ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

November 7, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Attn: Chris Petrie, Chief Counsel

Docket No. 20000-___-EA-14

RE: Schedule 37-Avoided Cost Purchases from Qualifying Facilities

Dear Mr. Petrie:

In accordance with the Rules of Practice & Procedure and General Regulations of the Public Service Commission of Wyoming, Rocky Mountain Power ("Company") hereby submits for electronic filing its Application and proposed tariff pages (including legislative format) for Schedule 37, Avoided Cost Purchases from Qualifying Facilities:

Second Revision of Sheet No. 37-1	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Second Revision of Sheet No. 37-2	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Second Revision of Sheet No. 37-3	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
First Revision of Sheet No. 37-4	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Original Sheet No. 37-5	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Original Sheet No. 37-6	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Original Sheet No. 37-7	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Original Sheet No. 37-8	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Original Sheet No. 37-9	Schedule 37	Avoided Cost Purchases from Qualifying Facilities

In addition to the electronic copy, an original and four hard copies of the Application and tariff Schedules will be provided to the Commission. Please find enclosed the Company's filing fee check in the amount of $15.00.

This filing updates Rocky Mountain Power's avoided costs and seeks approval of standard rates for purchases of power from qualifying facilities with a design capacity within the limits designated in tariff Schedule 37.

It is respectfully requested that all formal correspondence and Staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

with copies to: Brian Dickman
Manager, Net Power Costs
PacifiCorp Energy
825 NE Multnomah Street, Suite 600
Portland, Oregon 97232
Telephone No.: (503) 813-6484
e-mail: Brian.Dickman@PacifiCorp.com

Stacy Splittstoesser
Wyoming Regulatory Affairs Manager
Rocky Mountain Power
1807 Capitol Ave, Suite 200A
Cheyenne, Wyoming 82001
E-mail: stacy.splittstoesser@pacificorp.com

Daniel E. Solander
Senior Counsel
Rocky Mountain Power
201 South Main Street, Suite 2400
Salt Lake City, Utah 84111
E-mail: daniel.solander@pacificorp.com

Informal inquiries may be addressed to Stacy Splittstoesser, Wyoming Regulatory Affairs Manager, at (307) 632-2677 or Brian Dickman at (503) 813-6484.

Very truly yours,

Jeffrey K. Larsen

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

Daniel Solander
201 South Main Street, Suite 2400
Salt Lake City, Utah 84111
Telephone No.: (801) 220-4014
Facsimile No. (801) 220-3299
e-mail: Daniel.Solander@PacifiCorp.com

Attorney for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION	)	
OF ROCKY MOUNTAIN POWER FOR	)	
APPROVAL OF SCHEDULE 37	)	Docket No. 20000-______-EA-14
STANDARD RATES FOR PURCHASES OF	)	
POWER FROM QUALIFYING FACILITIES	)	Record No. _______

APPLICATION FOR APPROVAL OF SCHEDULE 37

Comes now Rocky Mountain Power ("RMP" or "Company"), a division of PacifiCorp, with an original and four copies of the following Application including supporting exhibits and proposed tariff Schedule 37, Standard Rates for Purchases of Power from Qualifying Facilities applicable in the state of Wyoming. Rocky Mountain Power respectfully requests that the Public Service Commission of Wyoming ("Commission") approve the standard rates included in this Application for the purchase of power from qualifying cogeneration and small power production facilities that qualify under the terms and conditions of Schedule 37. In support of this Application, Rocky Mountain Power represents as follows:

1. Rocky Mountain Power is a public utility in the state of Wyoming and is subject to the Commission's jurisdiction with respect to its public utility operations,

service, retail rates and accounting practices in Wyoming. The Company also provides retail electricity service under the name Rocky Mountain Power in the states of Utah and Idaho and under the name Pacific Power in the states of Oregon, Washington and California.

2. Communications regarding this application should be addressed to:

Brian Dickman
Manager, Net Power Costs
PacifiCorp Energy
825 NE Multnomah Street, Suite 600
Portland, Oregon 97232
Telephone No.: (503) 813-6484
e-mail: Brian.Dickman@PacifiCorp.com

Stacy Splittstoesser
Manager, Regulatory
Rocky Mountain Power
1807 Capitol Ave, Suite 200A
Cheyenne, WY 82001
Telephone No.: (307) 632-2677
e-mail: Stacy.Splittstoesser@PacifiCorp.com

And

Daniel Solander
Senior Attorney
Rocky Mountain Power
201 South Main Street, Suite 2400
Salt Lake City, Utah 84111
Telephone No.: (801) 220-4014
e-mail: Daniel.Solander@PacifiCorp.com

In addition, Rocky Mountain Power requests that all data requests regarding this application be sent in Microsoft Word or plain text format addressed to:

By email (preferred)	DataRequest@PacifiCorp.com
or by regular mail to:	Data Request Response Center PacifiCorp 825 NE Multnomah St., Suite 2000 Portland, OR 97232

Informal questions may be directed to Stacy Splittstoesser at (307) 632-2677 or Brian Dickman at (503) 813-6484.

3. This Application is filed pursuant to Section 317 of the Commission's Rules, which sets forth the Commission's regulations regarding arrangements between electric utilities and qualifying cogeneration and small power production facilities (Qualifying Facilities) pursuant to Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 USC §§ 796 and 824a-3. Section 317 (j) of the Commission's Rules requires each electric utility in Wyoming to prepare and file standard rates for purchases from Qualifying Facilities having a design capacity greater than 100 kilowatts. Section 317 (e) of the Commission's Rules requires system data from which avoided costs may be derived to be filed not less often than every two years.

4. Exhibit 1, Avoided Cost Prices for Purchase Power, attached to this Application, is a description of the terms, conditions, availability and standard rates for purchases of power from qualifying cogeneration and small power production facilities that qualify under the terms and conditions of Schedule 37.

5. Exhibit 2, Standard Rates for Avoided Cost Purchases from Qualifying Facilities That Qualify for Schedule 37, attached to this Application, is a detailed description of the methods and assumptions used to produce the Avoided Cost Study.

6. Exhibit 3, Avoided Cost Study Tables 1-10, attached to this Application, is a detailed set of calculations and work papers showing the avoided cost calculation.

7. First revised tariff sheets number 37-1, 37-2 and 37-3, and new tariff sheets number 37-5 through 37-9, Schedule 37, PSC Wyoming No. 14, are also attached to this Application.

8. The Avoided Cost Study prepared in support of this Application results in a proposed avoided cost price of $44.09/MWH on a 20-year (2015-2034) nominal levelized basis for a base load QF, which is a reduction of $9.65/MWH from rates currently in effect which were approved in August 2012. The proposed avoided cost prices are $36.13/MWh, $42.75/MWh, and $43.16/MWh on a 20-year (2015-2034) nominal levelized basis for a wind, fixed solar and tracking solar QF, respectively. The lower avoided cost reflected in this Application is due to lower forecast of wholesale power market prices, lower load forecast, removal of capacity payment during sufficiency period, inclusion of integration costs, the postponement of the resource surplus/resource deficit period from 2025 to 2027, and adjustment avoided capacity costs by peak capacity contribution of each QF type.

9. The Company also proposes several changes to the methodology for calculating Schedule 37 avoided cost rates, as described in the testimony of Company witness Gregory N. Duvall. The proposed changes are required to make avoided costs consistent with the Company's most recent resource planning information, to account for the unique characteristics of renewable QF resources, and to eliminate unnecessary differences between the calculation of avoided costs for small QFs under Schedule 37 and large QFs under Schedule 38. Changes include: accounting for integration costs of intermittent QF resources, adjusting for capacity contribution of each QF type, elimination of capacity costs during the sufficiency period, determining the resource

deficiency period based on the Company's resource procurement plans, and changing the offered pricing structure from separate capacity/energy payments to volumetric pricing. The Company respectfully requests that the proposed rates in tariff Schedule 37 attached to this Application become effective with service on and after December 1, 2014.

WHEREFORE, Rocky Mountain Power requests Commission approval of the standard rates for purchase of power from qualifying cogeneration and small power production facilities that qualify under the terms and conditions of Schedule 37, as contained in the Exhibits and tariff Schedules attached to this Application, subject to the tariff provision that the standard rates are applicable until 10 megawatts of system-wide resource capacity is acquired.

DATED this 7th day of November 2014.

Respectfully submitted,

Daniel E. Solander

Attorney for Rocky Mountain Power
One Utah Center, Suite 2400
Salt Lake City, Utah 84111
Telephone No.: (801) 220-4014
e-mail: Daniel.Solander@PacifiCorp.com

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

WYOMING – November 2014

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

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I. Non-firm Energy – Avoided Cost Prices

Availability: The prices shown below are available to owners of qualifying facilities (QFs) within the Wyoming service territory of Rocky Mountain Power (RMP) prior to commercial operation. After commercial operation is achieved, QFs will receive firm power prices. The term "Qualifying Facilities" refers to qualifying cogeneration facilities or qualifying small power production facilities within the meaning of sections 201 and 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Prices: The prices shown below are subject to change from time to time to reflect changes in the Company's determination of Wyoming avoided costs. The prices applicable to QFs shall be those in effect at the time the power is delivered.

Base Load Non-Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39

Wind Non-Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07

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AVOIDED COST PRICES FOR PURCHASE POWER

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Fixed Solar Non-Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

Tracking Solar Non-Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

II. Firm Power Time of Delivery Avoided Costs Prices

Availability: The prices shown below are available to owners of QFs within the Wyoming service territory of RMP after commercial operation is achieved.

Terms: To obtain the prices set forth below, owners of QFs may be required to enter into a written power sales contract with RMP. Advance approval of the contract by RMP's jurisdictional state regulatory commission may be required.

Prices: The prices shown below are subject to change from time to time to reflect changes in the Company's determination of Wyoming avoided costs. The prices applicable to QFs shall be those in effect at the time a written contract acceptable to RMP is signed on behalf of the QF and received by RMP at 825 NE Multnomah, Portland, Oregon 97232, or such other address as RMP shall designate.

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

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These prices will only be applied to Wyoming QF resources that enter into contracts with RMP until 10 megawatts of system-wide resources are acquired.

Base Load Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39
2018	3.19	3.77	2.50	2.69
2019	3.29	3.95	2.60	2.85
2020	3.49	4.10	2.86	2.99
2021	3.81	4.35	3.42	3.41
2022	4.24	4.63	4.02	3.87
2023	4.21	4.88	3.97	4.09
2024	3.92	5.27	3.70	4.35
2025	5.34	5.68	5.07	4.54
2026	5.29	6.09	5.02	4.90
2027	7.72	7.72	4.51	4.51
2028	7.95	7.95	4.68	4.68
2029	8.20	8.20	4.87	4.87
2030	8.46	8.46	5.07	5.07
2031	8.62	8.62	5.16	5.16
2032	8.78	8.78	5.26	5.26
2033	8.95	8.95	5.36	5.36
2034	9.12	9.12	5.46	5.46
2035	9.31	9.31	5.57	5.57
2036	9.50	9.50	5.69	5.69
2037	9.68	9.68	5.80	5.80
2038	9.87	9.87	5.91	5.91

20 Year (2015 to 2034) Levelized Prices (Nominal) @ 6.882% Discount Rate (1)

¢/kWh	4.81	5.23	3.60	3.64

Footnotes:
(1) Discount Rate - 2013 IRP Update Discount Rate

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

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Wind Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07
2018	2.87	3.45	2.18	2.36
2019	2.97	3.62	2.28	2.52
2020	3.16	3.77	2.53	2.65
2021	3.47	4.01	3.07	3.07
2022	3.89	4.28	3.67	3.52
2023	3.86	4.53	3.62	3.73
2024	3.56	4.91	3.34	3.98
2025	4.97	5.31	4.70	4.17
2026	4.92	5.72	4.64	4.53
2027	4.59	4.59	4.13	4.13
2028	4.76	4.76	4.29	4.29
2029	4.96	4.96	4.47	4.47
2030	5.15	5.15	4.66	4.66
2031	5.25	5.25	4.75	4.75
2032	5.35	5.35	4.84	4.84
2033	5.45	5.45	4.93	4.93
2034	5.55	5.55	5.02	5.02
2035	5.67	5.67	5.12	5.12
2036	5.78	5.78	5.23	5.23
2037	5.89	5.89	5.33	5.33
2038	6.01	6.01	5.44	5.44

20 Year (2015 to 2034) Levelized Prices (Nominal) @ 6.882% Discount Rate (1)

¢/kWh	3.73	4.15	3.25	3.29

Footnotes:

(1) Discount Rate - 2013 IRP Update Discount Rate

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

WYOMING –November 2014

Fixed Solar Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.51	5.51	4.42	4.42
2028	5.70	5.70	4.58	4.58
2029	5.91	5.91	4.77	4.77
2030	6.12	6.12	4.97	4.97
2031	6.24	6.24	5.06	5.06
2032	6.35	6.35	5.15	5.15
2033	6.48	6.48	5.25	5.25
2034	6.60	6.60	5.35	5.35
2035	6.73	6.73	5.46	5.46
2036	6.87	6.87	5.57	5.57
2037	7.00	7.00	5.68	5.68
2038	7.14	7.14	5.79	5.79

20 Year (2015 to 2034) Levelized Prices (Nominal) @ 6.882% Discount Rate (1)

¢/kWh	4.16	4.58	3.51	3.55

Footnotes:
(1) Discount Rate - 2013 IRP Update Discount Rate

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

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Tracking Solar Firm Energy Prices				
	Peak Energy Prices		Off-Peak Energy Prices	
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.67	5.67	4.42	4.42
2028	5.86	5.86	4.58	4.58
2029	6.07	6.07	4.77	4.77
2030	6.29	6.29	4.97	4.97
2031	6.41	6.41	5.06	5.06
2032	6.53	6.53	5.15	5.15
2033	6.66	6.66	5.25	5.25
2034	6.78	6.78	5.35	5.35
2035	6.92	6.92	5.46	5.46
2036	7.06	7.06	5.57	5.57
2037	7.20	7.20	5.68	5.68
2038	7.34	7.34	5.79	5.79

20 Year (2015 to 2034) Levelized Prices (Nominal) @ 6.882% Discount Rate (1)

¢/kWh	4.20	4.62	3.51	3.55

Footnotes:
(1) Discount Rate - 2013 IRP Update Discount Rate

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

WYOMING – November 2014

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

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The starting point for the avoided cost calculation is the Company's 2013 Integrated Resource Plan Update ("2013 IRP Update") dated March 31, 2014. It should be noted that many of the input assumptions for the 2013 IRP Update were fixed in late 2013, in order to enable filing in March 2014. Due to the age of the input assumptions, many of the inputs have been updated for known changes for purposes of this avoided cost calculation.

In addition to data updates, following methodology changes are incorporated in calculations of proposed Wyoming Schedule 37 Avoided costs:

- Elimination of capacity payment during sufficiency period.
- Determination of sufficiency/deficiency period based on resource additions in the 2013 IRP Update.
- Including integration costs for renewable QF resources.
- Recognition of capacity contribution of each QF resource.
- Replacement of separate capacity/energy pricing with volumetric seasonal on-peak/off-peak pricing

Table 1 (in Exhibit 3) presents the timing of deferrable resources as listed in Table 5.5 of the Company's 2013 IRP Update dated March 31, 2014. Table 1 shows that the 423 MW CCCT scheduled for 2027 is the Company's next deferrable resource in the 2013 IRP Update and the year of 2027 marks the start of the avoided cost resource deficiency period.

Avoided Cost Calculation

Based on the timing of the next deferrable resource shown in **Table 1 (**in Exhibit 3)**,** the avoided cost calculation is separated into two distinct periods: (1) the Short Run – a period of resource sufficiency (2014 through 2026); and (2) the Long Run – a period of resource deficiency (2027 and beyond).

1. <u>Short Run Avoided Costs</u>

During periods of resource sufficiency, the company's avoided energy costs are based on the displacement of purchased power and existing thermal resources as modeled by the Company's GRID model.

To calculate short-run avoided costs, two production cost studies are prepared. The only difference between the two studies is the inclusion of an assumed 50 aMW resource, at zero running cost. The 50 aMW resource serves as a proxy for qualifying facility ("QF")

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

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generation. The avoided energy cost could be viewed as the highest variable cost incurred to serve total system load from existing and non-deferrable resources. The outputs of the production cost model run are provided as **Table 2A** (in Exhibit 3). Table 2B, 2C, and 2D are provided for wind, fixed and tracking solar QF types, respectively, which include the impact of integration costs during short-run period.

Capacity payments based on one-fourth of the capacity cost of a simple cycle combustion turbine ("SCCT") during short-run period have been removed consistent with the Company's 2013 IRP Update. Prior to the start of the deficiency period in 2027, the Company will not procure additional thermal capacity resources; rather, it will utilize front office transactions, or wholesale market purchases, to meet its needs.

2. Long Run Avoided Costs

During the resource deficiency period (2027 and beyond), avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current proxy resource is a combined cycle combustion turbine ("CCCT").[1]

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a SCCT, which is usually acquired as a capacity resource, defines the portion of the fixed cost of the blended resource that is assigned to capacity.[2] Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. **Table 3** (in Exhibit 3) shows the capitalized energy costs.

The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document. **Table 4** (in Exhibit 3) shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 51.9% capacity factor, and the total avoided energy costs.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 6A, 6B, 6C, and 6D** (in Exhibit 3) show the calculation of on-peak and off-peak avoided cost prices for a base load, wind, fixed and tracking solar, respectively. Avoided costs are adjusted for wind and solar QFs to reflect

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[1] CCCT Dry "J", Adv 1x1 - East Side Resource (5,050') as listed for the 2013 IRP Update. Fuel costs are from the Company's September 2014 Official Forward Price Curve.
[2] SCCT Frame "F" x 1 - East Side Resource (4,250') as modeled for the 2013 IRP Update.

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

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the capacity contribution of each QF type. Capacity contribution values are based on the Company's latest capacity contribution study completed in October 2014. Avoided costs are also adjusted for wind and solar QFs to reflect integration costs. Solar resources are distinguished as configured either to maximize energy output (Fixed Solar) or to maximize output during peak load periods or with a tracking device (Tracking Solar). **Table 10** (in Exhibit 3) provides the details of the integration costs for wind and solar resources.

For informational purposes, **Table 7** (in Exhibit 3) shows a comparison between the avoided costs currently in effect in Wyoming and the proposed avoided costs in this filing.

Table 8 (in Exhibit 3) shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4** (in Exhibit 3). In this filing, the Company's next deferrable resource is a CCCT located on the east side of the Company's system. The use of an east side resource is consistent with the Company's addition of an east side CCCT as shown in Table 5.5 of the 2013 IRP Update.

Electricity and Gas Price Forecast

The electricity and natural gas prices used in this filing are from the Company's Official Forward Price Curve dated September 30, 2014. Both the electricity and natural gas prices are inputs to the Company's GRID model in the calculation of the proposed avoided costs in this filing. Natural gas prices are also used to calculate the fuel costs of the CCCT proxy resource for the Long Run avoided costs, as shown in **Table 9** (of Exhibit 3). The proxy resource natural gas prices are based upon the East Side gas index.

For the period from October 2014 through August 2020, the official forward prices are based on the information from the market forward transactions. For the period from September 2020 through August 2021, the official forward prices are the average of market information and the long-term price forecast. Beginning in September 2021, the official forward prices are based on a modeled long-term price forecast.

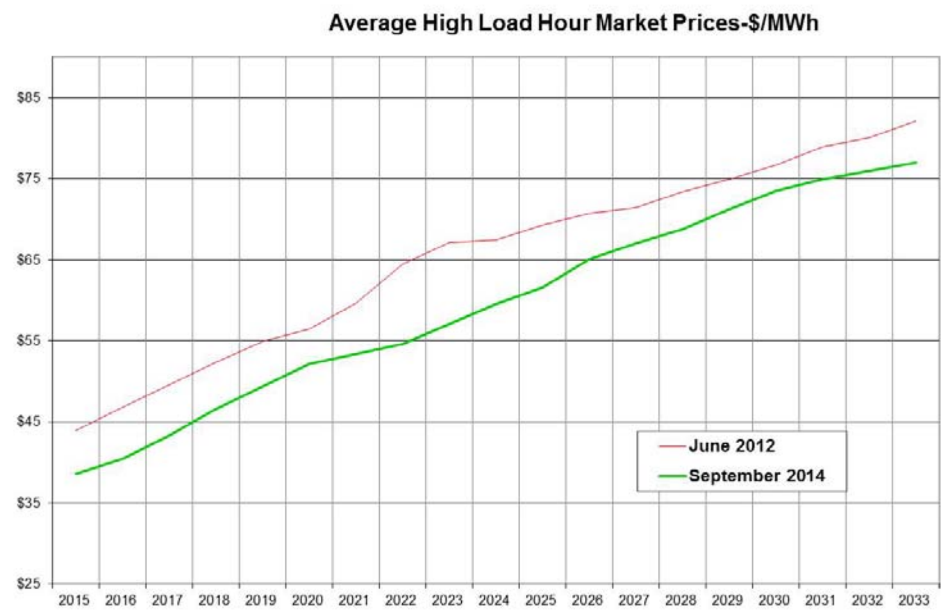
	Market	Long Term
Through August 2020	100%	0%
September 2020 – August 2021	50%	50%
September 2021 and beyond	0%	100%

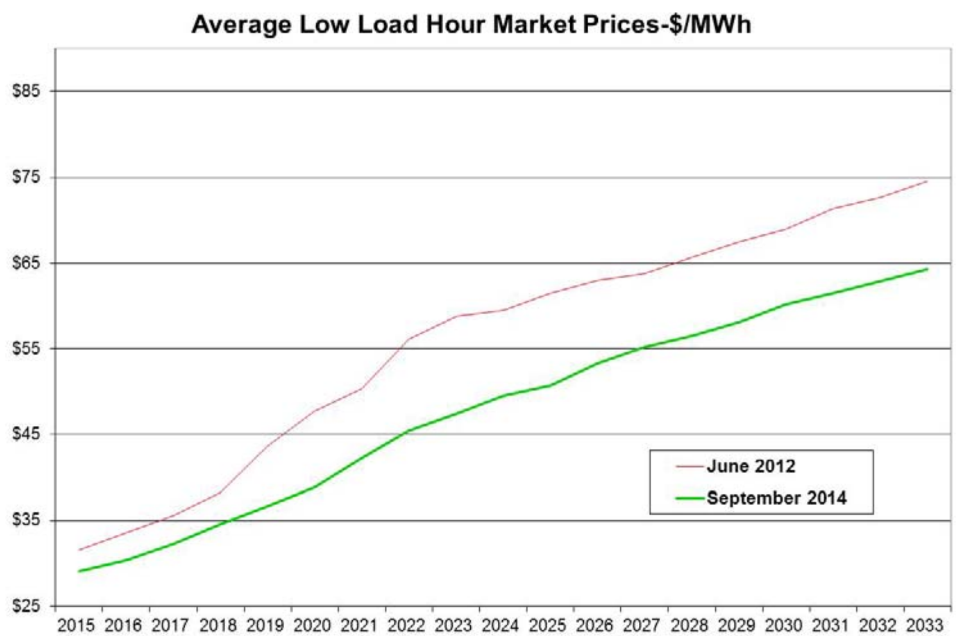
Cost Comparison

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

WYOMING – November 2014

Avoided costs have declined since the Commission approved Schedule 37 avoided costs in November 2012. The one of the primary drivers for this decline in the drop in the electric market and natural gas price forecast. The charts below show the change in electric market and natural gas prices.





ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

WYOMING – November 2014

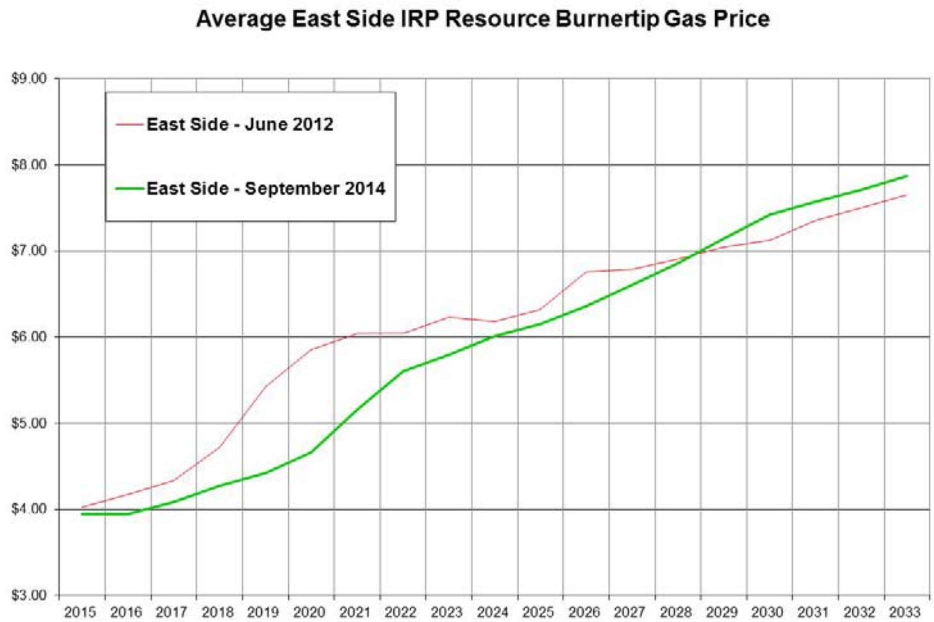


Exhibit 3

ROCKY MOUNTAIN POWER
AVOIDED COST PRICES FOR PURCHASE POWER

AVOIDED COST STUDY TABLES 1-10

WYOMING – November 2014

Table 1
IRP Preferred Portfolio
Excerpt from 2013 IRP Update Table 5.5

		Capacity (MW)													
	Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East	**Existing Plant Retirements/Conversions**														
	Carbon1 (Early Retirement/Conversion)	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon2 (Early Retirement/Conversion)	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-
	Naughton3 (Early Retirement/Conversion)	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-
	Coal Ret_WY - Gas RePower	-	338	-	-	-	-	-	-	-	-	-	-	-	-
East	**Expansion Resources**														
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423
	Lake Side II	645	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	184	296	-	-
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	74	-
	DSM, Class 2 Total	62	58	56	57	55	53	48	50	50	39	42	39	37	35
	Micro Solar - PV	11	14	16	17	13	13	13	13	13	13	13	13	13	13
	Micro Solar - Water Heating	-	-	-	-	-	0	2	2	2	2	2	2	2	2
	FOT Mona Q3	-	-	-	-	56	152	89	-	-	38	130	300	300	105
West	**Expansion Resources**														
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	4	48	-
	DSM, Class 2 Total	48	41	40	38	33	29	26	24	24	25	24	27	27	22
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
	Signed Contract - OR Solar	5.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-
	FOT COB Q3	-	-	-	-	-	-	297	297	223	297	297	297	297	297
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	345	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	-	83	201	331	375	375	375	245	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-
	Annual Additions, Long Term Resources	773	115	113	113	103	96	90	90	91	80	267	383	202	497
	Annual Additions, Short Term Resources	445	583	701	831	931	1,027	1,261	1,042	1,098	1,210	1,302	1,472	1,472	1,277
	Total Annual Additions	1,218	698	814	944	1,034	1,123	1,351	1,132	1,189	1,290	1,569	1,855	1,674	1,774

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

The 2013 IRP was prepared using a 13% planning reserve margin. See 2013 IRP, page 162.

Table 2A
Avoided Costs for Base Load QF
Avoided Energy - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study												
2014											$25.95	$25.74
2015	$24.28	$28.24	$29.11	$26.81	$24.72	$24.52	$31.55	$33.40	$27.03	$24.62	$27.92	$23.70
2016	$22.95	$25.81	$29.18	$24.82	$24.42	$25.01	$32.45	$34.43	$27.01	$23.98	$24.72	$24.99
2017	$24.28	$25.75	$30.67	$24.38	$23.72	$26.23	$34.04	$36.40	$29.04	$25.58	$25.68	$25.46
2018	$26.90	$29.91	$31.64	$27.73	$27.39	$28.88	$37.20	$40.56	$33.35	$30.06	$29.14	$28.02
2019	$28.22	$30.11	$32.63	$28.05	$29.01	$30.15	$39.69	$42.90	$33.06	$33.08	$30.51	$29.96
2020	$27.96	$29.26	$33.57	$32.22	$29.33	$31.23	$41.92	$45.25	$36.36	$32.41	$33.70	$36.22
2021	$31.13	$33.78	$37.59	$33.56	$32.39	$34.11	$45.68	$48.32	$38.31	$37.04	$43.34	$38.88
2022	$38.25	$39.15	$42.66	$40.54	$34.54	$38.63	$50.39	$52.63	$42.66	$38.61	$45.50	$42.29
2023	$39.46	$39.14	$41.50	$34.88	$37.59	$40.18	$52.85	$54.75	$43.78	$42.56	$47.65	$43.51
2024	$15.88	$41.57	$44.53	$43.95	$39.57	$42.16	$56.02	$59.15	$47.48	$47.41	$57.01	$27.70
2025	$53.10	$51.40	$48.43	$47.13	$41.50	$45.08	$60.19	$64.79	$49.93	$48.87	$58.23	$55.07
2026	$53.01	$53.16	$50.44	$41.07	$44.93	$48.12	$66.05	$68.16	$54.84	$51.81	$57.01	$55.61

Annual Seasonal Average

Year	Winter Season	Summer Season	Annual Average
2014	$25.84		$25.84
2015	$26.64	$27.66	$27.16
2016	$25.41	$27.90	$26.59
2017	$26.05	$29.19	$27.63
2018	$28.88	$32.93	$30.92
2019	$29.92	$34.68	$32.32
2020	$32.18	$36.11	$34.07
2021	$36.40	$39.34	$37.88
2022	$41.42	$42.93	$42.18
2023	$41.05	$45.32	$43.20
2024	$38.27	$48.67	$43.39
2025	$52.23	$51.77	$52.00
2026	$51.72	$55.70	$53.73

Source: GRID Production Cost Computer Model Study - Dated

Table 2A
Avoided Costs for Base Load QF
Avoided Energy - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study_OnPeak (1)												
2014											$28.08	$27.78
2015	$26.43	$30.66	$31.67	$30.03	$29.03	$28.58	$35.93	$38.56	$31.37	$26.56	$29.61	$25.36
2016	$24.74	$27.85	$32.05	$28.68	$28.27	$27.52	$39.67	$39.70	$30.01	$26.11	$26.62	$26.89
2017	$26.31	$27.94	$33.79	$28.39	$27.27	$28.96	$41.49	$41.95	$32.37	$27.97	$27.80	$27.65
2018	$29.23	$32.63	$35.01	$32.33	$31.55	$32.04	$45.27	$46.79	$37.55	$32.89	$31.76	$30.63
2019	$30.59	$32.77	$36.17	$32.25	$33.22	$33.51	$47.49	$49.24	$37.07	$36.10	$33.17	$32.67
2020	$30.26	$31.76	$37.12	$36.89	$33.67	$34.42	$49.88	$52.13	$40.42	$35.30	$35.49	$38.00
2021	$32.72	$35.60	$40.07	$36.59	$35.54	$36.72	$52.80	$54.81	$41.64	$39.16	$44.08	$39.48
2022	$38.90	$40.08	$44.00	$41.97	$36.23	$40.75	$57.08	$58.54	$45.37	$39.41	$46.21	$42.91
2023	$40.18	$40.11	$43.09	$36.59	$39.30	$42.56	$60.34	$60.96	$46.27	$43.22	$48.35	$44.12
2024	$16.17	$42.57	$46.08	$45.65	$41.29	$44.29	$63.73	$66.56	$51.08	$49.02	$57.85	$28.10
2025	$54.16	$52.57	$50.02	$48.53	$43.22	$47.50	$69.51	$75.70	$54.25	$50.24	$59.14	$56.01
2026	$54.01	$54.33	$52.15	$42.55	$46.27	$50.79	$77.53	$79.09	$59.03	$52.55	$57.92	$56.53

Annual Seasonal Average, OnPeak

Year	Winter Season	Summer Season	Annual Average
2014	$27.93		$27.93
2015	$28.92	$31.69	$30.32
2016	$27.81	$31.91	$29.80
2017	$28.66	$33.36	$31.03
2018	$31.92	$37.71	$34.84
2019	$32.94	$39.48	$36.24
2020	$34.94	$41.01	$37.91
2021	$38.11	$43.49	$40.82
2022	$42.36	$46.26	$44.33
2023	$42.10	$48.82	$45.49
2024	$39.23	$52.71	$45.89
2025	$53.42	$56.80	$55.12
2026	$52.92	$60.94	$56.96

(1): On-peak prices have been shaped by the relationship of Palo Verde On-peak market price to Palo Verde market price.
On-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly On-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2A
Avoided Costs for Base Load QF
Avoided Energy - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study_OffPeak (2)												
2014											$23.52	$23.15
2015	$21.56	$25.02	$25.84	$22.42	$19.72	$18.96	$26.00	$26.85	$21.60	$21.95	$25.99	$21.59
2016	$20.87	$23.05	$25.20	$19.53	$19.95	$21.58	$24.04	$27.13	$23.24	$21.27	$22.36	$22.57
2017	$21.91	$22.85	$26.34	$19.36	$19.23	$22.49	$25.38	$28.71	$24.89	$22.55	$23.04	$22.92
2018	$23.95	$26.28	$26.96	$21.99	$22.12	$24.55	$27.82	$31.93	$28.56	$26.14	$25.89	$24.98
2019	$25.22	$26.58	$28.12	$22.30	$23.66	$25.96	$29.79	$34.11	$28.47	$28.91	$27.21	$26.81
2020	$25.03	$25.87	$29.05	$25.83	$24.27	$26.87	$31.83	$36.52	$31.27	$28.41	$31.65	$33.97
2021	$29.28	$31.36	$34.14	$29.41	$28.73	$30.54	$36.65	$40.09	$34.15	$34.35	$42.42	$38.11
2022	$37.49	$37.92	$40.80	$38.58	$32.58	$35.74	$42.60	$44.44	$39.26	$37.61	$44.63	$41.52
2023	$38.62	$37.84	$39.31	$32.74	$35.43	$36.91	$44.15	$46.15	$40.67	$41.71	$46.77	$42.79
2024	$15.50	$40.21	$42.55	$41.63	$37.39	$39.49	$46.24	$48.90	$43.37	$45.18	$55.97	$27.23
2025	$51.75	$49.83	$46.40	$45.22	$39.33	$42.07	$48.36	$50.94	$44.54	$46.98	$57.18	$53.88
2026	$51.74	$51.59	$48.26	$39.05	$43.37	$44.48	$51.50	$54.31	$49.59	$50.78	$55.97	$54.44

Annual Seasonal Average, OffPeak

Year	Winter Season	Summer Season	Annual Average
2014	$23.33		$23.33
2015	$23.71	$22.54	$23.12
2016	$22.27	$22.87	$22.51
2017	$22.75	$23.88	$23.32
2018	$25.00	$26.86	$25.94
2019	$26.04	$28.50	$27.28
2020	$28.60	$29.87	$29.17
2021	$34.15	$34.10	$34.12
2022	$40.18	$38.72	$39.44
2023	$39.71	$40.86	$40.29
2024	$37.02	$43.45	$40.14
2025	$50.72	$45.39	$48.04
2026	$50.18	$49.03	$49.60

(2): Off-peak Prices have been shaped by the relationship of Palo Verde Off-peak market price to Palo Verde market price.
Off-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly Off-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2B
Avoided Costs for Wind QF
Avoided Energy reduced for Wind Integration Costs - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study (Average Energy Costs less Integration Costs)												
2014											$22.94	$22.73
2015	$21.22	$25.18	$26.05	$23.75	$21.66	$21.46	$28.49	$30.34	$23.97	$21.56	$24.86	$20.64
2016	$19.84	$22.70	$26.07	$21.71	$21.31	$21.90	$29.34	$31.32	$23.90	$20.87	$21.61	$21.88
2017	$21.12	$22.59	$27.51	$21.22	$20.56	$23.07	$30.88	$33.24	$25.88	$22.42	$22.52	$22.30
2018	$23.68	$26.69	$28.42	$24.51	$24.17	$25.66	$33.98	$37.34	$30.13	$26.84	$25.92	$24.80
2019	$24.94	$26.83	$29.35	$24.77	$25.73	$26.87	$36.41	$39.62	$29.78	$29.80	$27.23	$26.68
2020	$24.62	$25.92	$30.23	$28.88	$25.99	$27.89	$38.58	$41.91	$33.02	$29.07	$30.36	$32.88
2021	$27.72	$30.37	$34.18	$30.15	$28.98	$30.70	$42.27	$44.91	$34.90	$33.63	$39.93	$35.47
2022	$34.77	$35.67	$39.18	$37.06	$31.06	$35.15	$46.91	$49.15	$39.18	$35.13	$42.02	$38.81
2023	$35.91	$35.59	$37.95	$31.33	$34.04	$36.63	$49.30	$51.20	$40.23	$39.01	$44.10	$39.96
2024	$12.26	$37.95	$40.91	$40.33	$35.95	$38.54	$52.40	$55.53	$43.86	$43.79	$53.39	$24.08
2025	$49.41	$47.71	$44.74	$43.44	$37.81	$41.39	$56.50	$61.10	$46.24	$45.18	$54.54	$51.38
2026	$49.24	$49.39	$46.67	$37.30	$41.16	$44.35	$62.28	$64.39	$51.07	$48.04	$53.24	$51.84

Annual Seasonal Average

Year	Winter Season	Summer Season	Annual Average
2014	$22.83		$22.83
2015	$23.58	$24.60	$24.10
2016	$22.30	$24.79	$23.49
2017	$22.89	$26.03	$24.47
2018	$25.66	$29.71	$27.70
2019	$26.64	$31.40	$29.04
2020	$28.84	$32.77	$30.74
2021	$32.99	$35.93	$34.47
2022	$37.94	$39.45	$38.70
2023	$37.50	$41.77	$39.65
2024	$34.65	$45.05	$39.78
2025	$48.54	$48.08	$48.31
2026	$47.95	$51.93	$49.96

Source: GRID Production Cost Computer Model Study - Dated
Wind Integration Costs - See Table 10

Table 2B
Avoided Costs for Wind QF
Avoided Energy reduced for Wind Integration Costs - $/MWH

GRID Production Cost Model Study_OnPeak (1)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$25.07	$24.77
2015	$23.37	$27.60	$28.61	$26.97	$25.97	$25.52	$32.87	$35.50	$28.31	$23.50	$26.55	$22.30
2016	$21.63	$24.74	$28.94	$25.57	$25.16	$24.41	$36.56	$36.59	$26.90	$23.00	$23.51	$23.78
2017	$23.15	$24.78	$30.63	$25.23	$24.11	$25.80	$38.33	$38.79	$29.21	$24.81	$24.64	$24.49
2018	$26.01	$29.41	$31.79	$29.11	$28.33	$28.82	$42.05	$43.57	$34.33	$29.67	$28.54	$27.41
2019	$27.31	$29.49	$32.89	$28.97	$29.94	$30.23	$44.21	$45.96	$33.79	$32.82	$29.89	$29.39
2020	$26.92	$28.42	$33.78	$33.55	$30.33	$31.08	$46.54	$48.79	$37.08	$31.96	$32.15	$34.66
2021	$29.31	$32.19	$36.66	$33.18	$32.13	$33.31	$49.39	$51.40	$38.23	$35.75	$40.67	$36.07
2022	$35.42	$36.60	$40.52	$38.49	$32.75	$37.27	$53.60	$55.06	$41.89	$35.93	$42.73	$39.43
2023	$36.63	$36.56	$39.54	$33.04	$35.75	$39.01	$56.79	$57.41	$42.72	$39.67	$44.80	$40.57
2024	$12.55	$38.95	$42.46	$42.03	$37.67	$40.67	$60.11	$62.94	$47.46	$45.40	$54.23	$24.48
2025	$50.47	$48.88	$46.33	$44.84	$39.53	$43.81	$65.82	$72.01	$50.56	$46.55	$55.45	$52.32
2026	$50.24	$50.56	$48.38	$38.78	$42.50	$47.02	$73.76	$75.32	$55.26	$48.78	$54.15	$52.76

Annual Seasonal Average, OnPeak (1)

Year	Winter Season	Summer Season	Annual Average
2014	$24.92		$24.92
2015	$25.86	$28.63	$27.26
2016	$24.70	$28.80	$26.70
2017	$25.50	$30.20	$27.87
2018	$28.70	$34.49	$31.62
2019	$29.66	$36.20	$32.96
2020	$31.60	$37.67	$34.57
2021	$34.70	$40.08	$37.41
2022	$38.88	$42.78	$40.85
2023	$38.55	$45.27	$41.94
2024	$35.61	$49.09	$42.28
2025	$49.73	$53.11	$51.43
2026	$49.15	$57.17	$53.19

(1): On-peak prices have been shaped by the relationship of Palo Verde On-peak market price to Palo Verde market price.
On-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly On-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2B
Avoided Costs for Wind QF
Avoided Energy reduced for Wind Integration Costs - $/MWH

GRID Production Cost Model Study_OffPeak (2)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$20.51	$20.14
2015	$18.50	$21.96	$22.78	$19.36	$16.66	$15.90	$22.94	$23.79	$18.54	$18.89	$22.93	$18.53
2016	$17.76	$19.94	$22.09	$16.42	$16.84	$18.47	$20.93	$24.02	$20.13	$18.16	$19.25	$19.46
2017	$18.75	$19.69	$23.18	$16.20	$16.07	$19.33	$22.22	$25.55	$21.73	$19.39	$19.88	$19.76
2018	$20.73	$23.06	$23.74	$18.77	$18.90	$21.33	$24.60	$28.71	$25.34	$22.92	$22.67	$21.76
2019	$21.94	$23.30	$24.84	$19.02	$20.38	$22.68	$26.51	$30.83	$25.19	$25.63	$23.93	$23.53
2020	$21.69	$22.53	$25.71	$22.49	$20.93	$23.53	$28.49	$33.18	$27.93	$25.07	$28.31	$30.63
2021	$25.87	$27.95	$30.73	$26.00	$25.32	$27.13	$33.24	$36.68	$30.74	$30.94	$39.01	$34.70
2022	$34.01	$34.44	$37.32	$35.10	$29.10	$32.26	$39.12	$40.96	$35.78	$34.13	$41.15	$38.04
2023	$35.07	$34.29	$35.76	$29.19	$31.88	$33.36	$40.60	$42.60	$37.12	$38.16	$43.22	$39.24
2024	$11.88	$36.59	$38.93	$38.01	$33.77	$35.87	$42.62	$45.28	$39.75	$41.56	$52.35	$23.61
2025	$48.06	$46.14	$42.71	$41.53	$35.64	$38.38	$44.67	$47.25	$40.85	$43.29	$53.49	$50.19
2026	$47.97	$47.82	$44.49	$35.28	$39.60	$40.71	$47.73	$50.54	$45.82	$47.01	$52.20	$50.67

Annual Seasonal Average, OffPeak

Year	Winter Season	Summer Season	Annual Average
2014	$20.32		$20.32
2015	$20.65	$19.48	$20.06
2016	$19.16	$19.76	$19.41
2017	$19.59	$20.72	$20.16
2018	$21.78	$23.64	$22.72
2019	$22.76	$25.22	$24.00
2020	$25.26	$26.53	$25.83
2021	$30.74	$30.69	$30.71
2022	$36.70	$35.24	$35.96
2023	$36.16	$37.31	$36.74
2024	$33.40	$39.83	$36.53
2025	$47.03	$41.70	$44.35
2026	$46.41	$45.26	$45.83

(2): Off-peak Prices have been shaped by the relationship of Palo Verde Off-peak market price to Palo Verde market price.
Off-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly Off-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2C
Avoided Costs for Fixed Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

GRID Production Cost Model Study (Average Energy Costs less Integration Costs)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$25.20	$24.99
2015	$23.51	$27.47	$28.34	$26.04	$23.95	$23.75	$30.78	$32.63	$26.26	$23.85	$27.15	$22.93
2016	$22.17	$25.03	$28.40	$24.04	$23.64	$24.23	$31.67	$33.65	$26.23	$23.20	$23.94	$24.21
2017	$23.49	$24.96	$29.88	$23.59	$22.93	$25.44	$33.25	$35.61	$28.25	$24.79	$24.89	$24.67
2018	$26.09	$29.10	$30.83	$26.92	$26.58	$28.07	$36.39	$39.75	$32.54	$29.25	$28.33	$27.21
2019	$27.40	$29.29	$31.81	$27.23	$28.19	$29.33	$38.87	$42.08	$32.24	$32.26	$29.69	$29.14
2020	$27.12	$28.42	$32.73	$31.38	$28.49	$30.39	$41.08	$44.41	$35.52	$31.57	$32.86	$35.38
2021	$30.28	$32.93	$36.74	$32.71	$31.54	$33.26	$44.83	$47.47	$37.46	$36.19	$42.49	$38.03
2022	$37.38	$38.28	$41.79	$39.67	$33.67	$37.76	$49.52	$51.76	$41.79	$37.74	$44.63	$41.42
2023	$38.57	$38.25	$40.61	$33.99	$36.70	$39.29	$51.96	$53.86	$42.89	$41.67	$46.76	$42.62
2024	$14.97	$40.66	$43.62	$43.04	$38.66	$41.25	$55.11	$58.24	$46.57	$46.50	$56.10	$26.79
2025	$52.18	$50.48	$47.51	$46.21	$40.58	$44.16	$59.27	$63.87	$49.01	$47.95	$57.31	$54.15
2026	$52.07	$52.22	$49.50	$40.13	$43.99	$47.18	$65.11	$67.22	$53.90	$50.87	$56.07	$54.67

Annual Seasonal Average

Year	Winter Season	Summer Season	Annual Average
2014	$25.09		$25.09
2015	$25.87	$26.89	$26.39
2016	$24.63	$27.12	$25.82
2017	$25.26	$28.40	$26.84
2018	$28.07	$32.12	$30.11
2019	$29.10	$33.86	$31.50
2020	$31.34	$35.27	$33.24
2021	$35.55	$38.49	$37.03
2022	$40.55	$42.06	$41.31
2023	$40.16	$44.43	$42.31
2024	$37.36	$47.76	$42.48
2025	$51.31	$50.85	$51.08
2026	$50.78	$54.76	$52.79

Source: GRID Production Cost Computer Model Study - Dated
Solar Integration Costs - See Table 10

Table 2C
Avoided Costs for Fixed Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

GRID Production Cost Model Study_OnPeak (1)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$27.33	$27.03
2015	$25.66	$29.89	$30.90	$29.26	$28.26	$27.81	$35.16	$37.79	$30.60	$25.79	$28.84	$24.59
2016	$23.96	$27.07	$31.27	$27.90	$27.49	$26.74	$38.89	$38.92	$29.23	$25.33	$25.84	$26.11
2017	$25.52	$27.15	$33.00	$27.60	$26.48	$28.17	$40.70	$41.16	$31.58	$27.18	$27.01	$26.86
2018	$28.42	$31.82	$34.20	$31.52	$30.74	$31.23	$44.46	$45.98	$36.74	$32.08	$30.95	$29.82
2019	$29.77	$31.95	$35.35	$31.43	$32.40	$32.69	$46.67	$48.42	$36.25	$35.28	$32.35	$31.85
2020	$29.42	$30.92	$36.28	$36.05	$32.83	$33.58	$49.04	$51.29	$39.58	$34.46	$34.65	$37.16
2021	$31.87	$34.75	$39.22	$35.74	$34.69	$35.87	$51.95	$53.96	$40.79	$38.31	$43.23	$38.63
2022	$38.03	$39.21	$43.13	$41.10	$35.36	$39.88	$56.21	$57.67	$44.50	$38.54	$45.34	$42.04
2023	$39.29	$39.22	$42.20	$35.70	$38.41	$41.67	$59.45	$60.07	$45.38	$42.33	$47.46	$43.23
2024	$15.26	$41.66	$45.17	$44.74	$40.38	$43.38	$62.82	$65.65	$50.17	$48.11	$56.94	$27.19
2025	$53.24	$51.65	$49.10	$47.61	$42.30	$46.58	$68.59	$74.78	$53.33	$49.32	$58.22	$55.09
2026	$53.07	$53.39	$51.21	$41.61	$45.33	$49.85	$76.59	$78.15	$58.09	$51.61	$56.98	$55.59

Annual Seasonal Average, OnPeak

Year	Winter Season	Summer Season	Annual Average
2014	$27.18		$27.18
2015	$28.15	$30.92	$29.55
2016	$27.03	$31.13	$29.02
2017	$27.87	$32.57	$30.24
2018	$31.11	$36.90	$34.03
2019	$32.12	$38.66	$35.42
2020	$34.10	$40.17	$37.07
2021	$37.26	$42.64	$39.97
2022	$41.49	$45.39	$43.46
2023	$41.21	$47.93	$44.60
2024	$38.32	$51.80	$44.99
2025	$52.50	$55.88	$54.20
2026	$51.98	$60.00	$56.02

(1): On-peak prices have been shaped by the relationship of Palo Verde On-peak market price to Palo Verde market price.
On-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly On-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2C
Avoided Costs for Fixed Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

GRID Production Cost Model Study_OffPeak (2)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$22.77	$22.40
2015	$20.79	$24.25	$25.07	$21.65	$18.95	$18.19	$25.23	$26.08	$20.83	$21.18	$25.22	$20.82
2016	$20.09	$22.27	$24.42	$18.75	$19.17	$20.80	$23.26	$26.35	$22.46	$20.49	$21.58	$21.79
2017	$21.12	$22.06	$25.55	$18.57	$18.44	$21.70	$24.59	$27.92	$24.10	$21.76	$22.25	$22.13
2018	$23.14	$25.47	$26.15	$21.18	$21.31	$23.74	$27.01	$31.12	$27.75	$25.33	$25.08	$24.17
2019	$24.40	$25.76	$27.30	$21.48	$22.84	$25.14	$28.97	$33.29	$27.65	$28.09	$26.39	$25.99
2020	$24.19	$25.03	$28.21	$24.99	$23.43	$26.03	$30.99	$35.68	$30.43	$27.57	$30.81	$33.13
2021	$28.43	$30.51	$33.29	$28.56	$27.88	$29.69	$35.80	$39.24	$33.30	$33.50	$41.57	$37.26
2022	$36.62	$37.05	$39.93	$37.71	$31.71	$34.87	$41.73	$43.57	$38.39	$36.74	$43.76	$40.65
2023	$37.73	$36.95	$38.42	$31.85	$34.54	$36.02	$43.26	$45.26	$39.78	$40.82	$45.88	$41.90
2024	$14.59	$39.30	$41.64	$40.72	$36.48	$38.58	$45.33	$47.99	$42.46	$44.27	$55.06	$26.32
2025	$50.83	$48.91	$45.48	$44.30	$38.41	$41.15	$47.44	$50.02	$43.62	$46.06	$56.26	$52.96
2026	$50.80	$50.65	$47.32	$38.11	$42.43	$43.54	$50.56	$53.37	$48.65	$49.84	$55.03	$53.50

Annual Seasonal Average, OffPeak

Year	Winter Season	Summer Season	Annual Average
2014	$22.58		$22.58
2015	$22.94	$21.77	$22.35
2016	$21.49	$22.09	$21.73
2017	$21.96	$23.09	$22.53
2018	$24.19	$26.05	$25.13
2019	$25.22	$27.68	$26.46
2020	$27.76	$29.03	$28.33
2021	$33.30	$33.25	$33.27
2022	$39.31	$37.85	$38.57
2023	$38.82	$39.97	$39.40
2024	$36.11	$42.54	$39.24
2025	$49.80	$44.47	$47.12
2026	$49.24	$48.09	$48.66

(2): Off-peak Prices have been shaped by the relationship of Palo Verde Off-peak market price to Palo Verde market price.
Off-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly Off-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2D
Avoided Costs for Tracking Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

GRID Production Cost Model Study (Average Energy Costs less Integration Costs)

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014											$25.20	$24.99
2015	$23.51	$27.47	$28.34	$26.04	$23.95	$23.75	$30.78	$32.63	$26.26	$23.85	$27.15	$22.93
2016	$22.17	$25.03	$28.40	$24.04	$23.64	$24.23	$31.67	$33.65	$26.23	$23.20	$23.94	$24.21
2017	$23.49	$24.96	$29.88	$23.59	$22.93	$25.44	$33.25	$35.61	$28.25	$24.79	$24.89	$24.67
2018	$26.09	$29.10	$30.83	$26.92	$26.58	$28.07	$36.39	$39.75	$32.54	$29.25	$28.33	$27.21
2019	$27.40	$29.29	$31.81	$27.23	$28.19	$29.33	$38.87	$42.08	$32.24	$32.26	$29.69	$29.14
2020	$27.12	$28.42	$32.73	$31.38	$28.49	$30.39	$41.08	$44.41	$35.52	$31.57	$32.86	$35.38
2021	$30.28	$32.93	$36.74	$32.71	$31.54	$33.26	$44.83	$47.47	$37.46	$36.19	$42.49	$38.03
2022	$37.38	$38.28	$41.79	$39.67	$33.67	$37.76	$49.52	$51.76	$41.79	$37.74	$44.63	$41.42
2023	$38.57	$38.25	$40.61	$33.99	$36.70	$39.29	$51.96	$53.86	$42.89	$41.67	$46.76	$42.62
2024	$14.97	$40.66	$43.62	$43.04	$38.66	$41.25	$55.11	$58.24	$46.57	$46.50	$56.10	$26.79
2025	$52.18	$50.48	$47.51	$46.21	$40.58	$44.16	$59.27	$63.87	$49.01	$47.95	$57.31	$54.15
2026	$52.07	$52.22	$49.50	$40.13	$43.99	$47.18	$65.11	$67.22	$53.90	$50.87	$56.07	$54.67

Annual Seasonal Average

Year	Winter Season	Summer Season	Annual Average
2014	$25.09		$25.09
2015	$25.87	$26.89	$26.39
2016	$24.63	$27.12	$25.82
2017	$25.26	$28.40	$26.84
2018	$28.07	$32.12	$30.11
2019	$29.10	$33.86	$31.50
2020	$31.34	$35.27	$33.24
2021	$35.55	$38.49	$37.03
2022	$40.55	$42.06	$41.31
2023	$40.16	$44.43	$42.31
2024	$37.36	$47.76	$42.48
2025	$51.31	$50.85	$51.08
2026	$50.78	$54.76	$52.79

Source: GRID Production Cost Computer Model Study - Dated
Solar Integration Costs - See Table 10

Table 2D
Avoided Costs for Tracking Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study_OnPeak (1)												
2014											$27.33	$27.03
2015	$25.66	$29.89	$30.90	$29.26	$28.26	$27.81	$35.16	$37.79	$30.60	$25.79	$28.84	$24.59
2016	$23.96	$27.07	$31.27	$27.90	$27.49	$26.74	$38.89	$38.92	$29.23	$25.33	$25.84	$26.11
2017	$25.52	$27.15	$33.00	$27.60	$26.48	$28.17	$40.70	$41.16	$31.58	$27.18	$27.01	$26.86
2018	$28.42	$31.82	$34.20	$31.52	$30.74	$31.23	$44.46	$45.98	$36.74	$32.08	$30.95	$29.82
2019	$29.77	$31.95	$35.35	$31.43	$32.40	$32.69	$46.67	$48.42	$36.25	$35.28	$32.35	$31.85
2020	$29.42	$30.92	$36.28	$36.05	$32.83	$33.58	$49.04	$51.29	$39.58	$34.46	$34.65	$37.16
2021	$31.87	$34.75	$39.22	$35.74	$34.69	$35.87	$51.95	$53.96	$40.79	$38.31	$43.23	$38.63
2022	$38.03	$39.21	$43.13	$41.10	$35.36	$39.88	$56.21	$57.67	$44.50	$38.54	$45.34	$42.04
2023	$39.29	$39.22	$42.20	$35.70	$38.41	$41.67	$59.45	$60.07	$45.38	$42.33	$47.46	$43.23
2024	$15.26	$41.66	$45.17	$44.74	$40.38	$43.38	$62.82	$65.65	$50.17	$48.11	$56.94	$27.19
2025	$53.24	$51.65	$49.10	$47.61	$42.30	$46.58	$68.59	$74.78	$53.33	$49.32	$58.22	$55.09
2026	$53.07	$53.39	$51.21	$41.61	$45.33	$49.85	$76.59	$78.15	$58.09	$51.61	$56.98	$55.59

Annual Seasonal Average, OnPeak

Year	Winter Season	Summer Season	Annual Average
2014	$27.18		$27.18
2015	$28.15	$30.92	$29.55
2016	$27.03	$31.13	$29.02
2017	$27.87	$32.57	$30.24
2018	$31.11	$36.90	$34.03
2019	$32.12	$38.66	$35.42
2020	$34.10	$40.17	$37.07
2021	$37.26	$42.64	$39.97
2022	$41.49	$45.39	$43.46
2023	$41.21	$47.93	$44.60
2024	$38.32	$51.80	$44.99
2025	$52.50	$55.88	$54.20
2026	$51.98	$60.00	$56.02

(1): On-peak prices have been shaped by the relationship of Palo Verde On-peak market price to Palo Verde market price.
On-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly On-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 2D
Avoided Costs for Tracking Solar QF
Avoided Energy reduced for Solar Integration Costs - $/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Model Study_OffPeak (2)												
2014											$22.77	$22.40
2015	$20.79	$24.25	$25.07	$21.65	$18.95	$18.19	$25.23	$26.08	$20.83	$21.18	$25.22	$20.82
2016	$20.09	$22.27	$24.42	$18.75	$19.17	$20.80	$23.26	$26.35	$22.46	$20.49	$21.58	$21.79
2017	$21.12	$22.06	$25.55	$18.57	$18.44	$21.70	$24.59	$27.92	$24.10	$21.76	$22.25	$22.13
2018	$23.14	$25.47	$26.15	$21.18	$21.31	$23.74	$27.01	$31.12	$27.75	$25.33	$25.08	$24.17
2019	$24.40	$25.76	$27.30	$21.48	$22.84	$25.14	$28.97	$33.29	$27.65	$28.09	$26.39	$25.99
2020	$24.19	$25.03	$28.21	$24.99	$23.43	$26.03	$30.99	$35.68	$30.43	$27.57	$30.81	$33.13
2021	$28.43	$30.51	$33.29	$28.56	$27.88	$29.69	$35.80	$39.24	$33.30	$33.50	$41.57	$37.26
2022	$36.62	$37.05	$39.93	$37.71	$31.71	$34.87	$41.73	$43.57	$38.39	$36.74	$43.76	$40.65
2023	$37.73	$36.95	$38.42	$31.85	$34.54	$36.02	$43.26	$45.26	$39.78	$40.82	$45.88	$41.90
2024	$14.59	$39.30	$41.64	$40.72	$36.48	$38.58	$45.33	$47.99	$42.46	$44.27	$55.06	$26.32
2025	$50.83	$48.91	$45.48	$44.30	$38.41	$41.15	$47.44	$50.02	$43.62	$46.06	$56.26	$52.96
2026	$50.80	$50.65	$47.32	$38.11	$42.43	$43.54	$50.56	$53.37	$48.65	$49.84	$55.03	$53.50

Annual Seasonal Average, OffPeak

Year	Winter Season	Summer Season	Annual Average
2014	$22.58		$22.58
2015	$22.94	$21.77	$22.35
2016	$21.49	$22.09	$21.73
2017	$21.96	$23.09	$22.53
2018	$24.19	$26.05	$25.13
2019	$25.22	$27.68	$26.46
2020	$27.76	$29.03	$28.33
2021	$33.30	$33.25	$33.27
2022	$39.31	$37.85	$38.57
2023	$38.82	$39.97	$39.40
2024	$36.11	$42.54	$39.24
2025	$49.80	$44.47	$47.12
2026	$49.24	$48.09	$48.66

(2): Off-peak Prices have been shaped by the relationship of Palo Verde Off-peak market price to Palo Verde market price.
Off-Peak Price = [GRID Production Cost Model Avoided Cost Price] x [Monthly Off-Peak Palo Verde Market Price] / [Monthly Palo Verde Market Price]

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 51.9% CF ($/MWH)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 51.9%)
Avoided Energy				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
CCCT Proxy Resource				
2027	$154.04	$145.77	$8.27	$1.82
2028	$156.99	$148.55	$8.44	$1.86
2029	$159.98	$151.38	$8.60	$1.89
2030	$163.02	$154.26	$8.76	$1.93
2031	$166.11	$157.20	$8.91	$1.96
2032	$169.26	$160.20	$9.06	$1.99
2033	$172.67	$163.40	$9.27	$2.04
2034	$175.93	$166.51	$9.42	$2.07
2035	$179.46	$169.84	$9.62	$2.12
2036	$183.04	$173.23	$9.81	$2.16
2037	$186.70	$176.70	$10.00	$2.20
2038	$190.41	$180.25	$10.16	$2.23

Columns
- (a) Table 8 Column (f) - Table 8 Page 2
- (b) Table 8 Column (f) - Table 8 Page 1
- (d) 51.9% CCCT Energy Weighted Capacity Factor - Table 8 Page 3

Table 4
Total Avoided Energy Cost

Year	Gas Fuel Costs Delivered	Energy Cost	Capitalized Energy Costs 51.9% CF	Total Avoided Energy Cost
	($/MMBtu)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)
		(a) x 6.560		(b) + (c)
Avoided Energy				
2014				$25.84
2015				$27.16
2016				$26.59
2017				$27.63
2018				$30.92
2019				$32.32
2020				$34.07
2021				$37.88
2022				$42.18
2023				$43.20
2024				$43.39
2025				$52.00
2026				$53.73
CCCT Proxy Resource				
2027	$6.60	$43.30	$1.82	$45.12
2028	$6.85	$44.94	$1.86	$46.80
2029	$7.14	$46.84	$1.89	$48.73
2030	$7.43	$48.74	$1.93	$50.67
2031	$7.57	$49.66	$1.96	$51.62
2032	$7.71	$50.58	$1.99	$52.57
2033	$7.86	$51.56	$2.04	$53.60
2034	$8.01	$52.55	$2.07	$54.62
2035	$8.17	$53.60	$2.12	$55.72
2036	$8.34	$54.71	$2.16	$56.87
2037	$8.50	$55.76	$2.20	$57.96
2038	$8.67	$56.88	$2.23	$59.11

Columns
- (a) Table 8 Page 2 Column (g)
- (b) Table 8 Page 2 Column (i) Heat rate 6.560 MMBtu/MWh
- (c) Table 3 Column (d)
- (d) For 2014-2026 - Table 2A

Table 5
Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor 75%	85%	95%
	($/kW-yr)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
			(b)+(a)/(8.76 x 0.75)	(b)+((a)/(8.76 x 0.85)	(b)+((a)/(8.76 x 0.95)
Avoided Energy					
2014	$0.00	$25.84	$25.84	$25.84	$25.84
2015	$0.00	$27.16	$27.16	$27.16	$27.16
2016	$0.00	$26.59	$26.59	$26.59	$26.59
2017	$0.00	$27.63	$27.63	$27.63	$27.63
2018	$0.00	$30.92	$30.92	$30.92	$30.92
2019	$0.00	$32.32	$32.32	$32.32	$32.32
2020	$0.00	$34.07	$34.07	$34.07	$34.07
2021	$0.00	$37.88	$37.88	$37.88	$37.88
2022	$0.00	$42.18	$42.18	$42.18	$42.18
2023	$0.00	$43.20	$43.20	$43.20	$43.20
2024	$0.00	$43.39	$43.39	$43.39	$43.39
2025	$0.00	$52.00	$52.00	$52.00	$52.00
2026	$0.00	$53.73	$53.73	$53.73	$53.73
CCCT Proxy Resource					
2027	$145.77	$45.12	$67.31	$64.70	$62.64
2028	$148.55	$46.80	$69.41	$66.75	$64.65
2029	$151.38	$48.73	$71.77	$69.06	$66.92
2030	$154.26	$50.67	$74.15	$71.39	$69.21
2031	$157.20	$51.62	$75.55	$72.73	$70.51
2032	$160.20	$52.57	$76.95	$74.08	$71.82
2033	$163.40	$53.60	$78.47	$75.54	$73.23
2034	$166.51	$54.62	$79.96	$76.98	$74.63
2035	$169.84	$55.72	$81.57	$78.53	$76.13
2036	$173.23	$56.87	$83.24	$80.13	$77.69
2037	$176.70	$57.96	$84.85	$81.69	$79.19
2038	$180.25	$59.11	$86.55	$83.32	$80.77

Columns
- (a) Table 3 Column (b)
- (b) Table 4 Column (d)

Table 6A
Base Load - On- & Off Peak- Avoided Cost Prices

		Base Load QF			
Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Avoided Energy Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 91.1% x 57%)			
Avoided Energy					
2014	$0.00	$0.00	$25.84	$27.93	$23.33
2015	$0.00	$0.00	$27.16	$30.32	$23.12
2016	$0.00	$0.00	$26.59	$29.80	$22.51
2017	$0.00	$0.00	$27.63	$31.03	$23.32
2018	$0.00	$0.00	$30.92	$34.84	$25.94
2019	$0.00	$0.00	$32.32	$36.24	$27.28
2020	$0.00	$0.00	$34.07	$37.91	$29.17
2021	$0.00	$0.00	$37.88	$40.82	$34.12
2022	$0.00	$0.00	$42.18	$44.33	$39.44
2023	$0.00	$0.00	$43.20	$45.49	$40.29
2024	$0.00	$0.00	$43.39	$45.89	$40.14
2025	$0.00	$0.00	$52.00	$55.12	$48.04
2026	$0.00	$0.00	$53.73	$56.96	$49.60
CCCT Proxy Resource					
2027	$145.77	$32.05	$45.12	$77.17	$45.12
2028	$148.55	$32.66	$46.80	$79.46	$46.80
2029	$151.38	$33.28	$48.73	$82.01	$48.73
2030	$154.26	$33.91	$50.67	$84.58	$50.67
2031	$157.20	$34.56	$51.62	$86.18	$51.62
2032	$160.20	$35.22	$52.57	$87.79	$52.57
2033	$163.40	$35.92	$53.60	$89.52	$53.60
2034	$166.51	$36.61	$54.62	$91.23	$54.62
2035	$169.84	$37.34	$55.72	$93.06	$55.72
2036	$173.23	$38.08	$56.87	$94.95	$56.87
2037	$176.70	$38.85	$57.96	$96.81	$57.96
2038	$180.25	$39.63	$59.11	$98.74	$59.11

Columns
- (a) Table 3 Column (b)
- (b) Table 8 91.1% is the on-peak capacity factor of the Proxy Resource
- (c) Table 4 Column (d)

Table 6B
Wind- On- & Off- Peak - Avoided Cost Prices

Year	Wind QF: Capacity Cost Allocated to On-Peak Hours ($/MWH)	Total Avoided Energy Cost ($/MWH)	Wind Integration Cost ($/MWH)	On-Peak 4,993 Hours ($/MWH)	Off-Peak 3,767 Hours ($/MWH)
	(a)	(b)	(c)	(d)	(e)
	Table 6A (b) * 14.5%	Table 6A (c)			
Avoided Energy					
2014	$0.00	$25.84	$3.01	$24.92	$20.32
2015	$0.00	$27.16	$3.06	$27.26	$20.06
2016	$0.00	$26.59	$3.11	$26.69	$19.40
2017	$0.00	$27.63	$3.16	$27.87	$20.16
2018	$0.00	$30.92	$3.22	$31.62	$22.72
2019	$0.00	$32.32	$3.28	$32.96	$24.00
2020	$0.00	$34.07	$3.34	$34.57	$25.83
2021	$0.00	$37.88	$3.41	$37.41	$30.71
2022	$0.00	$42.18	$3.48	$40.85	$35.96
2023	$0.00	$43.20	$3.55	$41.94	$36.74
2024	$0.00	$43.39	$3.62	$42.27	$36.52
2025	$0.00	$52.00	$3.69	$51.43	$44.35
2026	$0.00	$53.73	$3.77	$53.19	$45.83
CCCT Proxy Resource					
2027	$4.65	$45.12	$3.84	$45.93	$41.28
2028	$4.74	$46.80	$3.92	$47.62	$42.88
2029	$4.83	$48.73	$3.99	$49.57	$44.74
2030	$4.92	$50.67	$4.07	$51.52	$46.60
2031	$5.01	$51.62	$4.14	$52.49	$47.48
2032	$5.11	$52.57	$4.22	$53.46	$48.35
2033	$5.21	$53.60	$4.31	$54.50	$49.29
2034	$5.31	$54.62	$4.39	$55.54	$50.23
2035	$5.41	$55.72	$4.48	$56.65	$51.24
2036	$5.52	$56.87	$4.57	$57.82	$52.30
2037	$5.63	$57.96	$4.66	$58.93	$53.30
2038	$5.75	$59.11	$4.75	$60.11	$54.36

Columns
- (a) Table 6A Column (b) multiplied by Capacity Contribution of 14.5%
- (b) Table 6A Column (c)
- (c) Table 10 Column (c)

Capacity Contribution
Wind QF 14.5%
Source: 2014 Capacity contribution study

Table 6C
Solar (Fixed) - On- & Off- Peak - Avoided Cost Prices

Year	Solar-Fixed QF Capacity Cost Allocated to On-Peak Hours ($/MWH)	Total Avoided Energy Cost ($/MWH)	Solar Integration Cost ($/MWH)	On-Peak 4,993 Hours ($/MWH)	Off-Peak 3,767 Hours ($/MWH)
	(a)	(b)	(c)	(d)	(e)
	Table 6A (b)	Table 6A (c)			
Avoided Energy					
2014	$0.00	$25.84	$0.75	$27.18	$22.58
2015	$0.00	$27.16	$0.77	$29.55	$22.35
2016	$0.00	$26.59	$0.78	$29.02	$21.73
2017	$0.00	$27.63	$0.79	$30.24	$22.53
2018	$0.00	$30.92	$0.81	$34.03	$25.13
2019	$0.00	$32.32	$0.82	$35.42	$26.46
2020	$0.00	$34.07	$0.84	$37.07	$28.33
2021	$0.00	$37.88	$0.85	$39.97	$33.27
2022	$0.00	$42.18	$0.87	$43.46	$38.57
2023	$0.00	$43.20	$0.89	$44.60	$39.40
2024	$0.00	$43.39	$0.91	$44.98	$39.23
2025	$0.00	$52.00	$0.92	$54.20	$47.12
2026	$0.00	$53.73	$0.94	$56.02	$48.66
CCCT Proxy Resource					
2027	$10.93	$45.12	$0.96	$55.09	$44.16
2028	$11.14	$46.80	$0.98	$56.96	$45.82
2029	$11.35	$48.73	$1.00	$59.08	$47.73
2030	$11.56	$50.67	$1.02	$61.21	$49.65
2031	$11.78	$51.62	$1.04	$62.36	$50.58
2032	$12.01	$52.57	$1.06	$63.52	$51.51
2033	$12.25	$53.60	$1.08	$64.77	$52.52
2034	$12.48	$54.62	$1.10	$66.00	$53.52
2035	$12.73	$55.72	$1.12	$67.33	$54.60
2036	$12.99	$56.87	$1.14	$68.72	$55.73
2037	$13.25	$57.96	$1.17	$70.04	$56.79
2038	$13.51	$59.11	$1.19	$71.43	$57.92

Columns
- (a) Table 6A Column (b) multiplied by Capacity Contribution of 34.1%
- (b) Table 6A Column (c)
- (c) Table 10 Column (c)

Capacity Contribution
Solar-Fixed QF 34.1%
Source: 2014 Capacity contribution study

Table 6D
Solar (Tracking) - On- & Off- Peak - Avoided Cost Prices

Year	Solar-Tracking QF				
	Capacity Cost Allocated to On-Peak Hours	Total Avoided Energy Cost	Solar Integration Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/MWH)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
	Table 6A (b)	Table 6A (c)			
Avoided Energy					
2014	$0.00	$25.84	$0.75	$27.18	$22.58
2015	$0.00	$27.16	$0.77	$29.55	$22.35
2016	$0.00	$26.59	$0.78	$29.02	$21.73
2017	$0.00	$27.63	$0.79	$30.24	$22.53
2018	$0.00	$30.92	$0.81	$34.03	$25.13
2019	$0.00	$32.32	$0.82	$35.42	$26.46
2020	$0.00	$34.07	$0.84	$37.07	$28.33
2021	$0.00	$37.88	$0.85	$39.97	$33.27
2022	$0.00	$42.18	$0.87	$43.46	$38.57
2023	$0.00	$43.20	$0.89	$44.60	$39.40
2024	$0.00	$43.39	$0.91	$44.98	$39.23
2025	$0.00	$52.00	$0.92	$54.20	$47.12
2026	$0.00	$53.73	$0.94	$56.02	$48.66
CCCT Proxy Resource					
2027	$12.53	$45.12	$0.96	$56.69	$44.16
2028	$12.77	$46.80	$0.98	$58.59	$45.82
2029	$13.01	$48.73	$1.00	$60.74	$47.73
2030	$13.26	$50.67	$1.02	$62.91	$49.65
2031	$13.51	$51.62	$1.04	$64.09	$50.58
2032	$13.77	$52.57	$1.06	$65.28	$51.51
2033	$14.04	$53.60	$1.08	$66.56	$52.52
2034	$14.31	$54.62	$1.10	$67.83	$53.52
2035	$14.60	$55.72	$1.12	$69.20	$54.60
2036	$14.89	$56.87	$1.14	$70.62	$55.73
2037	$15.19	$57.96	$1.17	$71.98	$56.79
2038	$15.50	$59.11	$1.19	$73.42	$57.92

Columns
- (a) Table 6A Column (b) multiplied by Capacity Contribution of 34.1%
- (b) Table 6A Column (c)
- (c) Table 10 Column (c)

Capacity Contribution
Solar-Tracking QF 39.1%
Source: 2014 Capacity contribution study

Table 7
Comparison between Proposed and Current Avoided Costs

Year	BASE LOAD: Total Avoided Costs with Capacity Costs included at 85.0% Capacity Factor			WIND: Total Avoided Costs with Capacity Costs included at 40.0% Capacity Factor			SOLAR FIXED: Total Avoided Costs with Capacity Costs included at 18.5% Capacity Factor			SOLAR TRACKING: Total Avoided Costs with Capacity Costs included at 29.0% Capacity Factor		
	Proposed (1) Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Difference ($/MWH)	Proposed (1) Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Difference ($/MWH)	Proposed (1) Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Difference ($/MWH)	Proposed (1) Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Difference ($/MWH)
	(a)	(b)	(c) (a) - (b)	(a)	(b)	(c) (a) - (b)	(a)	(b)	(c) (a) - (b)	(a)	(b)	(c) (a) - (b)
2014	$25.91	$30.88	($4.97)	$22.98	$35.99	($13.01)	$26.52	$47.21	($20.69)	$26.51	$39.65	($13.14)
2015	$27.16	$33.07	($5.91)	$24.05	$38.27	($14.22)	$28.65	$49.70	($21.05)	$28.65	$42.00	($13.35)
2016	$26.67	$33.87	($7.20)	$23.25	$39.16	($15.91)	$28.28	$50.78	($22.50)	$28.35	$42.96	($14.61)
2017	$27.64	$34.84	($7.20)	$24.08	$40.22	($16.14)	$29.41	$52.03	($22.62)	$29.50	$44.08	($14.58)
2018	$30.93	$37.54	($6.61)	$27.16	$43.00	($15.84)	$33.10	$55.00	($21.90)	$33.22	$46.92	($13.70)
2019	$32.30	$41.15	($8.85)	$28.35	$46.70	($18.35)	$34.53	$58.89	($24.36)	$34.68	$50.68	($16.00)
2020	$34.15	$44.68	($10.53)	$30.28	$50.33	($20.05)	$36.26	$62.71	($26.45)	$36.38	$54.37	($17.99)
2021	$37.88	$49.78	($11.90)	$34.06	$55.53	($21.47)	$39.31	$68.15	($28.84)	$39.42	$59.65	($20.23)
2022	$42.18	$57.23	($15.05)	$38.52	$63.09	($24.57)	$42.96	$75.95	($32.99)	$43.02	$67.28	($24.26)
2023	$43.21	$60.57	($17.36)	$38.99	$66.54	($27.55)	$44.25	$79.64	($35.39)	$44.44	$70.81	($26.37)
2024	$43.50	$62.25	($18.75)	$38.11	$68.33	($30.22)	$45.13	$81.69	($36.56)	$45.61	$72.69	($27.08)
2025	$52.01	$66.74	($14.73)	$48.54	$91.53	($42.99)	$53.32	$145.97	($92.65)	$53.29	$109.30	($56.01)
2026	$53.73	$70.20	($16.47)	$49.38	$95.46	($46.08)	$55.41	$150.92	($95.51)	$55.59	$113.56	($57.97)
2027	$63.09	$70.92	($7.83)	$43.99	$96.66	($52.67)	$53.51	$153.18	($99.67)	$54.73	$115.11	($60.38)
2028	$65.11	$72.13	($7.02)	$45.64	$98.36	($52.72)	$55.35	$155.96	($100.61)	$56.59	$117.16	($60.57)
2029	$67.39	$73.63	($6.24)	$47.55	$100.36	($52.81)	$57.44	$159.05	($101.61)	$58.71	$119.52	($60.81)
2030	$69.68	$74.57	($4.89)	$49.46	$101.82	($52.36)	$59.54	$161.62	($102.08)	$60.84	$121.34	($60.50)
2031	$71.00	$76.68	($5.68)	$50.39	$104.47	($54.08)	$60.65	$165.47	($104.82)	$61.98	$124.38	($62.40)
2032	$72.32	$78.23	($5.91)	$51.32	$106.58	($55.26)	$61.78	$168.80	($107.02)	$63.13	$126.89	($63.76)
2033	$73.74	$79.79	($6.05)	$52.32	$108.71	($56.39)	$63.00	$172.18	($109.18)	$64.37	$129.42	($65.05)
2034	$75.15	$81.37	($6.22)	$53.32	$110.86	($57.54)	$64.19	$175.60	($111.41)	$65.59	$131.99	($66.40)
2035	$76.66	$83.03	($6.37)	$54.39	$113.11	($58.72)	$65.49	$179.14	($113.65)	$66.92	$134.66	($67.74)

20 Year (2015 to 2034) Levelized Prices (Nominal) @ 6.882% Discount Rate (2)

$/MWH	$44.09	$53.74	($9.65)	$36.13	$66.51	($30.38)	$42.75	$94.54	($51.79)	$43.16	$75.66	($32.50)

Columns
(a) Table 5 Column (d)
(b) Avoided Costs approved by the Commission - November 2012

Note: (1) Proposed avoided costs are based on volumetric prices using hypothetical generation profiles.
(2) Discount Rate - 2013 IRP Update Discount Rate

Table 8
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWH	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr
	(a)	(b)	(c)	(d)	(e)	(f)
SCCT Frame "F" x 1 - East Side Resource (4,250')						
2012	$762	$60.57	$31.22	$10.22	$50.02	$110.59
2013		$61.42	$31.66	$10.36	$50.72	$112.14
2014		$62.46	$32.20	$10.54	$51.59	$114.05
2015		$63.58	$32.78	$10.73	$52.52	$116.10
2016		$64.53	$33.27	$10.89	$53.30	$117.83
2017		$65.69	$33.87	$11.09	$54.27	$119.96
2018		$66.94	$34.51	$11.30	$55.30	$122.24
2019		$68.14	$35.13	$11.50	$56.29	$124.43
2020		$69.43	$35.80	$11.72	$57.36	$126.79
2021		$70.82	$36.52	$11.95	$58.50	$129.32
2022		$72.24	$37.25	$12.19	$59.67	$131.91
2023		$73.68	$38.00	$12.43	$60.87	$134.55
2024		$75.23	$38.80	$12.69	$62.14	$137.37
2025		$76.73	$39.58	$12.94	$63.38	$140.11
2026		$78.26	$40.37	$13.20	$64.65	$142.91
2027		$79.83	$41.18	$13.46	$65.94	$145.77
2028		$81.35	$41.96	$13.72	$67.20	$148.55
2029		$82.90	$42.76	$13.98	$68.48	$151.38
2030		$84.48	$43.57	$14.25	$69.78	$154.26
2031		$86.09	$44.40	$14.52	$71.11	$157.20
2032		$87.73	$45.24	$14.80	$72.47	$160.20
2033		$89.48	$46.14	$15.10	$73.92	$163.40
2034		$91.18	$47.02	$15.39	$75.33	$166.51
2035		$93.00	$47.96	$15.70	$76.84	$169.84
2036		$94.86	$48.92	$16.01	$78.37	$173.23
2037		$96.76	$49.90	$16.33	$79.94	$176.70
2038		$98.70	$50.90	$16.66	$81.55	$180.25

Source: (a)(c)(d) Plant Costs - 2013 IRP - Table 6.1 & 6.2
(b) = (a) x 0.07954 Payment Factor
(e) = (d) x (8.76 x 21%) + (c)
(f) = (b) + (e)

SCCT Frame "F" x 1 - East Side Resource (4,250')	
181	MW Plant capacity
$762	Plant capacity cost - in $/kW
$8.79	Fixed O&M including Fixed Pipeline & on-going capital cost
$22.43	Fixed Pipeline
$31.22	Fixed O&M including Fixed Pipeline & Capitalized O&M ($/kW-Yr)
$10.22	Variable O&M Costs in $/MWh
7.954%	Payment Factor
21%	Capacity Factor

Table 8
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWH	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr	Fuel Cost $/MMBtu	Total Resource Energy Cost $/MWh	Total Resource Costs $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
CCCT Dry "J", Adv 1x1 - East Side Resource (5,050')									
2012	$1,015	$80.04	$24.78	$2.63	$36.74	$116.78			
2013		$81.16	$25.13	$2.67	$37.27	$118.43			
2014		$82.54	$25.56	$2.72	$37.93	$120.47			
2015		$84.03	$26.02	$2.77	$38.61	$122.64			
2016		$85.29	$26.41	$2.81	$39.19	$124.48			
2017		$86.83	$26.89	$2.86	$39.89	$126.72			
2018		$88.48	$27.40	$2.91	$40.63	$129.11			
2019		$90.07	$27.89	$2.96	$41.35	$131.42			
2020		$91.78	$28.42	$3.02	$42.15	$133.93			
2021		$93.62	$28.99	$3.08	$42.99	$136.61			
2022		$95.49	$29.57	$3.14	$43.85	$139.34			
2023		$97.40	$30.16	$3.20	$44.71	$142.11			
2024		$99.45	$30.79	$3.27	$45.66	$145.11			
2025		$101.44	$31.41	$3.34	$46.60	$148.04			
2026		$103.47	$32.04	$3.41	$47.54	$151.01			
2027		$105.54	$32.68	$3.48	$48.50	$154.04	$6.60	$43.30	$77.18
2028		$107.55	$33.30	$3.55	$49.44	$156.99	$6.85	$44.94	$79.47
2029		$109.59	$33.93	$3.62	$50.39	$159.98	$7.14	$46.84	$82.03
2030		$111.67	$34.57	$3.69	$51.35	$163.02	$7.43	$48.74	$84.60
2031		$113.79	$35.23	$3.76	$52.32	$166.11	$7.57	$49.66	$86.20
2032		$115.95	$35.90	$3.83	$53.31	$169.26	$7.71	$50.58	$87.81
2033		$118.27	$36.62	$3.91	$54.40	$172.67	$7.86	$51.56	$89.54
2034		$120.52	$37.32	$3.98	$55.41	$175.93	$8.01	$52.55	$91.25
2035		$122.93	$38.07	$4.06	$56.53	$179.46	$8.17	$53.60	$93.07
2036		$125.39	$38.83	$4.14	$57.65	$183.04	$8.34	$54.71	$94.97
2037		$127.90	$39.61	$4.22	$58.80	$186.70	$8.50	$55.76	$96.83
2038		$130.46	$40.40	$4.30	$59.95	$190.41	$8.67	$56.88	$98.76

Table 8
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d) Plant Costs - 2013 IRP - Table 6.1 & 6.2
(b) = (a) x 0.07886 Payment Factor
(e) = (d) x (8.76 x 51.9%) + (c)
(f) = (b) + (e)
(g) -
(h) = 6,560 MMBtu/MWH x (g)
(i) = (f) / (8.76 x 'Capacity Factor') + (h)

CCCT Dry "J", Adv 1x1 - East Side Resource (5,050')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "J" 1x1)	380	89.8%	$1,075	$25.39
CCCT Duct Firing (Dry "J" 1x1)	43	10.2%	$486	$19.41
Capacity Weighted	423	100.0%	$1,015	$24.78

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "J" 1x1)	380	56.0%	213	96.9%	$2.72	6,495
CCCT Duct Firing (Dry "J" 1x1)	43	16.0%	7	3.1%	0.08	8,611
Energy Weighted	423	51.9%	220	100.0%	$2.63	6,560
						Rounded

CCCT	Duct Firing	Plant Costs - 2013 IRP - Table 6.1 & 6.2
380	43	MW Plant capacity
$1,075	$486	Plant capacity cost
$10.75	$0.00	Fixed O&M & Capitalized O&M
$14.64	$19.41	Fixed Pipeline
$25.39	$19.41	Fixed O&M including Fixed Pipeline & on-going capital cost
$2.72	$0.08	Variable O&M Costs & Capitalized Variable O&M ($/MWh)
6,495	8,611	Heat Rate in btu/kWh
7.886%	7.886%	Payment Factor
56%	16%	Capacity Factor
	51.9%	Energy Weighted Capacity Factor
	91.1%	Capacity Factor - On-peak 51.9% / 57% (percent of hours on-peak)

Company Official Inflation Forecast Dated September 2014 Forecast

2012		2021	2.0%	2030	1.9%
2013	1.4%	2022	2.0%	2031	1.9%
2014	1.7%	2023	2.0%	2032	1.9%
2015	1.8%	2024	2.1%	2033	2.0%
2016	1.5%	2025	2.0%	2034	1.9%
2017	1.8%	2026	2.0%	2035	2.0%
2018	1.9%	2027	2.0%	2036	2.0%
2019	1.8%	2028	1.9%	2037	2.0%
2020	1.9%	2029	1.9%	2038	2.0%

Table 9
Natural Gas Price - Delivered to Plant
$/MMBtu

Year	Burnertip East Side Gas Fuel Cost
	(a)
2027	$6.60
2028	$6.85
2029	$7.14
2030	$7.43
2031	$7.57
2032	$7.71
2033	$7.86
2034	$8.01
2035	$8.17
2036	$8.34
2037	$8.50
2038	$8.67

Source
Offical Market Price Forecast dated September 2014

Table 10
Integration Costs
$/MWh

Year	Inter-hour Wind Integration Costs $/MWh	Intra-hour Wind Integration Costs $/MWh	Total Wind Integration Costs $/MWh	Solar Integration Costs $/MWh	Inflation Forecast
	(a)	(b)	(c) = (a) +(b)	(d) = (c) * 25%	(e)
2014	$0.70	$2.31	$3.01	$0.75	1.7%
2015	$0.71	$2.35	$3.06	$0.77	1.8%
2016	$0.72	$2.39	$3.11	$0.78	1.5%
2017	$0.73	$2.43	$3.16	$0.79	1.8%
2018	$0.75	$2.47	$3.22	$0.81	1.9%
2019	$0.76	$2.52	$3.28	$0.82	1.8%
2020	$0.78	$2.57	$3.34	$0.84	1.9%
2021	$0.79	$2.62	$3.41	$0.85	2.0%
2022	$0.81	$2.67	$3.48	$0.87	2.0%
2023	$0.82	$2.72	$3.55	$0.89	2.0%
2024	$0.84	$2.78	$3.62	$0.91	2.1%
2025	$0.86	$2.84	$3.69	$0.92	2.0%
2026	$0.87	$2.89	$3.77	$0.94	2.0%
2027	$0.89	$2.95	$3.84	$0.96	2.0%
2028	$0.91	$3.01	$3.92	$0.98	1.9%
2029	$0.93	$3.06	$3.99	$1.00	1.9%
2030	$0.94	$3.12	$4.07	$1.02	1.9%
2031	$0.96	$3.18	$4.14	$1.04	1.9%
2032	$0.98	$3.24	$4.22	$1.06	1.9%
2033	$1.00	$3.31	$4.31	$1.08	2.0%
2034	$1.02	$3.37	$4.39	$1.10	1.9%
2035	$1.04	$3.44	$4.48	$1.12	2.0%
2036	$1.06	$3.51	$4.57	$1.14	2.0%
2037	$1.08	$3.58	$4.66	$1.17	2.0%
2038	$1.10	$3.65	$4.75	$1.19	2.0%

Source:
Wind Integration costs -Table H.21 of 2014 Wind Integartion study provided as Exhibit___(GND-1) - Wind Integration Study
Solar Integration - 25% of wind integration costs as used by the most recent IRP study

Docket No. 20000-___-EA-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Gregory N. Duvall

November 2014

Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, Net Power Costs.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

PURPOSE OF TESTIMONY AND RECOMMENDATION

Q. What is the purpose of your testimony?

A. My testimony is provided in support of the Company's November 7, 2014 filing to update Schedule 37, Avoided Cost Purchases from Qualifying Facilities. The Company's filing provides updated Schedule 37 prices and proposes several changes to the way avoided costs are calculated for Schedule 37. My testimony provides support for each change proposed by the Company.

Q. What QF resources qualify for Schedule 37 pricing?

A. Published rates under Schedule 37 are available to QFs up to 1 MW capacity and with an annual capacity factor of 70 percent or lower, or to QF projects up to 10 MW and with a capacity factor higher than 70 percent.

Q. Please describe the specific changes to the calculation of Schedule 37 rates as proposed by the Company.

A. The Company proposes the following changes to the calculation of avoided cost rates in Schedule 37:

- Integration costs for wind and solar qualifying facilities ("QFs") should be included as a reduction to avoided costs consistent with the integrated resource plan ("IRP").
- Avoided capacity costs should be adjusted for the capacity contribution of intermittent QF resources consistent with the IRP.
- Determination of the resource deficiency period, and avoided capacity costs, should be based on the next deferrable resource identified in the Company's most recent IRP or IRP update.
- Avoided costs during the sufficiency period should not include capacity costs related to the deferral of a simple cycle combustion turbine ("SCCT") consistent with the IRP and pricing for large QFs under Schedule 38. Avoided costs should be offered on a volumetric basis (i.e. dollars-per-megawatt-hour, or $/MWh), replacing the rates paid as a fixed capacity payment plus a flat energy rate.

Q. Was the Company required to update the Schedule 37 avoided cost rates irrespective of the proposed changes?

A. Yes. The Company is required to file updated system data and avoided cost rates in order to be in compliance Section 317 of the Commission's Rules regarding arrangements between electric utilities and QFs within the meaning of Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Section 317 (e) of the Commission's Rules requires system data from which avoided costs may be derived to be filed not less often than every two years.

Q. When were the rates currently in effect approved by the Commission?

A. Wyoming Schedule 37 rates were last approved by the Commission November 19, 2012.

Q. Why is the Company proposing changes to the way Schedule 37 is calculated?

A. The proposed changes are required to achieve the PURPA objective of customer indifference to the Company's mandatory purchase obligation of QF output at avoided cost rates. The Company's proposed changes achieve this objective by reflecting avoided costs consistent with the Company's most recent resource planning information, accounting for the unique characteristics of intermittent QF resources, and eliminating unnecessary differences between the calculation of avoided costs for small QFs under Schedule 37 and large QFs under Schedule 38.

Without the proposed changes to the Schedule 37 methodology, retail customers will pay prices for QFs that are higher than the avoided cost of energy and capacity from other sources.

Q. What is the impact of updating Schedule 37 avoided cost rates?

A. Table 1 below shows the current Schedule 37 rates and the updated rates including the proposed changes in methodology.

Table 1

20 Year (2015 to 2034) Nominal Levelized Prices ($/MWh)			
	Current Rates (A)	Proposed Volumetric Rates (B)	Change (C)
Base Load (85% of CF)	$53.74	$44.09	($9.65)
Wind (40% of CF)	$66.51	$36.13	($30.38)
Fixed-Tilt Solar (18.5% of CF)	$94.54	$42.75	($51.79)
Tracking Solar (29% of CF)	$75.66	$43.16	($32.50)

Q. Are the proposed Schedule 37 rates in this filing in-line with rates in any other states served by the Company?

A. Yes. On October 21, 2014, the Utah Public Service Commission approved updated Schedule 37 rates. The Company's proposed changes to Wyoming Schedule 37 are identical to changes recently approved in Utah Schedule 37 rates. Table 2 below shows that the proposed Wyoming Schedule 37 rates are comparable to those recently approved in Utah.

Table 2

QF Resource Type	Proposed WY Schedule 37 Price ($/MWh)	Current UT Schedule 37 Price ($/MWh)
Base Load	$44.09	$45.46
Wind	$36.13	$35.79
Fixed-Tilt Solar	$42.75	$43.77
Tracking Solar	$43.16	$45.81

Q. How is the remainder of your testimony organized?

A. I first provide background information regarding the current method approved by the Commission for calculating avoided cost rates under Schedule 37. Next, I discuss each of the proposed changes and provide support for each change.

SCHEDULE 37 BACKGROUND

Q. Please provide a brief history of Schedule 37 pricing in Wyoming.

A. The framework for the calculation of rates under Schedule 37 was first approved by the Commission in Docket No. 20000-ET-92-45 and Docket No. 20000-ET-92-18. Schedule 37 prices have been reviewed and updated in several subsequent dockets, including most recently in Docket No. 20000-419-EA-12.

Q. Please describe the currently-approved method for calculating avoided costs for small QFs qualifying for published rates under Schedule 37.

A. The determination of avoided costs is divided into two periods: resource sufficiency and resource deficiency. During the sufficiency period, avoided energy costs are calculated using GRID, the Company's production cost model. Net power costs ("NPC") are calculated in GRID using two system dispatch simulations; one without any new QF resources and one with an additional 50 average megawatt ("aMW") resource included at zero cost. The difference in NPC between the two GRID runs divided by the energy produced by the 50 aMW QF resource determine the avoided energy cost. The current method also includes an additional capacity payment based on a three-month seasonal capacity purchase priced at the fixed cost of a SCCT. During the deficiency period avoided costs are equal to the fixed and variable costs of a proxy resource, currently a combined cycle combustion turbine ("CCCT").

Q. Is this same method used to calculate avoided costs for large QFs under Schedule 38?

A. No. Avoided costs for large QFs under Schedule 38 are calculated using the Partial Displacement Differential Revenue Requirement ("PDDRR") method. The methods are similar in that both utilize the GRID model to determine avoided costs during the sufficiency period and both include capacity costs of a CCCT in the deficiency period. The PDDRR method, however, continues to use a combination of the GRID model to determine energy costs and partial displacement of a CCCT to determine capacity costs during the deficiency period rather than basing avoided costs solely on the proxy CCCT capacity and energy costs. Furthermore, the PDDRR method accounts for the specific characteristics of a proposed QF, including geographic location and any transmission constraints, and prices are prepared for individual QF projects using project specific generation profiles rather than providing the same published prices for all QFs.

Q. Will the changes proposed by the Company make Schedule 37 unnecessarily complicated?

A. No. The changes proposed by the Company are discrete and easy to administer. Distinct rates will be published for base load, solar, and wind resources, and the mechanics of the avoided cost calculation for capacity and energy costs will largely remain intact. The benefits of transparency and ease of use afforded by Schedule 37 will not be diminished by the Company's proposals in this filing.

PROPOSED CHANGES

Integration Costs

Q. What does the Company propose with regard to integration costs in Schedule 37?

A. The Company proposes to publish distinct price streams for wind and solar resources that are reduced by the cost of integrating intermittent resources onto the Company system, consistent with the current method approved for large QFs. Tables 6A through 6D in Exhibit 3 of the Company's filing show how the adjustment for integration costs is made to the avoided cost rates.

Q. How are integration costs calculated?

A. The Company has prepared studies to calculate wind integration costs in the last several IRPs. The most recent study was completed in October 2014 and has been submitted to a technical review committee. A copy of the latest study is provided as Exhibit RMP___(GND-1). The 2014 wind integration study calculated integration costs for wind resources of $3.06/MWh in 2015 dollars.

Wind integration studies are performed to estimate the operating reserves required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards. The Company must provide sufficient operating reserves to allow the Balancing Authority to meet NERC's control performance criteria at all times. These incremental operating reserves are necessary to maintain area control error within required parameters due to sources outside the direct control of system operators including intra-hour changes in load demand and wind generation. The study results in a volume of operating reserves and the associated cost of these operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas. In the current Schedule 37 filing, the Company used the costs calculated in its 2014 integration study to adjust the avoided costs for wind QFs. In addition, the wind study determines the system balancing costs required to manage wind resources. System balancing costs capture the costs associated with the need to commit resources on a day-ahead basis, but operating those resources against actual conditions that occur the next day.

Q. Has the Company also completed a solar integration study?

A. No. The Company has not yet performed a solar integration study. As a result, solar integration costs in the current filing were assumed to be 25 percent of wind integration costs, which is consistent with the assumptions used in the Company's IRP. When a solar integration study is available, the Company will include it in future applications to update Schedule 37.

Q. Has the Commission addressed how integration costs should be included in the calculation of avoided costs for intermittent resources?

A. Yes. In its Order in Docket No. 20000-250-EA-06 (Record No. 10636) the Commission approved a Stipulation that required deduction of integration costs from the avoided costs when determining avoided costs prices for large QFs with intermittent generation.

Q. Do current Schedule 37 rates include an adjustment for integration costs?

A. No.

Q. Are retail customers indifferent if integration costs are not included in the calculation of avoided costs?

A. No. If an adjustment is not made to avoided costs to account for the cost to integrate intermittent resources, retail customers must bear the cost of integrating these resources into the Company's system, violating the ratepayer indifference objective prescribed by PURPA.

Capacity Contribution

Q. What does the Company propose with regard to capacity contribution in Schedule 37?

A. Capacity costs included in the calculation of Schedule 37 rates should be adjusted to reflect the capacity contribution of intermittent wind and solar resources. The capacity contribution of wind and solar resources, represented as a percentage of a resource's nameplate capacity, is a measure of the ability of these resources to reliably meet demand. For purposes of calculating Schedule 37 avoided cost prices, the capacity contribution of a QF resource must be applied to the fixed costs of the deferred proxy CCCT to accurately determine the capacity costs that can be avoided due to the addition of the QF resource.

Q. How is the capacity contribution of wind and solar resources calculated?

A. The Company recently completed a capacity contribution study in support of its 2015 IRP. The Company calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method ("CF Method") as outlined in a 2012 report produced by the National Renewable Energy Laboratory.[1] A description of the Company's study and the resulting capacity contributions for wind and solar resources are provided as Exhibit RMP___(GND-2). The results of the study show the following capacity contribution levels for wind, fixed-tilt solar, and tracking solar resources.

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

Table 3

	Wind			Fixed Solar PV			Tracking Solar PV		
	West	East	Weighted Average	West	East	Average	West	East	Average
Peak Capacity Contribution	25.4%	14.5%	18.1%	32.2%	34.1%	33.1%	36.7%	39.1%	37.9%

The Company proposes to adjust the amount of capacity costs included in avoided costs for wind and solar QFs by their respective capacity contributions. Tables 6A through 6D in Exhibit 3 of the Company's filing show how the adjustment for capacity contribution is made to the avoided cost rates.

Q. What differentiates capacity contribution from capacity factor?

A. The capacity factor of a generating resource is a measure of how much energy that resource is expected to produce over a given period of time. Like capacity contribution, the capacity factor is represented as a percentage of plant capacity; however, the two metrics have entirely different meanings. For example, consider two hypothetical power plants operating at a 50 percent capacity factor. Both plants produce energy at half of their full capability over the course of a year. However, assume one plant achieves a 50 percent capacity factor by producing energy in hours when the probability of reliability events are lowest and the other plant achieves its 50 percent capacity factor by producing energy in hours when the probability of reliability events are highest. The former would have a low capacity contribution value and the latter would have a high capacity contribution value. For Schedule 37 avoided cost rates, the QF's capacity contribution is applied to the capacity costs of the proxy CCCT, reducing the amount paid to an intermittent QF for capacity.

Q. Do current Wyoming Schedule 37 rates recognize a reduced level of capacity payments for intermittent resources?

A. No. Current rates paid to intermittent solar and wind QFs include deferral of a base load resource of the same nameplate capacity as the QF.

Q. Are retail customers indifferent if the capacity contribution of intermittent solar and wind QFs is not reflected in the calculation of avoided costs?

A. No. As described earlier, during the deficiency period Schedule 37 rates are calculated as the all-in cost of a base load CCCT. If no adjustment is made to reflect the capacity contribution of a QF, rates paid to intermittent solar and wind QFs would reflect deferral of a base load resource of the nameplate capacity as the QF even though an intermittent QF resource only provides a portion of the capacity provided by the CCCT. For example, during the deficiency period a 1 MW wind or solar QF is currently assumed to displace 1 MW of the proxy CCCT. Without an adjustment for capacity contribution, payments to intermittent QFs would not accurately reflect the Company's avoided costs.

Capacity Costs and Resource Sufficiency/Deficiency

Q. What does the Company propose with regard to avoided capacity costs?

A. Avoided capacity costs based on an avoided thermal resource should only be included during the deficiency period, which should be marked by the next deferrable resource included in the Company's IRP or IRP update. The current method of including the capacity costs of a SCCT during the sufficiency period should be eliminated from the calculation of Schedule 37 avoided costs. This change conforms Schedule 37 rates to the Company's resource planning process and is consistent with the avoided cost calculation for large QFs under Schedule 38.

Q. Are the Company's resource procurement plans an important consideration in the determination of Schedule 37 rates?

A. Yes. The current method for calculating Schedule 37 rates during the deficiency period relies on the fixed and variable costs of the next deferrable resource in the Company's latest IRP or IRP Update. Table 1 of the Company's Schedule 37 filing shows that in the 2013 IRP Update a 423 MW CCCT scheduled to come online in 2027 is the Company's next deferrable thermal capacity resource; consequently 2027 should mark the start of the resource deficiency period and the inclusion of deferred capacity costs in avoided cost rates. Prior to the start of the deficiency period in 2027, the Company will not procure additional thermal capacity resources but will utilize front office transactions, or wholesale market purchases, to meet its needs. These facts are taken into account when the Company evaluates significant resource acquisitions, including environmental upgrades and other requests for proposals, and the valuation of capacity and energy provided by a QF should not be treated differently.

Q. What capacity costs are currently included in Schedule 37 rates during the sufficiency period?

A. Current Schedule 37 rates include capacity payments based on three months of the annual capacity cost of a SCCT during the sufficiency period. Avoided cost prices during this period must be changed to be consistent with the Company's resource procurement plans and should not include an assumption that a QF will avoid the cost of a SCCT during part of the year. Prior to the addition of the next thermal resource in the Company's IRP, resource needs will be met using wholesale market transactions. Including extra capacity costs in the sufficiency period burdens retail customers with QF costs that are higher than the costs actually avoided by the Company.

In the past, the period of resource deficiency has been determined using a simulated load and resource balance calculated in the GRID model. The deficiency period was assumed to begin when the GRID model was short both energy and capacity on an annual basis. However, while the GRID model is a useful tool for determining system costs for a given set of resources, it provides only one snapshot of the Company's system dispatch under a given set of assumptions and it is not the model used to determine the Company's long-term resource plans. Through the IRP process the Company models its projected resource needs on a least-cost, least-risk basis and determines the timing and type of the resources it plans to procure in the future. Marking the period of resource deficiency based on capacity and energy shortages in a GRID model run is unnecessary and could result in inconsistencies with the Company's actual resource procurement plans as determined by the IRP.

Q. Is the proposed change to Schedule 37 for avoided capacity consistent with the calculation of avoided costs for large QFs?

A. Yes. Under the PDDRR method, a QF is assumed to partially displace the next deferrable resource in the Company's latest IRP which occurs in 2027 in the 2013 IRP Update. Consequently, avoided capacity costs of a proxy resource are only included in the avoided cost calculation once that proxy resource is included in the Company's resource procurement plan. It does not make sense to include additional capacity payments during the sufficiency period for a small QF when it is not appropriate for a larger QF.

Q. Given the Company's resource procurement plans, are retail customers indifferent under the current method of including capacity costs in the sufficiency period?

A. No. In order to maintain the ratepayer indifference objective, deferred capacity costs must be included in avoided costs in a manner consistent with the Company's resource procurement plans identified in the IRP or IRP update. The Company's latest plan, the 2013 IRP Update, indicates that the next avoidable thermal resource will not be procured until 2027, and that the Company will rely on wholesale market transactions to meet its resource needs prior to that time. Schedule 37 avoided costs should not include the capacity costs of a SCCT when the Company cannot avoid such costs.

Volumetric Rates

Q. Please explain the Company's proposal related to the payment structure available to QFs under Schedule 37.

A. The Company proposes to replace the separate capacity and energy pricing with volumetric winter and summer prices for on-peak and off-peak hours. The separate capacity and energy payment structure results in over-payments to low-capacity-factor resources such as wind and solar QFs. Structuring Schedule 37 prices as volumetric rates ensures customers remain indifferent regardless of the type of QF resource.

Q. How are the separate capacity and energy prices calculated under the current Schedule 37 tariff?

A. Under the current Schedule 37, a QF is paid separate capacity and energy payments. The capacity payment, stated as a fixed dollars-per-KW-month amount, is calculated based on the fixed costs of the deferrable proxy resource and paid based on the QF's maximum generation during peak hours regardless of whether that maximum generation coincides with the Company's system peak hour. The current energy price is differentiated by season (winter and summer) and is determined based on the avoided energy costs as modeled by the GRID model during the sufficiency period and the fuel and capitalized energy costs of the proxy CCCT during the deficiency period.

Q. Does the separate capacity and energy pricing over-compensate intermittent QFs with a low capacity factor?

A. Yes. Under the capacity and energy payment structure, the QF is paid the same total dollars for capacity regardless of its generation output. However, the nature of an intermittent resource is such that it is unpredictable whether it will actually generate during peak hours. Furthermore, a CCCT provides several benefits to the utility that are not provided by an intermittent QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide reserves. Under a volumetric pricing option, the QF will receive the total capacity dollars only if it generates an equivalent amount of energy as the avoided resource during on-peak hours.

Q. How are the proposed volumetric prices calculated for Schedule 37?

A. The proposed Schedule 37 rates include volumetric prices differentiated by season (summer and winter) and by on- and off-peak hours. During the sufficiency period, the avoided energy costs calculated in GRID are differentiated by season and then shaped to on-and off-peak periods consistent with the shape of wholesale market prices at the Palo Verde market hub. During the deficiency period, off-peak prices are equal to the energy cost of proxy CCCT, while on-peak prices include the energy cost of the proxy CCCT plus the avoided capacity costs spread to the on-peak hours using the capacity factor of the proxy resource as defined in the IRP. Tables 6A through 6D in Exhibit 3 of the Company's filing show the calculations for a base load resource, wind, fixed solar and tracking solar, respectively.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(GND-1)
Docket No. 20000-___-EA-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

November 2014

DRAFT 2014 WIND INTEGRATION STUDY

Introduction

This wind integration study (WIS) estimates the operating reserves required to both maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. The Company must provide sufficient operating reserves to meet NERC's balancing authority area control error limit (BAL-001-2) at all times, incremental to contingency reserves, which the Company maintains to comply with NERC standard BAL-002-WECC-2.[1,2] Apart from disturbance events that are addressed through contingency reserves, these incremental operating reserves are necessary to maintain area control error[3] (ACE), due to sources outside direct operator control including intra-hour changes in load demand and wind generation, within required parameters. The WIS estimates the operating reserve volume required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs) and estimates the incremental cost of these operating reserves.

The operating reserves contemplated within this WIS represent regulating margin, which is comprised of ramp reserve, extracted directly from operational data, and regulation reserve, which is estimated based on operational data. The WIS calculates regulating margin demand over two common operational timeframes: 10-minute intervals, called regulating; and one-hour-intervals, called following. The regulating margin requirements are calculated from operational data recorded during PacifiCorp's operations from January 2012 through December 2013 (Study Term). The regulating margin requirements for load variation, and separately for load variation combined with wind variation, are then applied in the Planning and Risk (PaR) production cost model to determine the cost of the additional reserve requirements. These costs are attributed to the integration of wind generation resources in the 2015 Integrated Resource Plan (IRP).

Estimated regulating margin reserve volumes in this study were calculated using the same methodology applied in the Company's 2012 WIS[4], with data updated for the current Study Term. The regulating margin reserve volumes in this study account for estimated benefits from PacifiCorp's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO). The Company expects that with its participation in the EIM future wind integration study updates will benefit as PacifiCorp gains access to additional and more specific operating data.

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[1] NERC Standard BAL-001-2: http://www.nerc.com/files/BAL-001-2.pdf

[2] NERC Standard BAL-002-WECC-2 (http://www.nerc.com/files/BAL-002-WECC-2.pdf), which became effective October 1, 2014, replaced NERC Standard BAL-STD-002, which was in effect at the time of this study.

[3] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/pa/stand/glossary of terms/glossary_of_terms.pdf

[4] 2012 WIS report is provided as Appendix H in Volume II of the Company's 2013 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Technical Review Committee

As was done for its 2012 WIS, the Company engaged a Technical Review Committee (TRC) to review the study results from the 2014 WIS. The Company thanks each of the TRC members, identified below, for their participation and professional feedback. The members of the TRC are:

- Andrea Coon - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- Matt Hunsaker - Manager, Renewable Integration for the Western Electricity Coordinating Council (WECC)
- Michael Milligan - Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory (NREL)
- J. Charles Smith - Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Robert Zavadil - Executive Vice President of Power Systems Consulting, EnerNex

In its technical review of the Company's 2012 WIS, the TRC made recommendations for consideration in future WIS updates.[5] The following table summarizes TRC recommendations from the 2012 WIS and how these recommendations were addressed in the 2014 WIS.

Table H.1 2012 WIS TRC Recommendations

2012 WIS TRC Recommendations	2014 WIS Response to TRC Recommendations
Reserve requirements should be modeled on an hourly basis in the production cost model, rather than on a monthly average basis.	The Company modeled reserves on an hourly basis in PaR. A sensitivity was performed to model reserves on monthly basis as in the 2012 WIS.
Either the 99.7% exceedance level should be studied parametrically in future work, or a better method to link the exceedance level, which drives the reserve requirements in the WIS, to actual reliability requirements should be developed.	In discussing this recommendation with the TRC, it was clarified that the intent was a request to better explain how the exceedance level ties to operations. PacifiCorp has included discussion in this 2014 WIS on its selection of a 99.7% exceedance level when calculating regulation reserve needs, and further clarifies that the WIS results informs the amount of regulation reserves planned for operations.
Future work should treat the categories "regulating," "following," and "ramping" differently by using the capabilities already in PaR and comparing these results to those using of the root-sum-of-squares (RSS) formula.	A sensitivity study was performed demonstrating the impact of separating the reserves into different categories.
Given the vast amount of data used, a simpler and more transparent analysis could be performed using a flexible statistics package rather than spreadsheets.	PacifiCorp appreciates the TRC comment; however, PacifiCorp continued to rely on spreadsheet-based calculations when calculating regulation reserves for its 2014 WIS. This allows stakeholders, who may not have access to specific statistics packages, to review work papers underlying PacifiCorp's 2014 WIS.

[5] TRC's full report is provided at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/Pacificorp_2012WIS_TRC-Technical-Memo_5-10-13.pdf

2012 WIS TRC Recommendations	2014 WIS Response to TRC Recommendations
Because changes in forecasted natural gas and electricity prices were a major reason behind the large change in integration costs from the 2010 WIS, sensitivity studies around natural gas and power prices, and around carbon tax assumptions, would be interesting and provide some useful results.	Changes in wind integration costs continue to align with movements in forward market prices for both natural gas and electricity. PacifiCorp describes how market prices have changed in relation to wind integration costs as updated in the 2014 WIS. With the U.S. Environmental Protection Agency's draft rule under §111(d) of the Clean Air Act, CO_2 tax assumptions are no longer assumed in PacifiCorp's official forward price curves.
Although the study of separate east and west BAAs is useful, the WIS should be expanded to consider the benefits of PacifiCorp's system as a whole, as some reserves are transferrable between the BAAs. It would be reasonable to conclude that EIM would decrease reserve requirements and integration costs.	PacifiCorp has incorporated estimated regulation reserve benefits associated with its participation in EIM in the 2014 WIS. With its involvement in EIM, future wind studies will benefit as PacifiCorp gains access to better operating data.

Executive Summary

The 2014 WIS estimates the regulating margin requirement from historical load and wind generation production data using the same methodology that was developed in the 2012 WIS. The regulating margin is required to manage variations to area control error due to load and wind variations within PacifiCorp's BAAs. The WIS estimates the regulating margin requirement based on load combined with wind variation and separately estimates the regulating margin requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin required to manage wind variability and uncertainty, provides the amount of incremental regulating margin required to maintain system reliability due to the presence of wind generation in PacifiCorp's BAAs. The resulting regulating margin requirement was evaluated deterministically in the PaR model, a production cost model used in the Company's Integrated Resource Plan (IRP) to simulate dispatch of PacifiCorp's system. The incremental cost of the regulating margin required to manage wind resource variability and uncertainty is reported on a dollar per megawatt-hour ($/MWh) of wind generation basis.[6]

When compared to the result in the 2012 WIS, which relied upon 2011 data, the 2014 WIS uses 2013 data and shows that total regulating margin increased by approximately 27 megawatts (MW) in 2012 and 47 MW in 2013. These increases in the total reserve requirement reflect different levels of volatility in actual load and wind generation. This volatility in turn impacts the operational forecasts and the deviations between the actual and operational forecast reserve requirements, which ultimately drives the amount of regulating margin needed.

Table H.2 depicts the combined PacifiCorp BAA annual average regulating margin calculated in the 2014 WIS, and separates the regulating margin due to load from the regulating margin due to wind. These data show that reserves for wind declined in both the west and east BAAs, while the reserves for load increased as compared to levels reported in the 2012 WIS. The change in total regulating margin remained relatively constant, increasing from 579 MW in the 2012 WIS to 580

[6] The PaR model can be run with stochastic variables in Monte Carlo simulation mode or in deterministic mode whereby variables such as natural gas and power prices do not reflect random draws from probability distributions. For purposes of the WIS, the intention is not to evaluate stochastic portfolio risk, but to estimate production cost impacts of incremental operating reserves required to manage wind generation on the system based on current projections of future market prices for power and natural gas.

MW in the 2014 WIS.

Table H.2 Average Annual Regulating Margin Reserves, 2011 - 2013 (MW)

		West BAA	East BAA	Combined
2011 Data (2012 WIS)	Load-Only Regulating Margin	147	247	394
	Incremental Wind Regulating Margin	54	131	185
	Total Regulating Margin	202	378	579
	Wind Capacity	589	1,536	2,126
2012 Data	Load-Only Regulating Margin	141	259	400
	Incremental Wind Regulating Margin	59	94	153
	Total Regulating Margin	199	354	553
	Wind Capacity	785	1,759	2,543
2013 (2014 WIS)	Load-Only Regulating Margin	166	275	441
	Incremental Wind Regulating Margin	42	97	139
	Total Regulating Margin	208	372	580
	Wind Capacity	785	1,759	2,543

Table H.3 lists the cost to integrate wind generation in PacifiCorp's BAAs. The cost to integrate wind includes the cost of the incremental regulating margin reserves to manage intra-hour variances (as outlined above) and the cost associated with day-ahead forecast variances, the latter of which affects how dispatchable resources are committed to operate, and subsequently, affect daily system balancing. Each of these component costs were calculated using the PaR model. A series of PaR simulations were completed to isolate each wind integration cost component by using a "with and without" approach. For instance, PaR was first used to calculate system costs solely with the regulating margin requirement due to load variations, and then again with the increased regulating margin requirements due to load combined with wind generation. The change in system costs between the two PaR simulations results in the wind integration cost.

Table H.3- Wind Integration Cost, $/MWh

	2012 WIS 2012$	2014 WIS 2015$
Intra-hour Reserve	$2.19	$2.35
Inter-hour/System Balancing	$0.36	$0.71
Total Wind Integration	$2.55	$3.06

The 2014 WIS results are applied in the 2015 IRP portfolio development process as part of the costs of wind generation resources. In the portfolio development process using the System Optimizer (SO) model, the wind integration cost on a dollar per megawatt-hour basis is included as a cost to the variable operation and maintenance cost of each wind resource. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study are used.

Data

The calculation of regulating margin reserve requirement was based on actual historical load and wind production data over the Study Term from January 2+012 through December 2013. Table H.4 outlines the load and wind generation 10-minute interval data used during the Study Term.

Table H.4 - Historical Wind Production and Load Data Inventory

	Wind Nameplate Capacity (MW)	Beginning of Data	End of Data	BAA
Wind Plants within PacifiCorp BAAs				
Chevron Wind	16.5	1/1/2012	12/31/2013	East
Combine Hills	41.0	1/1/2012	12/31/2013	West
Dunlap 1 Wind	111.0	1/1/2012	12/31/2013	East
Five Pine and North Point	119.7	12/1/2012	12/31/2013	East
Foot Creek Generation	85.1	1/1/2012	12/31/2013	East
Glenrock III Wind	39.0	1/1/2012	12/31/2013	East
Glenrock Wind	99.0	1/1/2012	12/31/2013	East
Goodnoe Hills Wind	94.0	1/1/2012	12/31/2013	West
High Plains Wind	99.0	1/1/2012	12/31/2013	East
Leaning Juniper 1	100.5	1/1/2012	12/31/2013	West
Marengo I	140.4	1/1/2012	12/31/2013	West
Marengo II	70.2	1/1/2012	12/31/2013	West
McFadden Ridge Wind	28.5	1/1/2012	12/31/2013	East
Mountain Wind 1 QF	60.9	1/1/2012	12/31/2013	East
Mountain Wind 2 QF	79.8	1/1/2012	12/31/2013	East
Power County North and Power County South	45.0	1/1/2012	12/31/2013	East
Oregon Wind Farm QF	64.6	1/1/2012	12/31/2013	West
Rock River I	49.0	1/1/2012	12/31/2013	East
Rolling Hills Wind	99.0	1/1/2012	12/31/2013	East
Seven Mile Wind	99.0	1/1/2012	12/31/2013	East
Seven Mile II Wind	19.5	1/1/2012	12/31/2013	East
Spanish Fork Wind 2 QF	18.9	1/1/2012	12/31/2013	East
Stateline Contracted Generation	175.0	1/1/2012	12/31/2013	West
Three Buttes Wind	99.0	1/1/2012	12/31/2013	East
Top of the World Wind	200.2	1/1/2012	12/31/2013	East
Wolverine Creek	64.5	1/1/2012	12/31/2013	East
Long Hollow Wind		1/1/2012	12/31/2013	East
Campbell Wind		1/1/2012	12/31/2013	West
Horse Butte		6/19/2012	12/31/2013	East
Jolly Hills 1		1/1/2012	12/31/2013	East
Jolly Hills 2		1/1/2012	12/31/2013	East
Load Data				
PACW Load	n/a	1/1/2012	12/31/2013	West
PACE Load	n/a	1/1/2012	12/31/2013	East

Historical Load Data

Historical load data for the PacifiCorp east (PACE) and PacifiCorp west (PACW) BAAs were collected for the Study Term from the PacifiCorp PI system.[7] The raw load data were reviewed

[7] The PI system collects load and generation data and is supplied to PacifiCorp by OSISoft. The Company Web site

for anomalies prior to further use. Data anomalies can include:

- Incorrect or reversal of sign (recorded data switching from positive to negative);
- Significant and unexplainable changes in load from one 10-minute interval to the next;
- Excessive load values.

After reviewing 210,528 10-minute load data points in the 2014 WIS, 1,011 10-minute data points, roughly 0.5% of the data, were identified as irregular. Since reserve demand is created by unexpected changes from one time interval to the next, the corrections made to those data points were intended to mitigate the impacts of irregular data on the calculation of the reserve requirements and costs in this study.

Of the 1,011 load data points requiring adjustment, 984 exhibited unduly long periods of unchanged or "stuck" values. The data points were compared to the values from the Company's official hourly data. If the six 10-minute PI values over a given hour averaged to a different value than the official hourly record, they were replaced with six 10-minute instances of the hourly value. For example, if PACW's measured load was 3,000 MW for three days, while the Company's official hourly record showed different hourly values for the same period, the six 10-minute "stuck" data points for an hour were replaced with six instances of the value from the official record for the hour. Though the granularity of the 10-minute readings was lost, the hour-to-hour load variability over the three days in this example would be captured by this method. In total, the load data requiring replacement for stuck values represented only 0.47% of the load data used in the current study.

The remaining 27 of data points requiring adjustment were due to questionable load values, three of which were significantly higher than the load values in the adjacent time intervals, and 24 of which were significantly lower. While not necessarily higher or lower by an egregious amount in each instance, these specific irregular data collectively averaged a difference of several hundred megawatts from their replacement values. Table H.5 depicts a sample of the values that varied significantly, as compared to the data points immediately prior to and after those 10-minute intervals. The replacement values, calculated by interpolating the prior value and the successive 10-minute period to form a straight line, are also shown in the table.

is http://www.osisoft.com/software-support/what-is-pi/what_is_PI_.aspx.

Table H.5- Examples of Load Data Anomalies and their Interpolated Solutions

Time	Original Load Value (MW)	Final Load Value (MW)	Method to Calculate Final Load Value
1/5/2012 12:20	5,805	5,805	n/a
1/5/2012 12:30	5,211	5,793	12:20 + 1/5 of (13:10 minus 12:20)
1/5/2012 12:40	5,074	5,781	12:20 + 2/5 of (13:10 minus 12:20)
1/5/2012 12:50	5,063	5,769	12:20 + 3/5 of (13:10 minus 12:20)
1/5/2012 13:00	5,465	5,756	12:20 + 4/5 of (13:10 minus 12:20)
1/5/2012 13:10	5,744	5,744	n/a
5/6/2013 8:50	5,651	5,651	n/a
5/6/2013 9:00	4,583	5,694	Average of 8:50 and 9:10
5/6/2013 9:10	5,737	5,737	n/a

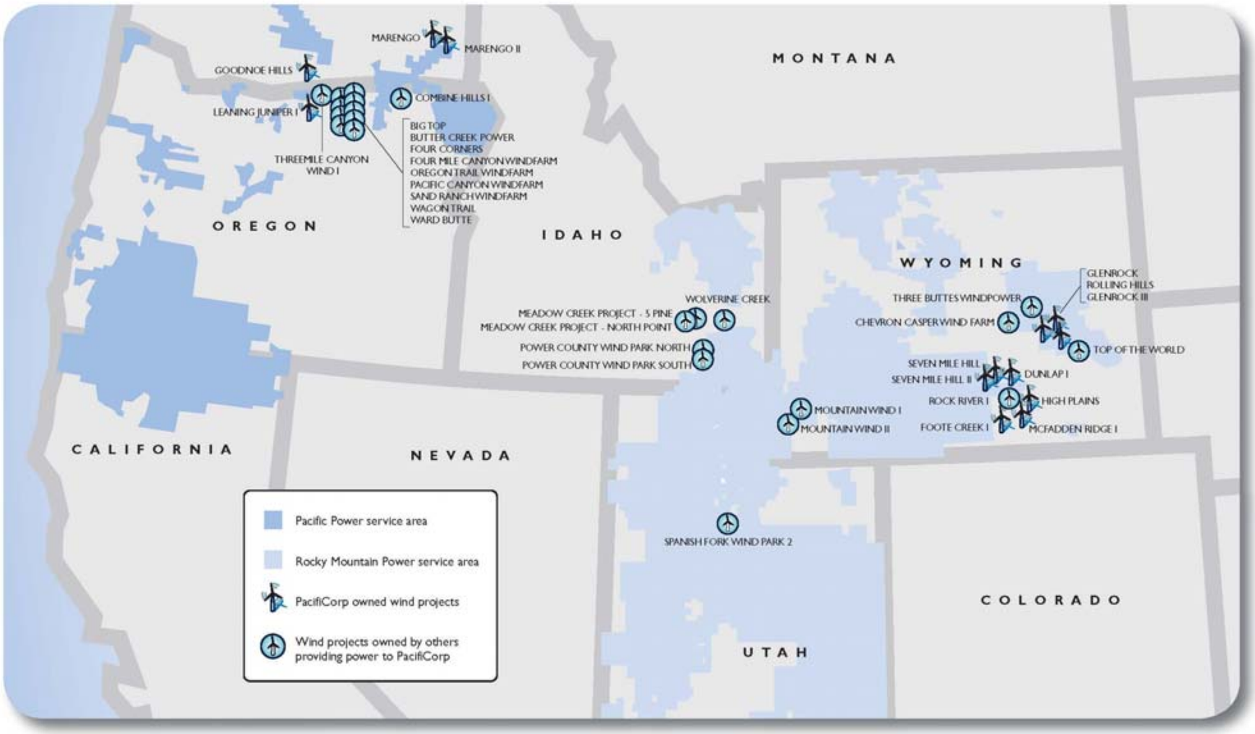
Historical Wind Generation Data

Over the Study Term, 10-minute interval wind generation data were available for the wind projects as summarized in Table H.4. The wind output data were collected from the PI system.

In 2011 the installed wind capacity in the PacifiCorp system was 589 MW in the west BAA and 1,536 MW in the east BAA. For 2012 and 2013, these capacities increased to 785 MW and 1,759 MW in the west and east BAAs, respectively. The increases were the result of 195 MW of existing wind projects transferring from Bonneville Power Administration (BPA) to PacifiCorp's west BAA, and 222 MW of new third party wind projects coming on-line during 2012 in the east BAA.

Figure H.1 shows PacifiCorp owned and contracted wind generation plants located in PacifiCorp's east and west BAAs. The third-party wind plants located within PacifiCorp's BAAs which the Company does not purchase generation from or own are not depicted in this figure.

Figure H.1- Representative Map, PacifiCorp Wind Generating Stations Used in this Study



The wind data collected from the PI system is grouped into a series of sampling points, or nodes, which represent generation from one or more wind plants. In consideration of occasional irregularities in the system collecting the data, the raw wind data was reviewed for reasonableness considering the following criteria:

- Incorrect or reversal of sign (recorded data switching from positive to negative);
- Output greater than expected wind generation capacity being collected at a given node;
- Wind generation appearing constant over a period of days or weeks at a given node.

Some of the PI system data exhibited large negative generation output readings in excess of the amount that could be attributed to station service. These meter readings often reflected positive generation and a reversed polarity on the meter rather than negative generation. In total, only 38 of 3,822,048 10-minute PI readings, representing 0.001% of the wind data used in this WIS, required substituting a positive value for a negative generation value.

Some of the PI system data exhibited large positive generation output readings in excess of plant capacity. In these instances, the erroneous data were replaced with a linear interpolation between the value immediately before the start of the excessively large data point and the value immediately after the end of the excessively large data point. In total, only 49 10-minute PI readings, representing 0.002% of the wind data used in this WIS, required substituting a linear interpolation for an excessively large generation value.

Similar to the load data, the PI system wind data also exhibited patterns of unduly long periods of unchanged or “stuck” values for a given node. To address these anomalies, the 10-minute PI values were compared to the values from the Company’s official hourly data, and if the six 10-

minute PI values over a given hour averaged to a different value than the official hourly record, they were replaced with six 10-minute instances of the hourly value. For example, if a node's measured wind generation output was 50 MW for three weeks, while the official record showed different hourly values for the same time period, the six 10-minute "stuck" data points for an hour were replaced with six instances of the value from the official record for the hour. Though the granularity of the 10-minute readings was lost, the hour-to-hour wind variability over the three weeks in this example would be captured by this method. In total, the wind generation data requiring replacement for stuck values represented only 0.2% of the wind data used in the WIS.

Methodology

Method Overview

This section presents the approach used to establish regulating margin reserve requirements and the method for calculating the associated wind integration costs. 10-minute interval load and wind data were used to estimate the amount of regulating margin reserves, both up and down, in order to manage variation in load and wind generation within PacifiCorp's BAAs.

Operating Reserves

NERC regional reliability standard BAL-002-WECC-2 requires each BAA to carry sufficient operating reserve at all times.[8] Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate committing generation resources that are sufficient to meet not only system load but also reserve requirements. Each of these types of operating reserve is further defined below.

Contingency reserve is capacity that the Company holds in reserve that can be used to respond to contingency events on the power system, such as an unexpected outage of a generator or a transmission line. Contingency reserve may not be applied to manage other system fluctuations such as changes in load or wind generation output. Therefore, this study focuses on the operating reserve component to manage load and wind generation variations which is incremental to contingency reserve, which is referred to as regulating margin.

Regulating margin is the additional capacity that the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulating reserves incremental to contingency reserves to maintain reliability.[9] However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BAA to meet the control performance standards. NERC standard BAL-001-2, called the Balancing Authority Area Control Error Limit (BAAL), allows a greater ACE during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when the ACE will help or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE. [10,11]

[8] NERC Standard BAL-002-WECC-2: http://www.nerc.com/files/BAL-002-WECC-2.pdf

[9] NERC Standard BAL-001-2:http://www.nerc.com/files/BAL-001-2.pdf

[10] The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails.

Thus the Company determines, based on the unique level of wind and load variation in its system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour. For this WIS, the Company further segregates regulating margin into two components: ramp reserve and regulation reserve.

Ramp Reserve: Both load and wind change from minute-to-minute, hour-to-hour, continuously at all times. This variability requires ready capacity to follow changes in load and wind continuously, through short deviations, at all times. Treating this variability as though it is perfectly known (as though the operator would know exactly what the net balancing area load would be a minute from now, 10-minutes from now, and an hour from now) and allowing just enough generation flexibility on hand to manage it defines the ramp reserve requirement of the system.

Regulation Reserve: Changes in load or wind generation which are not considered contingency events, but require resources be set aside to meet the needs created when load or wind generation change unexpectedly. The Company has defined two types of regulation reserve – regulating and following reserves. Regulating reserve are those covering short term variations (moment to moment using automatic generation control) in system load and wind. Following reserves cover uncertainty across an hour when forecast changes unexpectedly.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts: ramp reserve and regulation reserve. The ramp reserve represents an amount of flexibility required to follow the change in actual net system load (load minus wind generation output) from hour to hour. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load and wind following and load and wind regulating.

Determination of Amount and Costs of Regulating Margin Requirements

Regulating margin requirements are calculated for each of the Company's BAAs from production data via a five step process, each described in more detail later in this section. The five steps include:

1. Calculation of the ramp reserve from the historical data (with and without wind generation).
2. Creation of hypothetical forecasts of following and regulating needs from historical load and wind production data.
3. Recording differences, or deviations, between actual wind generation and load values in each 10-minute interval of the study term and the expected generation and load.
4. Group these deviations into bins that can be analyzed for the reserve requirement per forecast value of wind and load, respectively, such that a specified percentage (or tolerance level) of these deviations would be covered by some level of operating reserves.

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[11] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to: http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

5. The reserve requirements noted for the various wind and load forecast values are then applied back to the operational data enabling an average reserve requirement to be calculated for any chosen time interval within the Study Term.

Once the amount of regulating margin is estimated, the cost of holding the specified reserves on PacifiCorp's system is estimated using the PaR model. In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate the costs associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of load and wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time.

Regulating Margin Requirements

Consistent with the methodology developed in the Company's 2012 WIS, and the discussion above, regulating margin requirements were derived from actual data on a 10-minute interval basis for both wind generation and load. The ramp reserve represents the minimal amount of flexible system capacity required to follow net load requirements without any error or deviation and with perfect foresight for following changes in load and wind generation from hour to hour. These amounts are as follows:

- If system is ramping down: [(Net Area Load Hour H – Net Area Load Hour (H+1))/2]
- If system is ramping up: [(Net Area Load Hour (H+1)– Net Area Load Hour H)/2]

That is, the ramp reserve is half the absolute value of the difference between the net balancing area load at the top of one hour minus the net balancing load at the top of the prior hour.

The ramp reserve for load and wind is calculated using the net load (load minus wind generation output) at the top of each hour. The ramp reserve required for wind is the difference between that for load and that for load and wind.

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, the regulation reserve is necessary to cover uncertainty ever-present in power system operations. Very short-term fluctuations in weather, load patterns, wind generation output and other system conditions cause short term forecasts to change at all times. Therefore, system operators rely on regulation reserve to allow for the unpredictable changes between the time the schedule is made for the next hour and the arrival of the next hour, or the ability to follow net load. Also, these very same sources of instability are present throughout each hour, requiring flexibility to regulate the generation output to the myriad of ups and downs of customer demand, fluctuations in wind generation, and other system disturbances. To assess the regulation reserve requirements for PacifiCorp's BAAs, the Company compared operational data to hypothetical forecasts as described below.

Hypothetical Operational Forecasts
Regulation reserve consists of two components: (1) *regulating*, which is developed using the 10-minute interval data, and (2) *following*, which is calculated using the same data but estimated on an hourly basis. Load data and wind generation data were applied to estimate reserve

requirements for each month in the Study Term. The *regulating* calculation compares observed 10-minute interval load and wind generation to a 10-minute interval forecast, and *following* compares observed hourly averages to an average hourly forecast. Therefore, the regulation reserve requirements are composed of four component requirements, which, in turn, depend on differences between actual and expected needs. The four component requirements include: load following, wind following, load regulating, and wind regulating. The determination of these reserve requirements began with the development of the expected following and regulating needs (hypothetical forecasts) of the four components, each discussed in turn below.

Hypothetical Load Following Operational Forecast

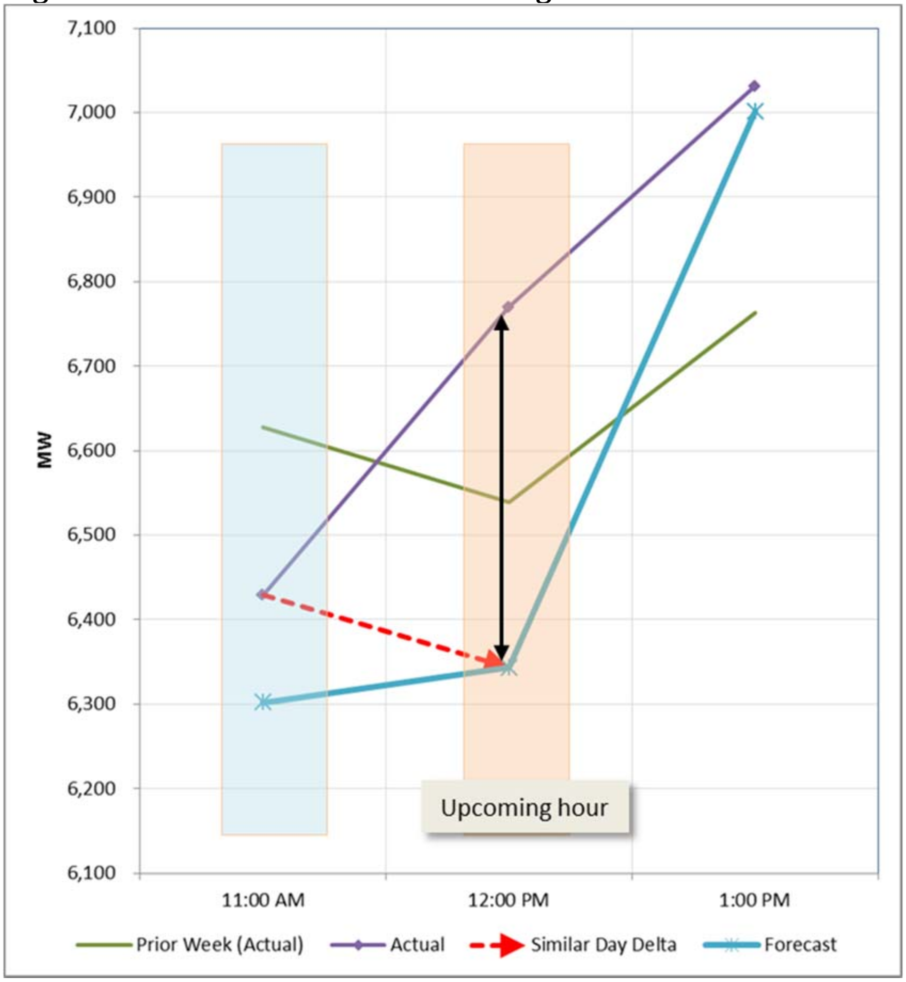
PacifiCorp maintains system balance by optimizing its operations to an hour-ahead load forecast every hour with changes in generation and market activity. This planning interval represents hourly changes in generation that are assessed roughly 20 minutes into each hour to meet a bottom-of-the-hour (i.e., 30 minutes after the hour) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demand with an expectation of how much higher or lower load may be. These activities are carried out by the group referred to as the real-time desk.

PacifiCorp's real-time desk updates the load forecast for the upcoming hour 40 minutes prior to the start of that hour. This forecast is created by comparing the load in the current hour to the load of a prior similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load difference or “delta”) is applied to the load for the current hour, and the sum is used as the forecast for the upcoming hour. For example, on a given Sunday, the PacifiCorp real-time desk operator may forecast hour-to-hour changes in load by referencing the hour-to-hour changes from the prior Sunday, which would be a similar-load-shaped day. If at 11:20 am, the hour-to-hour load change between 11:00 a.m. and 12:00 p.m. of the prior Sunday was five percent, the operator will use a five percent change from the current hour to be the upcoming hour’s load following forecast.

For the calculation in this WIS, the hour-ahead load forecast used for calculating load following was modeled using the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules. The differences observed between the actual hourly load and the load following forecasts comprised the load following deviations.

Figure H.2 shows an illustrative example of a load following deviation in August 2013 using operational data from PACE. In this illustration, the delta between hours 11:00 a.m. and 12:00 p.m. from the prior week is applied to the actual load at 11:00 a.m. on the “current day” to produce the hypothetical forecast of the load for the 12:00 p.m. (“upcoming”) hour. That is, using the actual load at 11:00 a.m. (beginning of the purple line), the load forecast for the 12:00 p.m. hour is calculated by following the dashed red line that is parallel to the green line from the prior week. The forecasted load for the upcoming hour is the point on the blue line at 12:00 p.m. Since the actual load for the 12:00 p.m. hour (the point on the purple line at 12:00 p.m.) is higher than the forecast, the deviation (indicated by the black arrow) is calculated as the difference between the forecasted and the actual load for 12:00 p.m. This deviation is used to calculate the load following component reserve requirement for 12:00 p.m.

Figure H.2 - Illustrative Load Following Forecast and Deviation



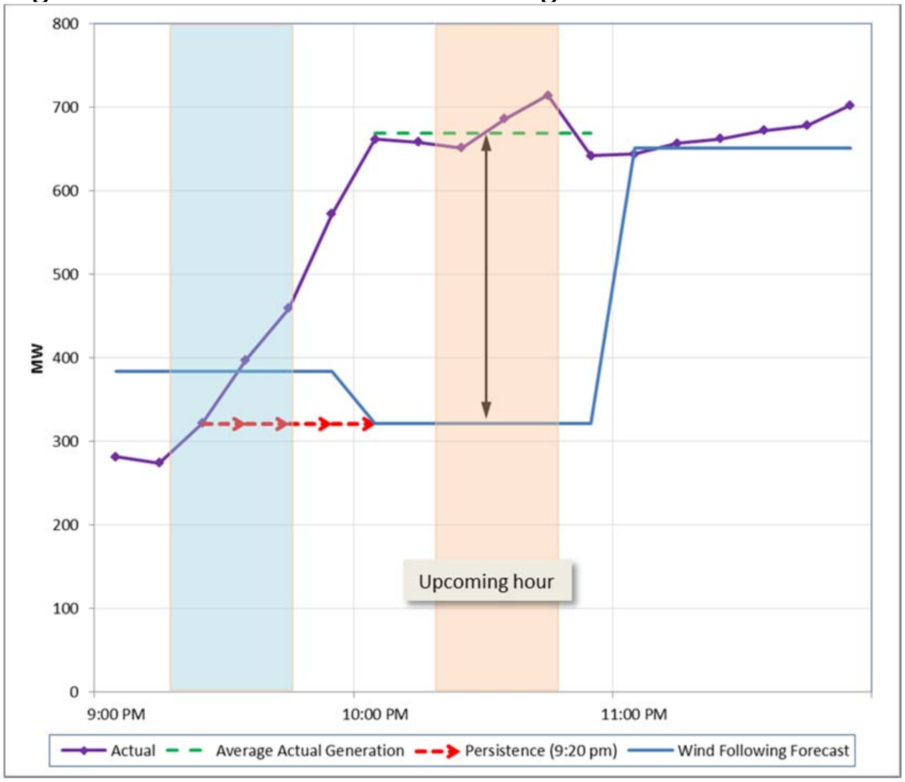
Hypothetical Wind Following Operational Forecast

The short term hourly operational wind forecast is based on the concept of persistence – using the instantaneous sample of the wind generation output at 20 minutes into the current hour as the forecast for the upcoming hour, and balancing the system to that forecast.

For the calculation in this WIS, the hour-ahead wind generation forecast for the "upcoming" hour used the 20^{th} minute output from the "current" hour. For example, if the wind generation is producing 300 MW at 9:20 p.m. in PACE, then it is assumed that 300 MW will be generated between 10:00 p.m. and 11:00 p.m., that same day. The difference between the hourly average of the six 10-minute wind generation readings and the wind generation forecast comprised the wind following deviation for that hour.

Figure H.3 shows an illustrative example of a wind following deviation in July 2013 using operational data from PACE. In this illustration, the wind generation output at 9:20 p.m. (within the "current" hour) is the hour-ahead forecast of the wind generation for the 10:00 p.m. hour (the "upcoming" hour). That is, following persistence scheduling, the wind following need for the 10:00 p.m. hour is calculated by following the dashed red line starting from the actual wind generation on the purple line at 9:20 p.m. for the entire 10:00 p.m. hour (blue line). Since the average of the actual wind generation during the 10:00 p.m. hour (dotted green line) is higher than the wind following forecast, the deviation (indicated by the black arrow) is calculated as the difference between the wind following forecast and the actual wind generation for the 10:00 p.m. hour. This deviation is used to calculate the wind following component reserve requirement for 10:00 p.m.

Figure H.3 - Illustrative Wind Following Forecast and Deviation



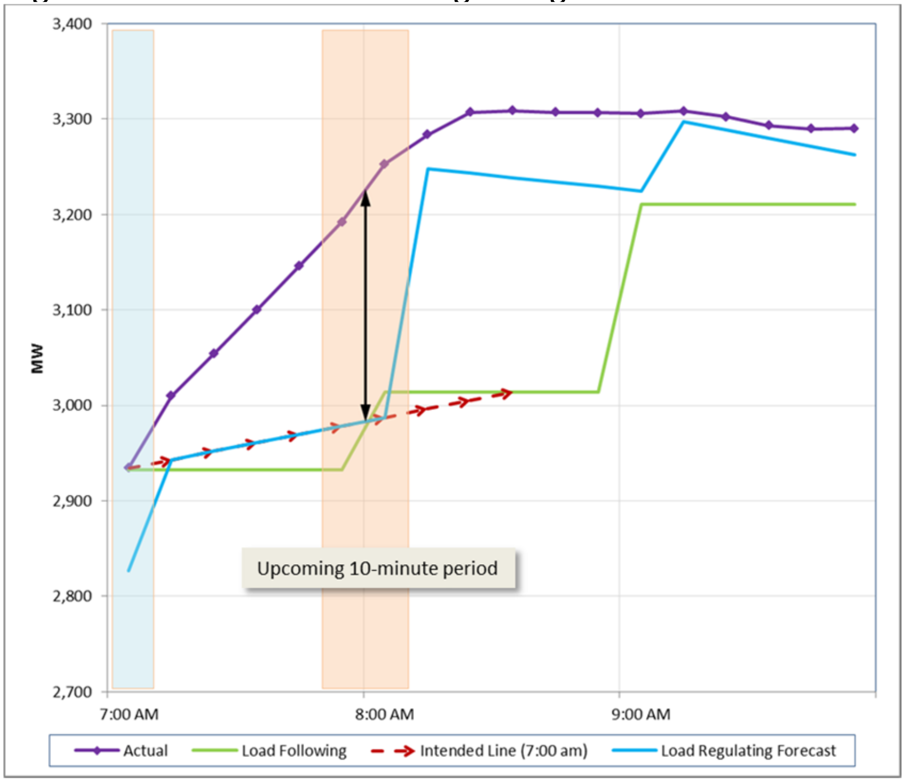
Hypothetical Load Regulating Operational Forecast

Separate from the variations in the hourly scheduled loads, the 10-minute load variability and uncertainty was analyzed by comparing the 10-minute actual load values to a *line of intended schedule*, represented by a line interpolated between the actual load at the top of the “current” hour and the hour-ahead forecasted load (the load following hypothetical forecast) at the bottom of the “upcoming” hour. The method approximates the real time operations process for each hour where, at the top of a given hour, the actual load is known, and a forecast for the next hour has been made.

For the calculation in this WIS, a line joining the two points represented a ramp up or down expected within the given hour. The actual 10-minute load values were compared to the portion of this straight line from the “current” hour to produce a series of load regulating deviations at each 10-minute interval within the “current” hour.

Figure H.4 shows an illustrative example of a load regulating deviation in November 2013 using operational data in PACW. In this illustration, the line of intended schedule is drawn from the actual load at 7:00 a.m. to the hour-ahead load forecast at 8:30 a.m. The portion of this line within the 7:00 a.m. hour becomes the load regulating forecast for that hour. That is, using the forecasted load for the 8:00 a.m. hour that was calculated for the load following hypothetical forecast, the line of intended schedule is calculated by following the dashed red line from the actual load at 7:00 a.m. (beginning of the purple line) to the point in the hour-ahead forecast (green line) at 8:30 a.m. The six 10-minute deviations within the 7:00 a.m. hour (one of which is indicated by the black arrow) are the differences between the actual 10-minute load readings (purple line) and the line of intended schedule. These deviations are used to calculate the load regulating component reserve requirement for the six 10-minute intervals within the 7:00 a.m. hour.

Figure H.4 - Illustrative Load Regulating Forecast and Deviation



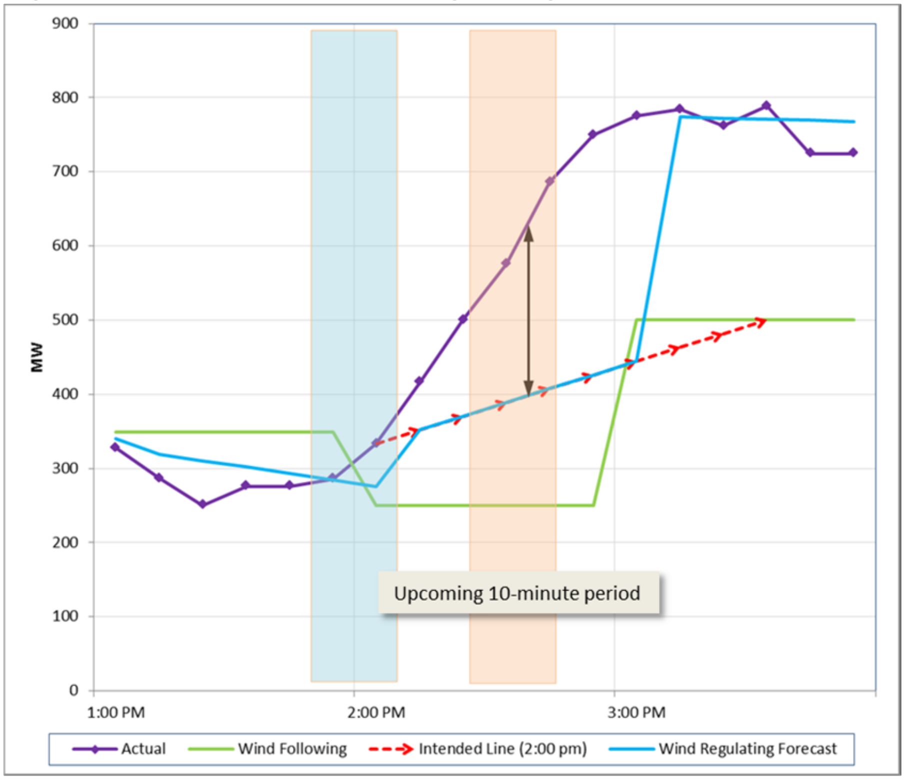
Hypothetical Wind Regulating Operational Forecast

Similarly, the 10-minute wind generation variability and uncertainty was analyzed by comparing the 10-minute actual wind generation values to a *line of intended schedule*, represented by a line interpolated between the actual wind generation at the top of the "current" hour and the hour-ahead forecasted wind generation (the wind following hypothetical forecast) at the bottom of the "upcoming" hour.

For the calculation in this WIS, a line joining the two points represented a ramp up or down expected within the given hour. The actual 10-minute wind generation values were compared to the portion of this straight line from the "current" hour to produce a series of wind regulating deviations at each 10-minute interval within the "current" hour.

Figure H.5 shows an illustrative example of a wind regulating deviation in July 2013 using operational data in PACE. In this illustration, the line of intended schedule is drawn from the actual wind generation at 2:00 p.m. to the hour-ahead wind forecast at 3:30 p.m. The portion of this line within the 2:00 p.m. hour becomes the wind regulating forecast for that hour. That is, using the forecasted wind generation for the 3:00 p.m. hour that was calculated for the wind following hypothetical forecast, the line of intended schedule is calculated by following the dashed red line from the actual wind generation at 2:00 p.m. (beginning of the purple line) to the point in the hour-ahead forecast (green line) at 3:30 p.m. The six 10-minute deviations within the 2:00 p.m. hour (one of which is indicated by the black arrow) are the differences between the actual 10-minute wind generation readings (purple line) and the line of intended schedule (red line). These deviations are used to calculate the wind regulating component reserve requirement for the six 10-minute intervals within the 2:00 p.m. hour.

Figure H.5- Illustrative Wind Regulating Forecast and Deviation



Analysis of Deviations

The deviations are calculated for each 10-minute interval in the Study Term and for each of the four components of regulation reserves (load following, wind following, load regulating, wind regulating). Across any given hourly time interval, the six 10-minute intervals within each hour have a common *following* deviation, but different *regulating* deviations. For example, considering load deviations only, if the load forecast for a given hour was 150 MW below the actual load realized in that hour, then a load following deviation of -150 MW would be recorded for all six of the 10-minute periods within that hour. However, as the load regulating forecast and the actual load recorded in each 10-minute interval vary, the deviations for load regulating vary. The same holds true for wind following and wind regulating deviations, in that the following deviation is recorded as equal for the hour, and the regulating deviation varies each 10-minute interval.

Since the recorded deviations represent the amount of unpredictable variation on the electrical system, the key question becomes how much regulation reserve to hold in order to cover the deviations, thereby maintaining system reliability. The deviations are analyzed by separating the deviations into bins by their characteristic forecasts for each month in the Study Term. The bins are defined by every 5th percentile of recorded forecasts, creating 20 bins for the deviations in each month for each component hypothetical operational forecast. In other words, each month of the Study Term has 20 bins of load following deviations, 20 bins of load regulating deviations, and the same for wind following and wind regulating.

As an example, Table H.6 depicts the calculation of percentiles (every five percent) among the load regulating forecasts for June 2013 using PACE operational data. For the month, the load ranged from 4,521 MW to 8,587 MW. A load regulating forecast for a load at 4,892 MW represents the fifth percentile of the forecasts for that month. Any forecast below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,892 MW and 5,005 MW will place the deviation for that particular forecast in Bin 19.

Table H.6 - Percentiles Dividing the June 2013 East Load Regulating Forecasts into 20 Bins

Bin Number	Percentile	Load Forecast
	MAX	8,587
1	0.95	7,869
2	0.90	7,475
3	0.85	7,220
4	0.80	6,984
5	0.75	6,807
6	0.70	6,621
7	0.65	6,482
8	0.60	6,383
9	0.55	6,285
10	0.50	6,158
11	0.45	6,023
12	0.40	5,850
13	0.35	5,720
14	0.30	5,568
15	0.25	5,404
16	0.20	5,275
17	0.15	5,134
18	0.10	5,005
19	0.05	4,892
20	MIN	4,521

Table H.7 depicts an example of how the data are assigned into bins based on the level of forecasted load, following the definition of the bins in Table H.6.

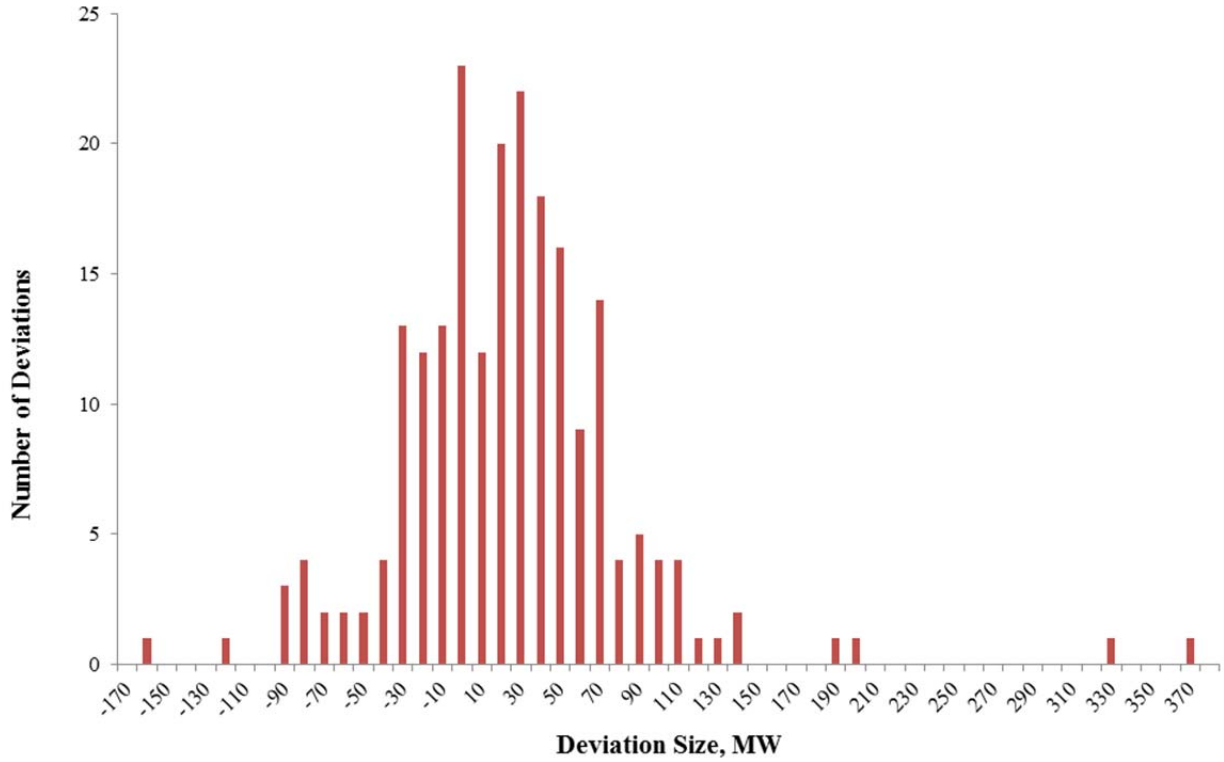
Table H.7 - Recorded Interval Load Regulating Forecasts and their Respective Deviations for June 2013 Operational Data from PACE

DATE / TIME	LOAD REGULATION FORECAST	LOAD REGULATION DEVIATION	BIN ASSIGNMENT
06/01/2013 6:00	4,755	88	20
06/01/2013 6:10	4,706	-67	20
06/01/2013 6:20	4,746	-13	20
06/01/2013 6:30	4,786	-36	20
06/01/2013 6:40	4,826	-26	20
06/01/2013 6:50	4,866	-46	20
06/01/2013 7:00	4,905	-46	19
06/01/2013 7:10	4,984	4	19
06/01/2013 7:20	5,016	-8	18
06/01/2013 7:30	5,048	-10	18
06/01/2013 7:40	5,081	16	18
06/01/2013 7:50	5,113	31	18
06/01/2013 8:00	5,145	12	17
06/01/2013 8:10	5,158	16	17
06/01/2013 8:20	5,182	-22	17
06/01/2013 8:30	5,207	-6	17
06/01/2013 8:40	5,231	4	17
06/01/2013 8:50	5,256	18	17
06/01/2013 9:00	5,280	10	16
06/01/2013 9:10	5,278	-30	16
06/01/2013 9:20	5,287	11	16
06/01/2013 9:30	5,295	2	16
06/01/2013 9:40	5,303	25	16
06/01/2013 9:50	5,311	-4	16

The binned approach prevents over-assignment of reserves in different system states, owing to certain characteristics of load and wind generation. For example, when the balancing area load is near the lowest value for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the load values in a month, it is likely to go only a little higher, but could drop substantially at any time. Similarly for wind, when wind generation output is at the peak value for a system, there will not be a deviation taking the wind value above that peak. In other words, the directional nature of reserve requirements can change greatly by the state of the load or wind output. At high load or wind generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or wind generation.

Figure H.6 shows a distribution of deviations gathered in Bin 14 for forecast load levels between 5,569 MW and 5,720 MW in June 2013. All of the deviations fall between -170 MW and +370 MW. Such deviations would need to be met by resources on the system in order to maintain the balance of load and resources. That is, when actual load is 170 MW lower than expected, there needs to be additional resources that are capable of being dispatched down, and when actual load is 370 MW higher than expected, there needs to be additional resources that are capable of being dispatched up to cover the increases in load.

Figure H.6 - Histogram of Deviations Occurring About a June 2013 PACE Load Regulating Forecast between 5,568 MW and 5,720 MW (Bin 14)



Up and down deviations must be met by operating reserves. To determine the amount of reserves required for load or wind generation levels in a bin, a tolerance level is applied to exclude deviation outliers. The bin tolerance level represents a percentage of component deviations intended to be covered by the associated component reserve. In the absence of an industry standard which articulates an acceptable level of tolerance, the Company must choose a guideline that provides both cost-effective and adequate reserves. These two criteria work against each other, whereby assigning an overly-stringent tolerance level will lead to unreasonably high wind integration costs, while an overly-lax tolerance level incurs penalties for violating compliance standards. Two relevant standards, CPS1 and BAAL, address the reliability of control area frequency and error. The compliance standard for CPS1 (rolling 12-month average of area frequency) is 100%, while the minimum compliance standard for BAAL is a 30-minute response. Working within these bounds and considering the requirement to maintain adequate, cost-effective reserves, the Company plans to a three-standard deviation (99.7 percent) tolerance in the calculation of component reserves, which are subsequently used to inform the need for regulating margin reserves in operations. In doing so, the Company strikes a balance between planning for as much deviation as allowable while managing costs, uncertainty, adequacy and reliability. Despite exclusion of extreme deviations with the use of the 99.7 percent tolerance, the Company's system operators are expected to meet reserve requirements without exception.

The binned approach is applied on a monthly basis, and results in the four component forecast values (load following, wind following, load regulating, wind regulating) for each 10-minute interval of the Study Period. The component forecasts and reserve requirements are then applied back to the operational data to develop summary level information for regulation reserve requirements, using the back casting procedure described below.

Back Casting

Given the development of component reserve requirements that are dependent upon a given system state, reserve requirements were assigned to each 10-minute interval in the Study Term according to their respective hypothetical operational forecasts to simulate the component reserves values as they would have happened in real-time operations. Doing so results in a total reserve requirement for each interval informed by the data.

To perform the back casts, component reserve requirements calculated from the bin analysis described above are first turned into reference tables. Table H.8 shows a sample (June 2013, PACE) reference table for load and wind following reserves at varying levels of forecasted load and wind generation, and Table H.9 shows a sample (June 2013, PACE) reference table for load and wind regulating reserves at varying forecast levels.

Table H.8 - Sample Reference Table for East Load and Wind Following Component Reserves

Bin	Up Reserve (MW)	Load Forecast (MW)	Down Reserve (MW)	Up Reserve (MW)	Wind Forecast (MW)	Down Reserve (MW)
	266	10000	283	358	5000	157
1	266	7841	283	358	1061	157
2	250	7528	192	348	940	213
3	200	7220	285	512	839	205
4	315	7005	294	298	755	290
5	262	6804	334	356	698	207
6	150	6626	321	198	627	231
7	280	6506	260	239	571	375
8	191	6381	212	332	502	308
9	147	6265	135	238	438	284
10	273	6168	99	195	395	374
11	237	6017	168	163	355	172
12	199	5859	338	166	302	241
13	279	5719	295	115	262	264
14	124	5574	151	114	226	203
15	87	5406	195	101	197	287
16	144	5264	171	84	163	326
17	179	5125	98	90	122	225
18	102	4991	86	44	78	242
19	87	4870	73	35	47	288
20	290	4505	63	41	-7	81
	290	0	63	41	-7	81

Table H.9 - Sample Reference Table for East Load and Wind Regulating Component Reserves

Bin	Up Reserve (MW)	Load Forecast (MW)	Down Reserve (MW)	Up Reserve (MW)	Wind Forecast (MW)	Down Reserve (MW)
	177	10000	261	373	10000	173
1	177	7869	261	373	1070	173
2	254	7475	183	459	935	228
3	161	7220	189	297	827	203
4	255	6984	222	277	762	306
5	271	6807	271	393	695	277
6	327	6621	253	233	628	219
7	232	6482	213	305	562	372
8	182	6383	164	279	508	225
9	179	6285	143	177	440	233
10	210	6158	158	172	394	406
11	258	6023	260	131	351	145
12	225	5850	448	134	305	168
13	237	5720	431	144	264	224
14	149	5568	353	112	229	158
15	163	5404	231	85	196	279
16	153	5275	104	74	162	494
17	96	5134	125	76	116	240
18	69	5005	111	44	82	94
19	51	4892	97	38	46	154
20	179	4521	87	21	-7	112
	179	0	87	21	-7	112

Each of the relationships recorded in the table is then applied to hypothetical operational forecasts. Building on the reference tables above, the hypothetical operational forecasts described in the previously sections were used to calculate a reserve requirement for each interval of historical operational data. This is clarified in the example outlined below.

Application to Component Reserves

For each time interval in the Study Term, component forecasts developed from the hypothetical forecasts are used, in conjunction with Table H.8 and Table H.9, to derive a recommended reserve requirement informed by the load and wind generation conditions. This process can be explained with an example using the tables shown above and hypothetical operational forecasts from June 2013 operational data for PACE. Table H.10 illustrates the outcome of the process for the load following and regulating components.

Table H.10 - Load Forecasts and Component Reserve Requirement Data for Hour-ending 11:00 a.m. June 1, 2013 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Load (10-min Avg) MW	Actual Load (Hourly Avg) MW	Following Forecast Load MW	Load Following Up Reserves Specified by Tolerance Level MW	Load Following Down Reserves Specified by Tolerance Level MW	Regulating Load Forecast MW	Load Regulating Up Reserves Specified by Tolerance Level MW	Load Regulating Down Reserves Specified by Tolerance Level MW
06/01/2013 10:00	5,337	5,395	5,344	144	171	5,319	153	104
06/01/2013 10:10	5,383	5,395	5,344	144	171	5,350	153	104
06/01/2013 10:20	5,386	5,395	5,344	144	171	5,363	153	104
06/01/2013 10:30	5,403	5,395	5,344	144	171	5,375	153	104
06/01/2013 10:40	5,433	5,395	5,344	144	171	5,388	153	104
06/01/2013 10:50	5,428	5,395	5,344	144	171	5,401	153	104

The load following forecast for this particular hour (hour ending 11:00 a.m.) is 5,344 MW, which designates reserve requirements from Bin 16 as depicted (with shading for emphasis) in Table H.8. Because the 5,344 MW load following forecast falls between 5,264 MW and 5,406 MW, the value from the higher bin, 144 MW, as opposed to 87 MW, is assigned for this period. Note the same following forecast is applied to each interval in the hour for the purpose of developing reserve requirements. The first 10 minutes of the hour exhibits a load regulating forecast of 5,319 MW, which designates reserve requirements from Table H.9, Bin 16. Note that the load regulating forecast changes every 10 minutes, and as a result, the load regulating component reserve requirement can change very ten minutes as well-although, this is not observed in the sample data shown above. A similar process is followed for wind reserves using Table H.11.

Table H.11 - Interval Wind Forecasts and Component Reserve Requirement Data for Hour-ending 11 a.m. June 1, 2013 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Wind (10-min Avg)	Actual Wind (Hourly Avg)	Following Forecast Wind:	Wind Follow Up Reserves Specified by Tolerance Level	Wind Follow Down Reserves Specified by Tolerance Level	East Wind Regulatin g Forecast:	Wind Regulating Up Reserves Specified by Tolerance Level:	Wind Regulatin g Down Reserves Specified by Tolerance Level:
06/01/2013 10:00	190	217	207	101	287	219	85	279
06/01/2013 10:10	208	217	207	101	287	193	74	494
06/01/2013 10:20	212	217	207	101	287	195	74	494
06/01/2013 10:30	231	217	207	101	287	198	85	279
06/01/2013 10:40	234	217	207	101	287	200	85	279
06/01/2013 10:50	226	217	207	101	287	203	85	279

The wind following forecast for this particular hour (hour ending 11:00 a.m.) is 207 MW, which designates reserve requirements from Bin 15 under wind forecasts as depicted in Table H.8. Note the following forecast is applied to each interval in the hour for developing reserve requirements. Meanwhile, the regulating forecast changes every 10 minutes. The first 10 minutes of the hour exhibits a wind regulating forecast of 219 MW, which designates reserve requirements from Bin 15 as depicted in Table H.9. Similar to load, the wind regulating forecast changes every 10 minutes, and as a result, the wind regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast (193 MW) shifts the wind regulating component reserve requirement from Bin 15 into Bin 16, per Table H.9, and the component reserve requirement changes accordingly.

The assignment of component reserves using component hypothetical operational forecasts as described above is replicated for each 10-minute interval for the entire Study Term. The load following reserves, wind following reserves, load regulating reserves, and wind regulating reserves are then combined into following reserves and regulating reserves. Given that the four component reserves are to cover different deviations between actual and forecast values, they are not additive. In addition, as discussed in the Company's 2012 WIS report, the deviations of load and wind are not correlated.[12] Therefore, for each time interval, the wind and load reserve requirements are combined using the root-sum-of-squares (RSS) calculation in each direction (up and down). The combined results are then adjusted as the appropriate system L_{10} is subtracted and the ramp added to obtain the final result:

$$\sqrt{Load\ Regulating_i{}^2 + Wind\ Regulating_i{}^2 + Load\ Following_i{}^2 + Wind\ Following_i{}^2} - L_{10} + Ramp,$$

where *i* represents a 10-minute time interval. Assuming the ramp reserve for the east at 10:00 a.m. is 50 MW, and drawing from the first 10-minute interval in the example in Table H.10 and Table H.11.

Load Regulating$_i$ = 153 MW
Wind Regulating$_i$ = 85 MW
Load Following$_i$ = 144 MW
Wind Following$_i$ = 101 MW
East System L_{10} = 48 MW
East Ramp$_i$ = 50 MW,

The regulating margin for 10:00 a.m. is determined as:

$$\sqrt{153^2 + 85^2 + 144^2 + 101^2} - 48 + 50 = 251\ MW$$

In this manner, the component reserve requirements are used to calculate an overall reserve requirement for each 10-minute interval of the Study Term. A similar calculation is also made for the regulating margin pertaining only to the variability and uncertainty of load, while assuming zero reserves for the wind components. The incremental reserves assigned to wind generation are calculated as the difference between the total regulating margin requirement and the load-only regulating margin requirement.

[12] The discussion starts on page 111 of Appendix H in Volume II of the Company's 2012 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Determination of Wind Integration Costs

Wind integration costs reflect production costs associated with additional reserve requirements to integrate wind in order to maintain reliability of the system, and additional costs incurred with daily system balancing that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To characterize how wind generation affects regulating margin costs and system balancing costs, PacifiCorp utilizes the Planning and Risk (PaR) model and applies the regulating margin requirements calculated by the method detailed in the section above.

The PaR model simulates production costs of a system by committing and dispatching resources to meet system load. For this study, PacifiCorp developed seven different PaR simulations. These simulations isolate wind integration costs associated with regulating margin reserves and system balancing practice. The former reflects wind integration costs that arise from short-term variability (within the hour and hour ahead) in wind generation and the latter reflects integration costs that arise from errors in forecasting wind generation on a day-ahead basis. The seven PaR simulations used in the WIS are summarized in Table H.12.

Table H.12 - Wind Integration Cost Simulations in PaR

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error	Comments
Regulating Margin Reserve Cost Runs						
1	2015	2015 Load Forecast	Expected Profile	Load	None	
2	2015	2015 Load Forecast	Expected Profile	Load and Wind	None	
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1						
System Balancing Cost Runs						
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None	Commit units based on day-ahead load forecast, and day-ahead wind forecast
4	2015	2013 Actual	2013 Actual	Yes	For Load and Wind	Apply commitment from Simulation 3
5	2015	2013 Actual	2013 Day-ahead Forecast	Yes	None	Commit units based on actual Load, and day-ahead wind forecast
6	2015	2013 Actual	2013 Actual	Yes	For Wind	Apply commitment from Simulation 5
7	2015	2013 Actual	2013 Actual	Yes	None	Commit units based on actual Load, and actual wind forecast
Load System Balancing Cost = System Cost from PaR Simulation 4, which uses the unit commitment from Simulation 3 based on day-ahead forecast load (and day-ahead wind) less System Cost from PaR Simulation 6, which uses the unit commitement from Simulation 5 based on actual load (and day-ahead wind)						
Wind System Balancing Cost = System Cost from PaR Simulation 6, which uses the unit commitment from Simulation 5 based on day-ahdead wind (and actual load) less System Cost from PaR Simulation 7, which commits units based on actual wind (and actual load)						

The first two simulations are used to determine operating reserve wind integration costs in forward planning timeframes. The approach uses "P50", or expected, wind generation profiles and forecasted loads that are applicable to 2015.[13] Simulation 1 includes only the load regulating margin reserves. Simulation 2 includes regulating margin reserves for both load and wind, while keeping other inputs unchanged. The difference in production costs between the two simulations determines the cost of additional reserves to integrate wind, or the intra-hour wind integration

[13] P50 signifies the probability exceedance level for the annual wind production forecast; at P50 generation is expected to exceed the assumed generation levels half the time and to fall below the assumed generation levels half the time.

cost. The remaining five simulations support the calculation of system balancing costs related to committing resources based on day-ahead forecasted wind generation and load. These simulations were run assuming operation in the 2015 calendar year, applying 2013 load and wind data. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis, as well as the current resource portfolio.[14] PacifiCorp resources used in the simulations are based upon the 2013 IRP Update resource portfolio.[15]

Determining system balancing costs requires a comparison between production costs with day-ahead information as inputs and production costs with actual information as inputs. 2013 was the most recent year with the availability of these two types of data. Day-ahead wind generation forecasts for all owned and contracted wind resources were collected from the Company's wind forecast service provider, DNV GL.[16] For 2012 and 2013, DNV GL provided data sets for the historical day-ahead wind forecasts. The day-ahead load forecast was provided by the Company's load forecasting department. There are five PaR simulations to estimate daily system balancing wind integration costs, labeled as Simulations 3 through 7. In this phase of the analysis, PacifiCorp generation assets were committed consistent with a day-ahead forecast of wind and load, but dispatched against actual wind and load. To simulate this operational behavior, the five additional PaR simulations included the incremental reserves from Simulation 2 and the unit commitment states associated with simulating the portfolio with the day-ahead forecasts.

Load system balancing costs capture the difference between committing resources based on a day-ahead load forecast and committing resources based on actual load, while keeping inputs for wind generation unchanged. Similarly, wind system balancing costs capture the difference between committing resources based on day-ahead wind generation forecasts and committing resources based on actual wind generation, while keeping inputs for load unchanged. Simulation 3 determines the resource commitment for load system balancing and Simulation 5 determines the resource commitment for wind system balancing. The difference in production costs between Simulations 4 and 6 is the load system balancing cost due to committing resources using imperfect foresight on load. The difference in production cost between Simulations 6 and 7 is the wind system balancing cost due to committing resources using imperfect foresight on wind generation.

Table H.12 above is a revision from what was presented in the 2012 WIS. The revision was made to remove the impact of volume changes between day-ahead forecasts and actuals on production costs. Table H.13 lists the simulations performed in the 2012 WIS, which shows that wind system balancing costs were determined based on the change in production costs between Simulation 5 and Simulation 4. The wind system balancing costs are captured by committing resources based on a day-ahead forecast of wind generation, while operating the resources based on actual wind generation. However, between Simulation 4 and Simulation 5, the volume of wind generation is different. As a result, the production cost of Simulation 5 is impacted by

[14] The Study uses the December 31, 2013 OFPC official forward price curve.
[15] The 2013 Integrated Resource Update report, filed with the state utility commissions on March 31, 2014 is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/es/irp.html
[16] This is the same service provider as used by the Company previously, Garrad Hassan. Garrad Hassan is now part of DNV GL.

changes in wind generation. Using the approach adopted in the 2014 WIS as discussed above isolates system balancing integration costs to changes unit commitment.

Table H.13 - Wind Integration Cost Simulations in PaR, 2012 WIS

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error
Regulating Margin Reserve Cost Runs					
1	2015	2015 Load Forecast	Expected Profile	No	None
2	2015	2015 Load Forecast	Expected Profile	Yes	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					
System Balancing Cost Runs					
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None
4	2015	2013 Actual	2013 Day-ahead Forecast	Yes	For Load
5	2015	2013 Actual	2013 Actual	Yes	For Load and Wind
Load System Balancing Cost = System Cost from PaR simulation 4 (which uses the unit commitment from Simulation 3) less system cost from PaR simulation 3					
Wind System Balancing Cost = System Cost from PaR simulation 5 (which uses the unit commitment from Simulation 4) less system cost from PaR simulation 4					

Also different from the 2012 WIS, the regulating margin reserves are input to the PaR model on an hourly basis, after being reduced for the estimated benefits of participating in the EIM, as discussed in more detail below. Table H.14 shows the intra-hour and inter-hour wind integration costs from the 2014 WIS.

Table H.14 - 2014 Wind Integration Costs

	2014 WIS (2015$)
Intra-hour Reserve ($/MWh)	$2.35
Inter-hour/System Balancing ($/MWh)	$0.71
Total Wind Integration ($/MWh)	$3.06

In the 2015 IRP process, the System Optimizer (SO) model uses the 2014 WIS results to develop a cost for wind generation services. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study are used.

Sensitivity Studies

The Company performed several sensitivity scenarios to address recommendations from the TRC in its review of PacifiCorp's 2012 WIS. Each is discussed in turn below.

Modeling Regulating Margin on a Monthly Basis

As shown in Table H.10 and Table H.11, the component reserves and the total reserves are determined on a 10-minute interval basis. In the 2012 WIS, PacifiCorp calculated reserve requirements on a monthly basis by averaging the data for all 10-minute intervals in a month and applying these monthly reserve requirements in PaR as a constant requirement in all hours during a month. The TRC recommended that the reserve requirements could be modeled on an hourly basis to reflect the timing differences of reserves. In calculating wind integration costs for the 2014 WIS, the PacifiCorp modeled hourly reserve requirements as recommended by the TRC. Table H.15 compares wind integration costs from the 2012 WIS with wind integration costs from the 2014 WIS calculated using both monthly and hourly reserve requirements as inputs to the PaR model.

Table H.15 - Comparison of Wind Integration Costs Calculated Using Monthly and Hourly Reserve Requirements as Inputs to PaR

	2012 WIS Monthly Reserves (2012$)	2014 WIS Hourly Reserves (2015$)	2014 WIS Monthly Reserves (2015$)
Intra-hour Reserve ($/MWh)	$2.19	$2.35	$1.66
Inter-hour/System Balancing ($/MWh)	$0.36	$0.71	$0.74
Total Wind Integration ($/MWh)	$2.55	$3.06	$2.40

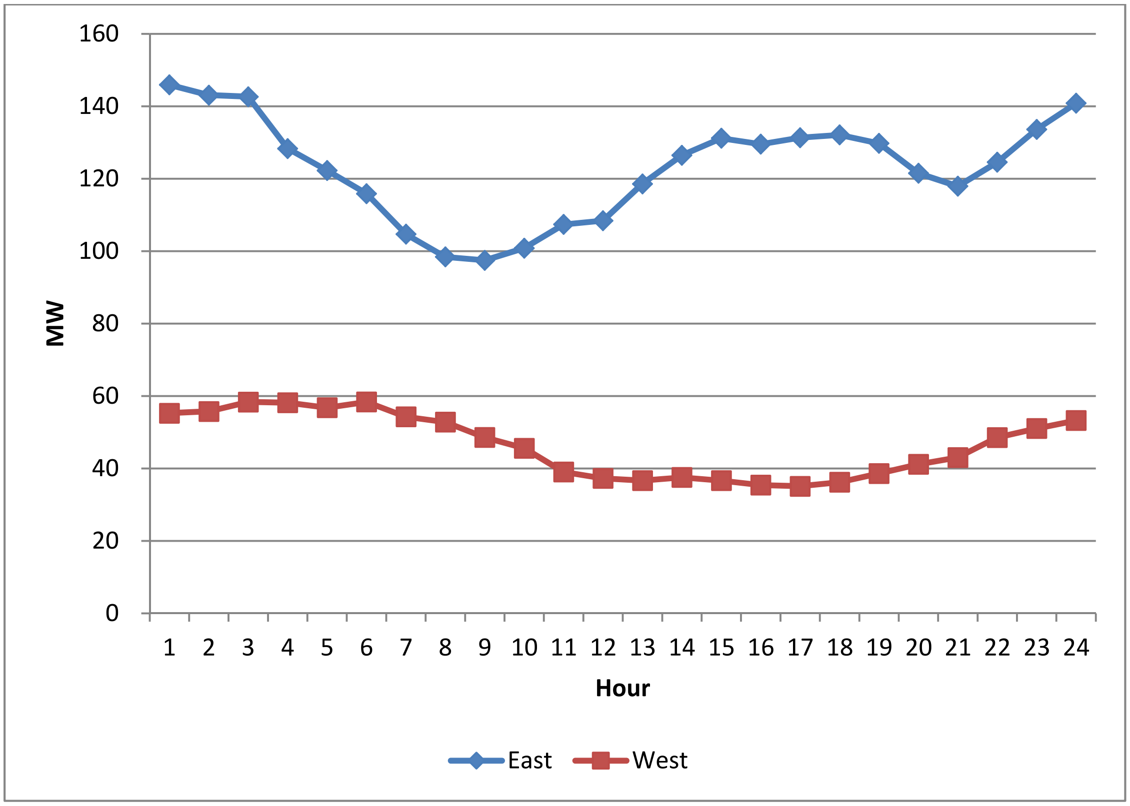
Compared to the 2012 WIS intra-hour reserve cost, the 2014 WIS intra-hour reserve cost is lower when reserves are modeled on a monthly basis in PaR. This is primarily due to the addition of a the Lake Side 2 combined-cycle plant, which can be used to cost effectively meet regulating margin requirements. Without Lake Side 2, the intra-hour reserve costs for the 2014 WIS Monthly Reserve sensitivity would increase from $1.66/MWh to $2.65/MWh. As compared to the 2012 WIS, which reported wind integration costs using monthly reserve data, the increase in cost is primarily due to increases in the market price for electricity and natural gas. Table H.16 compares the natural gas and electricity price assumptions used in the 2012 WIS to those used in the 2014 WIS.

Table H.16 - Average Natural Gas and Electricity Prices Used in the 2012 and 2014 Wind Integration Studies

Study	Palo Verde High Load Hour Power ($/MWh)	Palo Verde Low Load Hour Power ($/MWh)	Opal Natural Gas ($/MMBtu)
2012 WIS	$37.05	$25.74	$3.43
2014 WIS	$39.13	$29.31	$3.88

When modeling reserves on an hourly basis in PaR, the intra-hour reserve cost is higher than when modeling reserves on a monthly basis. This is due to more reserves being shifted from relatively lower-priced hours to relatively higher-priced hours. Figure H.7 shows the average profiles of wind regulating margin reserves from 2013.

Figure H.7 – Average Hourly Wind Reserves for 2013, MW



Separating Regulating and Following Reserves

In its review of the 2012 WIS, the TRC recommended treating categories of reserves differently by separating the component reserves of regulating, following and ramping. That is, instead of modeling regulating margin as:

$$\sqrt{Load\ Regulating_i{}^2 + Wind\ Regulating_i{}^2 + Load\ Following_i{}^2 + Wind\ Following_i{}^2} - L_{10} + Ramp,$$

The TRC recommendation requires calculating regulating reserves and following reserves using two separate calculations:

$$Regulating\ Reserves = \sqrt{Load\ Regulating_i{}^2 + Wind\ Regulating_i{}^2} - L_{10}, and$$

$$Following\ Reserves = \sqrt{+Load\ Following_i{}^2 + Wind\ Following_i{}^2} + Ramp.$$

Because regulating reserves are more restrictive than following reserves (fewer units can be used to meet regulating reserve requirements), the L_{10} adjustment is applied to the regulating reserve calculation. Ramp reserves can be met with similar types of resources as following reserves, and therefore, are combined with following reserves.

The impact of separating the component reserves as outlined above is to increase the total reserve requirement required on PacifiCorp's system. Table H.17 shows the total reserve requirement when the separately calculated regulating and following reserves are summed as compared to the total reserves combined using one RSS equation. The total reserve requirement, when calculated separately, is over 30% higher than the reserve requirement calculated from a single RSS equation. This is a significant increase in the amount of regulation reserves that is inconsistent with how the Company's resources are operated and dispatched. As a result, PacifiCorp did not evaluate this sensitivity in PaR.

Table H.17– Total Load and Wind Monthly Reserves, Separating Regulating and Following Reserves (MW)

	Combined (MW)		Regulating		Following		Total (MW)	
	West	East	West	East	West	East	West	East
Jan	238	400	107	196	211	354	318	550
Feb	212	363	100	182	187	318	287	500
Mar	219	357	97	179	202	313	299	492
Apr	240	422	123	224	208	362	331	586
May	192	400	84	205	180	348	264	553
Jun	183	462	70	240	179	393	249	633
Jul	219	427	88	180	206	391	294	572
Aug	220	428	90	188	206	388	296	576
Sep	210	392	100	171	188	361	287	533
Oct	153	335	75	159	131	301	206	461
Nov	301	438	165	228	249	375	414	603
Dec	274	433	122	216	251	375	373	592

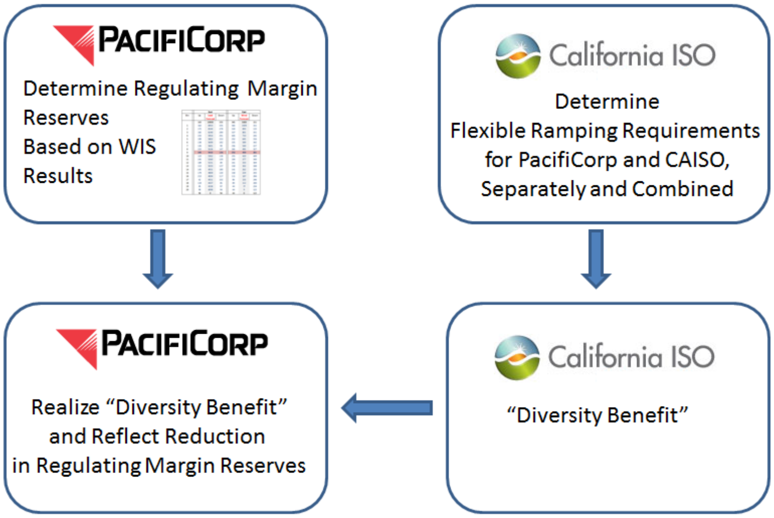
Energy Imbalance Market (EIM)

EIM is an energy balancing market that optimizes generator dispatch between PacifiCorp and the CAISO every five minutes via the existing real-time dispatch market functionality. PacifiCorp and the CAISO began a phased implementation of the EIM on October 1, 2014, when EIM was activated to allow the systems that will operate the market to interact under realistic conditions, allowing PacifiCorp to submit load schedules and bid resources into the EIM and allowing the CAISO to use its automated system to generate dispatch signals for resources on PacifiCorp's control areas. The EIM is expected to be fully operational November 1, 2014.

Once EIM becomes fully operational, PacifiCorp must provide sufficient flexible reserve capacity to ensure it is not leaning on other participating balancing authorities in the EIM for reserves. The intent of the EIM is that each participant in the market has sufficient capacity to meet its needs absent the EIM, net of a CAISO calculated reserves diversity benefit. In this manner, PacifiCorp must hold the same amount of regulating reserve under the EIM as it did prior to the EIM, but for a calculated diversity benefit.[17] Figure H.8 illustrates this process.

[17] Under the EIM, base schedules are due 75 minutes prior to the hour of delivery. The base schedules can be adjusted at 55 minutes and 40 minutes prior to the delivery hour in response to CAISO sufficiency tests. This is consistent with pre-EIM scheduling practices, in which schedules are set 40 minutes prior to the delivery hour.

Figure H.8 – Energy Imbalance Market



The CAISO will calculate the diversity benefit by first calculating the reserve requirement for each individual EIM participant and then by comparing the sum of those requirements to the reserve requirement for the entire EIM area. The latter amount is expected to be less than the sum due to the portfolio diversification effect of load and variable energy resource (wind and solar) variations. The CAISO will then allocate the diversity benefit among all the EIM participants. Finally, PacifiCorp will reduce its regulating reserve requirement by its allocation of diversity benefit.

In its 2013 report, Energy and Environmental Economics (E3) estimated the following benefits of the EIM system implementation:18

- PacifiCorp could see a 19 to 103 MW reduction in regulating reserves, depending on the level of bi-directional transmission intertie made available to EIM;
- Interregional dispatch savings: Five-minute dispatch efficiency will reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
- Intraregional dispatch savings: PacifiCorp generators will dispatch more efficiently through the CAISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;
- Reduced flexibility reserves by aggregating the two systems' load, wind, and solar variability and forecast errors;
- Reduced renewable energy curtailment by allowing BAAs to export or reduce imports of renewable generation when it would otherwise need to be curtailed.

Based on the E3 study, the relationship between the benefit in reducing regulating reserve requirements and the transfer capability of the intertie is shown in Table H.18.

[18] http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

Table H.18 - Estimated Reduction in PacifiCorp's Regulating Margin Due to EIM

Transfer Capability (MW)	Reduction in Flexible Reserves (MW)
100	19
400	78
800	103

Given that the transfer capacity in this WIS is assumed to be approximately 330 MW, through owned and contracted rights, the reduction in regulating reserve is assumed to be approximately 65 MW. This benefit is applied to reduce the regulating margin on PacifiCorp's west BAA because the current connection between PacifiCorp and CAISO is limited to the west only. Table H.19 summarizes the impact of estimated EIM regulating reserve benefits assuming monthly application of reserves in PaR to be comparable to how the 2012 WIS wind integration costs were calculated. The sensitivity shows that EIM regulating reserve benefits reduce wind integration costs by approximately $0.21/MWh.

Table H.19 – Wind Integration Cost with and without EIM Benefit

	2012 WIS (2012$)	2014 WIS With EIM Benefits (2015$)	2014 WIS Without EIM Benefits (2015$)
Intra-hour Reserve Cost ($/MWh)	$2.19	$1.66	$1.87
Inter-hour/System Balancing Cost ($/MWh)	$0.36	$0.74	$0.74
Total Wind Integration Cost ($/MWh)	$2.55	$2.40	$2.61

Summary

The 2014 WIS determines the additional reserve requirement, which is incremental to the mandated contingency reserve requirement, needed to maintain moment-to-moment system balancing between load and generation while integrating wind resources into PacifiCorp's system. The 2014 WIS also estimates the cost of holding these incremental reserves on its system.

PacifiCorp implemented the same methodology developed in the 2012 WIS for calculating regulating reserves for its 2014 WIS, and implemented recommendations from the TRC to implement hourly reserve inputs when determining wind integration costs using PaR. Also consistent with TRC recommendations, PacifiCorp further incorporated regulation reserve benefits associated with EIM in its wind integration costs. Table H.20 compares the results of the 2014 WIS total reserves to those calculated in the 2012 WIS.

Table H.17 - Regulating Margin Requirements Calculated for PacifiCorp's System (MW)

Year	Reserve Component	West BAA	East BAA	Ramp	Combined
2011	Load-Only Regulating Reserves	99	176	119	394
(2012 WIS)	Incremental Wind Reserves	50	126	9	185
	Total Reserves	149	302	128	579
2012	Load-Only Regulating Reserves	95	186	119	400
	Incremental Wind Reserves	71	123	11	206
	Total Reserves	166	309	130	606
2013	Load-Only Regulating Reserves	119	203	119	441
(2013 WIS)	Incremental Wind Reserves	51	123	12	186
	Total Reserves	169	326	131	626

The anticipated implementation of EIM with the CAISO is expected to reduce PacifiCorp's reserve requirements due to the diversification of resource portfolios between the two entities. PacifiCorp estimated the benefit of EIM regulating reserve benefits based on a study from E3. The assumed benefits reduce regulating reserves in PacifiCorp's west BAA by approximately 65 MW from the regulating reserves shown in the table above, which lowers wind integration costs by approximately $0.21/MWh.

Two categories of wind integration costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour reserve requirements, and one for inter-hour system balancing. Table H.21 compares 2014 wind integration costs, inclusive of estimated EIM benefits, to those published in the 2012 WIS.

Table H.21 – 2014 WIS Wind Integration Costs as Compared to 2012 WIS

	2012 WIS (2012$)	2014 WIS (2015$)
Intra-hour Reserve ($/MWh)	$2.19	$2.35
Inter-hour/System Balancing ($/MWh)	$0.36	$0.71
Total Wind Integration ($/MWh)	$2.55	$3.06

The 2014 WIS results are applied to the 2015 IRP portfolio development process as a cost for wind generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. After resource portfolios are developed using the SO model, the PaR model is used to evaluate the risk profiles of the portfolios in meeting load obligations, including incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with the 2014 WIS are used.

Rocky Mountain Power
Exhibit RMP___(GND-2)
Docket No. 20000-___-EA-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

November 2014

2014 Wind and Solar Capacity Contribution Study

Introduction

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of this report, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability (LOLP). PacifiCorp calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1].

The capacity contribution of wind and solar resources affects PacifiCorp's resource planning activities. PacifiCorp conducts its resource planning to ensure there is sufficient capacity on its system to meet its load obligation at the time of system coincident peak inclusive of a planning reserve margin. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's net coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

PacifiCorp derives its planning reserve margin from a LOLP study. The study evaluates the relationship between reliability across all hours in a given year, accounting for variability and uncertainty in load and generation resources, and the cost of planning for system resources at varying levels of planning reserve margin. In this way, PacifiCorp's planning reserve margin LOLP study is the mechanism used to transform hourly reliability metrics into a resource adequacy target at the time of system coincident peak. This same LOLP study was utilized for calculating the peak capacity contribution using the CF Method. Table 1 summarizes the peak capacity contribution results for PacifiCorp's east and west balancing authority areas (BAAs).

Table 1 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
CF Method Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to the more computationally intensive reliability-based effective load carrying capability (ELCC) metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors for a wind or solar resource to produce a weighted average capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

To determine the capacity contribution using the CF method, PacifiCorp implemented the following two steps:

1. A 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of the Company's system for a sample year (calendar year 2017). This PaR study is based on the Company's 2015 IRP planning reserve margin study using a 13% target planning reserve margin level. The LOLP for each hour in the year is calculated by counting the number of iterations in an hour in which system load could not be met with available resources and dividing by 500 (the total number iterations). For example, if in hour 9 on January 12th there are two iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.4%.[2]

[2] 0.4% = 2 / 500.

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours. In the example noted above, the sum of LOLP among all hours is 143%.[3] The weighting factor for hour 9 on January 12th would be 0.2797%.[4] The hourly weighting factors are then applied to the capacity factors of wind and solar resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0% in hour 9 on January 12th, its weighted annual capacity contribution for that hour would be 0.1146%.[5]

Results

Table 2 summarizes the resulting annual capacity contribution using the CF Method described above as compared to capacity contribution values assumed in the 2013 IRP.[6] In implementing the CF Method, PacifiCorp used actual wind generation data from wind resources operating in its system to derive hourly wind capacity factor inputs. For solar resources, PacifiCorp used hourly generation profiles, differentiated between single axis tracking and fixed tilt projects, from a feasibility study developed by Black and Veatch. A representative profile for Milford County, Utah was used to calculate East BAA solar capacity contribution values, and a representative profile for Lakeview County, Oregon was used to calculate West BAA solar capacity contribution values.

Table 2 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**	**Wind**	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**
CF Method Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%
2013 IRP Results	4.2%	13.6%	n/a	4.2%	13.6%	n/a

Figure 1 presents daily average LOLP results from the PaR simulation, which shows that loss of load events are most likely to occur during the spring, when maintenance is often planned, and during peak load months, which occur in the summer and the winter.

[3] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 715 ENS iteration-hours out of total of 8,760 hours. As a result, the sum of LOLP is 715 / 500 = 143%.
[4] 0.2797% = 0.4% / 143%, or simply 0.2797% = 2 / 715.
[5] 0.1146% = 0.2797% x 41.0%.
[6] In its 2013 IRP, PacifiCorp estimated capacity contribution values for wind and solar resources by evaluating capacity factors for wind and solar resources at a 90% probability level among the top 100 load hours in a given year.

Figure 1 - Daily LOLP

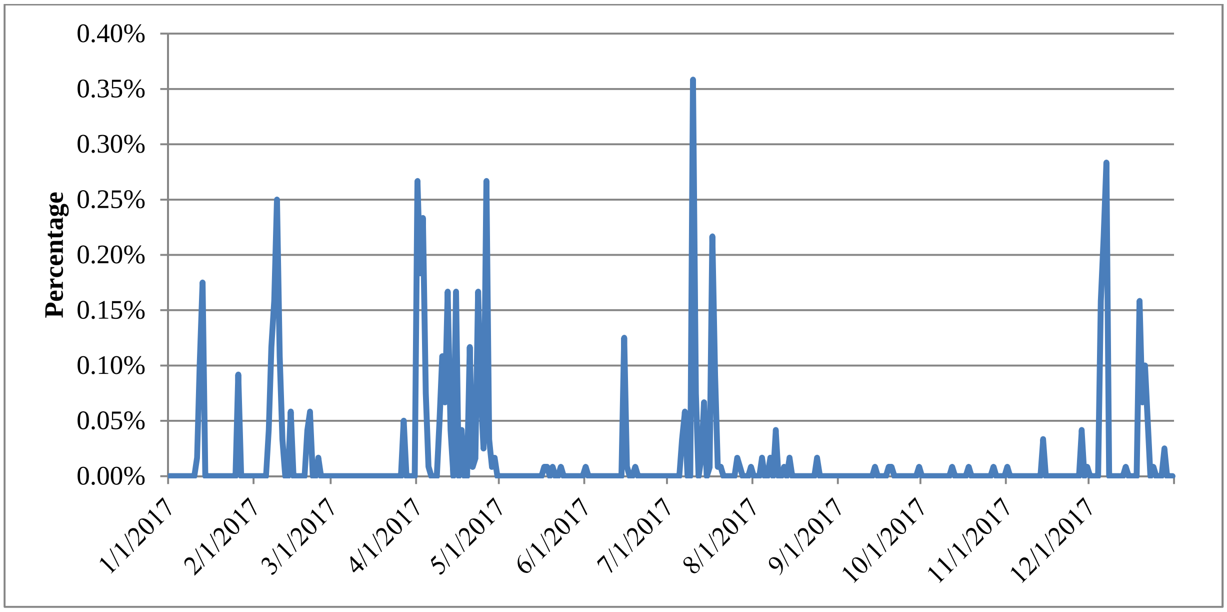
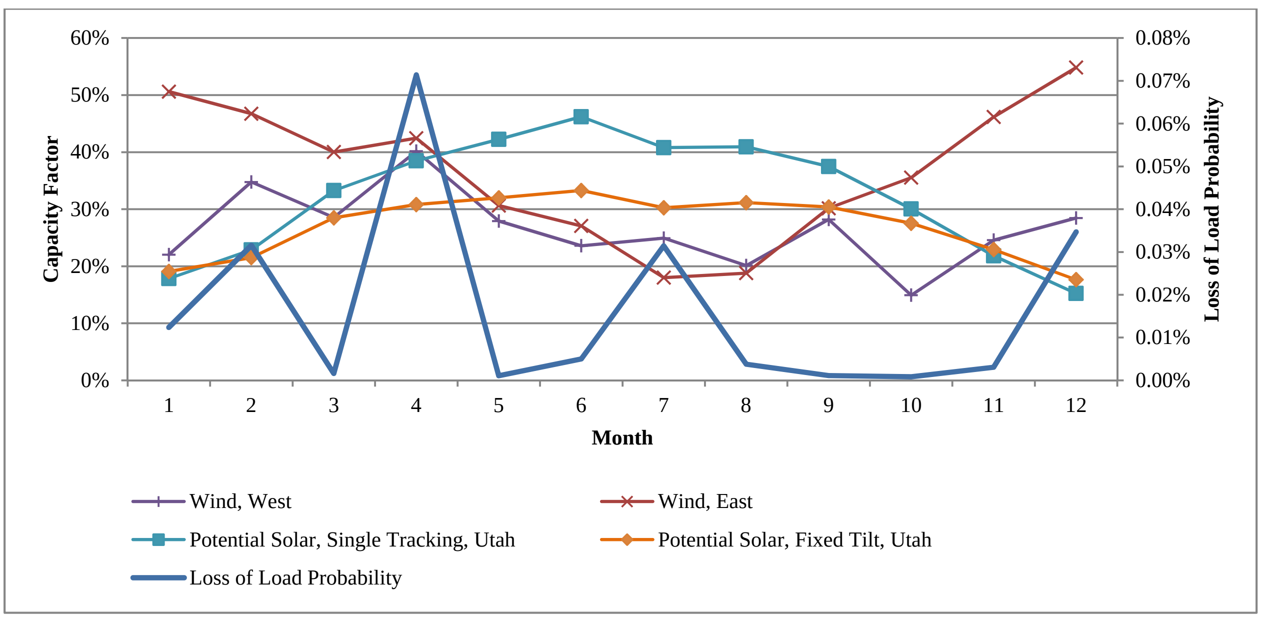


Figure 2 presents the relationship between monthly capacity factors among wind and solar resources (primary y-axis) and average monthly LOLP from the PaR simulation (secondary y-axis) in PacifiCorp's CF Method analysis. As noted above, the average monthly LOLP is most prominent in April (spring maintenance period), summer (July peak loads), and winter (when loads are high).

Figure 2 - Monthly Resource Capacity Factors as Compared to LOLP



Figures 3 through 5 present the hourly distribution of capacity factors among wind and solar resources (primary y-axis) as compared to the hourly distribution of LOLP (secondary y-axis) for a typical day in the months of April, July, and December, respectively. Among a typical day in April, LOLP events peak during morning and evening ramp periods when generating units are transitioning between on-peak and off-peak operation. Among a typical day in July, LOLP events peak during higher load hours and during the evening ramp. In December, LOLP events peak during higher load evening hours.

Figure 3 - Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in April

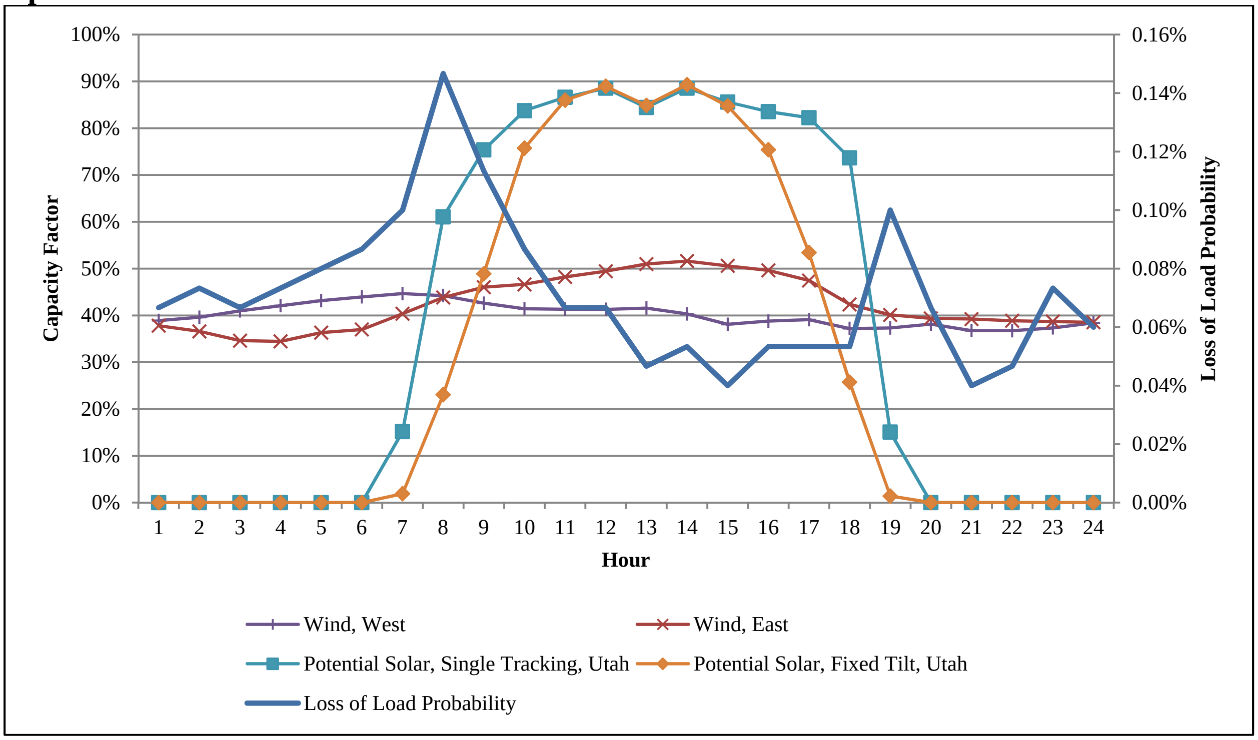


Figure 4 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in July

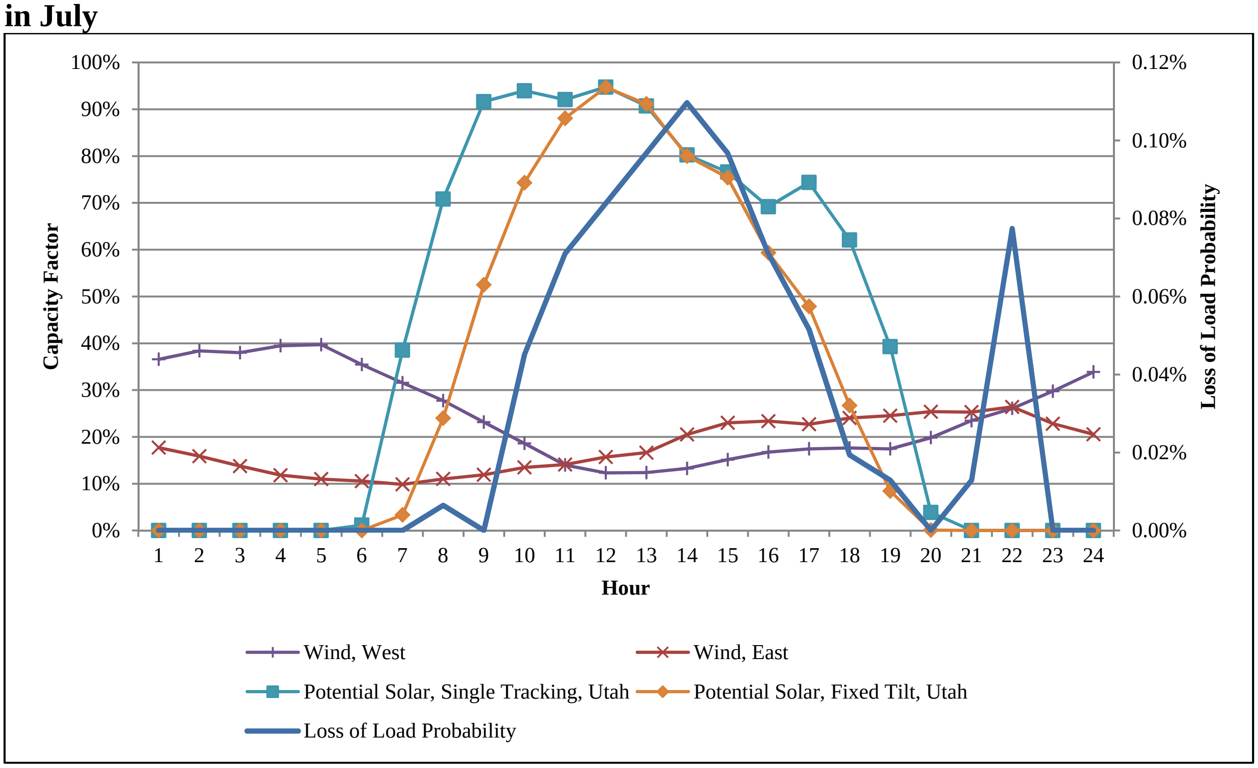
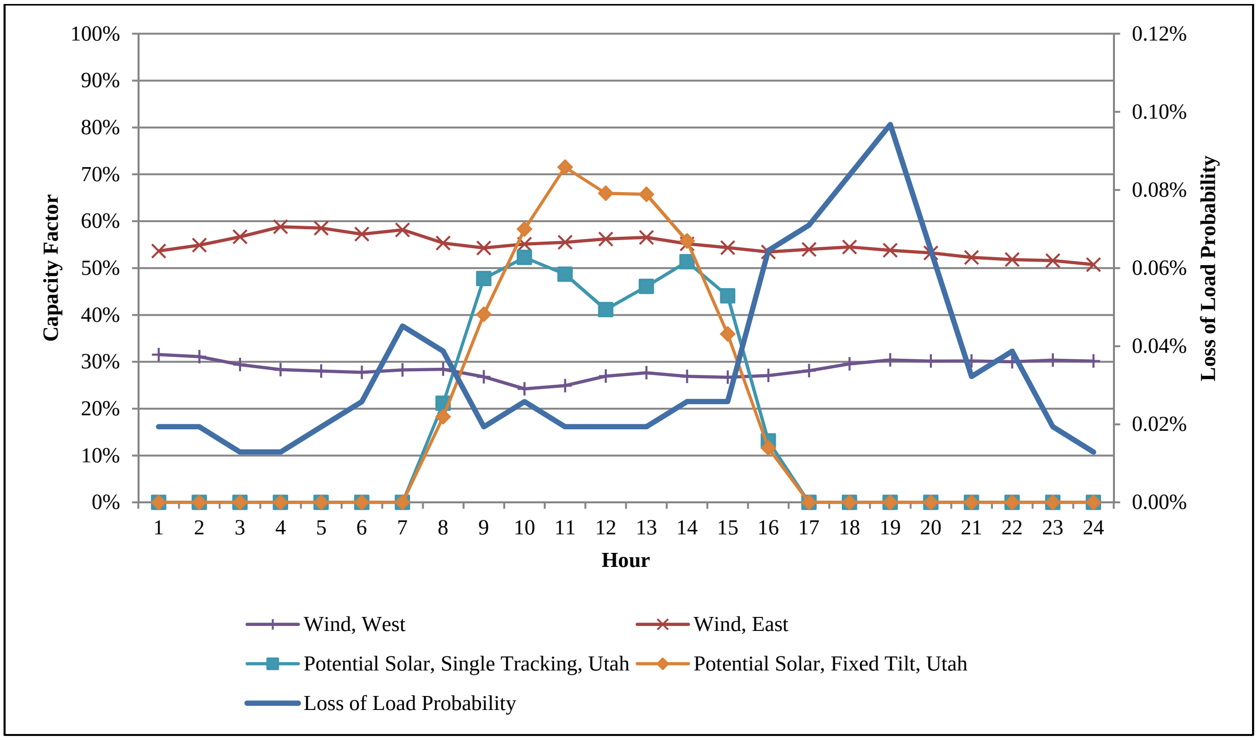


Figure 5 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in December



Conclusion

PacifiCorp conducts its resource planning by ensuring there is sufficient capacity on its system to meet its net load obligation at the time of system coincident peak inclusive of a planning reserve margin. The peak capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is the weighted average capacity factor of these resources at the time when the load cannot be met with available resources. The peak capacity contribution values developed using the CF Method are based on a LOLP study that aligns with PacifiCorp's 13% planning reserve margin, and therefore, the values represent the expected contribution that wind and solar resources make toward achieving PacifiCorp's target resource planning criteria.

PROPOSED TARIFFS

CLEAN AND REDLINE VERSIONS

Avoided Cost Purchases from Qualifying Facilities Schedule 37

Available

To owners of Qualifying Facilities in all territory served by the Company in the State of Wyoming.

Applicable

Applicable to the purchase by the Company of all non-firm energy produced by Qualifying Facilities over which the Commission has jurisdiction, prior to commercial operation and subject to a power sales contract. After commercial operation is achieved, Qualifying Facilities will receive firm power prices.

For firm power purchases from all Qualifying Facilities over which the Commission has jurisdiction with a historic or projected annual capacity factor of seventy percent or below up to 1 MW design capacity or up to a maximum of 10 MW of average monthly capacity and associated energy when the historic or projected annual capacity factor is greater than seventy percent. Owners of these Qualifying Facilities shall be required to enter into a written power sales contract with the Company.

Rates for Purchases

Non-firm Energy

The prices shown below are subject to change from time to time to reflect changes in the Company's determination of avoided costs. The prices applicable to a Wyoming Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time the power is delivered.

Base Load QF Non-Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39

(continued)

Rates for Purchases

Non-firm Energy *(continued)*

Wind QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07

Fixed Solar QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

Tracking Solar QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

(continued)

Avoided Cost Purchases from Qualifying Facilities Schedule 37

Firm Power Time of Delivery

The prices shown below are subject to change from time to time to reflect changes in the Company's determination of Wyoming avoided costs. The prices applicable to a Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time a written contract acceptable to the Company is signed on behalf of the Qualifying Facility and received by the Company at 825 N. E. Multnomah Street, Portland, Oregon, 97232, or such other address as the Company shall designate. These prices will only be applied to Qualifying Facility resources over which the Commission has jurisdiction that enter into contracts with the Company until 10 megawatts of system resources are acquired.

Base Load QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39
2018	3.19	3.77	2.50	2.69
2019	3.29	3.95	2.60	2.85
2020	3.49	4.10	2.86	2.99
2021	3.81	4.35	3.42	3.41
2022	4.24	4.63	4.02	3.87
2023	4.21	4.88	3.97	4.09
2024	3.92	5.27	3.70	4.35
2025	5.34	5.68	5.07	4.54
2026	5.29	6.09	5.02	4.90

(continued)

Rates for Purchases

Firm Power Time of Delivery *(continued)*

Base Load QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2027	7.72	7.72	4.51	4.51
2028	7.95	7.95	4.68	4.68
2029	8.20	8.20	4.87	4.87
2030	8.46	8.46	5.07	5.07
2031	8.62	8.62	5.16	5.16
2032	8.78	8.78	5.26	5.26
2033	8.95	8.95	5.36	5.36
2034	9.12	9.12	5.46	5.46
2035	9.31	9.31	5.57	5.57
2036	9.50	9.50	5.69	5.69
2037	9.68	9.68	5.80	5.80
2038	9.87	9.87	5.91	5.91

(continued)

Wind QF Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07
2018	2.87	3.45	2.18	2.36
2019	2.97	3.62	2.28	2.52
2020	3.16	3.77	2.53	2.65
2021	3.47	4.01	3.07	3.07
2022	3.89	4.28	3.67	3.52
2023	3.86	4.53	3.62	3.73
2024	3.56	4.91	3.34	3.98
2025	4.97	5.31	4.70	4.17
2026	4.92	5.72	4.64	4.53
2027	4.59	4.59	4.13	4.13
2028	4.76	4.76	4.29	4.29
2029	4.96	4.96	4.47	4.47
2030	5.15	5.15	4.66	4.66
2031	5.25	5.25	4.75	4.75
2032	5.35	5.35	4.84	4.84
2033	5.45	5.45	4.93	4.93
2034	5.55	5.55	5.02	5.02
2035	5.67	5.67	5.12	5.12
2036	5.78	5.78	5.23	5.23
2037	5.89	5.89	5.33	5.33
2038	6.01	6.01	5.44	5.44

(continued)

Fixed Solar QF Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.51	5.51	4.42	4.42
2028	5.70	5.70	4.58	4.58
2029	5.91	5.91	4.77	4.77
2030	6.12	6.12	4.97	4.97
2031	6.24	6.24	5.06	5.06
2032	6.35	6.35	5.15	5.15
2033	6.48	6.48	5.25	5.25
2034	6.60	6.60	5.35	5.35
2035	6.73	6.73	5.46	5.46
2036	6.87	6.87	5.57	5.57
2037	7.00	7.00	5.68	5.68
2038	7.14	7.14	5.79	5.79

(continued)

Tracking Solar QF Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.67	5.67	4.42	4.42
2028	5.86	5.86	4.58	4.58
2029	6.07	6.07	4.77	4.77
2030	6.29	6.29	4.97	4.97
2031	6.41	6.41	5.06	5.06
2032	6.53	6.53	5.15	5.15
2033	6.66	6.66	5.25	5.25
2034	6.78	6.78	5.35	5.35
2035	6.92	6.92	5.46	5.46
2036	7.06	7.06	5.57	5.57
2037	7.20	7.20	5.68	5.68
2038	7.34	7.34	5.79	5.79

(continued)

Green Tags

The Company retains Green Tags for the benefit of customers without any additional payment when it buys power from a QF resource. In the event a qualifying facility contract ends or is terminated, the Green Tags revert to the qualifying facility project until the developer sells or transfers the Green Tags to another purchaser.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Small Power Production Facility

A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

Solar Facility

A facility which produces electric energy using the sun as the primary energy source. A Solar Facility may be flat mounted (Fixed Solar) or configured with a device to orient the solar panels toward the sun (Tracking Solar).

Wind Facility

A facility which produces electric energy using wind as the primary energy source.

(continued)

Definitions *(continued)*

Winter Season
The months of November through April.

Summer Season
The months of May through October.

On-Peak Hours
On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Off-Peak Hours
All hours other than On-Peak hours.

Monthly Payments

The Monthly Payment shall be the sum of the winter and summer energy prices for Peak and Off-Peak hours. Winter and summer energy payments for Peak and Off-Peak hours are provided separately for a Base Load facility, Wind Facility, Fixed Solar Facility and a Tracking Solar Facility.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by the Wyoming Public Service Commission.

ROCKY MOUNTAIN POWER

~~First~~ Second Revision of Sheet No. 37-1
Canceling First Revision of ~~Original~~ Sheet No. 37-1

P.S.C. Wyoming No. 14

Avoided Cost Purchases from Qualifying Facilities Schedule 37

Available

To owners of Qualifying Facilities in all territory served by the Company in the State of Wyoming.

Applicable

Applicable to the purchase by the Company of all non-firm energy produced by Qualifying Facilities over which the Commission has jurisdiction, prior to commercial operation and subject to a power sales contract. After commercial operation is achieved, Qualifying Facilities will receive firm power prices.

For firm power purchases from all Qualifying Facilities over which the Commission has jurisdiction with a historic or projected annual capacity factor of seventy percent or below up to 1 MW design capacity or up to a maximum of 10 MW of average monthly capacity and associated energy when the historic or projected annual capacity factor is greater than seventy percent. Owners of these Qualifying Facilities shall be required to enter into a written power sales contract with the Company.

Rates for Purchases

Non-firm Energy

The prices shown below are subject to change from time to time to reflect changes in the Company's determination of avoided costs. The prices applicable to a Wyoming Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time the power is delivered.

Base Load QF Non-Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter ¢/kWh	Summer ¢/kWh	Winter ¢/kWh	Summer ¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39

(continued)

Avoided Cost Purchases from Qualifying Facilities
Schedule 37

~~Non-Firm Energy Prices~~

~~Deliveries Year~~	~~Winter ¢/kWh~~	~~Summer ¢/kWh~~
~~2012~~	~~1.62~~	~~1.86~~
~~2013~~	~~1.91~~	~~2.44~~
~~2014~~	~~2.39~~	~~2.87~~
~~2015~~	~~2.56~~	~~3.12~~

~~*(continued)*~~

Avoided Cost Purchases from Qualifying Facilities
Schedule 37

Rates for Purchases

Non-firm Energy *(continued)*

Wind QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07

Fixed Solar QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

Tracking Solar QF Non-Firm Energy Prices

Deliveries Year	Peak Energy Prices Winter ¢/kWh	Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31

(continued)

~~Firm Power Time of Delivery~~

~~The prices shown below are subject to change from time to time to reflect changes in the Company's determination of Wyoming avoided costs. The prices applicable to a Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time a written contract acceptable to the Company is signed on behalf of the Qualifying Facility and received by the Company at 825 N. E. Multnomah Street, Portland, Oregon, 97232, or such other address as the Company shall designate. These prices will only be applied to Qualifying Facility resources over which the Commission has jurisdiction that enter into contracts with the Company until 10 megawatts of system resources are acquired.~~

~~Deliveries Year~~	~~Capacity Price $/kW-mo~~	~~Firm Energy Winter ¢/kWh~~	~~Summer ¢/kWh~~
~~2013~~	~~$2.76~~	~~1.91~~	~~2.44~~
~~2014~~	~~$2.82~~	~~2.39~~	~~2.87~~
~~2015~~	~~$2.87~~	~~2.56~~	~~3.12~~
~~2016~~	~~$2.92~~	~~2.60~~	~~3.23~~
~~2017~~	~~$2.97~~	~~2.55~~	~~3.45~~
~~2018~~	~~$3.01~~	~~2.74~~	~~3.79~~
~~2019~~	~~$3.06~~	~~2.96~~	~~4.28~~
~~2020~~	~~$3.11~~	~~3.34~~	~~4.59~~
~~2021~~	~~$3.17~~	~~4.07~~	~~4.86~~
~~2022~~	~~$3.23~~	~~5.07~~	~~5.33~~
~~2023~~	~~$3.29~~	~~5.35~~	~~5.70~~
~~2024~~	~~$3.36~~	~~5.59~~	~~5.78~~
~~2025~~	~~$13.68~~	~~4.47~~	~~4.47~~
~~2026~~	~~$13.94~~	~~4.77~~	~~4.77~~
~~2027~~	~~$14.20~~	~~4.80~~	~~4.80~~

~~*(continued)*~~

Firm Power Time of Delivery

The prices shown below are subject to change from time to time to reflect changes in the Company's determination of Wyoming avoided costs. The prices applicable to a Qualifying Facility over which the Commission has jurisdiction shall be those in effect at the time a written contract acceptable to the Company is signed on behalf of the Qualifying Facility and received by the Company at 825 N. E. Multnomah Street, Portland, Oregon, 97232, or such other address as the Company shall designate. These prices will only be applied to Qualifying Facility resources over which the Commission has jurisdiction that enter into contracts with the Company until 10 megawatts of system resources are acquired.

Base Load QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter	Summer	Winter	Summer
	¢/kWh	¢/kWh	¢/kWh	¢/kWh
2014	2.79		2.33	
2015	2.89	3.17	2.37	2.25
2016	2.78	3.19	2.23	2.29
2017	2.87	3.34	2.28	2.39
2018	3.19	3.77	2.50	2.69
2019	3.29	3.95	2.60	2.85
2020	3.49	4.10	2.86	2.99
2021	3.81	4.35	3.42	3.41
2022	4.24	4.63	4.02	3.87
2023	4.21	4.88	3.97	4.09
2024	3.92	5.27	3.70	4.35
2025	5.34	5.68	5.07	4.54
2026	5.29	6.09	5.02	4.90

(continued)

ROCKY MOUNTAIN POWER

~~First~~ Second Revision of Sheet No. 37-3
Canceling First Revision of~~Original~~ Sheet No. 37-3

P.S.C. Wyoming No. 14

Avoided Cost Purchases from Qualifying Facilities
Schedule 37

~~**Rates for Purchases** *(continued)*~~

~~Deliveries Year~~	~~Capacity Price~~	~~Firm Energy Winter~~	~~Summer~~
	~~$/kW-mo~~	~~¢/kWh~~	~~¢/kWh~~
~~2028~~	~~$14.474.88~~	~~4.88~~	
~~2029~~	~~$14.754.99~~	~~4.99~~	
~~2030~~	~~$15.03~~	~~5.04~~	~~5.04~~
~~2031~~	~~$15.33~~	~~5.20~~	~~5.20~~
~~2032~~	~~$15.63~~	~~5.30~~	~~5.30~~
~~2033~~	~~$15.95~~	~~5.41~~	~~5.41~~
~~2034~~	~~$16.27~~	~~5.52~~	~~5.52~~
~~2035~~	~~$16.59~~	~~5.63~~	~~5.63~~
~~2036~~	~~$16.92~~	~~5.74~~	~~5.74~~

~~**Green Tags**~~
~~The Company retains Green Tags for the benefit of customers without any additional payment when it buys power from a QF resource. In the event a qualifying facility contract ends or is terminated, the Green Tags revert to the qualifying facility project until the developer sells or transfers the Green Tags to another purchaser.~~

~~*(continued)*~~

Rates for Purchases

Firm Power Time of Delivery *(continued)*

Base Load QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter	Summer	Winter	Summer
	¢/kWh	¢/kWh	¢/kWh	¢/kWh
2027	7.72	7.72	4.51	4.51
2028	7.95	7.95	4.68	4.68
2029	8.20	8.20	4.87	4.87
2030	8.46	8.46	5.07	5.07
2031	8.62	8.62	5.16	5.16
2032	8.78	8.78	5.26	5.26
2033	8.95	8.95	5.36	5.36
2034	9.12	9.12	5.46	5.46
2035	9.31	9.31	5.57	5.57
2036	9.50	9.50	5.69	5.69
2037	9.68	9.68	5.80	5.80
2038	9.87	9.87	5.91	5.91

(continued)

Avoided Cost Purchases from Qualifying Facilities Schedule 37

~~**Definitions**~~

~~**Cogeneration Facility**~~

~~A facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.~~

~~**Qualifying Facilities**~~

~~Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.~~

~~**Small Power Production Facility**~~

~~A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.~~

~~**Winter Season**~~

~~The months of November through April.~~

~~**Summer Season**~~

~~The months of May through October.~~

~~**Monthly Payments**~~

~~The Monthly Payment shall be the sum of the avoided cost energy payment and the avoided cost capacity payment if applicable.~~

~~**Rules**~~

~~Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by the Wyoming Public Service Commission.~~

ROCKY MOUNTAIN POWER

Original Sheet No. 37-5

P.S.C. Wyoming No. 14

Avoided Cost Purchases from Qualifying Facilities Schedule 37

Wind QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter	Summer	Winter	Summer
	¢/kWh	¢/kWh	¢/kWh	¢/kWh
2014	2.49		2.03	
2015	2.59	2.86	2.07	1.95
2016	2.47	2.88	1.92	1.98
2017	2.55	3.02	1.96	2.07
2018	2.87	3.45	2.18	2.36
2019	2.97	3.62	2.28	2.52
2020	3.16	3.77	2.53	2.65
2021	3.47	4.01	3.07	3.07
2022	3.89	4.28	3.67	3.52
2023	3.86	4.53	3.62	3.73
2024	3.56	4.91	3.34	3.98
2025	4.97	5.31	4.70	4.17
2026	4.92	5.72	4.64	4.53
2027	4.59	4.59	4.13	4.13
2028	4.76	4.76	4.29	4.29
2029	4.96	4.96	4.47	4.47
2030	5.15	5.15	4.66	4.66
2031	5.25	5.25	4.75	4.75
2032	5.35	5.35	4.84	4.84
2033	5.45	5.45	4.93	4.93
2034	5.55	5.55	5.02	5.02
2035	5.67	5.67	5.12	5.12
2036	5.78	5.78	5.23	5.23
2037	5.89	5.89	5.33	5.33
2038	6.01	6.01	5.44	5.44

(continued)

Fixed Solar QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter	Summer	Winter	Summer
	¢/kWh	¢/kWh	¢/kWh	¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.51	5.51	4.42	4.42
2028	5.70	5.70	4.58	4.58
2029	5.91	5.91	4.77	4.77
2030	6.12	6.12	4.97	4.97
2031	6.24	6.24	5.06	5.06
2032	6.35	6.35	5.15	5.15
2033	6.48	6.48	5.25	5.25
2034	6.60	6.60	5.35	5.35
2035	6.73	6.73	5.46	5.46
2036	6.87	6.87	5.57	5.57
2037	7.00	7.00	5.68	5.68
2038	7.14	7.14	5.79	5.79

(continued)

Tracking Solar QF Firm Energy Prices

Deliveries	Peak Energy Prices		Off-Peak Energy Prices	
Year	Winter	Summer	Winter	Summer
	¢/kWh	¢/kWh	¢/kWh	¢/kWh
2014	2.72		2.26	
2015	2.82	3.09	2.29	2.18
2016	2.70	3.11	2.15	2.21
2017	2.79	3.26	2.20	2.31
2018	3.11	3.69	2.42	2.61
2019	3.21	3.87	2.52	2.77
2020	3.41	4.02	2.78	2.90
2021	3.73	4.26	3.33	3.33
2022	4.15	4.54	3.93	3.79
2023	4.12	4.79	3.88	4.00
2024	3.83	5.18	3.61	4.25
2025	5.25	5.59	4.98	4.45
2026	5.20	6.00	4.92	4.81
2027	5.67	5.67	4.42	4.42
2028	5.86	5.86	4.58	4.58
2029	6.07	6.07	4.77	4.77
2030	6.29	6.29	4.97	4.97
2031	6.41	6.41	5.06	5.06
2032	6.53	6.53	5.15	5.15
2033	6.66	6.66	5.25	5.25
2034	6.78	6.78	5.35	5.35
2035	6.92	6.92	5.46	5.46
2036	7.06	7.06	5.57	5.57
2037	7.20	7.20	5.68	5.68
2038	7.34	7.34	5.79	5.79

(continued)

Green Tags

The Company retains Green Tags for the benefit of customers without any additional payment when it buys power from a QF resource. In the event a qualifying facility contract ends or is terminated, the Green Tags revert to the qualifying facility project until the developer sells or transfers the Green Tags to another purchaser.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Small Power Production Facility

A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

Solar Facility

A facility which produces electric energy using the sun as the primary energy source. A Solar Facility may be flat mounted (Fixed Solar) or configured with a device to orient the solar panels toward the sun (Tracking Solar).

Wind Facility

A facility which produces electric energy using wind as the primary energy source.

(continued)

Definitions *(continued)*

Winter Season

The months of November through April.

Summer Season

The months of May through October.

On-Peak Hours

On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Off-Peak Hours

All hours other than On-Peak hours.

Monthly Payments

The Monthly Payment shall be the sum of the winter and summer energy prices for Peak and Off-Peak hours. Winter and summer energy payments for Peak and Off-Peak hours are provided separately for a Base Load facility, Wind Facility, Fixed Solar Facility and a Tracking Solar Facility.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by the Wyoming Public Service Commission.