Calpine Solutions 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-339**
2019 Transition Adjustment	**)**	
Mechanism	**)**	

Opening Testimony of Kevin C. Higgins

on behalf of

Calpine Energy Solutions, LLC

June 11, 2018

OPENING TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 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 Calpine Energy Solutions, LLC ("Calpine Solutions"). Calpine Solutions is a retail energy supplier that serves commercial and industrial end-use customers in 18 states, the District of Columbia, and Baja California, Mexico. Calpine Solutions serves more than 15,000 retail customer sites nationwide, with an aggregate load in excess of 4,500 MW. Calpine Solutions' retail customers are located in the service territories of more than 55 utilities. In Oregon, Calpine Solutions is currently serving customers in the service territories of PacifiCorp and Portland General Electric ("PGE").

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-seven prior proceedings in Oregon, including nine previous PacifiCorp Transition Adjustment Mechanism ("TAM") proceedings, UE 323 (2018 TAM), UE 307 (2017 TAM), 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 six previous PGE general rate cases, UE 335 (2018), UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197 (2008), and UE

180 (2006). In addition, I testified in the PGE Opt-Out case, UE 236 (2012) and the PGE restructuring proceeding, UE 115 (2001).

I also testified in the Investigation into PacifiCorp's Non-Standard Avoided Cost Pricing, UM 1802 (2017), 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 testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 200 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 focuses on issues pertaining to direct access service, including the calculation of the Schedule 294, 295, and 296 transition adjustments; the treatment of Renewable Energy Certificates ("RECs") for direct access service; and the calculation of the Consumer Opt-Out Charge for PacifiCorp's Five-year Opt-Out program.

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

A. I offer the following primary conclusions and recommendations:

(1) I recommend that the process for transferring RECs from PacifiCorp to Electricity Service Suppliers ("ESSs") to account for the migration of direct access customers, as described in the Direct Testimony of PacifiCorp witness Michael G. Wilding, be approved by the Commission. The stakeholder-developed process described by Mr. Wilding reflects a constructive resolution of a longstanding dispute over the problem of direct access customers paying twice for Renewable Portfolio Standard ("RPS")-related resources: once from their "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. The REC transfer process described by Mr. Wilding reasonably resolves this problem by transferring RECs from PacifiCorp to ESSs for the benefit of their direct access customers, who pay for the RECs through the transition adjustment.

(2) I continue to believe that the most appropriate treatment for the Schedule 200 projections in years 6 through 10, as used in the calculation of the Consumer Opt-Out Charge, should decline 2.36% per year consistent with the effects of accumulated depreciation on a fixed pool of assets. At the same time, I recognize and appreciate that the Commission's Order 17-444 directed that a middle ground approach should be adopted in this 2019 TAM. Accordingly, I have prepared such a middle ground approach, which is presented in Exhibit Calpine Solutions/105, which I recommend be adopted by the Commission in this case.

PacifiCorp's approach to estimating the Schedule 200 projections in years 6 through 10 ignores the Commission's directive in Order 17-444 to identify a middle ground and should be rejected. Similarly, the Company's arguments that its approach is justified by its historical pattern of fixed generation costs should also be rejected, because the Company's analysis fails to remove all relevant incremental generation costs, including environmental upgrade costs.

<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 ESSs.[2] The law requires the Commission to implement rates that charge or credit the direct access customer an

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

amount related to the utility's stranded generation assets that prevents "unwarranted shifting of costs."[3]

The direct access law is intended to allow nonresidential customers to have the option to control their generation supply if they prefer to purchase generation from sources other than the incumbent utility's portfolio. For example, 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 wholesale electricity market.

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

A. Sixteen years after the 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. PacifiCorp's shopping participation levels in 2017 were only 4.7% of eligible shopping load, far below the 17.2% participation rate in the PGE territory.[4] Oregon businesses continue to face material barriers to acquiring market-priced power in PacifiCorp's territory, despite the proximity to

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[3] ORS 757.607(1), (2).
[4] Source: Oregon Public Utilities Commission, Status Report: Oregon Electric Industry Restructuring (June 2017). *See* Exhibit Calpine Solutions/101, Higgins/1.

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 which the direct access customer pays the ESS for generation supply and continues to pay PacifiCorp for Schedule 200 generation costs, subject to a transition adjustment discussed later in my testimony. At the conclusion of the one-year or three-year term the customer is required to return to cost-of-service or 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 for service commencing on 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 PacifiCorp for distribution delivery service.

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[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."

In contrast to the one-year and three-year programs, the five-year opt-out program allows customers to migrate to 100% market prices for generation services (purchased from an ESS) without any remaining obligations to compensate PacifiCorp 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 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. Consequently, despite the inherent appeal of a five-year opt-out program, the five-year opt-out program approved for PacifiCorp is not – and is unlikely to become – an economically viable proposition for most eligible customers. Consistent with this expectation, PacifiCorp indicated in its Response to Calpine Solutions Data Request 1.12.c.iii that only a single customer is enrolled in the five-year program.[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

[6] See Exhibit Calpine Solutions/102, Higgins/3, which contains PacifiCorp's Response to Calpine Solutions Data Request 1.12.c.iii.

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 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, 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 current PGE program and exacerbates the negative value proposition generally found in PacifiCorp's one-year and three-year programs.

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, the Company 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, PacifiCorp 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

[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.

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 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 2019 Schedule 294 rate for Schedule 48-P customers is an average credit of $6.98/MWh during Heavy Load Hours and an average credit of $4.50/MWh during Light Load Hours, while the average Schedule 200 charge for these customers in 2019 is projected to be $28.63/MWh.[8] Thus, the Schedule 200 charge is far greater than the transition adjustment credit, meaning that the direct

[8] Sources: The average Schedule 294 credits are derived from PacifiCorp's Confidential 15 day workpapers, GRID analysis files. See Exhibit Calpine Solutions/102, Higgins/1 for the relevant source material. The average Schedule 200 rate for 2018 is provided by PacifiCorp in the Confidential Attachment 2.14-1 to PacifiCorp's Response to Calpine Solutions Data Request 2.14. Certain non-confidential information from this attachment is presented in Exhibit Calpine Solutions/103. *See* Exhibit Calpine Solutions/103, Higgins/3 for the Schedule 200 charge referenced in my testimony. PacifiCorp consented to my use of this figure as non-confidential in this testimony.

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 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 (or 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?

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

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 avoided costs of 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 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.[10] I note that in the current low market price environment, the last several TAMs have been an

[10] I addressed this point at some length in UE 264. See Reply Testimony of Kevin C, Higgins, pp.16-21.

exception to this historical pattern, in that the GRID-calculated costs for 2017-2019 are greater than projected market prices on average.

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. This provision mitigates the negative value proposition typically faced by direct access customers in the PacifiCorp territory.

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 2019 TAM.[11]

Q. Are there other elements in the TAM calculation that contribute to the negative value proposition?

A. Yes. 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.

Q. Are you advocating for adoption of a BPA Point-to-Point transmission credit in this proceeding?

A. No. 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.

<u>Treatment of Renewable Energy Certificates for Direct Access Service</u>

Q. In UE 296, UE 307, and UE 323 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 that recommendation?

[11] This is confirmed in PacifiCorp Response to Calpine Solutions Data Request 1.10, included in Exhibit Calpine Solutions/102, Higgins/2.

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 as applicable to PacifiCorp service territory requires that 15% of supply come from qualifying renewable electricity in calendar years 2018 and 2019, 20% of supply come from qualifying renewable electricity in calendar years 2020 through 2024, and 27% in calendar years 2025 through 2029.[12] 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 the case of the five-year program, for example, customers opting out later this year would pay projected costs of the existing portfolio of RPS-compliant resources in Schedules 200 and 201 through the year 2028. In paying both the ESS and PacifiCorp for RPS power, direct access customers historically paid twice to meet RPS requirements, a circumstance that I argued was 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.[13] For each MWh of electric energy produced by the RPS-complaint resources in Schedules 200 and 201, the resource also produces a REC. As I discussed above, direct access customers are charged directly for

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

[13] 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.

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. In addition, direct access customers on the one-year and three-year programs, as well as new customers entering the five-year program, pay for Schedule 203, the Renewable Resource Deferral Supply Service Adjustment, which recovers the costs of RECs that were purchased following PacifiCorp's 2016 RFP, which funds the acquisition of incremental RPS-eligible resources.

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. Thus, just as the electric energy is freed up when the customer moves to direct access, the RECs are also freed up. The freed-up RECs are banked for future use by PacifiCorp's cost-of-service customers.

Q. Are direct access customers currently 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. There is now some compensation recognized in the calculation of the transition adjustment, but in my opinion, the current calculation understates the REC value. In UE 323, PacifiCorp agreed to recognize a REC credit in the calculation of the transition adjustment, and the Company's proposal was approved by the Commission, but with instructions to investigate an alternative approach for use in this case. The Commission's order in UE 323 recognized that parties continued to disagree over the method used to value RECs, and that it would be worthwhile to consider an entirely different approach in which the RECs would not be valued as part of the transition adjustment, but rather would be transferred to ESSs for the benefit of their direct access customers (who were paying for the RECs through the transition adjustment). As the Commission stated in Order No. 17-444:[14]

> We recognize that the valuation of RECs has been a primary point of disagreement among the parties for three TAM proceedings, with parties explaining the REC markets are volatile and illiquid. Parties believe that REC transfers may be a simpler solution, and we are interested in this option. PacifiCorp began working on two proposals for REC transfers before this TAM, and proposes to conduct another workshop on REC transfers before the 2019 TAM. We agree with the company's workshop proposal, and add a requirement for the 2019 TAM. In the 2019 TAM, the company is to present its best proposal for REC transfers, so that parties may weigh in and build a full record on this issue that will enable us to decide whether REC transfers are practical and feasible.

Q. Did PacifiCorp and other stakeholders follow through on the workshop that was referenced in the Commission's order?

A. Yes and the workshop was successful. Participants in the workshop – including PacifiCorp, Staff, ICNU, CUB, and Calpine Solutions – agreed on an approach for transferring RECs from PacifiCorp to ESSs to account for the migration of direct access load. This agreed-upon approach is explained on pages 46-47 of the Direct Testimony of PacifiCorp witness Michael G. Wilding.

Q. Do you recommend Commission approval of the approach for transferring RECs as described in Mr. Wilding's testimony?

[14] UE 323, Order No. 17-444 at 19. Footnotes omitted.

A. Yes, I do. The agreed-upon approach for REC transfers as described by Mr. Wilding represents a constructive and equitable resolution of this longstanding problem.

Calculation of the Five-Year Transition Adjustment (Schedule 296) and Consumer Opt-Out Charge

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

A. PacifiCorp's sample calculation of Schedule 296 is provided in Confidential Attachment 2.14-1 in Response to Calpine Solutions Data Request 2.14. I have provided a non-confidential excerpt from this data response that summarizes PacifiCorp's sample calculation for Schedules 30-S and 47/48-P in Exhibit Calpine Solutions/103, Higgins/1-3.[15]

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. PacifiCorp proposes to apply the REC credit it has calculated in this docket to this component.

[15] PacifiCorp consented to my use of these excerpts of its discovery response as non-confidential in this testimony.

In addition to the Schedule 296 charge, the customer must also pay PacifiCorp the base Schedule 200 charge for 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.[16] 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.

[16] As I noted above, the last two TAMs are exceptions to this historical result.

So, for example, according to PacifiCorp's sample calculation, in Year 1 (2019) of the five-year opt-out, a Schedule 48-P customer would pay an average of $28.63/MWh for Schedule 200, while receiving a Transition Adjustment credit of $0.80/MWh, for a net charge of $27.83/MWh, prior to considering the Consumer Opt-Out charge.[17] Conceptually, under ongoing valuation, this $27.83/MWh net 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 power from the competitive market. But, in addition, the five-year opt-out customer would pay a Consumer Opt-Out charge of $14.65/MWh.

Based on these sample charges, a participating customer using 100,000 MWh of energy per year (roughly the size of a 15 MW customer) would pay PacifiCorp $4,248,000 per year in Year 1 for transition costs (inclusive of Schedule 200 and the Consumer Opt-Out charge)[18] *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?

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[17] This information is presented in Exhibit Calpine Solutions 103, Higgins/3, which is an excerpt of PacifiCorp's confidential response to Calpine Solutions' Data Request 2.14. PacifiCorp consented to use of the excerpt in the exhibit and figures therein in this testimony as non-confidential information.

[18] ($27.83/MWh + $14.65/MWh) x 100,000 MWH = $4,248,000.

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 UE 296, UE 307, and UE 323 you proposed modifications to the calculation of the Consumer Opt-Out charge. What did you recommend in those dockets?

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 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 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 you estimate how much Schedule 200 should decline from Year 6 through Year 10 in the calculation of the Consumer Opt-Out charge as a result of your modification?

A. Yes. As I testified in UE 296, UE 307, and UE 323, 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 Calpine Solutions/104, Higgins/2-3, these refinements reduce the sample Consumer Opt-Out charge from $18.04/MWh to

$14.84/MWh for Schedule 30-S and from $14.65/MWh to $11.64/MWh for Schedule 48-P.

So, for example, with this change, a participating customer on Schedule 48-P using 100,000 MWh of energy per year (roughly the size of a 15 MW customer) would pay PacifiCorp $3,947,000 per year in Year 1 transition costs[19] (inclusive of Schedule 200 and the Consumer Opt-Out charge) or $301,000 less than under the Company's proposal.

Q. Has the Commission accepted your recommended refinements to the calculation of the Consumer Opt-Out charge?

A. Initially (UE 296) the Commission rejected my recommended changes, but in UE 323, the Commission accepted it, in part, for this 2019 TAM, stating:

> We are concerned, however, with PacifiCorp's new arguments asserting that incremental generation should be allowed in the year six through ten forecast. Thus, we provide new, clear guidance to further explain our intent for the opt-out charge. This guidance is necessary because the opt-out charge is relatively new and the calculation methodology was summarily established in our review of a contested stipulation.
>
> We direct PacifiCorp to more clearly demonstrate in the 2019 TAM that its opt-out charge meets the following criteria. First, the company may use a modest inflation adjustor to forecast year 6 through 10 costs. Second, the company should not include any new incremental generation in the years 6 through 10 forecast. Third, the company should account for depreciation. *With these three requirements, we expect the opt-out charge to fall somewhere in-between the company's current calculation and Calpine's suggestion, netting the company's 2.5 percent inflation escalator and Calpine's 8.38 percent depreciation rate*. These numbers are approximate, and PacifiCorp is directed to provide transparency into this calculation in the 2019 TAM with explanatory testimony and supporting exhibits.[20]

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[19] ($27.83/MWh + $11.64/MWh) x 100,000 MWh = $3,947,000.
[20] UE 323, Order No. 17-444 at 20-21. Emphasis added. Footnotes omitted.

Q. Has PacifiCorp complied with this Commission directive in this 2019 TAM filing?

A. No. PacifiCorp admits that it has not modified its calculation as directed by the Commission.[21] Instead, the Company has simply reargued its position on this issue as it did in the 2018 TAM. The sample Schedule 296 calculations provided by the Company for the five-year opt-out merely replicate the approach PacifiCorp presented in its 2018 TAM without any attempt to reach the middle ground between the Company and Calpine Solutions that was ordered by the Commission for the 2019 TAM.

Q. Have you presented a "middle ground" calculation of Schedule 296 in response to the Commission's Order No. 17-444?

A. Yes, I have. My middle ground calculation in response to the Commission's order is presented in Exhibit Calpine Solutions/105.

Q. Please describe the results of your "middle ground" calculation.

A. As I described above, the Schedule 200 entry should decline by approximately 2.36% per year from Years 6 through 10 as a result of accumulated depreciation. Meanwhile, the generation cost inflation assumption used by PacifiCorp escalates Schedule 200 costs at a rate of approximately 2.3% per year. If we take account of both of these two effects simultaneously, as required by the Commission's order, the two effects largely offset, resulting in a slight annual decline in Schedule 200 costs of about $0.04/MWh, as shown in column (d) of Exhibit Calpine Solutions/105, pages 1 and 2, for the years 2024-2028.

[21] See Direct Testimony of Michael G. Wilding, p. 53, line 10.

Q. Is your "middle ground" calculation responsive to the Commission's Order No. 17-444?

A. Yes. My calculation is fully responsive to the Commission's Order No. 17-444. In that order, the Commission made it clear that year 6 through 10 costs should account for depreciation, which I have demonstrated decreases fixed generation revenue requirements (on a fixed pool of assets) by approximately 2.36% per year. PacifiCorp makes no attempt to account for the effect of depreciation over this period. At the same time, the Commission is allowing for the use of a modest inflation adjustor for years six through ten, which, although I disagree with the premise, I have incorporated by using PacifiCorp's 2.3% inflation assumption. As expected by the Commission in its order, the results of my middle ground calculation fall in-between PacifiCorp's preferred calculation and my preferred calculation.

Q. Do you have any response to PacifiCorp's rearguing of its position from the 2018 TAM?

A. Yes. In rearguing its position from the 2018 TAM, PacifiCorp presents Exhibit PAC/110, which Mr. Wilding uses to argue that historical fixed generation costs have increased between 2006 and 2016, even after removing incremental costs of Major Plants Additions from the analysis.[22] However, Mr. Wilding's analysis does not remove all incremental generation costs from the analysis; in particular, his analysis does not remove minor plant additions nor does it remove new environmental upgrade costs.

[22] Id., p. 53.

Q. In determining the change in fixed generation costs over time for a fixed pool of assets, should incremental environmental upgrade costs be removed?

A. Yes. The removal of the cost of environmental upgrades is appropriate for purposes of the analysis in this case because the cost responsibility for such upgrades, which essentially allow coal plants to continue operating in order to provide going-forward service to bundled service customers, cannot reasonably be assigned to customers who departed bundled service six to ten years previously. To accept PacifiCorp's position that escalation of fixed generation costs in the calculation of the Consumer Opt-Out Charge is appropriate can only mean that departed customers are somehow held responsible for the cost of environmental upgrades some six to ten years after leaving bundled service. I believe that such a position is fundamentally unreasonable.

Q. Have you prepared an analysis that removes new environmental upgrade costs in the same way that Major Plant Additions are removed?

A. Yes. This analysis is presented in Exhibit Calpine Solutions/106. The results are summarized on pages 1-2 of that exhibit.

Q. What do the results of Exhibit Calpine Solutions/106 show?

A. The summary pages present PacifiCorp's Oregon-allocated fixed generation costs on a per-MWh basis for each possible measurement period ending in 2016, which is the final year in Mr. Wilding's Exhibit PAC/110 (e.g., 2007-2016, 2008-2016, etc.). Exhibit Calpine Solutions/106 shows this information for each of three scenarios: (1) Removal of Major Plant Capital Additions (excluding Environmental Upgrades); (2) Removal of Major and Minor

Plant Capital Additions (excluding Environmental Upgrades); and (3) Removal of Major and Minor Plant Capital Additions and Environmental Upgrades.[23]

The first row on page 1 of Exhibit Calpine Solutions/106 shows the per-MWh fixed generation cost for each year calculated by PacifiCorp in Exhibit PAC/110. For each measurement period, denoted by the boxes on the page, the cost per MWh in the first year of the measurement period is the same as in PacifiCorp's Exhibit PAC/110, and only the incremental costs subsequent to that initial year are removed. So, for example, for the period 2008-2016, for Scenario 3, PacifiCorp's calculated cost per MWh of $25.98/MWh is reported for 2008. When the cost of Major and Minor Plant Capital Additions and Environmental Upgrades) added subsequent to 2008 is removed, the remaining fixed generation cost in 2016 is $22.50/MWh.

Q. What is shown on pages 3 to 20 of Exhibit Calpine Solutions/106?

A. Pages 3 to 20 of the exhibit show the individual results for each standalone measurement period, starting with 2007-2016 and ending with 2015-2016. The results of these standalone cases are summarized on pages 1 and 2 of the exhibit, as I explained above.

Q. Exhibit Calpine Solutions/106 starts with the measurement period 2007-2016. Why didn't you start with 2006-2016?

A. As I explained in UE 323, the 2006 data are based on the March 2006 Results of Operations whereas the data for all other years are based on December

[23] These calculations do not include the effects of accumulated deferred income taxes, incremental operations and maintenance expense, or property taxes associated with incremental generation plant, in deference to the burdensomeness on PacifiCorp in providing this information.

Results of Operations. This suggests that the 2006 data are nearly two years removed from the rest of the time series and therefore are not directly comparable. The jump in average fixed generation costs of 43% from 2006 to 2007 as reported in the Company's table is a further indication that 2006 is an anomalous entry that is not useful as a point of reference in this analysis.

Q. Which of the three scenarios presented in your analysis is the most reasonable for the issues being considered in this case?

A. The most reasonable basis of analysis for the issues being considered in this case is Scenario 3 because it best reflects the change in the cost of the Company's generation assets once the pool of assets is fixed in any given year, comparable to what should be considered for opt-out customers six to ten years after they have left cost-of-service rates.

Q. What does your analysis show for Scenario 3?

A. In the case of Scenario 3, the removal of incremental generation costs added after the initial year of the measurement period results in a decline in 2016 fixed costs relative to the initial year for each of the nine measurement periods between 2007-2016 and 2015-2016. This is shown on pages 1 and 2 of Exhibit Calpine Solutions/106 by comparing (a) the per-MWh cost for the initial year of each measurement period with (b) the 2016 per-MWh cost with all incremental capital additions (including environmental upgrades) removed. My analysis provides powerful evidence that these fixed costs generally will *not* increase, but rather decline, if the new capital additions, including the cost of environmental upgrades, are removed.

Q. Please summarize your recommendations on this issue.

A. I continue to believe that the most appropriate treatment for the Schedule 200 projections in years 6 through 10, as used in the calculation of the Consumer Opt-Out Charge, should decline 2.36% per year consistent with the effects of accumulated depreciation on a fixed pool of assets. At the same time I recognize and appreciate that the Commission's Order 17-444 directed that a middle ground approach should be adopted in this 2019 TAM. Accordingly, I have prepared such a middle ground approach, which is presented in Exhibit Calpine Solutions/105, which I recommend be adopted by the Commission in this case.

PacifiCorp's approach to estimating the Schedule 200 projections in years 6 through 10 ignores the Commission's directive in Order 17-444 to identify a middle ground and should be rejected. Similarly, the Company's arguments that its approach is justified by its historical pattern of fixed generation costs should also be rejected, because the Company's analysis fails to remove all relevant incremental generation costs, including environmental upgrade costs.

Q. Does this conclude your opening testimony?

A. Yes, it does.

Docket No. UE 339

EXHIBIT

Calpine Solutions 101

Status Report

Oregon Electric Industry Restructuring

(Number of Participating Customers as of June 2017)

Status Report

Oregon Electric Industry Restructuring
(Number of Participating Customer as of June, 2017)

Portfolio Options*	PGE	PP&L
Fixed Renewable	8,762	12,024
Renewable Usage	154,838	40,914
Habitat		5,772
Habitat Rider**	9,453	
Time-of-use	5,764	1,506
Eligible Customers	853,859	582,871

* Available to residential and small nonresidential customers. Customers may, in certain circumstances, choose more than one option.
** 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: 6
Registered Electricity Service Aggregators: 12

Nonresidential Customer Choices (based on load):

	Cost of Service	Market Options	Direct Access
PGE	81.5%	1.3%	17.2%
PP&L	95.0%	0.3%	4.7%

This report reflects prior month results.

Produced by the Oregon Public Utility Commission
Energy Resources & Planning
(503) 378-6917

Docket No. UE 339

EXHIBIT

Calpine Solutions 102

PacifiCorp Responses to Data Requests Referenced

in Testimony

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

Initial Filing UE339 - Sample Calculations

	2019			
	30/730 Secondary		48/748 Primary	
	HLH	LLH	HLH	LLH
Jan-18	-1.154	-0.562	-0 947	-0.794
Feb-18	-0.761	-0.562	-1 003	-0.799
Mar-18	-0.155	-0.254	-0 330	-0.560
Apr-18	0 380	0.612	0.191	0.395
May-18	0.734	1.059	0 537	0.833
Jun-18	0.418	0.586	0 252	0.445
Jul-18	-1.775	-0.511	-2 011	-0.723
Aug-18	-1 373	-0.941	-1 578	-1.149
Sep-18	-0 998	-0.638	-1 238	-0.856
Oct-18	-0 222	-0.326	-0.456	-0.547
Nov-18	-0 653	-0.482	-0 893	-0.696
Dec-18	-0 677	-0.723	-0 904	-0.948
Annual Average*			-0 698	-0.450

Source File Names:	ORTAM19_Schedule 30 (2019) Secondary HLH
	ORTAM19_Schedule 30 (2019) Secondary LLH
	ORTAM19_Schedule 48 (2019) Primary HLH
	ORTAM19_Schedule 48 (2019) Primary LLH
Source Directory	CONF 15-Day Work Papers
Source Disk	OR Docket No. UE 339 2019 TAM Confidential 15 Day Work Papers

*Higgins Calculation

UE 339 / PacifiCorp
May 21, 2018
Calpine Energy Solutions 1.10

Calpine Energy Solutions 1.10

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-339.

Response to Calpine Energy Solutions Data Request 1.10

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 docket 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 "ORTAM19_Schedule."

UE 339 / PacifiCorp
May 21, 2018
Calpine Energy Solutions 1.12

Calpine Energy Solutions 1.12

Please provide the following information regarding PacifiCorp's Oregon retail load in 2017, expressed in MWh, and indicate whether 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 differentiated into the categories of (i) annual, (ii) three-year opt out, and (iii) five-year opt-out.

Response to Calpine Energy Solutions Data Request 1.12

(a) Total Oregon retail load excluding direct access for 2017 was 13,200,282 megawatt-hours (MWh). This includes sales to Georgia Pacific (GP) Camas.

(b) Non-residential retail customers are eligible for direct access. PacifiCorp's Oregon non-residential retail load for 2017 was 7,395,936 (MWh). This includes sales to GP Camas.

(c) Please refer to the responses to subparts (i) through (iii) below:

PacifiCorp objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Loads associated with specific customers are not relevant to this proceeding. Without waiving this objection, the company responds as follows:

i. Rounded to the nearest 5 average megawatts (aMW), the enrolled annual load is 10 aMW.

ii. Rounded to the nearest 5 average megawatts (aMW), the enrolled load is 10 aMW. PacifiCorp confirms that only three customers elected to participate in the three-year opt-out program.

iii. Rounded to the nearest 5 aMW, the enrolled load is 25 aMW. PacifiCorp confirms that only one customer elected to participate in the five-year opt-out program.

Docket No. UE 339

EXHIBIT

Calpine Solutions 103

Non-Confidential Excerpt from PacifiCorp Response to Calpine Solutions Data Request 2.14

Note: This exhibit contains excerpts from data responses originally designated as confidential that PacifiCorp has agreed may be presented as non-confidential.

Calpine Energy Solutions 2.14

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 Calpine Energy Solutions Data Request 2.14

Please refer to Confidential Attachment Calpine Energy Solutions 2.14-1 and Confidential Attachment Calpine Energy Solutions 2.14-2, which provide the sample calculation for Schedule 296.

The confidential attachments are 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 339 - 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		=25.63-7.59
2019	$26.92	$25.46	$1.46	-	$30.49	-	$18.04
2020	$25.62	$26.96	($1.34)	-	$31.28	-	$18.04
2021	$26.44	$29.19	($2.75)	-	$32.03	-	$18.04
2022	$27.10	$30.76	($3.66)	-	$32.77	-	$18.04
2023	$27.37	$31.74	($4.37)	-	$33.52	-	$18.04
2024	$28.61	$35.13		($6.52)		$34.29	
2025	$30.24	$39.57		($9.33)		$35.08	
2026	$30.07	$40.98		($10.91)		$35.89	
2027	$30.63	$43.78		($13.15)		$36.72	
2028	$33.62	$48.03		($14.41)		$37.56	
10-Year Net Present Value (1)				($31.20)		$105.35	$74.15
5-year Nominal Levelized Payment				($7.59)		$25.63	$18.04

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate
(2) Losses at 8.01%

Schedule 47/48
Schedule 339 - 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		=24.08-9.42
2019	$24.66	$25.46	($0.80)	-	$28.63	-	$14.65
2020	$23.47	$26.96	($3.49)	-	$29.38	-	$14.65
2021	$24.22	$29.19	($4.97)	-	$30.09	-	$14.65
2022	$24.83	$30.76	($5.93)	-	$30.78	-	$14.65
2023	$25.07	$31.74	($6.67)	-	$31.49	-	$14.65
2024	$26.20	$35.13		($8.93)		$32.21	
2025	$27.70	$39.57		($11.87)		$32.95	
2026	$27.55	$40.98		($13.43)		$33.71	
2027	$28.06	$43.78		($15.72)		$34.49	
2028	$30.80	$48.03		($17.23)		$35.28	
10-Year Net Present Value (1)				($38.74)		$98.95	$60.22
5-year Nominal Levelized Payment				($9.42)		$24.08	$14.65

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate
(2) Losses at 8.01%

Docket No. UE 339

EXHIBIT

Calpine Solutions 104

Schedule 296 - Five Year Cost of Service Opt-Out Program

Example Calculation as Recommended by Calpine Solutions

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

Line No.	(a) Description	(b) Value	(c) 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	See 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	See 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	See 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	See 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

Calpine Energy Solutions
Schedule 30 (Sec.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation as Recommended by Calpine Solutions ($/MWh)

Line No.	Year	Schedule 201 - Net Power Costs in Rates[1]	NPC Impact of 50 aMW Leaving System[1]	Transition Adjustment		Schedule 200 - Base Supply[2,3]		Consumer Opt Out Charge
		(a)	(b)	(c)		(d)		(e)
		(a) = Sch Avg		(c) = (a)-(b)		(d) = Sch Avg		= 22.43-7.59
1	2019	$26.92	$25.46	$1.46	-	$30.49	-	$14.84
2	2020	$25.62	$26.96	($1.34)	-	$31.28	-	$14.84
3	2021	$26.44	$29.19	($2.75)	-	$32.03	-	$14.84
4	2022	$27.10	$30.76	($3.66)	-	$32.77	-	$14.84
5	2023	$27.37	$31.74	($4.37)	-	$33.52	-	$14.84
6	2024	$28.61	$35.13		($6.52)		$32.73	
7	2025	$30.24	$39.57		($9.33)		$31.96	
8	2026	$30.07	$40.98		($10.91)		$31.21	
9	2027	$30.63	$43.78		($13.15)		$30.47	
10	2028	$33.62	$48.03		($14.41)		$29.75	
11	10-Year Net Present Value (1)				($31.20)		$92.18	$60.98
12	5-year Nominal Levelized Payment				($7.59)		$22.43	$14.84

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate.
(2) Losses at 8.01%

Data Sources:

1. For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

2. For Schedule 200 (Col. d), for 2019 - 2023, see PacifiCorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

3. For Schedule 200 (Col. d), for 2024 - 2028, the prior year value is reduced by Calpine Solutions' Annual Depreciation Impact percentage.

Calpine Energy Solutions
Schedule 47/48 (Pri.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation as Recommended by Calpine Solutions ($/MWh)

Line No.	Year	Schedule 201 - Net Power Costs in Rates[1]	NPC Impact of 50 aMW Leaving System[1]	Transition Adjustment		Schedule 200 - Base Supply[2,3]		Consumer Opt Out Charge
		(a)	(b)	(c)		(d)		(e)
		(a) = Sch Avg		(c) = (a)-(b)		(d) = Sch Avg		= 21.07-9.42
1	2019	$24.66	$25.46	($0.80)	-	$28.63	-	$11.64
2	2020	$23.47	$26.96	($3.49)	-	$29.38	-	$11.64
3	2021	$24.22	$29.19	($4.97)	-	$30.09	-	$11.64
4	2022	$24.83	$30.76	($5.93)	-	$30.78	-	$11.64
5	2023	$25.07	$31.74	($6.67)	-	$31.49	-	$11.64
6	2024	$26.20	$35.13		($8.93)		$30.75	
7	2025	$27.70	$39.57		($11.87)		$30.02	
8	2026	$27.55	$40.98		($13.43)		$29.31	
9	2027	$28.06	$43.78		($15.72)		$28.62	
10	2028	$30.80	$48.03		($17.23)		$27.94	
11	10-Year Net Present Value (1)				($38.74)		$86.58	$47.84
12	5-year Nominal Levelized Payment				($9.42)		$21.07	$11.64

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate.
(2) Losses at 8.01%

Data Sources:

1. For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

2. For Schedule 200 (Col. d), for 2019 - 2023, see PacifiCorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

3. For Schedule 200 (Col. d), for 2024 - 2028, the prior year value is reduced by Calpine Solutions' Annual Depreciation Impact percentage.

Docket No. UE 339

EXHIBIT

Calpine Solutions 105

Schedule 296 - Five Year Cost of Service Opt-Out Program

Example Calculation as Instructed in Commission Order 17-444

Calpine Energy Solutions
Schedule 30 (Sec.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation as Instructed in Commission Order 17-444 ($/MWh)

Line No.	Year	Schedule 201 - Net Power Costs in Rates[1]	NPC Impact of 50 aMW Leaving System[1]	Transition Adjustment		Schedule 200 - Base Supply[2,3]		Consumer Opt Out Charge
		(a)	(b)	(c)		(d)		(e)
		(a) = Sch Avg		(c) = (a)-(b)		(d) = Sch Avg		= 23.92-7.59
1	2019	$26.92	$25.46	$1.46	-	$30.49	-	$16.33
2	2020	$25.62	$26.96	($1.34)	-	$31.28	-	$16.33
3	2021	$26.44	$29.19	($2.75)	-	$32.03	-	$16.33
4	2022	$27.10	$30.76	($3.66)	-	$32.77	-	$16.33
5	2023	$27.37	$31.74	($4.37)	-	$33.52	-	$16.33
6	2024	$28.61	$35.13		($6.52)		$33.48	
7	2025	$30.24	$39.57		($9.33)		$33.44	
8	2026	$30.07	$40.98		($10.91)		$33.40	
9	2027	$30.63	$43.78		($13.15)		$33.36	
10	2028	$33.62	$48.03		($14.41)		$33.32	
11	10-Year Net Present Value (1)				($31.20)		$98.31	$67.10
12	5-year Nominal Levelized Payment				($7.59)		$23.92	$16.33

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate.
(2) Losses at 8.01%

Data Sources:

1. For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

2. For Schedule 200 (Col. d), for 2019 - 2023, see PacifiCorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

3. For Schedule 200 (Col. d), for 2024 - 2028, the prior year value is reduced by Calpine Solutions' Annual Depreciation Impact percentage and escalated by PacifiCorp's annual inflation adjustment.

Calpine Energy Solutions
Schedule 47/48 (Pri.)
Schedule 296 - Five Year Cost of Service Opt-Out Program
Example Calculation as Instructed in Commission Order 17-444 ($/MWh)

Line No.	Year	Schedule 201 - Net Power Costs in Rates[1]	NPC Impact of 50 aMW Leaving System[1]	Transition Adjustment		Schedule 200 - Base Supply[2,3]		Consumer Opt Out Charge
		(a)	(b)	(c)		(d)		(e)
		(a) = Sch Avg		(c) = (a)-(b)		(d) = Sch Avg		= 22.46-9.42
1	2019	$24.66	$25.46	($0.80)	-	$28.63	-	$13.04
2	2020	$23.47	$26.96	($3.49)	-	$29.38	-	$13.04
3	2021	$24.22	$29.19	($4.97)	-	$30.09	-	$13.04
4	2022	$24.83	$30.76	($5.93)	-	$30.78	-	$13.04
5	2023	$25.07	$31.74	($6.67)	-	$31.49	-	$13.04
6	2024	$26.20	$35.13	($8.93)		$31.45		
7	2025	$27.70	$39.57	($11.87)		$31.41		
8	2026	$27.55	$40.98	($13.43)		$31.37		
9	2027	$28.06	$43.78	($15.72)		$31.33		
10	2028	$30.80	$48.03	($17.23)		$31.29		
11	10-Year Net Present Value (1)			($38.74)		$92.33		$53.59
12	5-year Nominal Levelized Payment			($9.42)		$22.46		$13.04

Notes:
(1) 2019 through 2028 using a 6.91% Discount Rate.
(2) Losses at 8.01%

Data Sources:

1. For Schedule 201 (Cols. a & b), see Pacificorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

2. For Schedule 200 (Col. d), for 2019 - 2023, see PacifiCorp Response to Calpine Solutions DR No. 2.14 (Included in Calpine Solutions/103, Higgins/1-3).

3. For Schedule 200 (Col. d), for 2024 - 2028, the prior year value is reduced by Calpine Solutions' Annual Depreciation Impact percentage and escalated by PacifiCorp's annual inflation adjustment.

Docket No. UE 339

EXHIBIT

Calpine Solutions 106

Calpine Energy Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Calpine Energy Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Summary for Multiple Measurement Periods

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PacifiCorp Calculated Revenue Requirement ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49	31.15
Measurement Period: 2007-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	24.51	21.96	23.21	24.01	23.55	25.24	26.20	24.85	26.52
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	24.30	21.48	22.54	23.17	22.58	24.06	24.73	23.24	24.70
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	24.04	21.01	21.52	21.18	19.99	21.30	21.39	19.71	20.81
Measurement Period: 2008-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	23.37	24.60	25.37	24.82	26.46	27.41	26.07	27.79
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	23.08	24.11	24.70	24.01	25.44	26.10	24.62	26.13
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	22.91	23.38	23.01	21.70	22.94	23.01	21.34	22.50
Measurement Period: 2009-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	25.82	26.57	25.94	27.55	28.49	27.15	28.91
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	25.55	26.12	25.34	26.72	27.36	25.89	27.45
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	24.85	24.46	23.05	24.25	24.31	22.64	23.85
Measurement Period: 2010-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	26.85	26.20	27.80	28.73	27.40	29.17
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	26.50	25.69	27.06	27.70	26.23	27.80
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	25.66	24.18	25.33	25.38	23.72	24.97
Measurement Period: 2011-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	26.04	27.64	28.57	27.24	29.00
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	25.68	27.05	27.69	26.22	27.79
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	24.80	25.93	25.97	24.31	25.59

Calpine Energy Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Summary for Multiple Measurement Periods

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PacifiCorp Calculated Revenue Requirement ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49	31.15
Measurement Period: 2012-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	27.48	28.41	27.08	28.83
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	26.99	27.63	26.15	27.72
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	26.31	26.35	24.69	25.98
Measurement Period: 2013-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	28.25	26.91	28.67
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	27.53	26.06	27.62
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	26.18	24.53	25.81
Measurement Period: 2014-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	27.86	29.64
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	27.05	28.65
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	25.52	26.84
Measurement Period: 2015-2016											
Calpine Removal of Major Plant Capital Additions: Scenario 1 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49	29.46
Calpine Removal of Capital Additions <$1,000,000: Scenario 2 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49	28.56
Calpine Removal of Steam Plant Environmental Upgrades: Scenario 3 ($/MWh)	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49	26.89

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2007-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**
Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	(106,039,224)	(302,827,044)	(410,730,585)	(444,768,564)	(436,819,564)	(424,476,930)	(511,443,712)	(598,635,683)	(619,108,502)
Accumulated Depreciation	0	0	12,827,327	32,374,488	54,079,512	79,150,203	101,926,606	122,582,732	147,960,532	175,843,154	209,274,602
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	(93,211,897)	(270,452,556)	(356,651,074)	(365,618,361)	(334,892,959)	(301,894,199)	(363,483,180)	(422,792,528)	(409,833,901)
Return On Rate Base	0	0	(7,526,126)	(22,255,541)	(29,712,601)	(29,370,123)	(25,840,341)	(23,146,273)	(27,559,506)	(31,838,793)	(31,003,453)
Operating & Maintenance Expense											
Depreciation Expense	0	0	(12,827,327)	(19,865,909)	(23,216,345)	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	(2,026,265)	(5,991,876)	(7,999,546)	(7,907,341)	(6,957,015)	(6,231,689)	(7,419,867)	(8,571,983)	(8,347,083)
State Income Taxes	0	0	(275,336)	(814,196)	(1,087,005)	(1,074,476)	(945,343)	(846,783)	(1,008,237)	(1,164,790)	(1,134,230)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	(22,655,053)	(48,927,523)	(62,015,497)	(63,001,183)	(57,950,032)	(53,748,876)	(59,838,464)	(68,134,798)	(67,950,010)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	(1 48)	(3 32)	(4 25)	(4 37)	(3 99)	(3 69)	(4 06)	(4 63)	(4 62)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	376,009,345	323,084,849	338,355,693	345,834,533	342,309,936	367,328,707	386,326,542	365,391,978	390,003,087
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**24.51**	**21.96**	**23.21**	**24.01**	**23.55**	**25.24**	**26.20**	**24.85**	**26.52**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2007-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	(14,048,340)	(43,898,420)	(66,399,386)	(89,185,324)	(110,282,498)	(124,742,811)	(143,693,441)	(166,584,395)	(197,070,718)
Accumulated Depreciation	0	0	1,944,132	4,686,771	7,856,709	11,980,583	16,410,390	22,939,126	34,035,587	46,189,773	61,136,985
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	(12,104,208)	(39,211,648)	(58,542,678)	(77,204,741)	(93,872,108)	(101,803,684)	(109,657,854)	(120,394,622)	(135,933,733)
Return On Rate Base	0	0	(977,319)	(3,226,727)	(4,877,190)	(6,201,857)	(7,243,172)	(7,805,304)	(8,314,322)	(9,066,431)	(10,283,227)
Operating & Maintenance Expense											
Depreciation Expense	0	0	(1,944,132)	(2,790,949)	(3,388,727)	(4,062,646)	(4,646,400)	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	(263,124)	(868,734)	(1,313,090)	(1,669,731)	(1,950,085)	(2,101,428)	(2,238,471)	(2,440,962)	(2,768,561)
State Income Taxes	0	0	(35,754)	(118,047)	(178,427)	(226,889)	(264,984)	(285,549)	(304,171)	(331,686)	(376,201)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	(3,220,330)	(7,004,457)	(9,757,435)	(12,161,123)	(14,104,640)	(17,182,772)	(21,667,685)	(23,688,845)	(26,808,023)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	(0 21)	(0 48)	(0 67)	(0 84)	(0 97)	(1 18)	(1 47)	(1 61)	(1 82)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	372,789,015	316,080,392	328,598,258	333,673,410	328,205,296	350,145,935	364,658,857	341,703,132	363,195,063
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**24.30**	**21.48**	**22.54**	**23.17**	**22.58**	**24.06**	**24.73**	**23.24**	**24.70**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	(21,865,551)	(46,397,693)	(105,767,205)	(215,388,350)	(299,213,000)	(328,495,513)	(343,618,745)	(378,530,833)	(431,463,422)
Accumulated Depreciation	0	0	1,780,098	4,086,294	8,146,182	15,819,694	25,538,181	35,672,959	57,012,174	80,094,508	108,106,707
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	(20,085,453)	(42,311,399)	(97,621,023)	(199,568,656)	(273,674,820)	(292,822,555)	(286,606,571)	(298,436,325)	(323,356,715)
Return On Rate Base	0	0	(1,621,742)	(3,481,805)	(8,132,807)	(16,031,350)	(21,116,749)	(22,450,749)	(21,730,676)	(22,474,031)	(24,461,555)
Operating & Maintenance Expense											
Depreciation Expense	0	0	(1,780,096)	(2,350,429)	(4,250,647)	(7,610,028)	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	(436,623)	(937,409)	(2,189,602)	(4,316,133)	(5,685,279)	(6,044,432)	(5,850,567)	(6,050,701)	(6,585,803)
State Income Taxes	0	0	(59,330)	(127,378)	(297,531)	(586,491)	(772,535)	(821,338)	(794,995)	(822,190)	(894,901)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	(3,897,791)	(6,897,021)	(14,870,587)	(28,544,002)	(37,579,041)	(40,169,884)	(49,271,062)	(51,919,291)	(57,236,958)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	(0 25)	(0 47)	(1 02)	(1 98)	(2 58)	(2 76)	(3 34)	(3 53)	(3 89)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	368,891,224	309,183,371	313,727,672	305,129,408	290,626,255	309,976,051	315,387,795	289,783,841	305,958,105
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**24.04**	**21.01**	**21.52**	**21.18**	**19.99**	**21.30**	**21.39**	**19.71**	**20.81**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2008-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**
Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	(96,018,561)	(213,576,430)	(246,077,963)	(241,721,026)	(234,868,064)	(319,472,993)	(404,947,936)	(418,849,101)
Accumulated Depreciation	0	0	0	19,865,909	42,154,864	67,132,625	90,126,290	111,114,452	136,349,399	164,128,168	197,162,137
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	(76,152,652)	(171,421,566)	(178,945,338)	(151,594,737)	(123,753,612)	(183,123,594)	(240,819,768)	(221,686,965)
Return On Rate Base	0	0	0	(6,266,602)	(14,281,131)	(14,374,679)	(11,697,050)	(9,488,208)	(13,884,537)	(18,135,162)	(16,770,358)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	(19,865,909)	(23,216,345)	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	(1,687,162)	(3,844,920)	(3,870,106)	(3,149,206)	(2,554,518)	(3,738,145)	(4,882,544)	(4,515,096)
State Income Taxes	0	0	0	(229,257)	(522,461)	(525,883)	(427,925)	(347,117)	(507,952)	(663,457)	(613,527)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	(28,048,930)	(41,864,856)	(43,419,911)	(39,481,514)	(35,913,973)	(41,981,489)	(50,240,393)	(49,364,225)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	(1 91)	(2 87)	(3 01)	(2 72)	(2 47)	(2 85)	(3 42)	(3 36)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	343,963,442	358,506,335	365,415,805	360,778,454	385,163,610	404,183,518	383,286,382	408,588,872
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**23.37**	**24.60**	**25.37**	**24.82**	**26.46**	**27.41**	**26.07**	**27.79**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2008-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	(16,499,918)	(40,279,914)	(62,862,300)	(84,435,358)	(99,622,957)	(118,260,683)	(140,924,161)	(170,539,855)
Accumulated Depreciation	0	0	0	2,790,949	6,049,388	10,159,178	14,621,913	21,200,974	32,275,783	44,414,230	59,301,199
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	(13,708,968)	(34,230,525)	(52,703,121)	(69,813,445)	(78,421,983)	(85,984,900)	(96,509,931)	(111,238,655)
Return On Rate Base	0	0	0	(1,128,111)	(2,851,745)	(4,233,642)	(5,386,805)	(6,012,625)	(6,519,425)	(7,267,772)	(8,415,074)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	(2,790,949)	(3,388,727)	(4,062,646)	(4,646,400)	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	(303,722)	(767,778)	(1,139,827)	(1,450,294)	(1,618,784)	(1,755,230)	(1,956,708)	(2,265,597)
State Income Taxes	0	0	0	(41,271)	(104,328)	(154,884)	(197,071)	(219,966)	(238,507)	(265,884)	(307,857)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	(4,264,053)	(7,112,578)	(9,590,998)	(11,680,570)	(14,841,866)	(19,323,882)	(21,340,129)	(24,368,561)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	(0 29)	(0 49)	(0 67)	(0 80)	(1 02)	(1 31)	(1 45)	(1 66)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	339,699,388	351,393,756	355,824,807	349,097,884	370,321,744	384,859,636	361,946,253	384,220,311
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**23.08**	**24.11**	**24.70**	**24.01**	**25.44**	**26.10**	**24.62**	**26.13**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	(3,753,270)	(65,113,529)	(174,417,855)	(258,983,198)	(289,397,695)	(304,033,907)	(338,591,939)	(390,169,436)
Accumulated Depreciation	0	0	0	2,350,430	6,491,353	14,151,968	23,900,605	34,081,461	55,400,852	78,468,774	106,425,813
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	(1,402,841)	(58,622,176)	(160,265,887)	(235,082,593)	(255,316,234)	(248,633,055)	(260,123,165)	(283,743,623)
Return On Rate Base	0	0	0	(115,440)	(4,883,814)	(12,874,159)	(18,138,973)	(19,575,134)	(18,851,502)	(19,588,822)	(21,464,872)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	(2,350,429)	(4,250,647)	(7,610,028)	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	(31,080)	(1,314,873)	(3,466,120)	(4,883,570)	(5,270,228)	(5,075,405)	(5,273,914)	(5,779,004)
State Income Taxes	0	0	0	(4,223)	(178,669)	(470,988)	(663,596)	(716,136)	(689,663)	(716,637)	(785,271)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	(2,501,172)	(10,628,003)	(24,421,295)	(33,690,617)	(36,414,863)	(45,511,394)	(48,151,743)	(53,323,844)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	(0 17)	(0 73)	(1 70)	(2 32)	(2 50)	(3 09)	(3 28)	(3 63)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	337,198,216	340,765,754	331,403,512	315,407,267	333,906,881	339,348,242	313,794,510	330,896,467
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**22.91**	**23.38**	**23.01**	**21.70**	**22.94**	**23.01**	**21.34**	**22.50**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2009-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**

Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	(30,504,073)	(61,578,901)	(60,557,463)	(58,802,071)	(141,213,843)	(225,094,398)	(232,893,291)
Accumulated Depreciation	0	0	0	0	23,216,345	48,046,515	71,385,232	92,900,729	117,908,797	145,522,630	177,925,329
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	(7,287,729)	(13,532,386)	10,827,768	34,098,658	(23,305,046)	(79,571,768)	(54,967,962)
Return On Rate Base	0	0	0	0	(607,141)	(1,087,057)	835,471	2,614,349	(1,767,002)	(5,992,228)	(4,158,262)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	(23,216,345)	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	(163,461)	(292,669)	224,934	703,863	(475,731)	(1,613,292)	(1,119,532)
State Income Taxes	0	0	0	0	(22,212)	(39,769)	30,565	95,643	(64,644)	(219,220)	(152,126)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	(24,009,158)	(26,068,737)	(23,116,364)	(20,110,275)	(26,158,233)	(34,383,971)	(32,895,164)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	(1 65)	(1 81)	(1 59)	(1 38)	(1 77)	(2 34)	(2 24)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	376,362,033	382,766,978	377,143,604	400,967,307	420,006,774	399,142,805	425,057,933
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**25.82**	**26.57**	**25.94**	**27.55**	**28.49**	**27.15**	**28.91**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2009-2016

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Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	(8,820,592)	(31,157,811)	(53,304,045)	(69,367,615)	(87,628,467)	(110,017,964)	(138,585,037)
Accumulated Depreciation	0	0	0	0	3,388,727	7,477,782	11,988,994	18,642,139	29,685,074	41,800,349	56,598,632
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	(5,431,864)	(23,680,029)	(41,315,052)	(50,725,476)	(57,943,392)	(68,217,614)	(81,986,406)
Return On Rate Base	0	0	0	0	(452,529)	(1,902,217)	(3,187,869)	(3,889,130)	(4,393,302)	(5,137,192)	(6,202,175)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	(3,388,727)	(4,062,646)	(4,646,400)	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	(121,835)	(512,135)	(858,273)	(1,047,073)	(1,182,812)	(1,383,090)	(1,669,816)
State Income Taxes	0	0	0	0	(16,555)	(69,591)	(116,625)	(142,280)	(160,725)	(187,939)	(226,900)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	(3,979,646)	(6,546,589)	(8,809,166)	(12,068,974)	(16,547,559)	(18,557,987)	(21,478,926)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	(0 27)	(0 45)	(0 61)	(0 83)	(1 12)	(1 26)	(1 46)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	372,382,387	376,220,389	368,334,437	388,898,333	403,459,215	380,584,818	403,579,008
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**25.55**	**26.12**	**25.34**	**26.72**	**27.36**	**25.89**	**27.45**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	(57,957,412)	(167,205,969)	(251,901,693)	(282,515,449)	(297,065,933)	(331,561,642)	(382,900,608)
Accumulated Depreciation	0	0	0	0	4,250,647	11,893,800	21,683,262	31,926,509	53,219,057	76,267,464	104,149,815
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	(53,706,765)	(155,312,169)	(230,218,432)	(250,588,940)	(243,846,876)	(255,294,178)	(278,750,793)
Return On Rate Base	0	0	0	0	(4,474,311)	(12,476,227)	(17,763,654)	(19,212,691)	(18,488,612)	(19,225,171)	(21,087,170)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	(4,250,647)	(7,610,028)	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	(1,204,622)	(3,358,984)	(4,782,522)	(5,172,648)	(4,977,703)	(5,176,008)	(5,677,315)
State Income Taxes	0	0	0	0	(163,688)	(456,430)	(649,865)	(702,877)	(676,387)	(703,333)	(771,453)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	(10,093,268)	(23,901,669)	(33,200,520)	(35,941,581)	(45,037,526)	(47,676,882)	(52,830,635)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	(0 69)	(1 66)	(2 28)	(2 47)	(3 05)	(3 24)	(3 59)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	362,289,119	352,318,720	335,133,917	352,956,753	358,421,689	332,907,936	350,748,372
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**24.85**	**24.46**	**23.05**	**24.25**	**24.31**	**22.64**	**23.85**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2010-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**
Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	(95,311)	(185,415)	(128,768)	(81,809,679)	(165,158,911)	(170,924,245)
Accumulated Depreciation	0	0	0	0	0	24,649,243	48,410,951	70,572,897	95,302,840	122,714,481	154,343,319
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	24,553,932	48,225,536	70,444,129	13,493,161	(42,444,430)	(16,580,927)
Return On Rate Base	0	0	0	0	0	1,972,417	3,721,082	5,400,962	1,023,059	(3,196,318)	(1,254,328)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	531,035	1,001,830	1,454,105	275,439	(860,547)	(337,704)
State Income Taxes	0	0	0	0	0	72,159	136,132	197,589	37,428	(116,934)	(45,888)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	(22,073,631)	(19,348,290)	(16,471,475)	(22,514,929)	(30,733,031)	(29,103,163)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	(1 53)	(1 33)	(1 13)	(1 53)	(2 09)	(1 98)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	386,762,084	380,911,678	404,606,108	423,650,077	402,793,744	428,849,934
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**26.85**	**26.20**	**27.80**	**28.73**	**27.40**	**29.17**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2010-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross Plant in Service	0	0	0	0	0	(13,379,148)	(35,846,797)	(52,401,577)	(70,451,093)	(92,686,951)	(120,665,999)
Accumulated Depreciation	0	0	0	0	0	4,062,646	8,635,599	15,383,102	26,385,441	38,471,203	53,156,531
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	(9,316,502)	(27,211,198)	(37,018,475)	(44,065,652)	(54,215,748)	(67,509,468)
Return On Rate Base	0	0	0	0	0	(748,395)	(2,099,616)	(2,838,212)	(3,341,083)	(4,082,768)	(5,107,012)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	(4,062,646)	(4,646,400)	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	(201,491)	(565,281)	(764,134)	(899,522)	(1,099,207)	(1,374,965)
State Income Taxes	0	0	0	0	0	(27,379)	(76,812)	(103,833)	(122,230)	(149,364)	(186,835)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	(5,039,911)	(7,388,109)	(10,696,670)	(15,173,556)	(17,181,105)	(20,048,845)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	(0 35)	(0 51)	(0 73)	(1 03)	(1 17)	(1 36)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	381,722,173	373,523,569	393,909,437	408,476,521	385,612,640	408,801,088
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**26.50**	**25.69**	**27.06**	**27.70**	**26.23**	**27.80**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross Plant in Service	0	0	0	0	0	(50,387,807)	(137,195,449)	(171,036,803)	(184,198,658)	(217,684,858)	(265,160,085)
Accumulated Depreciation	0	0	0	0	0	7,610,027	17,476,934	27,838,539	49,080,165	72,091,553	99,832,219
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	(42,777,780)	(119,718,515)	(143,198,264)	(135,118,493)	(145,593,305)	(165,327,866)
Return On Rate Base	0	0	0	0	0	(3,436,339)	(9,237,481)	(10,979,032)	(10,244,763)	(10,964,042)	(12,506,859)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	(7,610,028)	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	(925,168)	(2,487,014)	(2,955,893)	(2,758,205)	(2,951,858)	(3,367,231)
State Income Taxes	0	0	0	0	0	(125,715)	(337,944)	(401,657)	(374,794)	(401,108)	(457,551)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	(12,097,251)	(22,066,917)	(25,189,947)	(34,272,586)	(36,889,378)	(41,626,338)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	(0 84)	(1 52)	(1 73)	(2 32)	(2 51)	(2 83)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	369,624,923	351,456,652	368,719,490	374,203,935	348,723,262	367,174,750
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scanerio 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**25.66**	**24.18**	**25.33**	**25.38**	**23.72**	**24.97**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2011-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**
Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	1,761	53,141	(81,625,504)	(164,973,088)	(170,732,118)
Accumulated Depreciation	0	0	0	0	0	0	24,207,334	47,050,320	71,487,256	98,685,884	129,499,453
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	24,209,095	47,103,461	(10,138,249)	(66,287,204)	(41,232,665)
Return On Rate Base	0	0	0	0	0	0	1,867,974	3,611,429	(768,688)	(4,991,821)	(3,119,203)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	502,916	972,308	(206,954)	(1,343,952)	(839,785)
State Income Taxes	0	0	0	0	0	0	68,338	132,120	(28,122)	(182,621)	(114,113)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	(21,768,106)	(18,808,273)	(24,854,619)	(33,077,625)	(31,538,345)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	(1 50)	(1 29)	(1 69)	(2 25)	(2 14)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	378,491,862	402,269,310	421,310,387	400,449,150	426,414,752
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**26.04**	**27.64**	**28.57**	**27.24**	**29.00**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2011-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	(9,572,255)	(26,866,347)	(44,597,785)	(66,602,406)	(93,696,428)
Accumulated Depreciation	0	0	0	0	0	0	4,646,400	11,506,150	22,460,197	34,510,851	49,061,807
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	(4,925,856)	(15,360,197)	(22,137,588)	(32,091,555)	(44,634,621)
Return On Rate Base	0	0	0	0	0	0	(380,079)	(1,177,669)	(1,678,485)	(2,416,685)	(3,376,557)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	(4,646,400)	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	(102,329)	(317,065)	(451,900)	(650,646)	(909,073)
State Income Taxes	0	0	0	0	0	0	(13,905)	(43,084)	(61,406)	(88,412)	(123,528)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	(5,142,712)	(8,528,308)	(13,002,511)	(15,005,508)	(17,789,191)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	(0 35)	(0 59)	(0 88)	(1 02)	(1 21)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	373,349,149	393,741,002	408,307,877	385,443,642	408,625,561
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**25.68**	**27.05**	**27.69**	**26.22**	**27.79**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	(38,241,725)	(74,867,433)	(86,831,360)	(119,446,686)	(163,588,778)
Accumulated Depreciation	0	0	0	0	0	0	10,004,486	20,576,350	41,727,515	64,673,140	92,162,105
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	(28,237,239)	(54,291,083)	(45,103,844)	(54,773,546)	(71,426,673)
Return On Rate Base	0	0	0	0	0	0	(2,178,785)	(4,162,505)	(3,419,800)	(4,124,774)	(5,403,344)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	(10,004,478)	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	(586,596)	(1,120,675)	(920,715)	(1,110,516)	(1,454,746)
State Income Taxes	0	0	0	0	0	0	(79,709)	(152,281)	(125,110)	(150,901)	(197,676)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	(12,849,568)	(16,288,826)	(25,360,449)	(27,958,560)	(32,350,464)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	(0 88)	(1 12)	(1 72)	(1 90)	(2 20)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	360,499,581	377,452,176	382,947,428	357,485,082	376,275,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**24.80**	**25.93**	**25.97**	**24.31**	**25.59**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2012-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**

Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	49,718	(81,628,969)	(164,976,584)	(170,735,733)
Accumulated Depreciation	0	0	0	0	0	0	0	23,524,131	47,668,013	74,653,598	104,651,772
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	23,573,850	(33,960,956)	(90,322,987)	(66,083,960)
Return On Rate Base	0	0	0	0	0	0	0	1,807,411	(2,574,939)	(6,801,858)	(4,999,174)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	486,611	(693,253)	(1,831,270)	(1,345,931)
State Income Taxes	0	0	0	0	0	0	0	66,122	(94,202)	(248,839)	(182,890)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	(21,163,988)	(27,213,249)	(35,441,198)	(33,993,239)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 45)	(1 85)	(2 41)	(2 31)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	399,913,595	418,951,758	398,085,577	423,959,858
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**27.48**	**28.41**	**27.08**	**28.83**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2012-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	(8,260,524)	(25,760,199)	(47,596,332)	(74,045,495)
Accumulated Depreciation	0	0	0	0	0	0	0	6,990,491	17,888,288	29,898,050	44,292,498
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	(1,270,033)	(7,871,910)	(17,698,282)	(29,752,997)
Return On Rate Base	0	0	0	0	0	0	0	(97,374)	(596,853)	(1,332,786)	(2,250,779)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	(6,990,491)	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	(26,216)	(160,691)	(358,827)	(605,979)
State Income Taxes	0	0	0	0	0	0	0	(3,562)	(21,835)	(48,759)	(82,342)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	(7,117,643)	(11,590,100)	(13,590,137)	(16,319,134)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(0 49)	(0 79)	(0 92)	(1 11)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	392,795,952	407,361,658	384,495,440	407,640,723
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**26.99**	**27.63**	**26.15**	**27.72**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	(536,070)	(11,574,093)	(43,516,301)	(85,082,142)
Accumulated Depreciation	0	0	0	0	0	0	0	10,853,370	31,883,422	54,740,998	81,892,975
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	10,317,299	20,309,329	11,224,697	(3,189,168)
Return On Rate Base	0	0	0	0	0	0	0	791,029	1,539,865	845,286	(241,257)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	(10,853,365)	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	212,969	414,579	227,577	(64,954)
State Income Taxes	0	0	0	0	0	0	0	28,939	56,334	30,924	(8,826)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	(9,820,427)	(18,884,046)	(21,468,582)	(25,609,734)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(0 67)	(1 28)	(1 46)	(1 74)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	382,975,525	388,477,612	363,026,858	382,030,989
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**26.31**	**26.35**	**24.69**	**25.98**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2013-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**

Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross Plant in Service	0	0	0	0	0	0	0	0	(81,729,645)	(165,078,160)	(170,840,755)
Accumulated Depreciation	0	0	0	0	0	0	0	0	23,850,855	50,623,414	79,806,265
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	(57,878,789)	(114,454,747)	(91,034,490)
Return On Rate Base	0	0	0	0	0	0	0	0	(4,388,403)	(8,619,124)	(6,886,652)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	(23,850,855)	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	(1,181,493)	(2,320,533)	(1,854,099)
State Income Taxes	0	0	0	0	0	0	0	0	(160,545)	(315,322)	(251,941)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	(29,581,297)	(37,814,210)	(36,457,936)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(2 01)	(2 57)	(2 48)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	416,583,709	395,712,565	421,495,161
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**28.25**	**26.91**	**28.67**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2013-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	(9,033,357)	(30,719,883)	(56,596,443)
Accumulated Depreciation	0	0	0	0	0	0	0	0	10,810,721	22,757,179	36,909,344
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	1,777,363	(7,962,704)	(19,687,099)
Return On Rate Base	0	0	0	0	0	0	0	0	134,761	(599,639)	(1,489,306)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	(10,810,721)	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	36,282	(161,441)	(400,967)
State Income Taxes	0	0	0	0	0	0	0	0	4,930	(21,937)	(54,485)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	(10,634,748)	(12,632,783)	(15,324,791)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(0 72)	(0 86)	(1 04)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	405,948,961	383,079,783	406,170,370
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**27.53**	**26.06**	**27.62**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	(10,488,597)	(42,421,097)	(83,949,778)
Accumulated Depreciation	0	0	0	0	0	0	0	0	20,894,857	43,654,150	70,429,959
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	10,406,261	1,233,053	(13,519,819)
Return On Rate Base	0	0	0	0	0	0	0	0	789,009	92,856	(1,022,758)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	(20,894,824)	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	212,425	25,000	(275,358)
State Income Taxes	0	0	0	0	0	0	0	0	28,865	3,397	(37,417)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	(19,864,525)	(22,451,117)	(26,630,231)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 35)	(1 53)	(1 81)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	386,084,436	360,628,666	379,540,139
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**26.18**	**24.53**	**25.81**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2014-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**
Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross Plant in Service	0	0	0	0	0	0	0	0	0	(156,856)	(323,817)
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	26,559,231	54,925,607
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	26,402,375	54,601,790
Return On Rate Base	0	0	0	0	0	0	0	0	0	1,988,256	4,130,561
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	(26,559,231)	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	535,300	1,112,074
State Income Taxes	0	0	0	0	0	0	0	0	0	72,738	151,112
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	(23,962,937)	(22,071,496)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 63)	(1 50)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	409,563,838	435,881,601
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**27.86**	**29.64**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2014-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	0	(12,491,575)	(37,749,665)
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	11,849,765	25,631,851
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	(641,810)	(12,117,814)
Return On Rate Base	0	0	0	0	0	0	0	0	0	(48,332)	(916,698)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	(11,849,765)	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	(13,012)	(246,803)
State Income Taxes	0	0	0	0	0	0	0	0	0	(1,768)	(33,536)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	(11,912,878)	(14,577,072)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(0 81)	(0 99)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	397,650,960	421,304,529
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**27.05**	**28.65**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	0	(21,256,279)	(62,066,857)
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	22,572,404	48,632,929
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	1,316,126	(13,433,928)
Return On Rate Base	0	0	0	0	0	0	0	0	0	99,112	(1,016,261)
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	(22,572,370)	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	26,684	(273,609)
State Income Taxes	0	0	0	0	0	0	0	0	0	3,626	(37,179)
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	(22,442,948)	(26,621,746)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 53)	(1 81)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	375,208,012	394,682,783
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**25.52**	**26.84**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2015-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**

Scenario 1: Calpine Removal of Major Plant Capital Additions:[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Gross Plant in Service	0	0	0	0	0	0	0	0	0	0	540
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	27,465,244
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	0	27,465,784
Return On Rate Base	0	0	0	0	0	0	0	0	0	0	2,077,754
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	0	(27,465,244)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	0	559,395
State Income Taxes	0	0	0	0	0	0	0	0	0	0	76,013
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	0	(24,752,082)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 68)
Revenue Requirement excl Major Plant Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	433,201,015
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 1 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**29.46**

Calpine Solutions Adjustments to PacifiCorp Fixed Generation Revenue Requirement

Measurement Period: 2015-2016

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

Scenario 2: Calpine Removal of Capital Additions <$1,000,000:[2]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	0	0	(11,918,858)
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	13,380,034
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	0	1,461,176
Return On Rate Base	0	0	0	0	0	0	0	0	0	0	110,536
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	0	(13,380,034)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	0	29,760
State Income Taxes	0	0	0	0	0	0	0	0	0	0	4,044
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	0	(13,235,694)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(0 90)
Revenue Requirement excl Major Plant & <$1M Additions ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	419,965,321
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 2 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**28.56**

Scenario 3: Calpine Removal of Steam Plant Environmental Upgrades:[3]	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Gross Plant in Service	0	0	0	0	0	0	0	0	0	0	(18,111,886)
Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	25,294,663
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Rate Base	0	0	0	0	0	0	0	0	0	0	7,182,777
Return On Rate Base	0	0	0	0	0	0	0	0	0	0	543,369
Operating & Maintenance Expense											
Depreciation Expense	0	0	0	0	0	0	0	0	0	0	(25,294,698)
Amortization Expense											
Taxes Other Than Income											
Federal Income Taxes	0	0	0	0	0	0	0	0	0	0	146,292
State Income Taxes	0	0	0	0	0	0	0	0	0	0	19,879
Deferred Income Taxes											
Misc Revenue & Expenses											
Revenue Credits											
Revenue Requirement ($)	0	0	0	0	0	0	0	0	0	0	(24,585,159)
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Revenue Requirement ($/MWh)	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	(1 67)
Rev Req excl Major & Minor Plant Adds & Env Upgrades ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	395,380,163
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821
Scenario 3 ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**26.89**

Notes: 1. NA = Data not available at the time of filing.
2. Federal and state income tax calculation assumes 50%/50% debt and equity capital structure components

Data Sources:
1. PacifiCorp Exhibit 110 workpaper.
2. PacifiCorp Response to Calpine Solutions Data Request Nos. 1.9 & 3.17.
3. PacifiCorp Response to Calpine Solutions Data Request No. 1.7 CONFIDENTIAL.