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-307**
2017 Transition Adjustment	)	
Mechanism	)	

Opening Testimony of Kevin C. Higgins

on behalf of

Noble Americas Energy Solutions LLC

July 8, 2016

OPENING TESTIMONY OF KEVIN C. HIGGINS

Introduction

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-three prior proceedings in Oregon, including seven PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 296 (2016 TAM), 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).

I also testified in the 2017 Inter-Jurisdictional Allocation proceeding, UM 1050 (2016) and 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 190 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.

<u>Overview and Conclusions</u>

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.

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 the alternative, PacifiCorp could agree to transfer to the ESS the RECs for which these customers are paying the Company and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer.

  Although in UE 296 the Commission did not accept my argument to adjust the transition adjustments to reflect the value of freed-up RECs, the recent passage of Senate Bill 1547 has significantly increased future Oregon RPS requirements. The increase in the RPS will exacerbate the inequities in requiring a double payment from direct access customers for RPS-related resources. This change in circumstances warrants a further consideration of this issue by the Commission in this case.

- In UE 296, I argued that 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. In my opinion, the effects of this decline in return should be passed through to the Consumer Opt-Out charge in the Schedule 296 transition adjustment.

The Commission did not accept this argument in UE 296. However, this matter is being appealed by Noble Solutions to the Oregon Court of Appeals. In the event that this issue is reconsidered by the Commission, the appropriate adjustments are presented in my testimony and exhibits in this docket.

The Transition Adjustment and Ongoing Valuation

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

[1] Or. Laws 1999, Ch. 865.

generation services from Commission-certified electricity service suppliers ("ESS").[2] The law requires the Commission to implement rates that charge or 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. Fourteen 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 2015 were only 1.4% of eligible shopping load, far below the 13.9% 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]

Currently, PacifiCorp offers one-year, three-year, and five-year direct access programs. None of these programs has achieved significant participation levels. Prior to the 2016 shopping year, customers in the PacifiCorp territory could only choose between the one-year and three-year programs, pursuant to

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[2] *See* ORS 757.600(6), (16), -601(1), -649(1)(a).
[3] ORS 757.607(1), (2).
[4] Source: Oregon Public Utilities Commission, Status Report: Oregon Electric Industry Restructuring (July 2015). 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."

which the direct access customer would pay the ESS for generation supply and would continue 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 is required to return to cost-of-service or else elect a new one-year or three-year term. Under this regime, the customer never stops paying for PacifiCorp's generation resources.

PacifiCorp's five-year opt-out program was initiated January 1, 2016, after the Company was ordered to adopt such a program in Order No. 12-500. In that order, the Commission required PacifiCorp to file a tariff for a five-year opt out program that would allow 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 would only pay the interconnected electric utility for distribution delivery service.

In contrast to the one-year and three-year programs, the five-year opt-out program, in theory, allows customers to migrate to 100% market prices for generation services (purchased from an ESS) without any remaining obligations to compensate the interconnected electric utility for generation resources it has acquired for bundled customers. PGE has had a five-year opt-out program for several years and it has been relatively successful. However, as I will discuss below, the structure of the new PacifiCorp five-year opt-out approved by the Commission in UE 267 and UE 296 exacerbates the negative value proposition typically 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, the five-year opt-out program approved for PacifiCorp is unlikely to be an economically viable proposition for most eligible customers. Consistent with this expectation, PacifiCorp indicated in response to Noble Solutions Data Request 1.4.e that only a single customer enrolled in the five-year program during last year's enrollment window.[6]

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 is applied to customers who select the five-year opt-out that was 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(41):

> 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

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[6] See Exhibit Noble Solutions/102, Higgins/1, which contains PacifiCorp Response to Noble Solutions Data Request 1.4.e.

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. Additionally, as customers and the Oregon utilities indicated in Docket UM 1690 regarding a voluntary renewable energy tariff, other customers may wish to purchase more renewable energy than is available through PacifiCorp's cost-of-service portfolio. 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 implemented a five-year opt-out program effective January 1, 2016. However, the design of the transition adjustment for the PacifiCorp five-year opt-out differs in important respects from the PGE program and exacerbates the negative value proposition found in PacifiCorp's one-year and three-year programs currently in effect. Consequently, in its current form, the PacifiCorp five-year opt-out program is unlikely to be viable for most eligible customers.

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

Q. What is the basic structure of PacifiCorp's current charges for generation services?

A. PacifiCorp assesses rates for generation services to cost-of-service customers on two different rate schedules. First, it charges customers for its net power costs in Schedule 201, which includes long-term power purchase contracts, short-term market purchases, and fuel for power generation. Second, it charges customers for all other generation costs, including the costs of its rate-based generation investments, in Schedule 200.

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.[7] 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 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

[7] 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.

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 2017 Schedule 294 rate for Schedule 48-P customers is an average credit of $1.81/MWh during Heavy Load Hours and an average charge of $0.24/MWh during Light Load Hours, while the average Schedule 200 charge for these customers in 2017 is projected to be $26.73/MWh.[8] 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 is freed up when a customer chooses direct access service is determined by running two system simulations – one simulation <u>with</u> PacifiCorp serving the direct access load and one simulation with the Company <u>not</u> 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 (or

[8] Sources: The average Schedule 294 credits are derived from PacifiCorp's Response to TAM Support Set 3. See Exhibit Noble Solutions/102, Higgins/2 for the relevant source material. The average Schedule 200 rate for 2017 is provided by PacifiCorp in the Confidential Attachment to PacifiCorp's Response to Noble Solutions Data Request 1.6. The calculation of this figure is included in Confidential Exhibit Noble Solutions/103, Higgins/2, and is provided in the non-confidential excerpt of the data response contained in Exhibit Noble Solutions/104/3. PacifiCorp consented to my use of this figure as non-confidential in this testimony.

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.[9] 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. Typically not. I explained in Docket UE 264 that this approach does not adhere strictly to the definition of Ongoing Valuation articulated in OAR 860-038-0005(41). 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 <u>not</u> 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 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 has historically produced 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

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

the transition adjustment credit), all other things being equal. Indeed, because shopping customers must pay an ESS 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. I note that with today's extremely low market prices, the 2017 TAM is an exception to this historical pattern, in that the GRID-calculated costs for 2017 are greater than projected market prices on average. Whether this exception represents the start of a new pattern or a one-time aberration to the general trend remains to be seen.

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. Transition Adjustment: 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 typically 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 2017 TAM.[10]

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 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.

Although I continue to believe this modification is appropriate, I am not advocating for this change in this proceeding because it was not adopted by the Commission in UE 264.

Q. In UE 296, you recommended that the Schedule 294 and 295 TAM calculations be modified to capture the effects of Oregon's RPS on the transition adjustment. Why did you make this recommendation?

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

[10] PacifiCorp Response to Noble Solutions Data Request 1.1, included in Exhibit Noble Solutions/102, Higgins/3.

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.[11] 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, a circumstance that I believe is unreasonable and inequitable.

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. [12] As I discussed above, direct access customers are charged directly for Schedule 200 and also pay for the difference between 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.[13]

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[11] ORS 469A.052(1), 469A.065.

[12] This fact was established in UE 296. See PacifiCorp Response to Noble Solutions Data Request 1.11, included in Exhibit Noble Solutions/102, Higgins/7 in that docket.

[13] See Exhibit Noble Solutions/102, Higgins/4, containing PacifiCorp Response to Noble Solutions Data Request 2.4.b.

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 did you recommend to address this concern in UE 296?

A. I recommended that direct access customers be credited with the value of freed-up RECs in the calculation of the Schedule 294 and 295 transition adjustments. 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 "structured" or "unstructured," depending on their attributes, which correspond generally to the "bundled" and "unbundled" attributes recognized in the Oregon RPS.[14] Since, under the law in effect last year, an ESS could acquire unbundled RECs to meet 100% of its Oregon RPS obligations, I recommended that the average price of unstructured RECs that are projected to be sold in the current

[14] A bundled REC includes the underlying electricity for which the REC was issued, whereas an unbundled REC generally does not. *See* ORS 469A.005 (4), (14).

year be used as the basis for valuing the RECs that are freed-up by a direct access customer. Thus, in UE 296, I proposed that unstructured REC prices for 2014 would be used to set the valuation for the 2016 TAM.

Q. How did you propose that this adjustment would work mechanically?

A. I recommended that 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 UE-296, PacifiCorp provided workpapers for a sample Schedule 294 calculation for Schedule 48 customers which indicated that the weighted average market price of freed-up energy during HLH (measured at sales) was $31.89/MWH.[15] I proposed that my adjustment be in the form of an adder to this price, where the adder equaled the 2014 average price of unstructured RECs multiplied by 15%.

Q. How did the Commission rule on your RPS proposal?

A. The Commission rejected my proposal, stating:

> Noble Solutions' formula for valuing freed-up RECs assumes PacifiCorp will sell its RECs. As PacifiCorp points out, today and for the foreseeable future, PacifiCorp will be banking RECs. Further, PacifiCorp states if the RECs are sold in the future, departing direct access customers will receive a share of the revenues from sales. At best, the net present value of the value of any freed-up RECs is *de minimis*.

Q. Given this rejection by the Commission in UE 296, why are you re-arguing for adoption of a REC component in the transition adjustment?

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[15] See UE 296, Opening Testimony of Kevin C. Higgins, p. 17. In the current docket, the equivalent value for 48-P is $27.35/MWH. This value is provided in PacifiCorp's Confidential Response to TAM Support Set 3 and is included in Confidential Exhibit Noble Solutions/103, Higgins/3. PacifiCorp consented to my use of this figure as non-confidential in this testimony.

A. Circumstances have changed since the Commission ruled on this matter in UE 296. With the signing into law of Senate Bill 1547 in May 2016, the Oregon RPS will increase significantly. Currently, the proportion of resources that must be RPS-eligible is 15% and prior to passage of Senate Bill 1547, the percentage had been scheduled to increase to 20% in 2020 and 25% in 2025. Under the new law, the proportion of resources that must be RPS-eligible is increased to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040.

Additionally, unlike the prior RPS which allowed the ESS to meet its RPS obligation entirely with unbundled RECs, Section 10 of Senate Bill 1547 limits the ESS's use of unbundled RECs from compliance year 2021 forward to only 20% of the ESS's RPS requirement.[16] Thus, the ESS will need to acquire bundled RECs to meet 80% of its RPS requirements from 2021 forward, just as PacifiCorp is required to do. Bundled RECs are likely to be more expensive and difficult to procure for the ESS. Although 2021 is several years from now, the ESS will need to acquire bundled RECs to meet this requirement for customers who enroll in the five-year program in this year's enrollment window. Thus, the new requirement has relevance to this year's TAM, as well as the ten-year projection of transition charges applicable to customers that enroll in the five-year program this year.

These significant changes in the RPS requirements warrant a further consideration by the Commission to address the problem caused by the inequity of requiring a double payment from direct access customers for RPS-related resources.

[16] ORS 469A.145(1) & (4).

Q. Is your recommended approach for valuing RECs freed up by direct access dependent on the assumption that PacifiCorp must sell the freed-up REC?

A. No. My argument recognizes at the outset that PacifiCorp banks freed-up RECs for the purpose of the Oregon RPS. The purpose of the valuation exercise is to establish a reasonable estimate of the value of the banked RECs that are attributable to direct access customers (who are paying PacifiCorp for the RPS-eligible resource *and* acquiring RPS-eligible resources from their ESS). While PacifiCorp may bank RECs for the purpose of the Oregon RPS, *the Company also regularly sells RECs*. The value of the Company's REC sales can be used to value the banked RECs for the purpose of incorporating the value of freed-up RECs in the transition adjustment.

As it currently stands, the direct access customer is paying PacifiCorp for a generation portfolio that contains 15% RPS-compliant energy but is only being credited back the freed-up value of lower-cost "brown power" calculated through the transition adjustment, which assumes that the only value freed-up is the revenue from market sales and other reduced fuel costs calculated through GRID. My proposal is to correct this disparity in treatment by also recognizing the value of the RECs freed up by the direct access election.

Q. What about the Company's argument that if RECs are sold in the future, departing customers will receive a share of the revenues from the sales?

A. The problem with this response is that is underscores my point that the current practice treats direct access customers inequitably. The freeing-up of the RECs at issue is caused (and paid for) by the direct access customer. If the freed-up RECs are sold, the direct access customer receives only an infinitesimal share of the revenue because it is being unjustly spread among all other customers. This fact exemplifies the very problem I am recommending that the Commission rectify. The Company's response on this point highlights the *problem*, not the solution.

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 banks the freed-up RECs rather than sells 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.

Q. Please summarize your recommendation regarding the treatment of RPS-eligible resources in the calculation of the Schedule 294 and 295 transition adjustment.

A. I recommend that direct access customers be credited with the value of RECs freed-up due to direct access in the calculation of the Schedule 294 and 295 transition adjustments. The value of a freed-up REC, multiplied by the RPS percentage requirement (e.g., 15% in 2017), should be added to the weighted average market price of freed-up energy in the TAM calculation. For the purpose of this calculation, the average price of PacifiCorp's unstructured REC sales for 2015 should be used to set the value of a freed-up REC for the 2017 TAM.

Q. Are there any alternative approaches to accomplishing your objective?

A. Yes. In the alternative, PacifiCorp could agree to transfer to the ESS the RECs for which the ESS's direct access customers are paying PacifiCorp and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer.

Calculation of the Five-Year Transition Adjustment (Schedule 296)

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

A. PacifiCorp's sample calculation of Schedule 296 is provided in a Confidential Attachment in Response to Noble Solutions Data Request 1.6. I have provided a non-confidential excerpt from this data response that summarizes PacifiCorp's sample calculation for Schedules 30-S and 48-P in Exhibit Noble Solutions/104, Higgins/1-3.[17]

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

[17] PacifiCorp consented to my use of these excerpts of its discovery response as non-confidential in this testimony. I note that PacifiCorp's calculation contains an error in that the discount rate being applied to the 10-Year Net Present Value by the Company is actually 7.154% rather than 6.66% as indicated in the Company-provided document. To maintain consistency between the rates presented by the Company and adjustments I make later in my testimony, I have not corrected this error.

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.[18] 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

[18] As I noted above, the 2017 TAM is an exception to this historical result.

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-P customer would pay an average of \$26.73/MWh for Schedule 200, while receiving a Transition Adjustment credit of \$1.76/MWh, for a net charge of \$24.97/MWh, prior to considering the Consumer Opt-Out charge.[19] Conceptually, under ongoing valuation, this \$24.97/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 \$13.37/MWh.

Based on these sample charges, a participating customer using 10,000 MWh of energy per month (roughly the size of a 10 MW customer) would pay PacifiCorp \$4,600,800 per year in Year 1 for transition costs (inclusive of Schedule 200 and the Consumer Opt-Out charge)[20] *in addition* to paying an ESS for market-priced power.

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?

[19] This information is presented in Exhibit Noble Solutions 104, Higgins/3, which is a non-confidential excerpt of PacifiCorp's confidential response to Noble Solutions' Data Request 1.6. PacifiCorp consented to use of the excerpt in the exhibit and figures therein in this testimony as non-confidential information.

[20] (\$24.97/MWh + \$13.37/MWh) x 120,000 MWH = \$4,600,800.

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 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 2017 TAM, I recommend using the 2015 REC value for this purpose, combined with the relevant RPS requirement percentage.

Q. You stated that in UE 296 you proposed a modification to the calculation of the Consumer Opt-Out charge. What did you recommend in that docket?

A. I recommended two refinements to the calculation. PacifiCorp's calculation of the Consumer Opt-Out charge is based on projected Schedule 200 costs for Years 6 through 10. Under PacifiCorp's approach, these projected costs are simply current Schedule 200 rates escalated at an assumed rate of inflation. However, I argued that 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). This allowance for escalation of costs in the first five years is very conservative because it assumes that PacifiCorp cannot unwind prior commitments for five full years after the date of the opt-out election.

My first refinement to the Consumer Opt-Out charge was 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 reasonable to assume increased Schedule 200 costs for departing customers beyond the projected Year 5 Schedule 200 price.

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. Did the Commission accept your recommendation?

A. No. The Commission rejected my recommendation, stating:

> We have previously addressed the claim that the customer opt-out charge should be reduced to reflect a more accurate estimate of fixed generation costs. Noble Solutions has produced no new evidence or argument to persuade us to change our positon (sic). PacifiCorp explains that incremental generation is not added after year five. PacifiCorp also explains that, in real (inflation-adjusted) terms, the fixed generation costs are held constant through year 10. As we did in previous orders, we find it reasonable to assume that fixed generation costs will increase at the rate of inflation after year five.

Q. You stated that Noble Solutions has appealed this decision in the Oregon Court of Appeals. If this issue is readdressed by the Commission, 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. As I testified in UE 296, 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%). As PacifiCorp has not conducted an Oregon general rate case since I made these calculations, these calculations remain applicable today.

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 in this case?

A. Yes. As shown in Exhibit Noble Solutions/105, Higgins/2-3, these refinements reduce the sample Consumer Opt-Out charge from \$18.80/MWh to \$13.78/MWh for Schedule 30-S and from \$13.37/MWh to \$10.55/MWh for Schedule 48-P.

So, for example, with this change, a participating customer on Schedule 48-P using 10,000 MWh of energy per month (roughly the size of a 10 MW customer) would pay PacifiCorp \$4,262,400 per year in Year 1 transition costs[21]

[21] (\$24.97/MWh + \$10.55/MWh) x 120,000 MWh = \$4,262,400.

(inclusive of Schedule 200 and the Consumer Opt-Out charge) or $338,400 less than under the Company's proposal.

Q. Please summarize your recommendations concerning 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, if the Commission readdresses the escalation of Schedule 200 costs as I proposed in UE 296, the appropriate adjustments are presented in my testimony and exhibits in this docket.

Q. Does this conclude your opening testimony?

A. Yes, it does.

List of Exhibits

Noble Solutions/101:

OPUC Status Report – Oregon Electric Industry Restructuring (July 2015)

Noble Solutions/102:

PacifiCorp Responses to Noble Solutions' Data Requests 1.4, 1.1, 2.14, and
Excerpt of TAM Support Set 3, Sample Calculation for Schedule 294 One-Year Option

Redacted and Confidential Noble Solutions/103:

Excerpt of PacifiCorp Response to Noble Solutions' Data Request 1.6,
Confidential Attachment 1.6-1 Average Schedule 200 Generation Costs, and
Excerpt of Confidential TAM Support Set 3, Calculation of Market Price of Freed-Up Energy

Noble Solutions/104:

Sample Calculation of PacifiCorp's Proposed Five-Year Opt-Out Rates for Schedules 30-S and 47/48-P
(Non-Confidential Excerpt of PacifiCorp's Confidential Attachment 1.6-1 in Response to Noble Solutions Data Request 1.6)

Noble Solutions/105:

Sample Calculation of Noble Solutions' Proposed Five-Year Opt-Out Rates With Adjustment for Accumulated Depreciation

Status Report

Oregon Electric Industry Restructuring
(Number of Participating Customers as of July, 2015)

Portfolio Options*	PGE	PP&L
Fixed Renewable	10,067	11,464
Renewable Usage	110,764	35,331
Habitat		4,395
Habitat Rider***	8,403	
Time-of-use	2,640	1,534
Eligible Customers	830,722	569,592**

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** As of June 2015.
*** 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: 4
Registered Electricity Service Aggregators: 11

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	81.6%	4.5%	13.9%
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 1.4

Please provide the following information regarding PacifiCorp's projected Oregon retail load in 2016, expressed in MWH and indicate the number of days during the year that PacifiCorp's sales to Georgia Pacific-Camas are included in (a) and (b):

(a) Total Oregon retail load excluding direct access.

(b) Total Oregon retail load that was eligible for direct access.

(c) Direct access load (annual and three-year opt out).

(d) Direct access load – three-year opt-out only.

(e) Direct access load – five-year opt-out only.

Response to NAES Data Request 1.4

(a) PacifiCorp's projected total Oregon retail sales in 2016 excluding direct access is 12,830,869 megawatt-hours (MWh). Sales to Georgia-Pacific Camas (GP Camas) are included for all of 2016.

(b) Non-residential retail customers are eligible for direct access. PacifiCorp's projected Oregon non-residential retail load in 2016, including direct access, is 7,665,470 MWh. Sales to GP Camas are included for all of 2016.

(c) At the time the forecast was produced, PacifiCorp's projected total Oregon direct access in 2016 was 219,320 MWh. All of the direct access sales were assumed to participate on an annual basis.

(d) The Company does not separately forecast for customers participating in the three-year opt out.

(e) PacifiCorp objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Subsequent to the forecast preparation, one customer opted to participate in the five-year opt-out. The load associated with a specific customer is not relevant to this proceeding.

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

Initial Filing UE307 - Sample Calculations

	2017			
	30/730 Secondary		48/748 Primary	
	HLH	LLH	HLH	LLH
Jan-17	-0.872	0.059	-0.523	-0.174
Feb-17	-0.311	0.080	-0.582	-0.170
Mar-17	0.332	0.327	0.127	0.105
Apr-17	0.724	0.663	0.486	0.430
May-17	0.300	0.765	0.067	0.596
Jun-17	0.839	1.215	0.544	0.943
Jul-17	-1.032	0.243	-1.099	0.047
Aug-17	-0.661	-0.005	-0.892	-0.207
Sep-17	0.471	0.123	0.307	-0.104
Oct-17	0.198	0.131	-0.019	-0.099
Nov-17	0.348	-0.265	0.209	-0.492
Dec-17	-0.600	-0.321	-0.802	-0.589
Annual Average*			-0.181	0.024

Source File Name: 15-M - ORTAM17w_Transition Adjustment Summary
Source Disk OR UE 307 TAM Support Set 3 Non-Confidential Attachement
*Higgins Calculation

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-307.

Response to NAES Data Request 1.1

PacifiCorp confirms that the calculation of the Sample Schedule 294 Transition Adjustment for Schedule 30 and Schedule 48 is consistent with the method set forth in Section 15 of the Transition Adjustment Mechanism (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 2.4

Reference PacifiCorp's response to Noble Solutions' Data Request 1.11, stating that for the years 2017 through 2027, PacifiCorp does not have any documents supporting the continued veracity of the statement in Order No. 15-394 at 12 that: "At best, the net present value of the value of any freed-up RECs is *de minimis*".

(a) Does the Company agree that the quoted statement in the order is no longer correct?

(b) Please explain why the Company believes that RECs produced in the years 2017 to 2027 will continue to have *de minimis* value after enactment of Oregon's 2015 Senate Bill 1547, Oregon Laws 2016, Chapter 28, and the 2015 California Clean Energy and Pollution Reduction Act of 2015, California Senate Bill 350.

Response to NAES Data Request 2.4

(a) No. The Company agrees with the quoted statement from Public Utility Commission of Oregon (OPUC) Order 15-394 at 12.

(b) As pointed out in the above-referenced OPUC Order, PacifiCorp will be banking renewable energy credits (REC), and that if any RECs are sold, departing direct access customers will receive a share of revenues from these sales. These circumstances have not changed, and therefore, PacifiCorp agrees with the OPUC's statement in the order.

UE 307 / PacifiCorp
April 21, 2016
NAES Data Request 1.6

NAES Data Request 1.6

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 1.6

Please refer to Confidential Attachment NAES 1.6 -1 and Confidential Attachment NAES 1.6 -2, which provide the sample calculation for Schedule 296.

The confidential attachment is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Remaining Pages of Noble Solutions 103

Redacted Subject to Protective Order No. 16-128

NAES Data Request 1.6

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 1.6

Please refer to Confidential Attachment NAES 1.6 -1 and Confidential Attachment NAES 1.6 -2, which provide the sample calculation for Schedule 296.

The confidential attachment is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

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		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=23.63-6.84
2017	$29.06	$28.37	$0.69	-	$28.49	-	$16.80
2018	$29.57	$30.03	($0.46)	-	$29.12	-	$16.80
2019	$30.16	$31.66	($1.50)	-	$29.76	-	$16.80
2020	$30.17	$32.71	($2.54)	-	$30.44	-	$16.80
2021	$30.42	$35.15	($4.73)	-	$31.17	-	$16.80
2022	$31.21	$37.53		($6.32)		$31.92	
2023	$32.05	$39.53		($7.48)		$32.72	
2024	$32.87	$43.27		($10.40)		$33.51	
2025	$33.63	$45.73		($12.10)		$34.28	
2026	$34.09	$47.37		($13.28)		$35.03	
10-Year Net Present Value (1)				($27.91)		$96.50	$68.58
5-year Nominal Levelized Payment				($6.84)		$23.63	$16.80

Notes:
(1) 2017 through 2026 using a 6.66% Discount Rate
(2) Losses at 8.01%

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		Customer Opt Out Charge
	(a)	(b)	(c)		(d)		(e)
	(a)=Sch Avg		(c)=(a)-(b)		(d)=Sch Avg		=22.17-8.79
2017	$26.61	$28.37	($1.76)	-	$26.73	-	$13.37
2018	$27.07	$30.03	($2.96)	-	$27.31	-	$13.37
2019	$27.61	$31.66	($4.05)	-	$27.91	-	$13.37
2020	$27.62	$32.71	($5.09)	-	$28.55	-	$13.37
2021	$27.85	$35.15	($7.30)	-	$29.24	-	$13.37
2022	$28.57	$37.53		($8.96)		$29.94	
2023	$29.34	$39.53		($10.19)		$30.69	
2024	$30.09	$43.27		($13.18)		$31.43	
2025	$30.79	$45.73		($14.94)		$32.15	
2026	$31.21	$47.37		($16.16)		$32.86	
10-Year Net Present Value (1)				($35.90)		$90.51	$54.61
5-year Nominal Levelized Payment				($8.79)		$22.17	$13.37

Notes:
(1) 2017 through 2026 using a 6.66% Discount Rate
(2) Losses at 8.01%

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	Docket UE-296 Exhibit Noble Solutions/102, Higgins/11.
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	Docket UE-296 Exhibit Noble Solutions/102, Higgins/14.
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	Docket UE-296 Exhibit Noble Solutions/102, Higgins/11-13.
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	Docket UE-296 Exhibit Noble Solutions/102, Higgins/15-16.
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 (Sec.)
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		=20.62-6.84
2017	$29.06	$28.37	$0.69	-	$28.49	-	$13.78
2018	$29.57	$30.03	($0.46)	-	$29.12	-	$13.78
2019	$30.16	$31.66	($1.50)	-	$29.76	-	$13.78
2020	$30.17	$32.71	($2.54)	-	$30.44	-	$13.78
2021	$30.42	$35.15	($4.73)	-	$31.17	-	$13.78
2022	$31.21	$37.53		($6.32)		$30.43	
2023	$32.05	$39.53		($7.48)		$29.71	
2024	$32.87	$43.27		($10.40)		$29.01	
2025	$33.63	$45.73		($12.10)		$28.33	
2026	$34.09	$47.37		($13.28)		$27.66	
10-Year Net Present Value (1)				($27.91)		$84.18	$56.27
5-year Nominal Levelized Payment				($6.84)		$20.62	$13.78

Notes:

(1) 2015 through 2024 using a 7.154% Discount Rate. While PacifiCorp's workpapers state that the Company uses a discount rate of 6.660%, in fact the Company used 7.154%, apparently inadvertently. To maintain comparability with PacifiCorp's calculation, this exhibit also uses 7.154%.
(2) Losses at 8.56%

* Data Sources:

For Schedule 201 (Cols. a & b), see Pacificorp Response to NAES DR No. 1.6 (Included in Noble Solutions/104, Higgins/1-3).

For Schedule 200 (Col. d), for 2017 - 2021, see PacifiCorp Response to NAES DR No. 1.6 (Included in Noble Solutions/104, Higgins/1-3).

Noble Solutions
Schedule 47/48 (Pri.)
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		=19.34-8.79
2017	$26.61	$28.37	($1.76)	-	$26.73	-	$10.55
2018	$27.07	$30.03	($2.96)	-	$27.31	-	$10.55
2019	$27.61	$31.66	($4.05)	-	$27.91	-	$10.55
2020	$27.62	$32.71	($5.09)	-	$28.55	-	$10.55
2021	$27.85	$35.15	($7.30)	-	$29.24	-	$10.55
2022	$28.57	$37.53		($8.96)		$28.55	
2023	$29.34	$39.53		($10.19)		$27.88	
2024	$30.09	$43.27		($13.18)		$27.22	
2025	$30.79	$45.73		($14.94)		$26.58	
2026	$31.21	$47.37		($16.16)		$25.95	
10-Year Net Present Value (1)				($35.90)		$78.99	$43.09
5-year Nominal Levelized Payment				($8.79)		$19.34	$10.55

Notes:

(1) 2015 through 2024 using a 7.154% Discount Rate. While PacifiCorp's workpapers state that the Company uses a discount rate of 6.660%, in fact the Company used 7.154%, apparently inadvertently. To maintain comparability with PacifiCorp's calculation, this exhibit also uses 7.154%.
(2) Losses at 8.56%

* Data Sources:

For Schedule 201 (Cols. a & b), see Pacificorp Response to NAES DR No. 1.6 (Included in Noble Solutions/104, Higgins/1-3).

For Schedule 200 (Col. d), for 2017 - 2021, see PacifiCorp Response to NAES DR No. 1.6 (Included in Noble Solutions/104, Higgins/1-3).

CERTIFICATE OF SERVICE

I certify that on July 8, 2016, I served the non-confidential portions of the Opening Testimony and Exhibits of Noble Americas Energy Solutions LLC in OPUC Docket No. 307 on all parties on the service list through the OPUC's electronic filing and service system. I further certify that I served the confidential portions of the filing upon the following persons via federal express with guaranteed delivery within two business days on or before July 12, 2016, in accordance with OAR 860-001-0170(f):

Michael Goetz
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97206

Robert Jenks
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205

Bradley Mullins
Mountain West Analytics
333 SW Taylor, Suite 400
Portland, OR 97204

Tyler C Pepple
Davison Van Cleave, PC
333 SW Taylor, Suite 400
Portland, OR 97204

S Bradley Van Cleave
Davison Van Cleave PC
333 SW Taylor, Suite 400
Portland, OR 97204

Katherine A McDowell
McDowell Rackner & Gibson PC
419 SW 11th Ave, Suite 400
Portland, OR 97205

Matthew McVee
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

John Crider
Public Utilities Commission of Oregon
201 High St SE, Suite 100
Salem, OR 97301

Sommer Moser
PUC Staff – Dept of Justice
1162 Court St NE
Salem, OR 97301

Michael T. Weirich
PUC Staff – Dept of Justice
Business Activities Section
1162 Court St NE
Salem, OR 97301

By: ______________________________

Gregory M. Adams, OSB #101779
Richardson Adams, PLLC
Of Attorneys for Noble Americas Energy Solutions LLC