Thirteen business days is the total amount of time required by OAR 860-038-0445(8) and (9).

NAES Data Request 2.17

Reference UE 267 PAC/300, Steward/11:20 - 12:6, describing a circumstance in which the Company does not receive a DASR "by the appropriate time to allow the ESS to provide service beginning on January 1."

a. Please identify each instance where the Company has not received a DASR "by the appropriate time to allow the ESS to provide service beginning on January 1" under the one-year and three-year opt-out programs. Please include identification of the schedule to which the customer elected to take direct access service and the date on which the DASR was received.

b. For each circumstance identified in subpart a., please explain onto which schedule the Company placed the customer until the DASR was received, and each schedule onto which the customer was subsequently placed after the DASR was received. Please explain the basis for each change in schedule for the customer during the twelve months following the January 1 date following the opt-out election and provide the date for each such change and the date of the event that caused such change.

Response to NAES Data Request 2.17

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Attachment NAES 2.17.

OR UE 296
NAES 2.17

Attachment NAES 2.17

	Response to NAES 2.17 (a)				**Response to NAES 2.17 (b)**	
Instance #	Rate Schedules Elected	DASR Received	DASR Effective Dt	Option	Before DASR Schedules	After DASR Schedules
1	28 and 201	12/19/2008	1/9/2009	1 Year	28, 220 and 294	728 and 294
2	28 and 201	12/19/2008	1/9/2009	1 Year	28, 220 and 294	728 and 294
3	28 and 201	12/19/2008	1/9/2009	1 Year	28, 220 and 294	728 and 294
4	28 and 201	12/19/2008	1/9/2009	1 Year	28, 220 and 294	728 and 294
5	30 and 201	12/19/2008	1/9/2009	3 Years	30, 220 and 294	730 and 295
6	30 and 201	12/19/2008	1/9/2009	3 Years	30, 220 and 294	730 and 295
7	30 and 201	12/19/2008	1/9/2009	3 Years	30, 220 and 294	730 and 295
8	30 and 201	12/19/2008	1/9/2009	3 Years	30, 220 and 294	730 and 295
9	48 and 201	5/6/2014	5/23/2014	1 Year	48, 220 and 294	748 and 294
10	30 and 201	3/20/2015	4/17/2015	1 Year	30, 220 and 294	730 and 294
11	30 and 201	3/20/2015	4/17/2015	1 Year	30, 220 and 294	730 and 294

All customers who have opted out of cost of services during the annual enrollment window are placed on the schedule 220 (standard offer supply services) and 294 (Transition Adjustment) as of January 1st. Once the company received, accepted and processed the DASR, the customer will be placed on the its applicable direct access schedule (700 series) and the transition adjustment rate schedule, 294 (one year) or 295 (three years).

NAES Data Request 2.18

Reference UE 267 PAC/300, Steward/11:20 - 12:6, describing a circumstance in which the Company does not receive a DASR “by the appropriate time to allow the ESS to provide service beginning on January 1.” Regardless of the response to request 17, for the upcoming 2015 election window, please explain onto which schedule PacifiCorp would place the customer for the twelve months following the January 1 date after the opt-out election under the following circumstances:
a. The customer timely elects the one-year opt-out program (Schedule 294), but the Company receives the DASR after “the appropriate time to allow the ESS to provide service beginning on January 1.” Please identify the Commission order, rule, or tariff upon which the Company would rely for the proposed treatment. If no order, rule or tariff addresses the facts, please explain the basis for the Company’s proposed treatment.
b. The customer timely elects the three-year opt-out program (Schedule 295), but the Company receives the DASR after “the appropriate time to allow the ESS to provide service beginning on January 1.” Please identify the Commission order, rule, or tariff upon which the Company would rely for the proposed treatment. If no order, rule or tariff addresses the facts, please explain the basis for the Company’s proposed treatment.
c. The customer timely elects the five-year opt-out program (Schedule 296), but the Company receives the DASR after “the appropriate time to allow the ESS to provide service beginning on January 1.” Please identify the Commission order, rule, or tariff upon which the Company would rely for the proposed treatment. If no order, rule or tariff addresses the facts, please explain the basis for the Company’s proposed treatment.

Response to NAES Data Request 2.18

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

a. A consumer electing the one-year opt-out program (Schedule 294) is placed on Standard Offer Supply Service, Schedule 220, beginning January 1 if a Direct Access Service Request (DASR) is not received within the appropriate time to allow the Energy Service Supplier (ESS) to provide service beginning on January 1. Schedule 220 indicates that “The Consumer shall remain on this option until the Company is properly notified of the Consumers’ election of Direct Access Service.” The proper notification of election of Direct Access Service is 13 business days prior to the effective date of service as required by OAR 860-038-0445(8)-(9). Under the one-year opt-out program, Direct Access service may begin on a date after January 1 of the opt-out year due to the ongoing nature of the transition adjustments under the program. The Consumer may be moved to one-year Direct Access service 13 business days after the DASR is received.

b. See the response to part (a) above. Consumers on the three-year opt-out program also continue to pay transition adjustments throughout the length of the program. While on Schedule 220 prior to the effective date of the DASR, the consumer is served through the one-year opt-out, Schedule 294, which is the only option available in conjunction with Schedule 220. The Consumer may be moved to three-year Direct Access service 13 business days after the DASR is received.

c. The treatment of a five-year opt-out program consumer in the identified circumstances was described in the testimony of Joelle Steward in Docket UE 267. Order No. 15-060 approved the Company's five-year opt out program. The testimony of Joelle Steward regarding the treatment of five-year opt out consumers for whom a DASR is not received in time for commencement of service on January 1 was not disputed in the docket.

UE 267 PAC/300, Steward/11:20 – 12:6, states:

> Service under Schedule 296 requires the customer to take supply service from an ESS. If the customer opts out, but the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, the Company proposes that the customer's opt-out election revert to the one-year program, Schedule 294. This means that the customer would be placed on Schedule 220, Standard Offer Supply Service, until a DASR is received. If a DASR is received, then the customer would be moved to Schedule 294, consistent with the tariff. The customer would have the ability to elect a Schedule 296 opt-out the following November, at which point the five-year transition would begin (assuming that the overall program cap has not been reached).

The five-year opt-out program is unique from the one-year and three-year programs. Due to the end of the transition adjustments and other charges after five years under the five-year opt out program, the consumer cannot be placed on the five-year option after January 1. Please see the Company's response to NAES Data Request 1.16 in this docket.

NAES Data Request 2.19

Reference UE 267 PAC/300, Steward/11:20 – 12:6, stating:
Service under Schedule 296 requires the customer to take supply service from an ESS. If the customer opts out, but the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, the Company proposes that the customer's opt-out election revert to the one-year program, Schedule 294. This means that the customer would be placed on Schedule 220, Standard Offer Supply Service, until a DASR is received. If a DASR is received, then the customer would be moved to Schedule 294, consistent with the tariff. The customer would have the ability to elect a Schedule 296 opt-out the following November, at which point the five-year transition would begin (assuming that the overall program cap has not been reached).
a. Does the Company agree that a more reasonable solution if the Company does not receive a DASR by the appropriate time to allow the ESS to provide service beginning on January 1, 2016, is to place the customer on Schedule 220 as the default supply schedule until such time as the Company receives and schedules a DASR for the customer, at which time the customer will be moved to Schedule 296 on their meter read date?
b. How does the Company propose to treat a DASR that is received too late to allow the ESS to provide service beginning on subsequent months, such as February 1, 2016? Does the Company agree that a reasonable resolution is that if the Company does not receive a DASR by the end of 2016, and the customer does not select an opt-out for 2017, the customer will be transferred to their applicable bundled-service schedule starting January 1, 2017? Please explain why.

Response to NAES Data Request 2.19

The Company objects to this request to the extent that it requests information outside the scope of this proceeding and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

a. No. Please see the Company's response to NAES Data Request 1.16 in this docket.

b. As described in UE 267 PAC/300, Steward/11:20 – 12:6, a consumer electing the five-year opt-out but for whom a Direct Access Service Request (DASR) is not received by the appropriate time to allow the ESS to provide service beginning on January 1 will be reverted to the one-year program for that year. A DASR subsequently received for this consumer within that year will allow the consumer to be served by the Energy Service Supplier (ESS) under the one-year program as of the appropriate effective date and according to the rules for service under the one-year program.

No, the Company does not agree that a consumer who has elected to opt-out of cost-based service but for whom a DASR is not received should be automatically transferred to bundled cost-based service the next year. The Consumer who has elected to opt-out from cost-based service will not be returned to cost-based service without the Consumer's written or electronic authorization as described in the Company's Rule 21.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 29th day of June, 2015, a true and correct copy of the **CONFIDENTIAL TESTIMONY & EXHIBITS OF KEVIN HIGGINS ON BEHALF OF NOBLE AMERICAS ENERGY SOLUTIONS LLC, IN DOCKET UE 296** was served as follows to the following qualified parties:

Michael T Weirich **(C)** PUC STAFF- DEPARTMENT OF JUSTICE 1162 Court Street, NE Salem OR 97301-4096 michael.weirich@doj.state.or.us	__ Hand Delivery _X_ U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Jorge Ordonez **(C)** OREGON PUBLIC UTILITIES COMM. PO Box 1088 Salem OR 97308-2148 jorge.ordonez@state.or.us	_ Hand Delivery _X_ U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
Sommer Templet **(C)** Robert Jenks **(C)** CITIZENS' UTILITY BOARD OF OREGON 610 SW Broadway Ste 400 Portland OR 97205 sommer@oregoncub.org bob@oregoncub.org	__ Hand Delivery X_ U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
S Bradley Van Cleve **(C)** DAVISON VAN CLEAVE 333 SW Taylor Ste 400 Portland OR 97204 mjd@dvclaw.com	__ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Bradley Mullins **(C)** MOUNTAIN WEST ANALYTICS 333 SW Taylor Ste 400 Portland OR 97204 brmullins@mwanalytics.com	_X Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _ Electronic Mail

Katherine A McDowell **(C)** McDowell Rackner & Gibson PC 419 SW 11th Ave Ste 400 Portland OR 97205	_X Hand Delivery __U.S. Mail, postage pre-paid __ Facsimile _ Electronic Mail

Signed: */s/ Gregory M. Adams*

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Gregory M. Adams