

**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

UM 1610

Phase II

In the Matter of

PUBLIC UTILITY COMMISSION
OF OREGON

Investigation into Qualifying Facility
Contracting and Pricing.

OPENING TESTIMONY OF

KEVIN C. HIGGINS

ON BEHALF OF

RENEWABLE ENERGY COALITION (“REC”),

COMMUNITY RENEWABLE ENERGY ASSOCIATION (“CREA”),

ONEENERGY and

OBSIDIAN RENEWABLES, LLC

REDACTED

MAY 22, 2015

1 **OPENING TESTIMONY OF KEVIN C. HIGGINS**

2

3 **Introduction**

4 **Q. Please state your name and business address.**

5 A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah,
6 84111.

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

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

11 **Q. On whose behalf are you testifying in this proceeding?**

12 A. My testimony is being sponsored by the Renewable Energy Coalition
13 ("REC"), the Community Renewable Energy Association ("CREA"), OneEnergy,
14 and Obsidian Renewables, LLC ("Joint QF Parties").

15 **Q. Please describe your professional experience and qualifications.**

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

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

7 **Q. Have you ever testified before this Commission?**

8 A. Yes. I have testified in twenty prior proceedings in Oregon, including five
9 PGE general rate cases, UE 283 (2014), UE 262 (2013), UE 215 (2010), UE 197
10 (2008) and UE 180 (2006), the PGE Opt-Out case, UE 236 (2012), and the PGE
11 restructuring proceeding, UE 115 (2001).

12 I have also testified in six PacifiCorp general rate cases, UE 263 (2013),
13 UE 246 (2012), UE 210 (2009), UE 179 (2006), UE 170 (2005), and UE 147
14 (2003) and six PacifiCorp Transition Adjustment Mechanism (“TAM”)
15 proceedings, UE 264 (2014 TAM), UE 245 (2013 TAM), UE 227 (2012 TAM),
16 UE 216 (2011 TAM), UE 207 (2010 TAM), and UE 199 (2009 TAM), as well as
17 the PacifiCorp Five-Year Opt-Out case, UE 267 (2013).

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

19 A. Yes. I have testified in approximately 180 proceedings on the subjects of
20 utility rates and regulatory policy before state utility regulators in Alaska,
21 Arizona, Arkansas, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky,
22 Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York,
23 North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah,

1 Virginia, Washington, West Virginia, and Wyoming. I have also prepared
2 affidavits that have been filed with the Federal Energy Regulatory Commission
3 and prepared expert reports in state and federal court proceedings involving utility
4 matters. My involvement in the determination of avoided costs dates back to the
5 initial Qualifying Facility (“QF”) buyback rates established for the Utah Power &
6 Light Company in 1984.

7
8 **Overview and Conclusions**

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

10 A. My testimony addresses Question 6 in the UM 1610 Phase II Issues List:
11 “Do the market prices used during the Resource Sufficiency Period sufficiently
12 compensate for capacity?” I am not testifying regarding any other issues in Phase
13 II.

14 **Q. Could you briefly explain the Commission’s current implementation scheme
15 for avoided cost compensation during the Resource Sufficiency Period and
16 the Resource Deficiency Period?**

17 A. As explained in Order No. 14-058, the Commission requires electric utilities
18 to set rates based on the cost of a proxy resource during periods of resource
19 deficiency and on monthly market prices during periods of resource sufficiency. The
20 Resource Deficiency Period is determined in each utility’s Integrated Resource Plan
21 (“IRP”) and it is the period for which a deferrable planned resource is identified. The
22 proxy resource is a natural gas combined-cycle combustion turbine proxy resource
23 for standard avoided cost prices, and the next avoidable renewable resource identified
24 in the electric company’s IRP for renewable avoided cost prices. The total fixed costs

1 of the avoided proxy resource are allocated to on- and off-peak prices. Non-standard
2 avoided cost rates for large QFs are negotiated between the utility and the individual
3 QF using the standard avoided cost rates as a starting point, with specific guidelines
4 and methodologies approved by the Commission.¹

5 In the PacifiCorp service territory, rates for avoided cost purchases for
6 QFs that are 10 MW or less are presented in Schedule 37, which contains pricing
7 provisions for both standard avoided cost rates and renewable avoided cost rates.
8 For Portland General Electric, the analogous rate schedule is Schedule 201, and
9 for Idaho Power Company, it is Schedule 85.

10 **Q. What is your primary conclusion and recommendation to the Commission on**
11 **the question of whether market prices used during the Resource Sufficiency**
12 **Period sufficiently compensate for capacity?**

13 A. I have concluded that the market prices used during the Resource
14 Sufficiency Period do not sufficiently compensate for capacity in the PacifiCorp
15 territory. There are two fundamental reasons for this conclusion.

16 The first is that there is a structural problem in the way the PacifiCorp IRP
17 is interpreted for determining QF pricing. Specifically, in the IRP, small QFs are
18 presumed to extend their contracts upon expiration – and this very assumption is
19 then embedded in determining the value of QF capacity, resulting in a logical
20 circularity. To remedy this problem, the assumption in the IRP that small QFs
21 extend their contracts upon expiration should be eliminated for the purpose of
22 determining QF pricing. This would require the development of an Alternative
23 IRP scenario that re-determined the preferred resource portfolio absent the

¹ Order No. 14-058 at 8.

1 (assumed) renewing QFs in order to properly value the capacity that QFs would
2 avoid. I want to be clear that I am not challenging how PacifiCorp plans for how
3 QFs renew their contracts, as it is my understanding that most small QFs enter
4 into PURPA contracts when their current contracts expire. While it is appropriate
5 to assume that small QFs renew their contracts for *planning* purposes, this is not
6 an appropriate assumption for QF *pricing*.

7 The second reason is that the extraordinarily long sufficiency period
8 indicated by the 2015 PacifiCorp IRP is sending a price signal to prospective QFs
9 that the long-term value of their capacity has no value except for the relatively
10 small premium that may be included in the price of firm energy based on
11 projected market prices. This price signal is sent despite the fact that: 1) the
12 development of rules by the Environmental Protection Agency (“EPA”) under the
13 auspices of Section 111(d) of the Clean Air Act is creating significant uncertainty
14 with respect to the Company’s long-term resource plan; and 2) PacifiCorp itself is
15 planning on a series of significant investments in environmental upgrades to
16 *retain* its coal capacity. I find this dichotomy to be a source of concern. It strikes
17 me as unwise to be signaling to QFs, particularly renewable QFs and zero-
18 emitting QFs, that their capacity is of little long-term value, and consequently
19 discouraging their development, at a time when new environmental regulations
20 are placing long-term resource planning in a state of flux. This seems particularly
21 unwise when it is understood that development of renewable QFs and zero-
22 emitting QFs is encouraged by the pending environmental rules as a means of
23 gaining compliance. Meanwhile, far from eschewing investment in capacity as

1 suggested nominally by the designation of a sufficiency period based on the next
2 deferrable resource in the IRP, PacifiCorp is in reality planning on making
3 significant investments in capacity *retention* that the Company will ask customers
4 to pay for.

5 In light of these circumstances, I recommend that the Commission adopt
6 an interim capacity pricing mechanism for Schedule 37 sales by renewable QFs
7 and zero-emitting QFs until the uncertainty surrounding implementation of
8 Section 111(d) is resolved. This approach would be used until the state plans
9 implementing the Section 111(d) rules are binding upon PacifiCorp. Under this
10 interim approach, the value of capacity from renewable QFs and zero-emitting
11 QFs would be determined by the net present value of the revenue requirement
12 associated with environmental upgrades that are planned for the sufficiency
13 period. For a renewable QF or zero-emitting QF entering a contract during the
14 interim period, the capacity value would be added to the energy price until the
15 pricing in the contract was governed either by the displaceable renewable IRP
16 resource or displaceable IRP thermal resource, whichever is applicable to that
17 contract. In other words, this adjustment to the capacity value only applies during
18 the resource sufficiency period prices.

19 The mechanics for performing this calculation are presented in detail later
20 in my testimony.

1 **Assumed Renewal of Small QF Contracts**

2 **Q. What does PacifiCorp assume with respect to the continuation of small QF**
3 **contracts after contract terms expire?**

4 A. According to the 2015 IRP, PacifiCorp assumes that these contracts are
5 extended when they expire.²

6 **Q. Do you have any concerns or objections to this assumption?**

7 A. I do not object to this assumption in the context of the IRP being used in
8 its traditional role as a planning tool. That is, for *planning* purposes, it is
9 reasonable to assume these contracts are extended, so as to avoid planning to
10 construct or acquire duplicative facilities. REC witness John Lowe addresses in
11 more detail contract renewals by existing QFs.

12 However, it is important to make a distinction when it comes to using the
13 IRP for *determining QF prices*. In that limited context, it is not reasonable to
14 assume that small QF contracts are extended when contracts expire because that
15 assumption produces a logically circular result. That is, when the purpose of the
16 exercise is to determine the value of QF capacity, the act of assuming that all or a
17 portion of the QF capacity that is being valued simply “shows up” via contract
18 extension improperly predetermines the answer to the valuation question – and
19 will understate the value of the QF capacity.

20 **Q. Do you have a simple example to illustrate this point?**

21 A. Yes. Assume for illustrative purposes that a utility has 300 MW of small
22 power QF generation selling power under standard fixed avoided cost contracts
23 and that all of these contracts expire five years from now. For simplicity, further

² PacifiCorp 2015 IRP, Vol. I, p. 75.

1 assume that front-office transactions are near their planning maximum, load
2 growth is flat, and there are no planned changes regarding other resources over
3 the IRP time horizon. Under the assumptions used by PacifiCorp to value QF
4 capacity, all 300 MW of small power QF capacity will be assumed to extend their
5 contracts and continue to be in service from Year 6 through the end of the IRP
6 planning horizon. Under the current method, the IRP would indicate that the
7 Company was in a sufficiency period throughout the remainder of the time
8 horizon and that no capacity payment (other than what is attributed to purchases
9 of firm energy based on projected market prices) was required.

10 Yet it is easy to comprehend that, but for the assumption that small QF
11 contracts were extended, the utility would require 300 MW of capacity at the end
12 of Year 5. Properly done, the pricing method should be crediting QFs with the
13 value of this avoided capacity. This would occur if, for the purpose of
14 determining the value of QF capacity, the analysis assumed that QF contracts
15 were not renewed at expiration. But as it is, the method yields no credit to the
16 QFs for avoiding this capacity due to the logical circularity of the analysis that
17 assumes that the QFs (whose value the analysis is supposed to determine) are
18 providing this capacity, effectively for free, through their assumed contract
19 renewals.

20 **Q. Does the assumption that small QF contracts are renewed upon expiration**
21 **have a material impact on the valuation of QF capacity?**

22 A. According to PacifiCorp's Response to Data Request REC 8.5,
23 Confidential Attachment REC 8.5, 122 MW of QF contracts that expire prior to

1 2028 are assumed to be extended in the 2015 IRP. In certain circumstances,
2 relaxing this assumption could potentially move the deficiency period for thermal
3 capacity up by a year, perhaps, depending on the amount of capacity attributed to
4 the renewing QFs and how close front-office transactions are to their maximum
5 levels. However, relaxing this assumption is not likely to have a material impact
6 in the current IRP, for which the next thermal resource is strongly driven by the
7 planned retirement of the Dave Johnson units in 2027, rather than the projected
8 level of front-office transactions.

9 **Q. What is your recommendation to the Commission on this issue?**

10 A. I recommend that for the limited purpose of determining the capacity
11 value of QF pricing under Schedule 37, the Commission require PacifiCorp to
12 identify an Alternative IRP scenario that removes the assumption that small QFs
13 will extend their contracts upon expiration. This Alternative IRP scenario would
14 be used to help determine the year of the next deferrable resource for the purpose
15 of valuing QF capacity.

16 **Q. Are you taking a position on the Phase II issue regarding the appropriate
17 forum for disputed avoided cost inputs and assumptions?**

18 A. No. My recommendation would apply if the Commission takes up
19 avoided cost input and assumptions in an expanded IRP process or in an avoided
20 cost review after the utilities file their avoided cost rates. The analysis regarding
21 the capacity value of small renewing QFs will be necessary regardless of the
22 specific forum that the Commission decides to use when addressing the inputs and
23 assumptions used to set avoided cost rates.

1

2 **Uncertainty Surrounding Compliance with Proposed Section 111(d) Rules**

3 **Q. Please explain your concerns regarding the pricing of QF capacity in the**
4 **context of the uncertainty surrounding PacifiCorp's compliance with EPA's**
5 **proposed Section 111(d) rules.**

6 A. Currently, PacifiCorp's Schedule 37 indicates that the sufficiency period
7 for which no thermal resource deferrals will be recognized in QF capacity prices
8 extends until the end of 2023, a very long period. The preferred portfolio in the
9 Company's 2015 IRP indicates that the sufficiency period will extend even
10 further – until the end of 2027. This extraordinarily long sufficiency period is
11 sending a price signal to prospective QFs that the long-term value of their
12 capacity is worth very little. At the same time, the Company is facing the
13 challenge of compliance with EPA's proposed Section 111(d) rules, which
14 propose significant reductions in greenhouse gas emissions. The proposed rules
15 are creating significant uncertainty with respect to the Company's long-term
16 resource plan. An important policy question that the Commission should consider
17 is whether it is wise to be signaling to QFs, particularly renewable QFs and zero-
18 emitting QFs, that their capacity is of little long-term value, and consequently
19 discouraging their development, at this critical time of changing environmental
20 regulations. This question is particularly important when it is understood that
21 development of renewable QFs and zero-emitting QFs are encouraged by the
22 pending environmental rules as a means of gaining compliance.

23 **Q. Please describe EPA's proposed Section 111(d) rules.**

1 A. EPA's proposed Section 111(d) rules are intended to limit carbon dioxide
2 emissions from existing power plants. The proposed rules, which are being
3 promulgated under Section 111(d) of the Clean Air Act, require states to submit a
4 111(d) compliance plan to the EPA in the 2016 to 2018 timeframe. Subject to
5 EPA approval of these plans, states will be required to submit interim reports to
6 the EPA beginning in 2022 to demonstrate interim goals are being met before
7 achieving full compliance by 2030.

8 In the proposed rule, the EPA identified emission reduction goals for each
9 state based on its formulation of best system of emission reduction, which is made
10 up of four building blocks: (1) heat rate improvements at existing coal-fueled
11 resources; (2) increased utilization of natural gas resources; (3) increased
12 deployment of renewable resource and zero-emitting resources; and (4) increased
13 end-use energy efficiency. The EPA applied the four building blocks to the loads
14 and resources in each state as a whole. Each state may propose how to meet its
15 goal and is not required to achieve emission reductions in the same manner as that
16 used by the EPA to calculate the goal.

17 The proposed rule is currently in the midst of a comment period and a
18 final rule is expected later in 2015. States will be required to submit compliance
19 plans by 2016, although extensions are possible. The rule is likely to be subject to
20 extensive litigation.

21 **Q. Does PacifiCorp's 2015 IRP take compliance with Section 111(d) into**
22 **account?**

1 A. Yes. However, as the rule is not final and is the focus of extensive
2 commentary and criticism, for planning purposes, compliance planning
3 necessarily must consider a range of rule outcomes and interpretations. As
4 PacifiCorp states in its IRP:

5 In this IRP, the Company provides extensive analysis of potential
6 future resource portfolios under a variety of compliance approaches
7 to the EPA's proposed Clean Power Plan. However, *significant*
8 *uncertainty regarding the implementation of this program continues*
9 *to exist*. Once final, the rule is likely to be subject to litigation, the
10 outcome of which may not be known for many years. In addition,
11 the makeup of the final rule and the manner in which states choose
12 to implement the program will have a significant impact on ultimate
13 compliance approaches and similarly may not be known for some
14 years.³

15 **Q. How does the uncertainty surrounding implementation of Section 111(d)**
16 **impact the formulation of the 2015 IRP?**

17 A. To develop a preferred portfolio in the 2015 IRP, PacifiCorp necessarily
18 had to make certain assumptions regarding implementation of the final rule. For
19 example, all 2015 IRP cases defined as having a 111(d) emission rate target
20 assume, for compliance purposes, that the Company can allocate *system*
21 renewable energy toward meeting emission rate targets in any given state. The
22 2015 IRP also assumes that a flexible allocation of "111(d) attributes" from
23 renewable resources is applied to cumulative Class 2 DSM energy efficiency
24 savings from Idaho and California, where PacifiCorp does not have a 111(d)
25 compliance obligation. Further, this Company's base case compliance approach
26 assumes that two distinct attributes (RPS attributes and 111(d) attributes) can be
27 used for compliance independent of one another. If the final rule permits a

³ Id., Vol. I, p. 28. Emphasis added.

1 flexible allocation of renewable energy and select Class 2 DSM energy efficiency
2 savings, as well as independence of attributes, as PacifiCorp assumes, the
3 Company will benefit because this approach does not lead to any incremental
4 system costs from adding resources for the purpose of meeting 111(d)
5 requirements and results in the lowest cost compliance action.⁴

6 However, not all versions of the final rule will produce lowest-cost
7 outcomes for the Company. For example, PacifiCorp has prepared a sensitivity
8 case S-15, which assumes that state renewable portfolio standard (“RPS”)-eligible
9 RECs and 111(d) attributes must be surrendered at the same time. As explained
10 in the 2015 IRP:

11 Linking the Washington RPS program to 111(d) would force
12 PacifiCorp to meet its share of the state 111(d) emission rate target
13 with situs assigned renewable resources, or alternatively,
14 PacifiCorp could eliminate its Washington 111(d) compliance
15 obligation by retiring Chehalis at the end of 2019. Considering the
16 low emission rate targets proposed by EPA in its 111(d) rule for
17 Washington, a significant amount of situs assigned renewables
18 would be required to offset emissions from Chehalis. For this
19 sensitivity, PacifiCorp assumes a lower cost alternative *would be to*
20 *retire Chehalis at the end of 2019.* With this early retirement,
21 sensitivity case S-15 includes incremental FOTs and DSM
22 resources, along with a *2020 west side natural gas peaking*
23 *resource.*⁵

24 Obviously, sensitivity case S-15 produces a different thermal sufficiency
25 period for QF pricing than does the preferred portfolio. And while PacifiCorp
26 may advocate for adoption of a final rule that incorporates the flexibility assumed
27 in the preferred portfolio, the disposition of this issue is yet to be determined.

⁴ Id., Vol. I, pp. 140, 154.

⁵ Id., Vol. I, p. 207. Emphasis added.

1 **Q. What are the implications for Oregon QF pricing of the resource planning**
2 **uncertainty engendered by 111(d)?**

3 A. With the final rule yet to be decided, and with litigation certain to follow,
4 the Commission should reflect on whether it is in the public interest to send a
5 price signal to Oregon QFs that for an extended upcoming period, capacity from
6 renewable QFs and zero-emitting QFs has virtually no value, particularly since
7 increased output from renewable resources and zero-emitting resources constitute
8 one of EPA's four building blocks. In my opinion, in light of these
9 considerations, it would be reasonable to recognize some capacity value for
10 renewable QFs and zero-emitting QFs in Schedule 37, at least on an interim basis,
11 while the uncertainty surrounding the implications of 111(d) on the Company's
12 resource planning is being sorted out.⁶

13 **Q. On what basis should a capacity value be derived during this interim period?**

14 A. PacifiCorp is planning a series of environmental upgrades to keep its coal
15 plants operating. These upgrades represent planned investment in capacity
16 *retention*. As such, the planned expenditures are indicative of the valuation the
17 Company is placing on capacity during the IRP sufficiency period. I believe it is
18 reasonable to use the projected per-kW revenue requirement associated with these
19 investments in capacity retention to value the capacity contribution from
20 renewable QFs and zero-emitting QFs while the implications from 111(d) are
21 being determined.

⁶ While certain resources are both renewable and zero-emitting, others, such as certain hydro resources, may not be classified as "renewable" for purposes of Schedule 37, but are nonetheless zero-emitting. Other resources may be renewable, but are not necessarily zero-emitting. My recommendation is directed to QFs that demonstrate either one of the characteristics of being renewable or zero-emitting (or of course both).

1 **Q. What environmental upgrades is PacifiCorp planning?**

2 A. According to the 2015 IRP,⁷ the Company has the following
3 environmental upgrade projects identified for planning purposes, recognizing that
4 agency, regulator, and joint owner perspectives on acceptability have not
5 necessarily been determined:

- 6 • Hayden 1 Selective Catalytic Reduction (“SCR”) by Jun 2015
- 7 • Jim Bridger 3 SCR by Dec 2015
- 8 • Hayden 2 SCR by Jun 2016
- 9 • Jim Bridger 4 SCR by Dec 2016
- 10 • Craig 2 SCR by Jan 2018
- 11 • Naughton 3 Conversion by Jun 2018
- 12 • Craig 1 SCR by Aug 2021
- 13 • Hunter 1 SCR by Dec 2021
- 14 • Jim Bridger 2 SCR by Dec 2021
- 15 • Jim Bridger 1 SCR by Dec 2022
- 16 • Colstrip 4 SCR by Dec 2022
- 17 • Huntington 1 SCR by Dec 2022
- 18 • Colstrip 3 SCR by Dec 2023
- 19 • Hunter 3 SCR by Dec 2024
- 20 • Cholla 4 Conversion by Jun 2025

21 **Q. How can this information be used to derive a capacity value for renewable**
22 **QFs and zero-emitting QFs during your proposed interim period?**

23 A. The cost information for these projects can be used to calculate the
24 weighted average per-kW revenue requirement (on a present value basis) for the
25 portfolio of environmental upgrades that the Company has planned during the
26 Schedule 37 thermal sufficiency period. This value represents the planned cost of
27 capacity retention.

28 **Q. How should this value be calculated?**

⁷ Id., Vol. II, pp. 298-299.

1 A. I have prepared a sample calculation consisting of the first six
2 environmental upgrades listed above using information provided by PacifiCorp in
3 its Confidential Response to REC 5.7. For the purpose of determining the
4 capacity value, I recommend using all of the projects that are identified in the IRP
5 during the sufficiency period. My sample calculation is summarized in
6 Confidential Exhibit Joint QF Parties/101. Step 1 of the calculation is to identify
7 the projected stream of annual revenue requirements for each project. For this
8 purpose I used an approach that is comparable to what PacifiCorp uses for
9 determining the revenue requirement of a deferrable thermal plant in calculating
10 Schedule 37 rates. This stream of revenue requirements is then converted into a
11 nominal levelized annual value over the remaining Oregon depreciable life of the
12 facility and expressed on a per-kW basis for each project.⁸ A blended capacity
13 value for the entire portfolio is then determined by taking an average of the
14 individual project per-kW revenue requirements, weighted by installed capacity.
15 The blending occurs on a net present value basis, i.e., after discounting the
16 revenue requirements calculated over disparate time periods to a common starting
17 date.

18 The resulting per-kW capacity value then can be converted into on-peak
19 energy prices consistent with the Schedule 37 method. For a renewable QF
20 entering a contract during the interim period, this capacity component would be
21 added to the market energy price until the pricing in the contract was governed

⁸ Conceptually, this is comparable to the nominal levelized prices calculated by PacifiCorp in its Schedule 37 workpapers, except that I am expressing the value on a per-kW basis rather than on a per-MWh basis as PacifiCorp does.

1 either by the displaceable renewable IRP resource or displaceable IRP thermal
2 resource, whichever is applicable to that contract.

3 **Q. As a reference point, what is the capacity value that results from the sample**
4 **calculation you performed?**

5 A. The capacity value that results is \$47.00 per kW-year. Using the Schedule
6 37 method for converting capacity values into on-peak energy charges, this value
7 translates into an on-peak capacity price of \$10.25/MWH for a baseload resource,
8 \$0.43/MWH for a wind resource, and \$1.39/MWH for a solar resource, using the
9 capacity contribution assumptions currently incorporated in Schedule 37. In
10 using the current Schedule 37 capacity contribution assumptions I am not
11 endorsing these assumptions, which I understand are being addressed separately.
12 Also, for purposes of this proceeding, I have treated these prices as confidential
13 because the underlying projected costs of the individual projects are deemed to be
14 confidential by the Company. However, I do not believe that a composite
15 capacity valuation or corresponding composite energy prices should ultimately be
16 viewed as confidential.

17 **Q. Please summarize your recommendation to the Commission regarding the**
18 **use of environmental upgrade costs to derive a QF capacity value.**

19 A. I recommend that the Commission adopt an interim capacity pricing
20 mechanism for renewable QFs and zero-emitting QFs selling power to PacifiCorp
21 under the Schedule 37 until the uncertainty surrounding implementation of
22 Section 111(d) is resolved. Under this interim approach, the value of QF capacity
23 would be determined by the net present value of the revenue requirement

1 associated with environmental upgrades that PacifiCorp is planning for the
2 sufficiency period. For a renewable QF or zero-emitting QF entering a contract
3 during the interim period, the capacity value would be added to the market energy
4 price until the pricing in the contract was governed either by the displaceable
5 renewable IRP resource or displaceable IRP thermal resource, whichever is
6 applicable to that contract.

7 **Q. Is your recommendation limited just to PacifiCorp or does it have more**
8 **general applicability?**

9 A. My proposal is limited to PacifiCorp at this time because of its
10 extraordinarily extended sufficiency period. However, my recommendation
11 would have more generic applicability if the sufficiency periods for other utilities
12 became greatly extended while the uncertainty surrounding implementation of
13 111(d) remained.

14 **Q. Does this conclude your opening testimony?**

15 A. Yes, it does.

REDACTED

CERTIFICATE OF SERVICE

I hereby certify that I caused to be served the foregoing **OPENING TESTIMONY OF KEVIN C HIGGINS** via electronic mail and, where paper service is not waived, via postage-paid first class mail upon the following parties of record with the CONFIDENTIAL version sent only to those parties who have signed Protective Order 12-461:

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