BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-144160 DECLARATION OF JEREMY B. TWITCHELL

Jeremy B. Twitchell declares:

1. My name is Jeremy B. Twitchell, and I am a regulatory analyst at the Washington Utilities and Transportation Commission (Commission). My business address is 1300 Evergreen Park Drive SW, Olympia, Washington 98504.

2. I am over the age of twenty-one, have personal knowledge of the facts set forth herein, and am competent to testify to those facts.

3. I have been employed by the Commission since June 2013. I hold a master's degree in public administration with a concentration in energy, environment and technology policy from Texas A&M University and a bachelor's degree in communications, with an emphasis in print journalism, from Brigham Young University. I have testified before the Commission as a cost of service witness in Docket UE-140762 and led the development of the Commission's rule for the implementation of Washington's renewable portfolio standard.

4. The purpose of this declaration is to present the response of Commission staff (Staff) to the declaration of Brian S. Dickman in support of the Schedule 37 tariff filing of Pacific Power & Light Company (Pacific Power or Company). My declaration responds to the Company's primary and alternate proposals for the structuring of Schedule 37 rates, presents

Staff's proposed rate structure, and recommends that the Commission order the Company to address remaining issues in its next Schedule 37 tariff filing.

5. Specifically, Staff accepts Pacific Power's proposed energy payments, but opposes the Company's proposal to eliminate capacity payments to qualifying facilities. The Company's reliance on market purchases throughout the planning period demonstrates that it is capacity deficient. The Company also undervalues the market risk that qualifying facilities help it to avoid; Staff recommends that the Commission order the Company to address this deficiency in its subsequent Schedule 37 tariff filings.

A. Background

6. Congress enacted the Public Utilities Regulatory Policies Act (PURPA) to encourage the development of cogeneration and small power production facilities—known as qualifying facilities (QFs)—by creating a market for the power they produce and by exempting them from certain state and federal laws governing electric utilities.[1] PURPA is executed jointly by federal and state utility regulators: Congress directed the Federal Energy Regulatory Commission (FERC) to establish rules necessary to encourage QF power production, and tasked state utility commissions with implementing FERC's rules.[2]

7. PURPA requires electric utilities to purchase electricity offered by QFs at rates that are just and reasonable to electric customers, that do not discriminate against QFs, and that equal the utility's full avoided cost—that is, the cost that the utility avoids by not having to generate itself or purchase electricity from another source.[3] Avoided cost rates implement a

[1] *FERC v. Mississippi*, 456 U.S. 742, 751 (1982).
[2] 16 U.S.C. § 824a-3(a), (f).
[3] 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.302(b); 18 C.F.R. § 292.101(6).

policy of ratepayer neutrality under which the utility and its customers are protected from shouldering QF costs that exceed the utility's own service costs.

8. FERC regulations further require utilities to maintain a schedule of their avoided costs for energy and capacity on file with their state regulatory authority, and to provide regular updates to that schedule.[4] The Commission has adopted rules that require utilities to update their avoided cost schedule at least once per year,[5] and to file a standard tariff for purchases from small QFs.[6]

9. Pacific Power addresses both of these requirements with a single tariff, Schedule 37, that the Company updates every year to serve both as its avoided cost schedule and as its standard offer tariff for small QFs. The tariff creates a standard offer contract, with a five-year term, that is available to QFs of two megawatts (MW) or fewer. Since the Company only files a standard offer tariff, and not a separate avoided cost schedule, the rates in Schedule 37 also serve as the template for negotiations with larger QFs.

10. Pacific Power initiated this docket on December 29, 2014, when it filed an update to Schedule 37 that made three changes to the schedule's rates:

- New energy payments based on updated market price projections;
- A change in the way capacity payments are determined that would eliminate them for the duration of any contract entered into before 2019; and
- Imposition of an integration charge for wind and solar facilities.

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[4] 18 C.F.R. § 292.302(b).
[5] WAC 480-107-055(1).
[6] WAC 480-107-095(2).

11. At the February 12, 2015, Open Meeting, Staff expressed concerns with the Company's proposal and recommended that the Commission suspend the filing.[7] The Commission accepted this recommendation and issued a suspension order.[8]

12. In the process of settlement negotiations, the Company agreed to withdraw its proposal to assess an integration charge on wind and solar facilities.[9] The parties were unable to negotiate a resolution on the matters of capacity payments and the overall rates.

B. Resource Sufficiency

13. The fundamental point of disagreement between the Company and Staff is whether the Company is in a period of resource sufficiency, and should therefore be permitted to forego providing capacity payments to QFs. FERC regulations obligate a utility to purchase the energy and capacity output of a QF within its service territory at the utility's avoided cost, which FERC defines as:

> The incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[10]

14. FERC's rules lists a number of factors for state utility commissions to consider in setting avoided cost rates, including the utility's planned capacity acquisitions for the next ten years.[11] Pacific Power argues that since it does not plan to build another thermal resource until 2027, which is beyond this ten-year planning horizon, the Company is in a period of resource

[7] *UTC v. PacifiCorp*, Docket UE-144160, Staff Open Meeting Memo (Feb. 12, 2015).
[8] *UTC v. PacifiCorp*, Docket UE-144160, Order 01 (Feb. 12, 2015).
[9] *UTC v. PacifiCorp*, Docket UE-144160, Letter from R. Bryce Dalley (May 1, 2015).
[10] 18 C.F.R. § 292.101(b)(6).
[11] 18 C.F.R. § 292.302(e).

sufficiency, and therefore should not be required to include any value for capacity in its avoided cost rate.[12]

15. Mr. Dickman defines a period of resource deficiency—which would necessitate capacity payments—as one in which a new base load thermal generator is needed within the ten-year planning horizon.[13] According to the Company's 2013 Integrated Resource Plan (IRP) Update, the next base load thermal generator will be needed in 2027.[14] Subsequent to the Company's initial filing in this docket, the Company filed its 2015 IRP, which identifies the next major resource addition in 2028.[15] In the interest of using the Company's most current needs assessment, my declaration will refer to the 2015 IRP.

16. Though the Company's capacity acquisition strategy presented in the 2015 IRP does not select a new, Company-built resource until 2028, it does call for the annual acquisition of significant amounts of capacity from market resources. In the ten-year period from 2015 to 2024, the Company's plan calls for an average annual procurement of 843 megawatts of capacity through market purchases, which the Company calls front-office transactions (FOTs).[16] For comparison, Pacific Power's average annual procurement of capacity from FOTs (843 megawatts) is nearly double the capacity of the resource that the Company plans to put into service in 2028 (423 megawatts).[17] Pacific Power relies heavily on FOTs to meet its capacity needs.

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[12] *UTC v. PacifiCorp*, Docket UE-144160, Declaration of Brian S. Dickman ¶ 6 (June 12, 2015).
[13] *Id.* at ¶ 7.
[14] *In the Matter of PacifiCorp 2013 Integrated Resource Plan*, Docket UE-120416, PacifiCorp 2013 IRP Update, Volume I at 54.
[15] *In the Matter of PacifiCorp 2015 Integrated Resource Plan,* Docket UE-140546, PacifiCorp 2015 IRP, Volume I at 196.
[16] *Id.*
[17] *Id.*

17. Pacific Power defines FOTs as "proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis *to help the Company cover short positions*."[18] FOTs represent future, potential contracts into which Pacific Power has not yet entered. As long as the Company's plan to meet its ongoing capacity obligations calls for it to make annual market purchases, then the Company is, by definition, resource deficient.

18. FERC has established that avoided cost rates properly include a value for capacity whenever the QF reduces the utility's need for future market purchases:

> If [a QF] demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.[19]

19. Pacific Power can still avoid FOTs because FOTs are future market purchases that the Company anticipates making, but has not yet made. Any QF that enters Pacific Power's system prior to a future market purchase will reduce the amount of capacity that the Company needs to acquire, and must be compensated appropriately for those avoided capacity costs. The Commission should not allow the Company to rely on the market as a means of shedding its obligation to pay QFs for the capacity that they provide to the Company.

20. Current and future QFs also enable the Company to avoid capacity costs associated with the Company's projected 2028 thermal resource. Pacific Power's 2015 IRP assumes that all QFs on its system will renew their contracts and remain on the Company's system for the duration of the 20-year planning period.[20] Existing QFs therefore impact the size

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[18] *Id.* at 128 (Emphasis added).

[19] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public utility Regulatory Policy Act of* 1978, Order No. 69, 45 Fed. Reg. 12,214, 12225 (Feb. 25, 1980); See also 45 Fed. Reg. 12,214, 12225-6).

[20] *In the Matter of PacifiCorp 2015 Integrated Resource Plan,* Docket UE-140546, PacifiCorp 2015 IRP, Volume I at 75.

and timing of the next thermal resource, despite the resource lying outside the ten-year window of the avoided cost analysis. Any new QF that comes onto the Company's system would be included in subsequent IRPs and similarly impact the timing and size of future thermal resource construction.

21. PURPA prohibits avoided cost rates that discriminate against QFs.[21] A rate that fails to compensate a QF for the capacity that it provides to Pacific Power—capacity around which the Company makes its long-term plans—is discriminatory. Pacific Power relies heavily on future FOTs to meet its capacity needs. By purchasing power from QFs, the Company can avoided some of these future market purchases. Pacific Power's avoided cost rate must compensate QFs for the value of avoided FOTs.

C. Company Proposal

22. Pacific Power proposes to pay QFs for only the energy that they provide to the Company's system. To calculate this payment, the Company runs two iterations of its Generation and Regulation Initiative Decision (GRID) model: one with the Company's system as it is, and another with a generic QF resource that generates 50 average MW (aMW). The difference in cost of the two portfolios is the avoided cost that is paid to QFs.[22] Mr. Dickman testified that virtually all of the avoided costs captured in this analysis are the result of avoided FOTs.[23]

23. Pacific Power also proposes to limit when it provides capacity payments to QFs. The Company proposes to make capacity payments based on the fixed costs of a combined cycle combustion turbine (CCCT) *only when* its resource acquisition plan calls for a new thermal resource within the next ten years.[24] This is a departure from the Company's current practice,

[21] 18 C.F.R. § 292.304(a)(1)(ii).
[22] *WUTC v. PacifiCorp,* Docket UE-144160, Declaration of Brian S. Dickman ¶ 4 (June 12, 2015).
[23] *Id.* ¶ 12.
[24] *Id.* ¶ 7.

which calculates avoided capacity payments based on a simple cycle combustion turbine (SCCT), but prorates the unit's costs to just 25 percent on the assumption that the Company would only incur capacity costs to meet its needs during the three peak months of the year.[25]

24. Mr. Dickman's testimony also includes an alternate proposal that was not part of the Company's original filing. Like its primary proposal, the Company would compensate QFs for only their energy output. However, it would pay different energy rates based on when the energy is produced—a higher rate during heavy load hours, and a lower rate during light load hours.[26] The blended rate in the Company's primary proposal is a weighted average of the heavy load hour and light load hour rates.

D. Market Risk

25. The Company's wholesale energy price forecasts do not fully capture the costs that the Company avoids when it purchases power under contract from a QF rather than through FOTs. The selection of FOTs is based on a projection of future market prices—a projection that will change based on hydropower availability, unplanned generator outages, and changing demand throughout the Western U.S. Unanticipated variations in any one of those factors could create higher market prices, as the California energy crisis showed, which represents a significant risk to Pacific Power.

26. The Northwest Power and Conservation Council (Council), the body tasked with planning for the region's long-term energy needs, has specifically cautioned against calculating avoided costs based solely on wholesale market projections as Pacific Power has done, stating that "[a wholesale] price forecast may not be a suitable stand-alone measure of avoided resource

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[25] *Id.* ¶ 6.
[26] *Id.* ¶ 16.

costs."[27] The Council goes on to state that when it uses market price projections as a metric for avoided costs, it adjusts them to include a risk premium.[28]

27. The Council's avoided cost calculations are done in the context of energy efficiency measures, but its approach is relevant in the context of QFs as well. Both QFs and energy efficiency measures increase the amount of energy and capacity available to the utility at a known price, and reduce the utility's need for future market purchases at an unknown, variable price.

28. In its Sixth Power Plan, the Council tested a wide range of risk premiums to find the cost-effectiveness limit of conservation measures, from $10 per megawatt-hour (MWh) to $80 per MWh.[29] Additionally, the Pacific Northwest Electric Power Planning and Conservation Act mandates a 10 percent credit to conservation resources.[30]

29. I have conducted an in-depth review of the Council's approach to quantifying market risk, but lacked the tools to identify a definitive quantification of market risk in terms of dollars per MWh. The difficulty of this task is exacerbated by the fact that the risk will be different for every utility because the cost of the market risk that a company faces is dependent on the timing and size of that company's projected market reliance.

30. Quantifying the market risk that a utility faces, and could avoid through QF contracts, requires access to regional power planning software that Staff does not possess. It is also a larger issue that could affect the avoided cost calculations of all three of Washington's investor-owned utilities, and a process into which all three utilities should have input. Therefore,

[27] Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan, Council Document 2010-09, at Appendix D-22 (2010).
[28] *Id.* at Appendix D-23.
[29] *Id.* at Appendix E-5.
[30] 16 U.S.C. § 839a(4)(D).

on the matter of quantifying a utility's market risk for the purposes of avoided cost calculations, I recommend that the Commission order Pacific Power to propose a means of calculating a market risk premium in its next avoided cost filing. The Commission's order would also serve as guidance to the state's other investor-owned utilities, who should proactively work to address market risk in their avoided cost filings, if they do not do so already.

E. Staff Proposal

31. In the absence of a method to quantify a market risk premium, Staff recommends that the Commission order Pacific Power to calculate its avoided cost using the same methodology that the Commission recently adopted for calculating incremental costs in the context of renewable portfolio standard (RPS) reporting. This methodology is codified at WAC 480-109-210(2)(a).

32. The incremental cost methodology is ideally suited to this issue, because the avoided cost calculation in Schedule 37 and the incremental cost calculation in the RPS report have a common purpose: to determine the avoided costs that the utility would have faced but for the regulatory requirement to purchase a different resource (a QF in this case, or a renewable resource in the case of the RPS). The avoided cost of the utility should be the same regardless of the counterfactual to which it is compared.

33. The incremental cost methodology was developed in consultation with stakeholders, including representatives from Pacific Power, and was ultimately supported by all parties involved.[31] Given the consensus that the parties developed on the incremental cost calculation, as well as the applicability of that methodology to this issue, it is appropriate to use it in this setting.

[31] *In the Matter of Amending, Adopting, and Repealing Rules in WAC 480-109 Relating to the Energy Independence* Act, Docket UE-131723, General Order R-578 ¶ 114 (March 13, 2015).

34. The incremental cost calculation is divided into separate components for energy and capacity. The rule does not prescribe how utilities calculate their avoided energy cost, but does prescribe that utilities use the levelized capital cost of the lowest-cost capacity resource in their most recent Commission-acknowledged IRP as the avoided capacity cost.[32]

35. The incremental cost calculation is similar to the manner in which Pacific Power calculated its proposed avoided cost rates. Since the rule is not prescriptive regarding a utility's calculation of its avoided energy cost, Staff recommends that the Commission accept the Company's avoided energy costs as initially filed.

36. Staff's proposal differs from the Company's proposal in its treatment of capacity costs. The Company only proposes to make capacity payments if a thermal resource is in the Company's ten-year planning horizon, and then to make capacity payments based on the cost of a combined cycle combustion turbine. The incremental cost methodology instead directs utilities to calculate their avoided capacity cost as the "lowest-cost … capacity resource identified in its most recent integrated resource plan acknowledged by the Commission."[33] Staff proposes to include capacity payments any time a utility has an avoidable capacity acquisition within the next ten years, not just when there is an avoidable thermal resource.

[32] WAC 480-109-210(2)(a).
[33] WAC 480-109-210(2)(a)(i)(E).

37. Table 1 shows Staff's proposed rates:

Table 1: Staff's Proposed Schedule 37 Rates

Year	Energy Payment[34] ($/MWH)	Capacity Payment[35] ($/kw-month)
2015	$32.48	$4.58
2016	$34.12	$4.58
2017	$36.40	$4.58
2018	$39.10	$4.58
2019	$41.70	$4.58

38. Table 2 shows the difference in total annual payments to a 2-MW generator under various annual capacity factor assumptions, using the Company's current rate, the Company's proposed rate, and Staff's proposed rate, using 2016 as an example year:

Table 2: Rate Comparisons, 2016

Capacity Factor	Current Rate	Company Proposal	Staff Proposal
90%	$531,288	$538,004	$538,691
50%	$295,160	$298,891	$299,273
30%	$177,096	$179,335	$179,564

39. Staff's proposal more accurately reflects the capacity costs that Pacific Power avoids when it contracts with a QF. As shown in Table 2, Staff's proposal makes a small difference in the overall payments to a QF when compared with the Company's proposal.[36]

[34] Per the Company's initial filing in this docket.
[35] Based on the "CCCT Dry 'J' DF, Adv. 1x1" resource on page 116 of PacifiCorp's 2013 Integrated Resource Plan. At $54.94/kW-Yr, this appears to be the resource with the lowest fixed costs in the Company's most recently acknowledged IRP. Staff calculated this figure by dividing the amount in the "Total Fixed ($/kW-Yr)" column by 12 to align with the Company's current practice of calculating QF capacity payments on a $kW-Mo basis.
[36] Although Staff's proposal would nearly double the Company's current capacity payments, capacity payments only represent 0.1 percent of the total annual payments to a QF.

Though it has a minor impact on the small QFs that may take advantage of the standard offer tariff, the obligation to provide capacity payments is an important distinction to make because Schedule 37 serves as a template for negotiations with the developers of larger projects—projects that would help the Company avoid more risky market purchases in the future. It is therefore important that Schedule 37 fairly compensate developers for the costs that QFs help the Company avoid because failure to do so would place larger QF developers at a disadvantage when negotiating rates based on Schedule 37.

40. Regarding Pacific Power's alternate proposal, Staff does not support it because it would exacerbate the uncertainty that QF developers in Washington already face. Washington's use of a five-year term for the standard offer tariff benefits the Company and ratepayers by ensuring that avoided cost rates accurately reflect current market conditions. The five-year term however disadvantages developers by creating uncertainty over the long term, which complicates project financing. Creating variable QF rates would only subject developers to greater uncertainty and further discourage future QF development. Staff's analysis of the alternate proposal also suggests that it would disproportionately affect resources by fuel type: solar facilities would receive higher payments; while wind, hydro and methane facilities would all receive lower payments. Staff recommends that the Commission reject the Company's alternate proposal.

F. Conclusion

41. Pacific Power is in a long-term period of resource deficiency. The fact that the Company has chosen, through its IRP, to rely on the market to meet the majority of its capacity needs does not mean that those needs have already been met. Granting the Company's proposal would violate PURPA by establishing rates that discriminate against QFs by failing to

compensate them for the benefits that they provide to the Company's system. Allowing such rates to go into effect would also discourage the development of small, independent power in Pacific Power's territory and create a precedent that could spread to other utilities. I therefore respectfully recommend that the Commission reject the Company's primary and alternate proposals, accept Staff's proposal, and order the Company to include a method for calculating a market risk premium in its next Schedule 37 filing.

I declare that under the laws of the State of Washington that the foregoing is true and correct.

Signed at Olympia, Washington on July 14, 2015.

Jeremy B. Twitchell