- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Advice Filing No. 09-12 – Annual Update for Schedule 37 Avoided Cost Purchases From Qualifying Facilities (QF)	))))))	DOCKET NO. 09-035-T14 REPORT AND ORDER APPROVING RATES WITH MODIFICATIONS

ISSUED: December 14, 2009

SHORT TITLE

Update of Electric Service Schedule No. 37 Rates for Power Purchases from Qualifying Facilities.

SYNOPSIS

The Commission approves Schedule No. 37, "Avoided Cost Purchases from Qualifying Facilities" rates as modified and discussed herein.

By The Commission:

INTRODUCTION AND PROCEDURAL BACKGROUND

On August 4, 2009, PacifiCorp, dba Rocky Mountain Power ("Company"), filed proposed changes to Electric Service Schedule No. 37, "Avoided Cost Purchases from Qualifying Facilities" ("Schedule No. 37"), of Tariff P.S.C.U. No. 47 with a requested effective date of September 3, 2009. This filing was made in response to the Public Service Commission of Utah's ("Commission") February 12, 2009, Report and Order Directing Tariff Modification in Docket No. 08-035-78[1] requiring the Company to update Schedule No. 37 annually.

Schedule No. 37 establishes standard prices for purchases of power from Utah-located cogeneration Qualifying Facilities ("QFs") with a design capacity of 1,000 Kilowatts (kW) or less and small power production QFs with a design capacity of 3,000 kW or less. The rates are based on avoided costs developed from the Company's Integrated Resource Plan ("IRP"). Avoided costs are costs the Company would incur to serve its native load "but for" the generation provided by the QFs. Schedule No. 37 prices may also be used to evaluate special contracts, demand side resource programs and form the basis of credits paid under Electric Service Schedule No. 135, the Company's Net Metering Service tariff. Specifically in this filing the Company updates the rates for known and expected changes to system costs.

On August 4, 2009, the Commission requested the Utah Division of Public Utilities ("Division") to investigate and review the proposed changes. On August 27, 2009, the

[1]Docket No. 08-035-78, "In the Matter of the Consideration of Changes to Rocky Mountain Power's Schedule No. 135 - Net Metering Service."

Division requested an extension of time, until September 3rd, for its review. Based upon the Division's request, on August 31, 2009, the Commission issued an Order suspending the tariff filing pending further investigation by the Division and comment from interested parties. On September 3, 2009, the Division filed its review and recommendation for the Commission to adopt the Schedule No. 37 rates as proposed. No other party provided comment.

On September 30, 2009, the Commission issued an Order ("September Order") declining to approve the Schedule No. 37 rates as proposed by the Company and directing the Company to file corrected Schedule No. 37 rates within two weeks of the date of the Order. On October 14, 2009, the Company filed a request for extension of time of one week to make the requested filing. On October 21, 2009, the Company filed its response to the September Order including updated tariff sheets, Appendix 1 - Rocky Mountain Power Avoided Cost Calculation spreadsheet, and Appendix 2 - Response to the Commission's September Order (collectively referred to as "Revised Filing"). On October 21, 2009, the Commission issued an action request to the Division to review the updated prices to ensure compliance with the Commission's September Order. On November 4, 2009, the Division filed comments on the Company's Revised Filing recommending approval of the updates to Schedule No. 37.

DISCUSSION, FINDINGS AND CONCLUSIONS

In our September Order, we directed the Company to refile Schedule No. 37 rates with several corrections, additional data and further explanation or clarification. We limit our discussion, findings, and conclusions herein to the items requiring additional action in our September Order. These items are: 1) Additional data regarding the Company's load and resource balance; 2) Corrections to, or additional explanation regarding, non-fuel variable operation and maintenance costs; 3) Corrections to, or additional explanation regarding, the conversion of fixed costs to variable costs; and 4) Additional data to support the natural gas and wholesale power price assumptions.

Load and Resource Balance

In our September Order we directed the Company to update its Table 1 - Load and Resources 2009 through 2019 ("Table 1") with complete information including winter peak conditions, or to provide an explanation of why a winter peak load and resource balance is not necessary for the determination of resource deficiency and sufficiency periods. We also directed the Company to annotate the load and resource balance with the planning reserve margin used in the load and resource balance.

In its Revised Filing the Company responds to the September Order by asserting it has incorporated an updated Table 1 which includes winter peak data and the planning reserve margins as requested. The Company explains it did not initially provide winter peak data because it intended to provide only the information which directly supports the determination of avoided costs.

The Company explains its understanding of the method authorized in Docket No. 03-035-T10 is to use only the energy load and resource balance for determining the deficiency and sufficiency periods. The Company's understanding of the authorized method is that capacity payments are calculated for the number of months the Company is capacity deficit during a given year, which it provides in its Table 3. Thus, it is the Company's conclusion the summer and winter peaks do not provide information directly used in the study of avoided costs. The Company explains it provided the summer peak data in its initial filing for informational purposes only because the Company's system is a summer-peak system.

Much time has passed since we approved the current method for computing avoided costs for Schedule No. 37 rates in Docket No. 94-2035-03 and since we approved adjustments to this method in Docket No. 03-035-T10.[2] It is now worthwhile to restate the general method to avoid future confusion.

The method adopted in Docket No. 94-2035-03 is a hybrid method of a differential revenue requirements method and a proxy plant method. During periods of resource sufficiency, avoided costs are determined using the differential revenue requirements method. This is done by evaluating system energy costs with and without the addition of a 10 megawatt, zero-cost resource. In Docket No. 03-035-T10, we approved inclusion of capacity payments based on the fixed costs of a simple cycle combustion turbine ("SCCT") proxy resource for months during the resource sufficiency period in which the Company is capacity deficit and the Company plans to purchase this capacity.

During the period of resource deficiency, avoided capacity and energy costs are based on the proxy plant method. Avoided capacity and energy costs are developed from the expected costs of resource(s) the Company plans to build or buy and which are avoidable or deferrable.

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[2] Docket No. 94-2035-03, "In the Matter of the Application of PacifiCorp for an Order Approving its Avoided Cost Rates." Docket No. 03-035-T10, "In the Matter of the Application of PacifiCorp, dba Utah Power & Light Company, for Approval of Standard Rates for Purchases of Power from Qualifying Facilities Having a Design Capacity of 1,000 Kilowatts or Less."

The Company's load and resource plan developed in conjunction with the Company's IRP, and updated for known changes, is the basis for determining the periods of resource sufficiency and deficiency.[3] Accordingly, the Company must include in its filing the load and resource plan it uses to develop its proposed avoided costs. The load and resource balance plan must be presented in sufficient detail to demonstrate the proposed periods for resource sufficiency and deficiency are consistent with the Company's most recent IRP or IRP update. In the past, the Company's Table 1 showing load and resource balance for energy, and both summer and winter peaks, and a description of revisions made to loads and resources since the Company's most recent IRP or IRP update, has generally been adequate for this purpose.

In addition to including winter peak data in its updated Table 1 in its Revised Filing, the Company also provides a completely new load and resource analysis for energy and summer peaks (and presumably winter peaks) for use in determining the periods of resource sufficiency and deficiency. The Company states this new load and resource balance extends the energy balance surplus to 2019 and therefore the Company proposes the period of resource sufficiency be extended through 2018 rather than 2013 as in its initial filing, and this forms the basis for the revised rates the Company filed in this case. This load and resource balance continues to show summer peak deficit in 2010.

The Company explains it updated this load and resource analysis to be "consistent with the Commission's order to exclude the environmental adders." However, the Commission did not order the Company to exclude the environmental adders. The Company provides no

[3] This discussion is drawn from the Company's April 29, 1994, testimony of Rodger Weaver in Docket No. 94-2035-03, "In the Matter of the Application of PacifiCorp for an Order Approving Avoided Cost Rates."

further discussion to explain how the exclusion of environmental adders causes the period of resource deficiency to be delayed by five years nor how the new load and resource balance is consistent with the Company's most recent IRP. Indeed, this revision is inconsistent with our September Order in which we accepted the Company's proposed load and resource balance for determining the periods of resource sufficiency and deficiency.

The Division does not mention the new load and resource balance and does not comment on whether and how it is consistent with the Company's IRP or with our September Order. The Division simply asserts that it has reviewed the Company's filing and found that the Company has appropriately included the winter peaks and the planning reserve margins in its Table 1.

Since we have no meaningful support or discussion regarding the Company's revised load and resource balance, we reject its use in developing the rates in this case, and uphold our acceptance of the load and resource balance initially filed in this case. And finally, contrary to both the Company and Division's assertions, nowhere in the revised filing does the Company annotate the load and resource balance with the planning reserve margin assumption. We direct the Company to label Table 1 with the applicable planning reserve margin assumption, (e.g., 12 or 15 percent) in all subsequent filings of Schedule No. 37 rates.

Non-Fuel Variable Operation and Maintenance Costs

In our September Order we observed the Company included, for the first time, costs associated with a potential carbon tax in its estimate of the non-fuel variable operation and maintenance costs of a CCCT. The Company cites its 2008 IRP supply side resource tables for estimates of certain types of non-fuel operation and maintenance values. We observed the Company had changed the columnar heading of one of these types of costs from “Fuel/Other” to “Gas Transportation/Wind Integration” in its IRP and excluded this amount from the avoided cost initial filing, though amounts in this or its previously entitled column had been included in avoided cost filings in the past. Therefore we directed the Company to: define or identify the costs included in the “Variable Costs” columns of the supply-side resource tables in the 2008 IRP; indicate which costs are appropriate to be included in determining non-fuel variable costs for the avoided cost calculation and why; and identify and explain changes to its assumptions of these costs used in the previous Docket No. 06-035-T06[4] and why the changes are appropriate and in the public interest.

The Company explains the definition of variable operation and maintenance costs has not changed in the IRP. The previous name of “Fuel/Other” has been changed to “Gas Transportation/Wind Integration” to be more explicit regarding the costs listed in that column. The Company states these variable costs incorporate the incremental costs incurred to deliver gas to the burner-tips of the gas plants and the non-fuel costs related to operating and maintaining the plants. The Company agrees its prior filing in Docket No. 06-035-T06 did not include carbon adders and also agrees that it is not appropriate to include them in the current filing. The Company also indicates it inadvertently excluded the gas transportation cost based on an assumption that such cost was still part of the fuel costs in the price curve. The Company states

[4] Docket No. 06-035-T06, “In the In the Matter of the Application of PacifiCorp, dba Utah Power & Light Company, for Approval of Standard Rates for Purchases of Power from Cogeneration Qualifying Facilities Having a Design Capacity of 1,000 Kilowatts or Less or Small Power Production Qualifying Facilities Having a Design Capacity of 3,000 Kilowatts or Less”

Appendix 1 of the Revised Filing incorporates the updated Tables 1 through 8, which includes gas transportation cost and excludes the environmental adders.

The Division states the Company, as shown in Table 8 of the Revised Filing, has included the variable gas transportation cost, which was inadvertently excluded from the previous filing. The Division believes the Company's changes in its Revised Filing adequately address the Commission's requirements of variable operation and maintenance costs.

We accept the Company's explanation regarding this issue and approve use of the proposed non-fuel variable operation and maintenance costs in this case. However, we note the Company did not fully explain what each cost included in the IRP represents nor which amounts are appropriate to include in avoided cost analysis and why.

For example, in its initial filing, the Company included an environmental cost and stated it was primarily for a carbon tax. In its Revised Filing, the Company excluded all environmental cost and did not address whether any of the costs in the "Environmental" column of the IRP supply side tables include existing environmental cost (such as costs associated with emission of sulfur dioxide, oxides of nitrogen or any other pollutant) which, for compliance purposes, the Company is currently incurring and which might appropriately be included as non-fuel variable operation and maintenance costs in the avoided cost calculation. We also note gas transportation costs have increased substantially, (from between $2.46 and $3.78 per megawatt hour in Docket No. 06-035-T06 to between $5.96 and $9.78 per megawatt hour in the current docket). Since this gas transportation cost appears to be increasing, and the Company proposes classifying this cost as capacity-related rather than energy-related, we request additional discussion regarding whether this is appropriate going forward. We direct the Company to address these issues in its next annual update of Schedule No. 37 rates.

Conversion of Fixed Costs and Variable Costs

In the method adopted for Schedule 37 avoided cost determination in Docket Nos. 94-2035-03 and 03-035-T13, there are three calculations wherein the Company converts fixed costs, expressed in dollars per kilowatt-year ($/kW-yr) to variable costs expressed in dollars per megawatt hour ($/MWh) or visa versa. In the first of the three calculations, the Company converts non-fuel variable operation and maintenance costs to a fixed cost and includes this amount in the total fixed cost of a proxy resource. In the second of the three calculations, a portion of the capital costs of the proxy resource are converted to energy costs. This is because in Docket 94-2035-06, the Company argued its proxy resource, a CCCT, would be added for baseload power and therefore provide both capacity and energy. Thus, the fixed costs of the CCCT were split into energy and capacity costs. The fixed cost of a SCCT, which due to its higher operating cost would be acquired as a capacity resource, defined the portion of the fixed cost of the CCCT that is classified as capacity-related. The remaining CCCT fixed cost was classified as energy related and added to the variable production cost of the CCCT to determine the total avoided energy cost. In Docket No. 03-035-T10, this calculation was modified so that one half of the difference in cost between the fixed costs of a CCCT and SCCT was approved to be classified as energy-related. In the third of the three calculations, the Company converts the total avoided capacity cost into a variable cost to be added to the $/MWh rate for on-peak energy, as this is an energy-only rate.

To convert fixed costs, expressed in $/kW-yr, to variable costs in dollars per megawatt-hour ($/MWh), or visa versa, a capacity factor must be assumed for the operation of the CCCT or other relevant proxy resource. This assumed capacity factor has varied in filings over the years.

In Docket No. 03-035-T10, the Company's proxy plant was a CCCT and it assumed an 85 percent capacity factor for all three conversions noted above. The Company assumed a 15 percent capacity factor to convert SCCT non-fuel variable operation and maintenance costs to fixed costs to determine its total fixed resource cost.

In Docket No. 06-035-T06, the Company's proxy resources were a CCCT plant with duct firing and a coal plant. For conversion of each plant's non-fuel variable operation and maintenance costs into fixed cost, the Company assumed a 45 percent energy weighted average capacity factor for the CCCT with duct firing, a 91 percent capacity factor for the coal plant and an 18 percent capacity factor for the SCCT. The Company assumed an 85 percent capacity factor to convert the energy-related portion of the blended CCCT-duct firing-coal resource capital costs[5] into variable costs and for the conversion of capacity costs for on-peak energy rates.

In the Company's initial filing in Docket No. 09-035-T14, the Company's proxy plant was a CCCT with duct-firing. The Company used an energy weighted capacity factor of 51.5 percent for the conversion of non-fuel operation and maintenance costs into fixed costs and

[5] The proxy plant capital costs were defined by the weighted average of plant capacity, 51 percent CCCT with duct firing and 49 percent coal.

also for the conversion of the energy-related portion of the CCCT and duct-firing capital costs. The Company assumed a 21 percent capacity factor to convert SCCT non-fuel variable operation and maintenance costs to fixed costs. The Company introduced a new capacity factor, 90.4 percent, for use in converting capacity costs for on-peak energy rates. This capacity factor is calculated by dividing 51.5 percent, the energy weighted capacity factor of the CCCT and duct-firing, by 57 percent, which is the percent of hours in the year that are on peak.

In our September Order we directed the Company to explain the origin of and reason for using an energy weighted capacity factor for converting the portion of the proxy plant's fixed costs to energy costs and its effect on the calculation of avoided energy costs for Schedule No. 37. In addition, we directed the Company to explain the origin of, and the reason for, using a new capacity factor calculation for converting capacity costs to on-peak energy rates and its effect on the calculation of on-peak and off-peak energy rates.

In its Revised Filing, the Company cites its most recent IRP, its 2008 IRP, as the source for the capacity factors it used in its initial filing. The Company states it elected to use the IRP resource-specific factors to be consistent with its determination of avoided costs of the larger qualifying facilities using the Partial Displacement Differential Revenue Requirements (PDDRR) method. The Company states it also used the IRP resource specific capacity factors in Docket No. 06-035-T06. In its Revised Filing, the Company again uses an energy weighted capacity factor of 51.5 percent for the conversion of the CCCT and duct firing non-fuel variable operation and maintenance costs into fixed costs and cites its IRP as the source for the capacity factor assumptions. However, the Company states it now supports use of an 85 percent capacity factor for the conversion of the energy-related portion of the CCCT and duct-firing capital costs into variable costs and for converting capacity costs into on-peak energy rates, contrary to its explanation noted above. It does not explain why, other than to state "the avoided costs in the current proceeding are not affected by the operation of proxy resources." We presume this comment relates to the Company's use of a new load and resource balance in which it defines a long period of resource sufficiency. As noted earlier, we reject use of this load and resource balance as it is unsupported analytically.

The Division states in the Revised Filing the Company has changed the capacity factor from the 51.5 percent used in the initial filing to 85 percent which is consistent with the capacity factor for the blended resource used in Docket No. 06-035-T10. No other explanation is provided nor does the Division comment on whether this is appropriate.

In order to improve our understanding of the choice of capacity factor for the aforementioned conversions, the September Order requested a review and explanation of the Company's rationale for using an energy weighted capacity factor for converting the energy-related fixed costs to variable costs and using the newly created on-peak capacity factor in the calculation of on-peak energy rates. The issue at hand is not whether the capacity factor for a blended resource should be the same as used in Docket No. 06-035-T06 – but what the capacity factor should be in light of the avoided cost method and relevant assumption regarding avoidable resources.

We are persuaded by the explanation the Company provided in its Revised Filing supporting its selection of capacity factors used in its initial filing. We accept use of a 51.5

percent capacity factor because it is consistent with the assumptions used in the IRP, with the conversion of non-fuel variable operation and maintenance costs into fixed costs, and with the determination of avoided costs for larger qualifying facilities using the PDDRR method. Further, neither the Company nor Division provides any explanation, let alone a convincing argument, the 85 percent capacity factor is related to anything in this docket. For these reasons, we decline to accept both the Company's and the Division's recommendation to increase the capacity factor used to convert the energy-related capacity cost to energy costs to 85 percent.

In this docket, the Company also developed and introduced an on-peak capacity factor for the CCCT and duct-firing of 90.4 percent based upon a 51.5 percent capacity factor divided by 57 percent (the percent of hours on-peak). Again, no additional explanation or support is provided for this new approach, as we had requested, nor for the revised use of an 85 percent capacity factor.

The on-peak capacity factor is used to allocate avoided capacity costs to on-peak energy prices in order to compensate a qualifying facility which chooses to be paid through energy-only prices for the capacity costs the Company can avoid. The assumption of a 90.4 percent capacity factor in this calculation effectively means avoided capacity costs are allocated to 90.4 percent of the on-peak hours. This results in a slightly higher on-peak energy rate than if the capacity costs were simply allocated to all on-peak hours. We will accept use of the Company's 90.4 percent capacity factor proposed in its initial filing in this case because it does not appear to produce an unreasonable result and is related to other capacity factor assumptions used and supported in this case. We direct additional discussion of this issue the next time the Company files an update to Schedule No. 37 rates.

Natural Gas Price

In our September Order we directed the Company to provide additional information on how the gas price forecast is developed and to provide prices assumed in years prior to 2014. The Company states Appendix 1 incorporates the updated Table 9 - Natural Gas Price Delivered to Plant, which shows prices before 2014 as well as the remaining years of the study. These prices per million British Thermal Units are $3.11 in 2009, $5.21 in 2010 and between $6.00 and $8.00 from 2011 to 2029.

The Company explains that it bases its forward price curves, both of natural gas and electricity, upon mid-point market price quotations, when available, or internal models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, commodity exchanges, direct communication with market participants, and/or actual transactions executed by the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the forward six years. Beyond that, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs and internal and external fundamental data inputs. The gas prices shown in Table 9 of its Revised Filing are the nominal average annual prices from the Company's official forward price curve dated June 30, 2009. The June 30, 2009 forward price curve is derived from forward market quotes (through July 2015), an average of market forwards and a long-term fundamentals price forecast (August 2015 through July 2016), and a long-term fundamentals-based price projection (August 2016 and beyond).

The Division reviewed the Company's response and concluded it is appropriate. We accept the Company's explanation and the Division's conclusion addressing this issue.

Wholesale Power Price

In our September Order we directed the Company to provide information on wholesale power prices as they relate to this docket and to provide the wholesale power prices used in GRID during the period of resource sufficiency.

The Company states the GRID database provided to the Division contains the wholesale power prices for all years, both during the sufficiency and the deficiency periods. The wholesale power prices are generated using the same process as described above for generating the prices for natural gas. However, the Company did not provide the Commission with the wholesale power prices, as directed.

The Division specifies it has determined that the wholesale power prices for all years, both the sufficiency and deficiency periods, are contained in the Grid model as the Company claims. However, the Division did not provide the Commission with the wholesale power prices assumed in this docket. We once again direct the Company to provide the assumptions for wholesale power prices used in its analysis of avoided costs and to do so in its next update to Schedule 37 rates.

Summary

Based upon the decisions in this order we have calculated Schedule No. 37 rates which are attached as Appendix A to this Order. These rates are based on the Company's initial filing adjusted for corrections to the non-fuel variable operation and maintenance costs for a CCCT and SCCT as discussed herein. The approved 20-year levelized price, is $66.32 per megawatt-hour. This levelized price is about 24 percent higher than the current 20-year levelized price of $53.64 per megawatt-hour for the same 20-year period. On an annual basis, the new rates in comparison to existing rates are 3 to 40 percent lower in the years 2009 through 2011, and 23 to 58 percent higher in years 2012 through 2028.

Having provided a complete review of the bases for these changes in this order and our September Order we approve the new Schedule No. 37 rates as identified in Attachment A effective the date of this order.

ORDER

NOW, THEREFORE, PURSUANT TO OUR DISCUSSION, FINDINGS AND CONCLUSIONS MADE HEREIN, WE ORDER:

1. The avoided cost rates contained in PacifiCorp's application to change rates for Electric Service Schedule No. 37, P.S.C.U. Tariff 47 dated August 4, 2009, are approved with the adjustments noted herein. Specifically, non-fuel variable operation and maintenance costs are based upon the costs provided by the Company in its October 21, 2009, Revised Filing. The effective date of the approved rates shall be the date of this order.

2. The Company shall submit to the Commission the appropriate tariff sheets for Electric Service Schedule No. 37 which reflect the decisions made herein within one week of the date of this Order. The Division shall review the revised sheets and supporting information for compliance with this Order and provide its recommendation to the Commission within one week of the filing of the Company's revised tariff sheets and supporting information.

3. The Company shall address the issues raised herein in its next annual update to Schedule No. 37 rates.

DATED at Salt Lake City, Utah, this 14th day of December, 2009.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#64746

Appendix A

Docket No. 09-035-T14
Tariff 47 Utah Schedule No. 37 Prices

Year	Capacity Price $/kW-mo	Capacity Price $/kW-yr	Energy Only Price ¢/kWh [1]	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh	Total Price @ 85% Capacity Factor ¢/kWh
2009	$0.66	$7.93	$3.11	3.45	3.05	3.27	2.87	3.22
2010	$2.67	$32.06	$4.01	4.51	5.13	3.80	4.42	4.44
2011	$4.76	$57.11	$4.71	5.75	6.43	4.48	5.17	5.48
2012	$6.23	$74.75	$5.11	6.52	7.26	4.87	5.60	6.11
2013	$6.35	$76.16	$5.47	6.94	7.60	5.25	5.91	6.49
2014	$11.06	$132.74	$5.35	8.29	8.29	5.35	5.35	7.13
2015	$11.27	$135.26	$5.40	8.40	8.40	5.40	5.40	7.22
2016	$11.49	$137.85	$5.30	8.35	8.35	5.30	5.30	7.15
2017	$11.71	$140.48	$5.29	8.40	8.40	5.29	5.29	7.18
2018	$11.93	$143.16	$5.33	8.50	8.50	5.33	5.33	7.25
2019	$12.16	$145.89	$5.56	8.79	8.79	5.56	5.56	7.52
2020	$12.39	$148.68	$5.83	9.13	9.13	5.83	5.83	7.83
2021	$12.63	$151.52	$6.07	9.42	9.42	6.07	6.07	8.11
2022	$12.87	$154.41	$6.00	9.42	9.42	6.00	6.00	8.07
2023	$13.11	$157.36	$6.08	9.57	9.57	6.08	6.08	8.19
2024	$13.36	$160.36	$5.52	9.07	9.07	5.52	5.52	7.67
2025	$13.62	$163.43	$5.77	9.40	9.40	5.77	5.77	7.97
2026	$13.88	$166.54	$6.13	9.82	9.82	6.13	6.13	8.37
2027	$14.14	$169.72	$6.16	9.92	9.92	6.16	6.16	8.44
2028	$14.41	$172.96	$6.36	10.20	10.20	6.36	6.36	8.68
2029	$14.69	$176.26	$6.53	10.43	10.43	6.53	6.53	8.90
2030	$14.97	$179.62	$6.75	10.73	10.73	6.75	6.75	9.16
2031	$15.25	$183.05	$6.89	10.95	10.95	6.89	6.89	9.35
2032	$15.55	$186.55	$7.02	11.16	11.16	7.02	7.02	9.53
2033	$15.84	$190.11	$7.16	11.37	11.37	7.16	7.16	9.71
20 Year (2009 to 2028) Levelized Prices (Nominal) @ 7.10% Discount Rate (2)								
¢/kWh	9.09		5.17	7.53	7.70	5.11	5.28	6.632
	$/MWH		51.68	75.31	76.97	51.15	52.81	$\boxed{66.32}$

Footnotes:
(1) Energy Only is the average of off-peak energy prices and does not include capacity costs.
(2) Discount Rate - Company Official Discount Rate - Dated June 2009