UM 1610 –REC Cross-Examination List			
Number	Witness	Party	Title
REC-400	MacFarlane-Mortan	PGE	Schedule 201: Qualifying Facility 10 MW or Less
REC-401	MacFarlane-Mortan	PGE	Schedule 202: Qualifying Facility 10 MW or More
REC-402	MacFarlane-Mortan	PGE	PGE Responses to REC Data Requests 030-032
REC-403	Dickman	PacifiCorp	Schedule 37: Avoided Cost Purchases from Qualifying Facilities of 10,000 KW or Less
REC-404	Dickman	PacifiCorp	Schedule 38: Avoided Cost Purchases from Qualifying Facilities of Greater Than 10,000 KW
REC-405	Dickman	PacifiCorp	Excerpt of PacifiCorp 2013 IRP: Pages 1-3, 5-7, 11-12
REC-406	Dickman	PacifiCorp	PacifiCorp Responses to REC Data Requests 4.1 and 4.3
REC-407	Dickman	PacifiCorp	Confidential PacifiCorp Responses to REC Data Request 4.2

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Avoided Costs, Standard Contracts and negotiated Power Purchase Agreements, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard Contract Power Purchase Agreement.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard Contract Power Purchase Agreement (Standard Contract), a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security as deemed sufficient by the Company as set out in the Standard Contract.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

SCHEDULE 201 (Continued)

POWER PURCHASE AGREEMENT

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a Power Purchase Agreement with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard Contract.

Any Seller may elect to negotiate a Power Purchase Agreement with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time.

STANDARD CONTRACTS (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the applicable Standard Contract (Appendix 1 to this schedule) and submit the executed Agreement to the Company prior to service under this schedule. The Standard Contract is available at www.portlandgeneral.com. The available Standard Contracts are: Standard Contract Power Purchase Agreement, Standard Contract Off System Power Purchase Agreement, Standard Contract for Intermittent Resources and Standard Contract for Off System Intermittent Resources. The Standard Contracts applicable to Intermittent Resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES

In order to execute the Standard Contract the Seller must complete all of the general project information requested in the applicable Standard Contract.

When all information required in the Standard Contract has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard Contract.

The Seller may request in writing that the Company prepare a final draft Standard Contract. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard Contract.

When both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the Standard Contract has been executed by both parties.

SCHEDULE 201 (Continued)

OFF SYSTEM POWER PURCHASE AGREEMENT

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable standard or negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase rates are based on the Company's Avoided Costs. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

The Avoided Costs as listed in Tables 1 and 2 below include monthly On- and Off-Peak prices.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Avoided Costs are based on forward market price estimates through December 2014, the period of time during which the Company's Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the period 2015 through 2030, the Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

PRICING OPTIONS FOR STANDARD CONTRACTS

Pricing options represent the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard Contract up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard Contract pricing will be based on the Avoided Cost in effect at the time the agreement is executed.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

Four pricing options are available for Standard Contracts. The pricing options include one Fixed Rate Option and three Market Based Options.

1) Fixed Price Option

The Fixed Price Option is based on Avoided Costs including forecasted natural gas prices.

This option is available for a maximum term of 15 years. Sellers with contracts exceeding 15 years will make a one time election at execution to select a Market-Based Option for all years up to five in excess of the initial 15. Under the Fixed Price Option, prices will be as established at the time the Standard Contract is executed and will be equal to the Avoided Costs in Tables 1 and 2 effective at execution for a term of up to 15 years.

TABLE 1
Avoided Costs
Fixed Price Option
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	34.92	34.16	31.10	28.04	24.48	20.40	35.69	41.55	40.53	36.45	39.25	42.82
2014	41.17	40.26	36.63	33.00	28.77	23.93	42.07	49.03	47.82	42.98	46.31	50.54
2015	44.20	43.22	39.33	35.44	30.89	25.71	45.17	52.63	51.33	46.15	49.71	54.26
2016	82.25	82.05	81.50	80.01	80.13	80.28	80.55	80.68	80.70	80.95	81.58	82.88
2017	85.15	84.94	84.40	82.92	83.03	83.19	83.47	83.60	83.63	83.88	84.45	85.76
2018	86.77	87.01	86.98	85.65	85.34	85.44	85.79	85.86	86.07	86.56	88.06	88.27
2019	89.97	90.14	90.35	89.41	89.41	89.65	89.86	90.07	90.18	90.39	91.36	91.96
2020	93.30	93.58	93.41	92.71	92.43	92.60	93.09	93.27	93.27	93.65	95.08	95.57
2021	97.85	98.06	97.82	96.32	96.32	96.42	96.60	96.84	97.05	97.37	98.73	99.29
2022	100.27	100.55	99.64	98.25	98.25	98.49	98.84	99.09	99.23	99.50	101.74	102.19
2023	104.15	104.40	104.29	103.35	103.35	103.87	104.29	104.43	104.22	104.50	105.58	106.18
2024	106.59	106.35	104.85	103.80	103.34	103.76	104.11	104.60	104.43	105.02	106.28	106.77
2025	107.67	107.98	106.31	105.33	104.95	105.51	105.68	106.20	106.10	106.76	108.05	108.47
2026	110.06	110.34	109.15	108.17	107.79	108.17	108.42	108.91	108.77	109.36	110.86	111.46
2027	112.19	112.50	110.86	109.99	109.85	110.02	110.62	110.79	110.65	111.25	113.10	113.69
2028	114.35	114.56	112.53	111.52	111.49	111.66	112.33	112.71	112.64	113.37	115.57	116.24
2029	117.17	117.24	115.99	114.90	114.69	114.87	115.64	116.13	116.09	116.65	118.40	119.06
2030	120.20	120.45	118.42	117.58	116.82	117.06	118.08	118.63	118.60	119.30	121.74	122.34
2031	122.73	123.08	121.09	119.94	119.87	119.91	121.06	121.55	121.13	121.72	124.06	124.69
2032	124.57	124.92	122.89	121.72	121.65	121.69	122.86	123.36	122.93	123.54	125.92	126.56

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 2
Avoided Costs
Fixed Price Option
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	30.08	29.06	24.99	18.36	10.21	4.61	19.38	28.30	31.87	31.36	33.90	37.22
2014	37.34	36.05	30.94	22.62	12.38	5.34	23.90	35.09	39.58	38.94	42.14	46.29
2015	40.98	39.57	33.96	24.83	13.59	5.87	26.23	38.52	43.44	42.73	46.25	50.81
2016	31.27	31.07	30.52	29.03	29.15	29.30	29.57	29.70	29.72	29.97	30.60	31.90
2017	32.90	32.69	32.14	30.67	30.78	30.94	31.21	31.35	31.38	31.63	32.20	33.51
2018	33.72	33.97	33.93	32.60	32.29	32.40	32.75	32.82	33.03	33.51	35.01	35.22
2019	35.95	36.12	36.33	35.39	35.39	35.63	35.84	36.05	36.16	36.37	37.35	37.94
2020	38.46	38.74	38.57	37.87	37.59	37.77	38.25	38.43	38.43	38.81	40.24	40.73
2021	41.83	42.04	41.79	40.29	40.29	40.40	40.57	40.82	41.03	41.34	42.70	43.26
2022	43.21	43.49	42.59	41.19	41.19	41.44	41.78	42.03	42.17	42.45	44.68	45.14
2023	45.86	46.10	46.00	45.06	45.06	45.58	46.00	46.14	45.93	46.21	47.29	47.88
2024	47.60	47.36	45.86	44.81	44.36	44.78	45.13	45.61	45.44	46.03	47.29	47.78
2025	47.41	47.72	46.04	45.07	44.68	45.24	45.42	45.94	45.83	46.50	47.79	48.21
2026	48.69	48.96	47.78	46.80	46.42	46.80	47.05	47.53	47.39	47.99	49.49	50.08
2027	49.69	50.00	48.36	47.49	47.35	47.52	48.12	48.29	48.15	48.74	50.59	51.19
2028	50.70	50.91	48.88	47.87	47.83	48.01	48.67	49.06	48.99	49.72	51.92	52.58
2029	52.35	52.42	51.16	50.08	49.87	50.05	50.81	51.30	51.27	51.83	53.57	54.24
2030	54.19	54.43	52.41	51.57	50.80	51.05	52.06	52.62	52.58	53.28	55.72	56.32
2031	55.50	55.85	53.86	52.71	52.64	52.67	53.83	54.32	53.90	54.49	56.83	57.46
2032	56.53	56.89	54.86	53.69	53.62	53.65	54.83	55.33	54.90	55.50	57.88	58.52

Under the Fixed Price Option, the Company will pay Seller the Off-Peak Avoided Cost pursuant to Table 2 for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller the On-Peak Avoided Cost pursuant to Table 1 for all other output. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS:

Market Based Price Options include Option 2, Deadband Index Gas Price; Option 3, Index Gas Price; and Option 4, Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity Firm Price Index (DJ-Mid-C Firm Index). The price components for pricing Options 2 and 3 are defined as follows:

On Peak Price:	P_{Peak}
Off Peak Price:	P_{Off}
Variable Operating and Maintenance, Fixed Costs, and Gas Transportation (Table 6):	VFG
Capacity Value (Table 7):	C
Heat Rate:	HR = 6,732 BTU/kWh
Losses:	1.9%
Forecasted Gas Price (Table 5):	GP_F
First of Month* Northwest Pipeline Corp. Canadian Border Index as Reported in <u>Platts Inside FERC's Gas Market Report</u>	GP_{Sumas}
First of Month* one-month spot price averages for AECO/NIT transactions as Reported in <u>Canadian Gas Price Reporter Natural Gas Market Report</u> (in US dollars):	GP_{AECO}
Monthly Indexed Gas Price:	$GP_{MI} = (GP_{Sumas} + GP_{AECO})/2$
Deadband Gas Index:	GP_{DB}

Where:
If $GP_{MI} > GP_F$
GP_{DB} = Minimum of (GP_{MI} or $1.1*GP_F$)
Otherwise
GP_{DB} = Maximum of (GP_{MI} or $.9*GP_F$)

* "First of Month" means the first such monthly issuance.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Tables 3 and 4 below list applicable rates for Options 2 (Deadband Index Gas Price Option) and 3 (Index Gas Price Option) for the period through 2014. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options.

TABLE 3
Avoided Costs
On-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	34.92	34.16	31.10	28.04	24.48	20.40	35.69	41.55	40.53	36.45	39.25	42.82
2014	41.17	40.26	36.63	33.00	28.77	23.93	42.07	49.03	47.82	42.98	46.31	50.54
2015	44.20	43.22	39.33	35.44	30.89	25.71	45.17	52.63	51.33	46.15	49.71	54.26

TABLE 4
Avoided Costs
Off-Peak Resource Sufficiency Rate ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	30.08	29.06	24.99	18.36	10.21	4.61	19.38	28.30	31.87	31.36	33.90	37.22
2014	37.34	36.05	30.94	22.62	12.38	5.34	23.90	35.09	39.58	38.94	42.14	46.29
2015	40.98	39.57	33.96	24.83	13.59	5.87	26.23	38.52	43.44	42.73	46.25	50.81

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

2) Deadband Index Gas Price Option

The Deadband Index Gas Price Option bases the fuel price component of the Energy rate on comparisons between the Forecast Gas Price (Table 5) and the simple average of the First of Month gas indices for Sumas and AECO trading hubs. The Northwest Pipeline Gas Index (Sumas) will be as reported in Platts Inside FERC's Gas Market Report. The AECO/NIT (AECO) Gas Index will be as reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars). The fuel price component used will be bound between 90% and 110% of the natural gas price forecast but based on the then current gas price.

The price paid per MWh will be:

$P_{Peak} = GP_{DB}$*HR/1,000/(1-Losses) +VFG +C
$P_{Off} = GP_{DB}$*HR/1,000/(1-Losses) +VFG

Under the Deadband method, the Company will pay Seller the Off-Peak prices for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

3) Index Gas Price Option

The Index Gas Price Option is the simple average of the First of Month gas indices for Sumas and AECO trading hubs used in establishing the Avoided Costs. The Sumas Gas Index will be as reported in Platts Inside FERC's Gas Market Report. The AECO Gas Index will be as reported in the Canadian Gas Price Reporter Natural Gas Market Report (in US dollars).

The price paid per MWh will be:

$$P_{Peak} = GP_{MI}*HR/1{,}000/(1\text{-}Losses) + VFG + C$$
$$P_{Off} = GP_{MI}*HR/1{,}000/(1\text{-}Losses) + VFG$$

Under the Index Gas Price, the Company will pay Seller the Off-Peak Prices for: (a) for all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) for Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

4) Mid C Index Price Option

Under this option, prices paid per MWh will be based on the DJ-Mid-C Firm Index plus 0.211 ¢ per kWh for wholesale wheeling.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 5 contains the gas pricing components for Option 1 (Fixed Price Option) and Option 2 (Deadband Index Gas Price Option).

TABLE 5

Forecasted Gas Price - GP_F ($/MMBTU) - Without Transportation

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	4.54	4.51	4.43	4.22	4.24	4.26	4.30	4.31	4.32	4.35	4.44	4.63
2017	4.78	4.75	4.67	4.46	4.47	4.50	4.53	4.55	4.56	4.59	4.68	4.86
2018	4.90	4.93	4.93	4.74	4.69	4.71	4.76	4.77	4.80	4.87	5.08	5.11
2019	5.22	5.24	5.27	5.14	5.14	5.17	5.20	5.23	5.25	5.28	5.42	5.50
2020	5.58	5.62	5.59	5.49	5.45	5.48	5.55	5.57	5.57	5.63	5.83	5.90
2021	6.06	6.09	6.06	5.84	5.84	5.86	5.88	5.92	5.95	5.99	6.19	6.27
2022	6.26	6.30	6.17	5.97	5.97	6.01	6.06	6.09	6.11	6.15	6.47	6.54
2023	6.64	6.68	6.66	6.53	6.53	6.60	6.66	6.68	6.65	6.69	6.85	6.93
2024	6.89	6.86	6.64	6.49	6.43	6.49	6.54	6.61	6.58	6.67	6.85	6.92
2025	6.87	6.91	6.67	6.53	6.48	6.56	6.58	6.66	6.64	6.74	6.92	6.98
2026	7.05	7.09	6.92	6.78	6.73	6.78	6.82	6.89	6.87	6.95	7.17	7.25
2027	7.20	7.24	7.01	6.88	6.86	6.89	6.97	7.00	6.98	7.06	7.33	7.41
2028	7.34	7.37	7.08	6.94	6.93	6.96	7.05	7.11	7.10	7.20	7.52	7.61
2029	7.58	7.59	7.41	7.26	7.23	7.25	7.36	7.43	7.43	7.51	7.76	7.85
2030	7.85	7.88	7.59	7.47	7.36	7.40	7.54	7.62	7.62	7.72	8.07	8.15
2031	8.04	8.09	7.80	7.64	7.63	7.63	7.80	7.87	7.81	7.89	8.23	8.32
2032	8.18	8.23	7.94	7.78	7.77	7.77	7.94	8.01	7.95	8.04	8.38	8.47

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 6 contains the Variable O&M and Fixed Costs that are derived from a natural gas-fired CCCT.

TABLE 6

Variable O&M, Fixed Costs and Gas Transportation Forecast - VFG ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	0.12	0.11	0.10	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.11	0.13
2017	0.13	0.12	0.11	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.14
2018	0.13	0.13	0.13	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.15	0.16
2019	0.16	0.16	0.17	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.19	0.20
2020	0.20	0.21	0.21	0.19	0.19	0.19	0.20	0.21	0.20	0.21	0.24	0.24
2021	0.24	0.25	0.24	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.26	0.27
2022	0.26	0.26	0.25	0.22	0.22	0.23	0.23	0.24	0.24	0.24	0.28	0.29
2023	0.29	0.30	0.30	0.28	0.28	0.29	0.30	0.30	0.30	0.30	0.32	0.33
2024	0.32	0.32	0.29	0.27	0.27	0.27	0.28	0.29	0.28	0.29	0.32	0.33
2025	0.29	0.30	0.27	0.25	0.25	0.26	0.26	0.27	0.27	0.28	0.30	0.31
2026	0.31	0.31	0.29	0.27	0.27	0.27	0.28	0.29	0.28	0.29	0.32	0.33
2027	0.31	0.32	0.29	0.27	0.27	0.27	0.28	0.29	0.28	0.29	0.33	0.34
2028	0.33	0.33	0.30	0.28	0.28	0.28	0.29	0.30	0.30	0.31	0.35	0.36
2029	0.33	0.33	0.31	0.29	0.29	0.29	0.31	0.32	0.31	0.32	0.35	0.37
2030	0.35	0.36	0.32	0.31	0.29	0.30	0.32	0.33	0.32	0.34	0.38	0.39
2031	0.36	0.37	0.33	0.31	0.31	0.31	0.33	0.34	0.33	0.34	0.39	0.40
2032	0.38	0.39	0.35	0.33	0.33	0.33	0.35	0.36	0.35	0.36	0.40	0.41

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 7 represents the variable C in the formulas for Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 7												
Capacity Value - C ($/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	50.98	50.98	50.98	50.98	50.98	50.98	50.98	50.98	50.98	50.98	50.98	50.98
2017	52.25	52.25	52.25	52.25	52.25	52.25	52.25	52.25	52.25	52.25	52.25	52.25
2018	53.04	53.04	53.04	53.04	53.04	53.04	53.04	53.04	53.04	53.04	53.04	53.04
2019	54.02	54.02	54.02	54.02	54.02	54.02	54.02	54.02	54.02	54.02	54.02	54.02
2020	54.84	54.84	54.84	54.84	54.84	54.84	54.84	54.84	54.84	54.84	54.84	54.84
2021	56.03	56.03	56.03	56.03	56.03	56.03	56.03	56.03	56.03	56.03	56.03	56.03
2022	57.06	57.06	57.06	57.06	57.06	57.06	57.06	57.06	57.06	57.06	57.06	57.06
2023	58.29	58.29	58.29	58.29	58.29	58.29	58.29	58.29	58.29	58.29	58.29	58.29
2024	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99
2025	60.26	60.26	60.26	60.26	60.26	60.26	60.26	60.26	60.26	60.26	60.26	60.26
2026	61.37	61.37	61.37	61.37	61.37	61.37	61.37	61.37	61.37	61.37	61.37	61.37
2027	62.50	62.50	62.50	62.50	62.50	62.50	62.50	62.50	62.50	62.50	62.50	62.50
2028	63.65	63.65	63.65	63.65	63.65	63.65	63.65	63.65	63.65	63.65	63.65	63.65
2029	64.82	64.82	64.82	64.82	64.82	64.82	64.82	64.82	64.82	64.82	64.82	64.82
2030	66.02	66.02	66.02	66.02	66.02	66.02	66.02	66.02	66.02	66.02	66.02	66.02
2031	67.23	67.23	67.23	67.23	67.23	67.23	67.23	67.23	67.23	67.23	67.23	67.23
2032	68.03	68.03	68.03	68.03	68.03	68.03	68.03	68.03	68.03	68.03	68.03	68.03

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard Contract:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on his/her own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES AND STANDARD CONTRACT

A QF will be eligible to receive the standard rates and Standard Contract if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, does not exceed 10 MW.

Definition of Person(s) or Affiliated Person(s)

As used above, the term "same person(s)" or "affiliated person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a "passive investor" if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and Standard Contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

SCHEDULE 201 (Concluded)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES AND STANDARD CONTRACT (Continued)

Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to the standard rates and Standard Contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and Standard Contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard Contract.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and Standard Contract. Any dispute concerning a QF's entitlement to the standard rates and Standard Contract will be presented to the Commission for resolution.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Contracts entered into pursuant to this schedule will not terminate prior to the Standard or negotiated contract's termination date if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

SCHEDULE 202
QUALIFYING FACILITIES GREATER THAN 10MW
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information regarding procedures and timelines leading to a power purchase agreement between the Company and a Qualifying Facility (QF) with an aggregate nameplate capacity greater than 10,000 kW.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

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

A QF with nameplate capacity greater than 10,000 kW will be required to enter into a negotiated written power purchase agreement (Negotiated Agreement) with the Company.

A QF with nameplate capacity less than 10,000 kW or less may elect the option of a Standard Contract with terms and pricing as defined in Schedule 201.

POWER PURCHASE INFORMATION

A QF may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

GUIDELINES

The Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, that is made available to Company by the Seller, pursuant to a Negotiated Agreement with the Company executed prior to delivery of such power. The Negotiated Agreement will comply with the requirements of the Federal Energy Regulatory Commission (FERC) and the guidelines established by Commission Order No. 07-360.

The Negotiated Agreement may have a term of up to 20 years, as selected by the Seller.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT

1. The Seller may request indicative power purchase prices. To obtain an indicative pricing proposal for a proposed project, the Seller must provide in writing, general project information reasonably required for the development of indicative pricing, including, but not limited to:

   - Demonstration of ability to obtain QF status.
   - Design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system.
   - Generation technology and other related technology applicable to the site.
   - Quantity and timing of monthly power deliveries (including project ability to respond to dispatch orders from the Company).
   - Proposed site location and electrical interconnection point.
   - Status of interconnection and transmission arrangements.
   - Proposed on-line date and outstanding permitting requirements.
   - Motive force or fuel plan consisting of fuel type(s) and source(s).
   - Proposed contract term and pricing provisions.

2. The Company will not be obligated to provide an indicative pricing proposal until all the information described above has been received in writing from the Seller. Within 30 business days following receipt of all required information, the Company will provide the Seller with an indicative pricing proposal, which may include other terms and conditions, tailored to the individual characteristics of the proposed project. Such proposal may be used by the Seller to make determinations regarding project planning, financing and feasibility. However, such prices are indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in Negotiated Agreement, once executed by both parties. The Company will provide with the indicative prices a description of the methodology used to develop the prices.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

3. The Avoided Cost Prices specified in Schedule 201 provide a starting point for indicative prices, and will be modified to address the following specific factors established in OPUC Order No. 07-360 and FERC 18 § CFR 292.304(e):

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors will, to the extent practicable, be taken into account.

(1) The data provided pursuant to 18 CFR § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the Company to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the Company's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the Company's system; and

(vii) The smaller capacity increments and the shorter lead time available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in part (e) (2) of this section, to the ability of the Company to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the Company generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

4. If the Seller desires to proceed with negotiations after reviewing the Company's indicative price proposal, the Seller must request in writing that the Company prepare a draft Negotiated Agreement to serve as the basis for negotiations between the parties. In connection with such request, the Seller must provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of the Negotiated Agreement, which may include, but will not be limited to:

   - Updated information for the project information listed above in paragraphs 1 and 3.
   - Evidence of adequate control of proposed site.
   - Timelines for obtaining any necessary governmental permits, approvals or authorizations.
   - Assurance of fuel supply or motive force.
   - Anticipated timelines for completion of key project milestones.
   - Evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements have been executed or are under negotiation.

5. Within 30 days following receipt of updated information required by the Company, the Company will provide the Seller with a draft Negotiated Agreement. The draft agreement will contain proposed terms and conditions in addition to indicative pricing. The draft agreement is not binding; however; it will serve as the basis for subsequent negotiations.

6. After reviewing the draft Negotiated Agreement, the Seller will notify the Company in writing of its intent to proceed with negotiations. The Seller may prepare an initial set of written comments and proposals regarding the agreement and forward them to the Company. The Company will not be obligated to begin negotiations with a Seller until the Company has received an initial set of written comments. After the Company's receipt of comments and proposals, the Seller may contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

   - Will not unreasonably delay negotiations and will respond in good faith to any additions, deletions or modifications to the draft Negotiated Agreement that are proposed by the Seller.
   - May request to visit the site of the proposed project if such a visit has not previously occurred.
   - Will update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed project or proposed terms of the draft Negotiated Agreement.
   - May request any additional information from the Seller necessary to finalize the terms of the Negotiated Agreement and satisfy the Company's due diligence regarding the QF project.

SCHEDULE 202 (Concluded)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

7. When both parties are in full agreement as to all terms and conditions of the draft Negotiated Agreement, the Company will prepare and forward to the Seller a final, executable version of the agreement within 15 business days. Prices and other terms and conditions in the Negotiated Agreement will not be final and binding until the agreement has been executed by both parties.

8. If parties are not in full agreement within 60 days from the date of written notice, the Seller may file a complaint with the Commission asking the Commission to adjudicate the disputed contract terms.

OFF SYSTEM POWER PURCHASE AGREEMENT

A QF that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

April 4, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Fourth Set of Data Request No. 030
Dated March 22, 2013

Request:

Please refer to PGE/100, Macfarlane-Morton/20. Please provide illustrative avoided cost prices for both a 10 MW and 20 MW run of the river hydro resource and a 10 MW and 20 MW in-system wind resource (assuming a 20 year contract term) under existing OPUC approved pricing methods (standard for the 10 MW projects and non-standard for the 20 MW projects). In performing this analysis please use the same gas cost and market price assumptions as were used in the derivation of the current avoided cost rates. As part of this response, please provide an electronic copy of all workpapers used to derive the prices.

Response:

PGE objects to this request on the grounds that it is unduly burdensome and seeks information beyond that required by applicable rules. Subject to and without waiving its objections, PGE responds as follows:

Avoided cost prices for any eligible qualifying facility (QF) 10 MW or less can be found in PGE's current Schedule 201. PGE has not performed the requested study for resources over 10 MW. PGE's current Schedule 201 can be found at:
http://www.portlandgeneral.com/renewables_efficiency/generate_power/business/selling_power_pge.aspx

April 4, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Fourth Set of Data Request No. 031
Dated March 22, 2013

Request:

Please refer to PGE/100, Macfarlane-Morton/20. Please provide illustrative avoided cost prices for a 10 MW and 20 MW run of the river hydro resource and a 10 MW and 20 MW in-system wind resource (assuming a 20 year contract term) under PGE's proposed renewable avoided cost method Please assume the avoided resource is a CCCT. As part of this response, please provide an electronic copy of all workpapers used to derive the prices.

Response:

PGE objects to this request on the grounds that it is unduly burdensome and seeks information beyond that required by applicable rules. Subject to and without waiving its objections, PGE responds as follows:

PGE has not performed the requested study.

April 4, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Fourth Set of Data Request No. 032
Dated March 22, 2013

Request:

Please refer to PGE/100, Macfarlane-Morton/20. Please provide illustrative avoided cost prices for a 10 MW and 20 MW run of the river hydro resource and a 10 MW and 20 MW CHP resource (assuming a 20 year contract term) under PGE's proposed renewable avoided cost method Please assume the avoided resource is a wind resource. As part of this response, please provide an electronic copy of all workpapers used to derive the prices.

Response:

PGE objects to this request on the grounds that it is unduly burdensome and seeks information beyond that required by applicable rules. Subject to and without waiving its objections, PGE responds as follows:

PGE has not performed the requested study.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 37

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF 10,000 KW OR LESS

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

For power purchased from Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility
A facility which produces electric energy together with steam or other form 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.

On-Peak Hours or 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.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

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

West Side Gas Market Index
The monthly indexed gas price shall be the average of the price indexes published by Platts in "Inside FERC's Gas Market Report" monthly price report for Northwest Pipeline Corp. Rock Mountains, Northwest Pipeline Corp. Canadian Border, and Rockies/Northwest Stanfield, OR.

Excess Output
Excess output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-peak Price as described and calculated under pricing option 5 for all Excess Output.

(continued)

Same Site
Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)
A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a "passive investor" if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Shared Interconnection and Infrastructure
QFs otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved standard contract.

Dispute Resolution
Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract. Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution.

Self Supply Option
Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

(continued)

Pricing Options

1. Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under either the Firm Market Indexed, the Banded Gas Market Indexed or the Gas Market Indexed Avoided Cost pricing option.

2. Gas Market Indexed Avoided Cost Prices

Fixed prices apply during the resource sufficiency period (2012 through 2015), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Prices are available for a term of up to 20 years.

3. Banded Gas Market Indexed Avoided Cost Prices

Fixed prices apply during the resource sufficiency period (2012 through 2015), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. The gas indexed portion of the avoided cost prices are banded to limit the amount that prices can vary with changes in gas prices. Prices are available for a term of up to 20 years.

4. Firm Market Indexed Avoided Cost Prices

Firm market index avoided cost prices are available to Qualifying Facilities that contract to deliver firm power. Monthly on-peak / off-peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

5. Non-firm Market Index Avoided Cost Prices

Non- Firm market index avoided cost prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

(continued)

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of three Pricing Options as specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the fixed prices as provided in this tariff. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

Gas Market Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.696 to get actual gas price in cents/kWh. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Banded Gas Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.696 to get actual gas price in cents/kWh. This price is banded such that the actual gas price shall be no lower than the Gas Market Index Floor nor greater than the Gas Market Index Ceiling as listed in the price section of this tariff. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Firm Market Indexed and Non-firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

(continued)

Avoided Cost Prices

Pricing Option 1 – Fixed Avoided cost Prices ¢/kWh

Deliveries During Calendar Year	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)
2012	3.09	2.32
2013	3.72	2.62
2014	4.13	2.80
2015	4.39	2.99
2016	6.04	3.69
2017	6.32	3.91
2018	6.66	4.21
2019	6.99	4.50
2020	6.94	4.41
2021	7.23	4.65
2022	7.67	5.04
2023	7.92	5.24
2024	7.89	5.16
2025	8.09	5.32
2026	8.39	5.57
2027	8.66	5.78
2028	8.88	5.95
2029	9.07	6.09
2030	9.20	6.16

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 37

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF 10,000 KW OR LESS

Avoided Cost Prices (Continued)

Pricing Option 2 – Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices		Gas Market Index		Forecast	Estimated Prices (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Capacity Adder (1)	Off-Peak Energy Adder	West Side Gas Market Index Price (2) $/MMBtu	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c) Avoided Firm Capacity Costs / (0.876 * 88.6% * 57%)	(d) Total Avoided Energy Costs - ((e) * 0.696)	(e)	(f) (g) + (c)	(g) ((e) * 0.696) + (d)
2012	3.09	2.32	Market Based Prices 2012 through 2015				
2013	3.72	2.62					
2014	4.13	2.80					
2015	4.39	2.99					
2016			2.36	0.44	$4.66	6.042	3.685
2017			2.40	0.47	$4.95	6.316	3.914
2018			2.45	0.47	$5.38	6.660	4.212
2019			2.49	0.47	$5.79	6.988	4.496
2020			2.53	0.47	$5.66	6.943	4.409
2021			2.58	0.48	$5.98	7.225	4.645
2022			2.63	0.50	$6.53	7.667	5.041
2023			2.67	0.52	$6.78	7.916	5.242
2024			2.72	0.53	$6.66	7.885	5.163
2025			2.77	0.54	$6.87	8.093	5.322
2026			2.82	0.55	$7.21	8.385	5.565
2027			2.87	0.57	$7.49	8.655	5.781
2028			2.93	0.60	$7.69	8.877	5.948
2029			2.98	0.62	$7.85	9.070	6.086
2030			3.04	0.64	$7.92	9.197	6.156
2031			3.10	0.64	$8.06	9.348	6.246
2032			3.16	0.65	$8.21	9.526	6.365
2033			3.22	0.66	$8.37	9.705	6.484
2034			3.29	0.68	$8.53	9.902	6.616

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2011 IRP.

(2) A heat rate of 0.696 is used to adjust gas prices from $/MMBtu to ¢/kWh

(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices.
Actual prices will be calculated each month using actual index gas prices.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 37

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF 10,000 KW OR LESS

Avoided Cost Prices (Continued)

Pricing Option 3 – Banded Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices		Banded Gas Market Index				Forecast West Side Gas Market Index Price (2)	Estimated Prices (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Capacity Adder (1)	Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	$/MMBtu	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Avoided Firm Capacity Costs / (0.876 * 88.6% * 57%)	Total Avoided Energy Costs - ((e) * 0.696)	(g) * 0.696 * 90%	(g) * 0.696 * 110%		(i) + (c)	MIN(MAX(((g) * 0.696) , (e)) , (f)) + (d)
2012	3.09	2.32	Market Based Prices 2010 through 2013						
2013	3.72	2.62							
2014	4.13	2.80							
2015	4.39	2.99							
2016			2.36	0.44	2.92	3.57	$4.66	6.04	3.69
2017			2.40	0.47	3.10	3.79	$4.95	6.32	3.91
2018			2.45	0.47	3.37	4.12	$5.38	6.66	4.21
2019			2.49	0.47	3.63	4.43	$5.79	6.99	4.50
2020			2.53	0.47	3.55	4.33	$5.66	6.94	4.41
2021			2.58	0.48	3.75	4.58	$5.98	7.23	4.65
2022			2.63	0.50	4.09	5.00	$6.53	7.67	5.04
2023			2.67	0.52	4.25	5.19	$6.78	7.92	5.24
2024			2.72	0.53	4.17	5.10	$6.66	7.89	5.16
2025			2.77	0.54	4.30	5.26	$6.87	8.09	5.32
2026			2.82	0.55	4.52	5.52	$7.21	8.39	5.57
2027			2.87	0.57	4.69	5.73	$7.49	8.66	5.78
2028			2.93	0.60	4.82	5.89	$7.69	8.88	5.95
2029			2.98	0.62	4.92	6.01	$7.85	9.07	6.09
2030			3.04	0.64	4.96	6.06	$7.92	9.20	6.16
2031			3.10	0.64	5.05	6.17	$8.06	9.35	6.25
2032			3.16	0.65	5.14	6.29	$8.21	9.53	6.37
2033			3.22	0.66	5.24	6.41	$8.37	9.71	6.48
2034			3.29	0.68	5.34	6.53	$8.53	9.90	6.62

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2011 IRP.
(2) A heat rate of 0.696 is used to adjust gas prices from $/MMBtu to ¢/kWh
(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices.
Actual prices will be calculated each month using actual index gas prices.

(continued)

Example of Gas Pricing Options available to the Qualifying Facility
An example of the two gas pricing options using different assumed gas prices is provided at the end of this tariff.

Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Qualifying Facilities up to 10,000 kW

APPLICATION: To owners of existing or proposed QFs with a design capacity less than or equal to 10,000 kW who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

(continued)

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions (i.e.,fixed, deadband, gas indexed);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utilities Commission in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

(continued)

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

(continued)

II. Process for Negotiating Interconnection Agreements (continued)

A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director – Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 37

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF 10,000 KW OR LESS

Example of Gas Pricing Options given Assumed Gas Prices ¢/kWh

Banded Gas Market Index

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
2016	2.36	0.44	2.92	3.57	$2.00	1.39	2.92	Floor	3.36	5.72	3.69	6.04
					$4.00	2.78	2.92	Floor	3.36	5.72		
					$5.00	3.48	3.48	Actual	3.92	6.28		
					$7.00	4.87	3.57	Ceiling	4.01	6.37		
					$10.00	6.96	3.57	Ceiling	4.01	6.37		

Gas Market Method

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Fuel Index Floor 90%	Fuel Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
2016	2.36	0.44	Not Relevant		$2.00	1.39	Not Relevant		1.83	4.19	3.69	6.04
					$4.00	2.78			3.22	5.58		
					$5.00	3.48			3.92	6.28		
					$7.00	4.87			5.31	7.67		
					$10.00	6.96			7.40	9.76		

SCHEDULE 38

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF GREATER THAN 10,000 KW

Available

To owners of Qualifying Facilities ("QF") making sales of electricity to the Company in the State of Oregon.

Applicable

For power purchased from Qualifying Facilities with a nameplate capacity greater than 10,000 kW. Owners of these Qualifying Facilities will be required to enter into a negotiated written power purchase agreement with the Company. Pursuant to Order No. 05-584 and 07-360, the pricing options specified in Schedule 37 should serve as a starting point for prices under a negotiated power purchase agreement.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other form 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.

On-Peak Hours or 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.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

Off-Peak Hours

All hours other than On-Peak.

Excess Output

Excess output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding either the Facility Capacity Rating or the amount committed to in the contract. PacifiCorp shall pay the Qualifying Facility the Non-Firm Market Index Avoided Cost Price for all Excess Output.

(continued)

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Qualifying Facilities Contracting Procedure

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

B. Procedures

1. To obtain an indicative pricing proposal with respect to a proposed project, the owner must provide in writing to the Company, general project information reasonably required for the development of indicative pricing, including, but not limited to:
   a) generation technology and other related technology applicable to the site
   b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system
   c) quantity, firmness, and timing of daily and monthly power deliveries (including project ability to respond to dispatch orders from the Company and maintenance schedule)
   d) proposed site location and electrical interconnection point
   e) proposed on-line date and outstanding permitting requirements
   f) demonstration of ability to obtain QF status
   g) fuel type (s) and source (s)
   h) plans for fuel and transportation agreements
   i) proposed contract term and pricing provisions (i.e., fixed, deadband, electric or gas market indexed)
   j) status of interconnection arrangements

(continued)

B. Procedures (Continued)

2. The Company shall not be obligated to provide an indicative pricing proposal until all information described in Paragraph 1 has been received in writing from the Qualifying Facility owner. Within 30 days following receipt of all information required in Paragraph 1, the Company will provide the owner with an indicative pricing proposal, which may include other indicative contract terms and conditions as allowed under federal law, state law, and per Order No. 07-360, tailored to the individual characteristics of the proposed project. Such proposal may be used by the owner to make determinations regarding project planning, financing and feasibility. However, such prices are merely indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in a power purchase agreement executed by both parties. The Company will provide with the indicative prices a description of the allowed price adjustments and the methodology used to develop the prices. Prices specified in Schedule 37 will provide a starting point for negotiated prices, and will be modified to address specific factors or adjustments as allowed under federal law and per Order No. 07-360. Any adjustments other than those approved in Order No. 07-360 must first be approved by the Commission.

   The following factors or adjustments, to the extent practicable will be included in the price delivered in the indicative pricing proposal.

   a. Dispatchability – Adjustment will reflect the ability of PacifiCorp to schedule and dispatch the Qualifying Facility as compared to the proxy resource on a forward, probabilistic basis. This adjustment will also account for the Company backing down more economic generating resources in lieu of wheeling the Qualifying Facility's power outside a load-constrained area.
   b. Reliability – Adjustment to be made based on the Qualifying Facility's demonstrated reliability (including the ability of the Qualifying Facility to supply reserves with its delivered energy) and availability of its capacity and energy as compared to its contracted level of reliability and availability during the Company's daily and seasonal peak periods. The value of the adjustment will reflect the Company's avoided resource in the Company's sufficiency and deficiency periods, as appropriate, and provide the Qualifying Facility an incentive for contracted performance and a disincentive for non-performance.
   c. Fossil Fuel Risk – Applicable only during the Company's resource deficiency period and if the Company's avoided resource is a fossil fuel plant. Adjustment will be based on the benefit of reduced fuel cost volatility of the Qualifying Facility compared to the avoided resource.

(continued)

B. Procedures (Continued)

d. Line Losses – Adjustment will be the costs or savings resulting from variations in line losses using a proximity-based approach to compare Qualifying Facility's location and the Company's proxy plant location relative the closest load area served by the Qualifying Facility. Qualifying Facilities serving on-site loads, or other loads closer to the Qualifying Facility than the utility proxy resource, allow the utility to avoid transmission losses except in those cases where the utility must wheel the Qualifying Facility's power in excess of the on-site or local loads to other loads.

e. Transmission and Distribution System – Adjustment will be based on the potential savings that can be achieved for avoided transmission and distribution system costs, including upgrade deferrals or avoidance resulting from the Qualifying Facility's location relative to the Company's avoided resource. This adjustment does not include any costs associated with upgrades as part of the interconnection of the Qualifying Facility to PacifiCorp's system.

3. If the owner desires to proceed forward with the project after reviewing the Company's indicative pricing proposal, it may request in writing that the Company prepare a draft power purchase agreement to serve as the basis for negotiations between the parties. In connection with such request, the owner must provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of a draft power purchase agreement, which may include, but shall not be limited to:

a) updated information of the categories described in Paragraph B.1,
b) evidence of adequate control of proposed site
c) identification of, and timelines for obtaining any necessary governmental permits, approvals or authorizations
d) assurance of fuel supply or motive force
e) anticipated timelines for completion of key project milestones
f) evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements are being made in accordance with Part II.

4. The Company shall not be obligated to provide the owner with a draft power purchase agreement until all information required pursuant to Paragraph 3 has been received by the Company in writing. Within 30 days following receipt of all information required pursuant to paragraph 3, the Company shall provide the owner with a draft power purchase agreement containing a comprehensive set of proposed terms and conditions, including specific pricing for purchases from the project. Such draft shall serve as the basis for subsequent negotiations between the parties and, unless clearly indicated, shall not be construed as a binding proposal by the Company.

(continued)

B. Procedures (Continued)

5. After reviewing the draft power purchase agreement, the owner may prepare an initial set of written comments and proposals regarding the draft power purchase agreement and forward such comments and proposals to the Company. The Company shall not be obligated to commence negotiations with a Qualifying Facility owner until the Company has received an initial set of written comments and proposals from the Qualifying Facility owner. Following the Company's receipt of such comments and proposals, the owner may contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:
   a) will not unreasonably delay negotiations and will respond in good faith to any additions, deletions or modifications to the draft power purchase agreement that are proposed by the owner
   b) may request to visit the site of the proposed project if such a visit has not previously occurred
   c) will update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed project or proposed terms of the draft power purchase agreement
   d) may request any additional information from the owner necessary to finalize the terms of the power purchase agreement and satisfy the Company's due diligence with respect to the project.

6. When both parties are in full agreement as to all terms and conditions of the power purchase agreement, the Company will prepare and forward to the owner a final, executable version of the agreement within 15 business days. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

7. At any time after 60 days from the date that Qualifying Facility has provided its written notification pursuant to Paragraph 5, the Qualifying Facility may file a complaint with the Commission asking the Commission to adjudicate any unresolved contract terms or conditions.

2013

Integrated Resource Plan

Volume I

Let's turn the answers on.

April 30, 2013

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2013 Integrated Resource Plan (2013 IRP), representing the 12th plan submitted to state regulatory commissions, presents a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks to its customers. It was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.

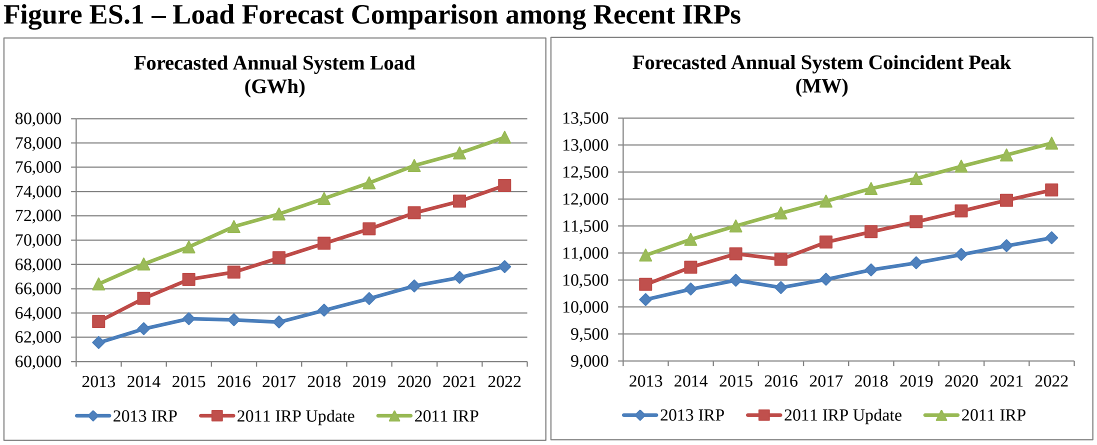
The key elements of the 2013 IRP include (1) a finding of resource need, focusing on the 10-year period 2013-2022, (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need, and (3) an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The process and outcome of the IRP—the preferred portfolio and action plans—meet applicable state IRP standards and guidelines. PacifiCorp continues to plan on a system-wide basis while accommodating state resource acquisition mandates and policies.

2013 IRP Highlights

Development of the 2013 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. Key drivers to the 2013 IRP preferred portfolio and associated action plan include the following:

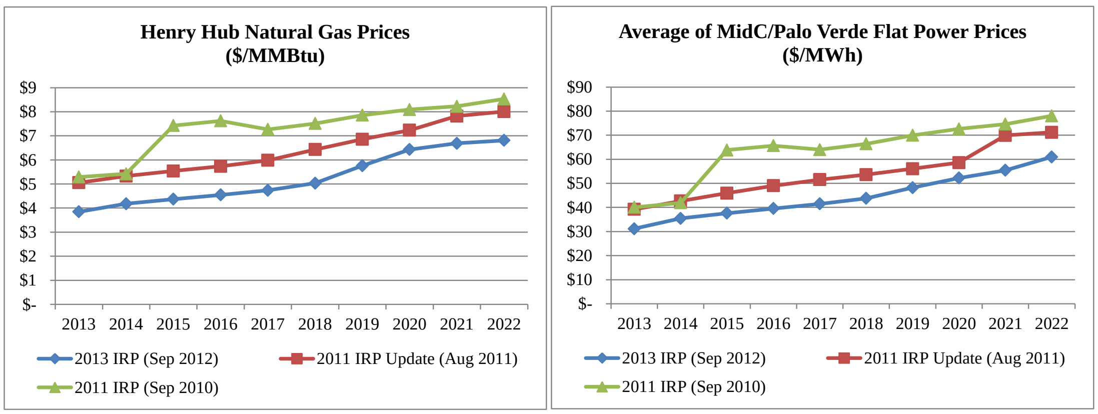
- As shown in Figure ES.1, the Company's load forecast in the 2013 IRP is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The lower load forecast is driven significantly by industrial self generation taking advantage of low natural gas prices, as well as by load request cancellations in Utah and Wyoming and postponements prompted by prolonged recessionary impacts and permitting issues. The reduced load forecast has greatly mitigated, but not eliminated the need for resources in the front ten years of the planning horizon, and is a significant driver in resource portfolio modeling performed for the 2013 IRP.

Figure ES.1 – Load Forecast Comparison among Recent IRPs



- Figure ES.2 shows that base case wholesale power prices and natural gas prices used in the 2013 IRP are significantly lower than the base case market prices used in the 2011 IRP and 2011 IRP Update. The decline in forward natural gas prices has largely been influenced by continued growth in prolific shale gas plays in North America. With continued declines in natural gas prices and reduced regional loads, forward power prices have also declined significantly over the past two years. Given these favorable market conditions, front office transactions play a critical role in meeting coincident peak loads throughout the front ten years of the planning horizon.

Figure ES.2 – Power and Natural Gas Price Comparison among Recent IRPs



- In all portfolios evaluated in the 2013 IRP, energy efficiency resources play an important role in meeting load growth throughout the front ten years of the planning horizon. In the 2013 IRP preferred portfolio, the accumulated acquisition of incremental energy efficiency resources meets 67 percent of currently forecasted load growth from 2013 levels by 2022, and the 2013 IRP action plan identifies steps the Company will take in the next two to four years to accelerate acquisition of cost-effective energy efficiency resources.

- Policy and market developments have contributed to higher renewable resource costs and reduced benefits. On the policy front, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise, making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources highly uncertain. Policy makers have also not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. With higher after-tax costs, lower power prices, and continued greenhouse gas regulation uncertainty, the need for new renewable resources will be driven by state-specific renewable portfolio standard (RPS) regulations. To mitigate the cost of RPS compliance, analyses in the 2013 IRP supports the use of unbundled renewable energy credits (RECs) to meet state RPS obligations through the first ten years of the planning period.

- On March 15, 2013, the Utah Public Service Commission approved the Company's application for a Certificate of Public Convenience and Necessity (CPCN) for the Sigurd to Red Butte transmission project. The Company began construction of the Sigurd to Red Butte transmission project in April, 2013 with a scheduled in-service date of June, 2015. For the 2013 IRP, the Company has completed preliminary analysis of the Windstar to Populus transmission project (Energy Gateway Segment D) that supports on-going permitting activities. Permitting activities for other Energy Gateway transmission segments will continue in parallel with the on-going development of analytical tools that can be used to evaluate transmission benefits that are not traditionally captured in the resource portfolio modeling process used in the IRP.

- The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_X) and sulfur dioxide (SO_2) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Modeling and Process Improvements

In developing the 2013 IRP, the Company has significantly advanced its analytical methods and portfolio development approach. The notable improvements that are summarized below have very much influenced the 2013 IRP and establish a sound foundation for analysis in future IRPs.

- Energy Gateway Transmission

  In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

  In addition to incorporating Energy Gateway transmission investments into the resource portfolio modeling process, the 2013 IRP introduces the System Operational and Reliability Benefits Tool (SBT), which identifies and quantifies transmission benefits that are not captured using production cost dispatch models traditionally used for IRP analyses. In this way, the SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project renewable resources are added to a portfolio for the sole purpose of meeting state-specific RPS compliance targets. In those cases where RPS compliance targets are assumed and incremental renewable resources are needed for the sole purpose of achieving RPS targets, the RPS Scenario Maker model was introduced into the 2013 IRP. The RPS Scenario Maker model was used to establish a minimum level of new renewable resources needed to meet RPS compliance targets while considering compliance flexibility mechanisms such as "banking" unique to each state RPS program.

- Public Process

  The involvement of stakeholders is a critical element of the IRP process. Over the course of developing the 2013 IRP, the Company expanded its open and collaborative approach to resource planning by increasing opportunities for stakeholder participation. The Company hosted 15 public input meetings, more than twice the number of public input meetings held for the 2011 IRP, supplemented communications with stakeholder conference calls, and held five state meetings. In addition, the Company made available to stakeholders a website used to provide data and to communicate Company responses to stakeholder questions received throughout the public process.

Resource Need

PacifiCorp's need for new resources is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. For capacity expansion planning, the Company uses a 13 percent planning reserve margin, which is applied to PacifiCorp's obligation net of offsetting "load resources" such as dispatchable load control capacity.[1]

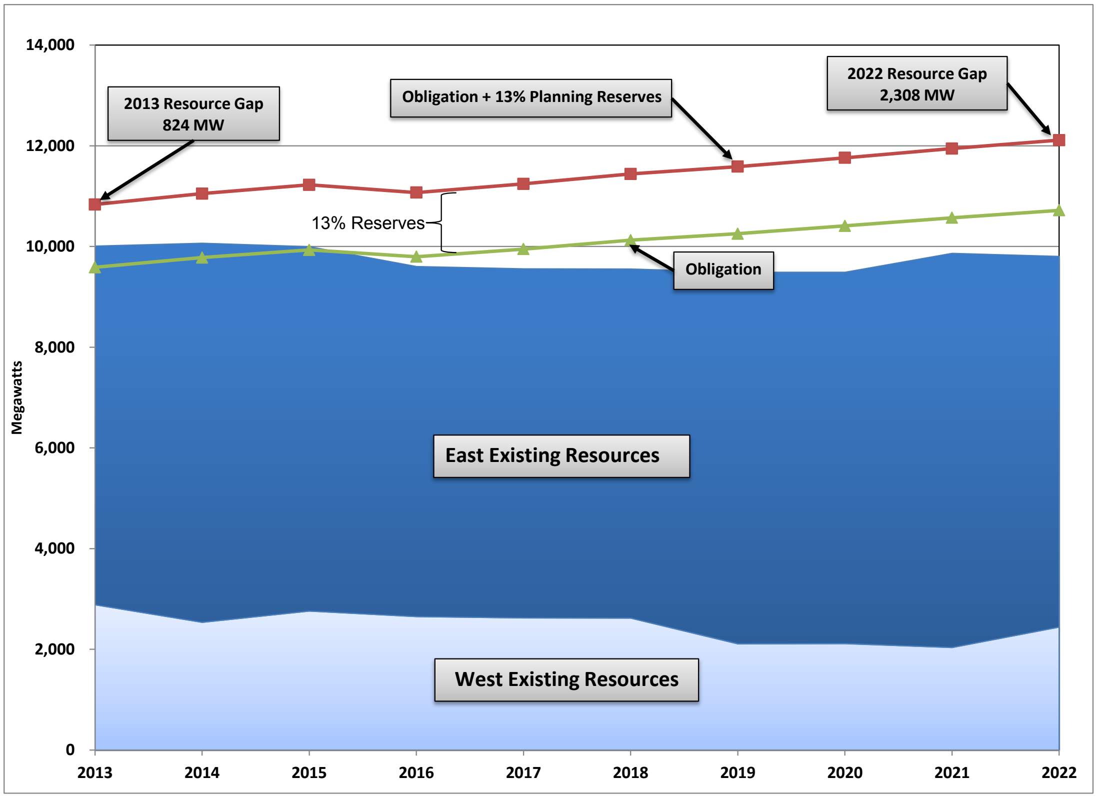
Table ES.1 shows the Company's annual capacity position for 2013 through 2022, and Figure ES.3 graphically highlights the capacity resource gap in relation to currently owned and contracted east and west-side resources. Without new resources, the system experiences a capacity deficit of 824 megawatts in 2013, down by 57 percent as compared to the 2011 IRP and down by 39 percent as compared to the 2011 IRP Update. By 2022, the system capacity deficit reaches 2,308 megawatts. Over the 2013 to 2022 timeframe, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent (prior to forecasted load reductions from energy efficiency). On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year.

Table ES.1 – PacifiCorp 10-year Capacity Position Forecast (Megawatts)

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

[1] The 13 percent planning reserve margin is supported by a stochastic loss of load probability study that is summarized in Volume II, Appendix I of the 2013 IRP.

Figure ES.3 – PacifiCorp Capacity Resource Gap



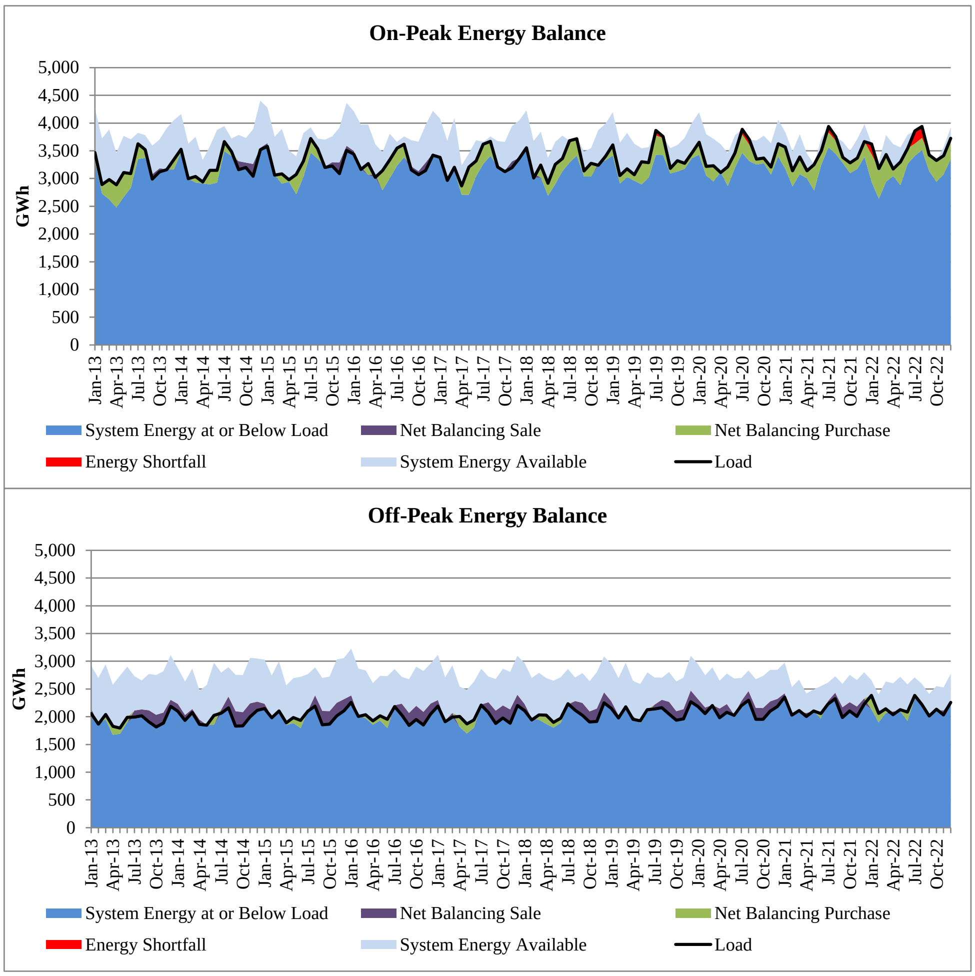
The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations, facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs.

Figure ES.4 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.[2] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp's system. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak

[2] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

periods. Figure ES.4 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

Figure ES.4 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



Future Resource Options and Portfolio Modeling

In line with state IRP standards and guidelines, PacifiCorp included a wide variety of resource options in portfolio modeling covering generation, demand-side management and transmission. Cost and performance assumptions for resource alternatives were developed using multiple sources, including: third party estimates, data from actual and projected PacifiCorp or utility

The 2013 IRP Preferred Portfolio

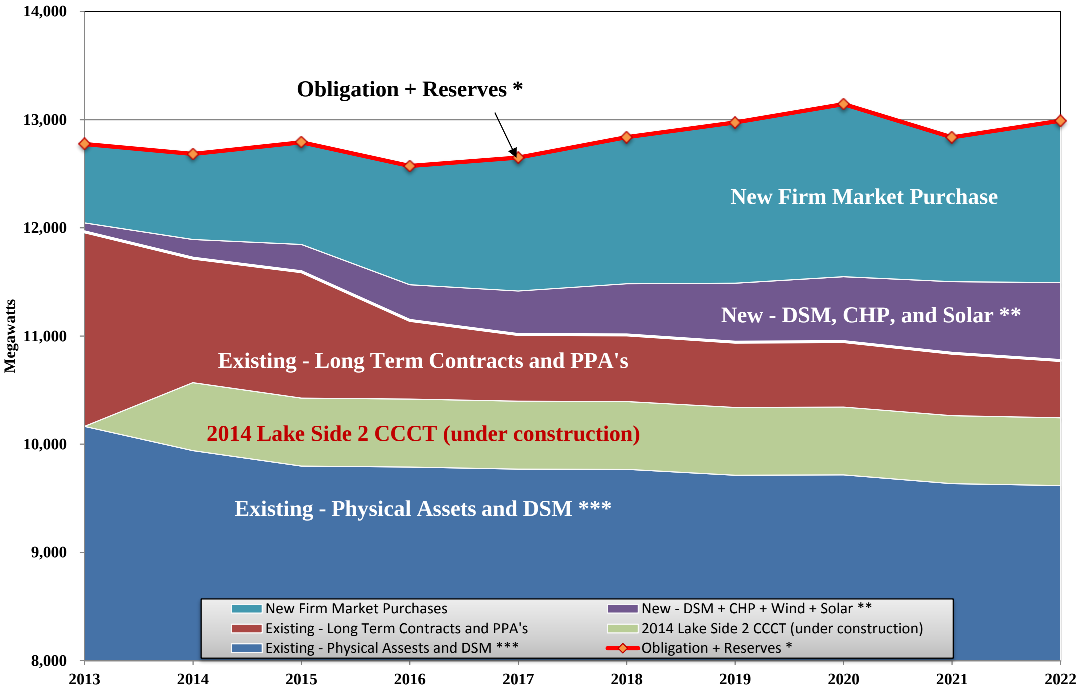
Table ES.3 lists the resource types and annual nameplate megawatt capacity additions over the period 2013 through 2032. Figure ES.4 shows how the preferred portfolio, along with existing resources, meets capacity requirements at the time of system peak through 2022. The drop in obligation and reserves in 2016 and 2021 coincides with termination of two exchange contracts. With reduced loads and favorable market conditions, incremental resource needs in the front 10 years of the planning horizon are met largely with cost-effective energy efficiency acquisitions and firm market purchases.

As informed by portfolio modeling completed for the 2013 IRP, the Company's action plan focuses on accelerating acquisition of cost effective DSM measures, to take advantage of the risk mitigation benefits of DSM resources by reducing the need for new firm market purchases in the near-term. With policy and market drivers contributing to unfavorable economics for new renewable resources, renewable resource additions in the 2013 IRP preferred portfolio reflect a near-term unbundled REC compliance strategy. Near-term renewable resources include small scale utility solar resources needed to meet Oregon requirements and distributed solar resources associated with the Utah Solar Incentive Program. Over the long-term, the 2013 IRP preferred portfolio includes additional wind resources, totaling 650 megawatts in the 2024 to 2025 timeframe, which contribute to meeting long-term state and assumed RPS obligations.

Table ES.3 – 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	**2,054**	**1,606**	**1,509**	**1,640**	**1,648**	**1,639**	**1,685**	**1,281**	**1,500**	

Figure ES.6 – Addressing PacifiCorp's Peak Capacity Deficit, 2013 through 2022



* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Solar resources peak contribution is 8 MW by 2022 and Combined Heat and Power (CHP) contributes 12 MW.
*** Includes retirements, turbine upgrades, and gas repower. DSM includes both Class 1 and 2.

Figure ES.7 shows PacifiCorp's forecasted RPS compliance position for the California, Oregon, and Washington[4] programs, along with a federal RPS program scenario[5], covering the period 2013 through 2022 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2013 to 2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet RPS requirements.

[4] The Washington RPS requirement is tied to January 1st of the compliance year.
[5] The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025

UM 1610/PacifiCorp
April 3, 2013
REC Data Request 4.1

REC Data Request 4.1

For the past five years for each state in which the Company has filed avoided cost rates with a resource sufficiency/deficiency demarcation, please provide the date of the avoided cost rate filing, the date the avoided cost rates were approved, acknowledged, allowed to go into effect or rejected, and the date for the resource sufficiency/deficiency demarcation.

Response to REC Data Request 4.1

Please refer to Attachment REC 4.1.

History of Avoided Cost Filings

State	Original Filing Date	Approval / Rejection Date	Deficit Year	Note
Oregon	2009 07 09	2009 12 28	2014	(1)
	2010 03 04	2010 03 30	2014	
	2012 03 02	2012 03 27	2016	(2)
Utah	2009 08 04	2009 12 14	2014	
	2010 06 07	2010 07 07	2013	
	2011 06 28	2011 12 14	2015	
	2012 06 29	2013 03 07	2020	(3)
Washington	2008 12 31	2009 02 13	NA	(4)
	2009 12 30	2010 02 25	NA	(4)
	2010 12 30	2011 02 10	NA	(4)
	2011 12 30	2012 04 12	NA	(5)
	2012 12 28	2013 02 14	2022	(6)
Wyoming	2010 02 23	2010 07 01	2014	
	2012 08 28	2012 11 19	2025	

Notes

(1) Approved 2009 09 08 subject to review. Affirmed 2009 12 28
(2) Deficit year determined by 2011 IRP Table 8.16
(3) Deficit Year as Filed - Filing rejected by Commission
(4) No Deficit year during five year study period. Washington WCA methodology
(5) No Deficit year during ten year study period. Washington WCA methodology
(6) Washington WCA methodology

UM 1610/PacifiCorp
April 3, 2013
REC Data Request 4.3

REC Data Request 4.3

Since the Commission's Order No. 05-584, please identify all QFs that submitted the required information to enter into power purchase agreement, but did not enter into a contract or other legally enforceable obligation.

Response to REC Data Request 4.3

Please refer to the list below, which provides a list of qualifying facilities (QFs) that submitted the requirement information, since Public Utility Commission of Oregon Order No. 05-584 (issued May 13, 2005), and did not enter into a contract or other legally enforceable obligation:

1. Mariah Wind LLC.
2. Orem Family Wind LLC.
3. Madison Wind.
4. Ironsides Wind.
5. Jefferson County Renewable Energy – Schedule 38.
6. Meduri Farms.
7. Old Maids Wind Farm.
8. Poplars Ranch Wind – Schedule 38.
9. Seattle Flats Wind Farm.
10. Blue River Hydro.
11. Del Rio Vineyards.
12. D H & Energy LLC – Schedule 38.
13. Energy Recovery Group.

UM 1610/PacifiCorp
April 3, 2013
REC Data Request 4.2

REC Data Request 4.2

Please refer to the Company's response to OPUC data request 4. Please provide a revised response that includes the data upon which the power purchase agreement was signed and the date of power deliveries. Please provide a redacted copy of the response. For each piece of information the Company believes should be confidential, please provide the full legal basis for why the information should be considered confidential.

Response to REC Data Request 4.2

The Company provided a revised response (and attachment) to OPUC Data Request 4. The Company therefore has based the response to REC Data Request 4.2 on Confidential Attachment OPUC 4 1st Revised.

Please refer to Confidential Attachment REC 4.2, which updates Confidential Attachment OPUC 4 1st Revised to include the date the power purchase agreement was executed, and the date of power deliveries. Information in Confidential Attachment REC 4.2 is designated as confidential under the protective order in this docket and may only be disclosed to qualified persons as defined in Order No. 12-461.

Please refer to Redacted Attachment REC 4.2, which removes the confidential information provided in Confidential Attachment REC 4.2. The redacted information has commercial value, is competitively sensitive and provided confidential pursuant to OAR 860-001-0070.

QFs using the Standard Contract since Order 05-584

		OPUC Data Request 4 (1st Revised Response)															REC Data Request 4.2	
		Blank cells indicate that there was no written record of a documented date (i.e., phone call, steps combined, etc.)																
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Plant Name	New PPA (N) or Renewal (R)	Initial QF Request	On PAC System	Date QF submit Info for PPA	Date PAC responded with request for Info	Date QF requested Interconnection [2]	Date GIA Signed [2]	Date Off-Sys QF provide PAC with 3rd Party GIA	Date PAC deemed QF info "Complete"	Date PAC provided draft PPA	Date QF requested finalized PPA	Date PAC requested Info to finalize PPA	Date QF provide final PPA info.	Date PAC deemed info sufficient to finalize PPA	Date Parties agree to all PPA terms	Date PAC provided final executable PPA	Date agreement signed	Date of power deliveries (Actual Commercial Operations Date)(7)
AG Hydro	[redacted]	08/31/2010	[redacted]	11/16/2010	11/24/2010	[redacted]	[redacted]	[redacted]		12/29/2010	02/10/2011	02/10/2011	03/01/2011	03/14/2011	[redacted]	[redacted]	[redacted]	[redacted]
Big Top LLC (QF)	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
Butter Creek Power LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
C Drop	[redacted]	02/18/2011	[redacted]	02/18/2011		[redacted]	[redacted]	[redacted]		02/25/2011		02/16/2011	08/16/2011	08/16/2011	[redacted]	[redacted]	[redacted]	[redacted]
CBG Portland	[redacted]	10/29/2010	[redacted]		06/03/2011	[redacted]	[redacted]	[redacted]		6/7/2011, 11/7/2011		07/15/2012	02/21/2012	02/21/2012	[redacted]	[redacted]	[redacted]	[redacted]
Central Oregon Irrigation District - Juniper Ridge	[redacted]		[redacted]	04/14/2009		[redacted]	[redacted]	[redacted]		06/11/2009		08/15/2009	08/16/2009		[redacted]	[redacted]	[redacted]	[redacted]
City of Albany, Dept of Public Works	[redacted]		[redacted]		04/02/2007	[redacted]	[redacted]	[redacted]	02/21/2008	03/13/2008				04/02/2008	[redacted]	[redacted]	[redacted]	[redacted]
City of Portland, Portland Water Bureau	[redacted]	10/12/2009	[redacted]	07/11/2011	07/11/2011	[redacted]	[redacted]	[redacted]	10/18/2011	10/18/2011		10/26/2011		10/31/2011	[redacted]	[redacted]	[redacted]	[redacted]
Curtiss Livestock (Cameron Curtis)	[redacted]		[redacted]			[redacted]	[redacted]	[redacted]		09/28/2011					[redacted]	[redacted]	[redacted]	[redacted]
Dorena Hydro	[redacted]	12/22/2010	[redacted]	02/10/2011	03/15/2011	[redacted]	[redacted]	[redacted]		03/30/2011	04/04/2011				[redacted]	[redacted]	[redacted]	[redacted]
Douglas Country Forest Products	[redacted]		[redacted]			[redacted]	[redacted]	[redacted]	02/12/2010	02/18/2010	05/18/2010			07/12/2010	[redacted]	[redacted]	[redacted]	[redacted]
Duane Wiggins Hydro	[redacted]	08/14/2009	[redacted]	09/10/2009	09/24/2009	[redacted]	[redacted]	[redacted]	04/07/2010	04/13/2010		04/26/2010	09/01/2010		[redacted]	[redacted]	[redacted]	[redacted]
EBD Hydro	[redacted]	02/23/2011	[redacted]	01/13/2012	2/15/2012, 3/1/2012, 3/13/2012	[redacted]	[redacted]	[redacted]	03/26/2012	03/30/2011		04/03/2012	04/03/2012		[redacted]	[redacted]	[redacted]	[redacted]
Evergreen BioPower	[redacted]	04/20/2006	[redacted]	06/20/2006		[redacted]	[redacted]	[redacted]	11/13/2006	11/16/2006		12/14/2006			[redacted]	[redacted]	[redacted]	[redacted]
Farm Power Misty Meadow	[redacted]	02/10/2011	[redacted]			[redacted]	[redacted]	[redacted]		02/17/2011		02/24/2012	03/01/2012	03/07/2012	[redacted]	[redacted]	[redacted]	[redacted]
Farmers Irrigation [1]	[redacted]	06/05/2009	[redacted]	08/19/2009	06/15/2009	[redacted]	[redacted]	[redacted]		10/13/2010				11/02/2010	[redacted]	[redacted]	[redacted]	[redacted]
Finley Bioenergy	[redacted]	06/15/2007	[redacted]	06/12/2007		[redacted]	[redacted]	[redacted]		07/24/2007					[redacted]	[redacted]	[redacted]	[redacted]
Four Corners Windfarm LLC [3]	[redacted]		[redacted]	05/02/2008		[redacted]	[redacted]	[redacted]				12/18/2008	04/29/2009	05/29/2009	[redacted]	[redacted]	[redacted]	[redacted]
Four Mile Canyon Windfarm LLC [3]	[redacted]		[redacted]	05/02/2008		[redacted]	[redacted]	[redacted]				12/18/2008	04/29/2009	05/29/2009	[redacted]	[redacted]	[redacted]	[redacted]
High Plateau Windfarm LLC [6]	[redacted]	05/23/2011	[redacted]	05/23/2011	06/14/2011	[redacted]	[redacted]	[redacted]	08/02/2011	08/07/2011	11/08/2011	11/08/2011	11/17/2011	11/17/2011	[redacted]	[redacted]	[redacted]	[redacted]
Jim & Sharon Jans (Odell Creek)	[redacted]		[redacted]	11/16/2010		[redacted]	[redacted]	[redacted]	11/16/2010	11/16/2010			12/22/2010		[redacted]	[redacted]	[redacted]	[redacted]
Lower Ridge Windfarm LLC [6]	[redacted]	05/23/2011	[redacted]	05/23/2011	06/14/2011	[redacted]	[redacted]	[redacted]	08/02/2011	08/07/2011	11/08/2011	11/08/2011	11/17/2011	11/17/2011	[redacted]	[redacted]	[redacted]	[redacted]
Loyd Fery	[redacted]		[redacted]		08/08/2007	[redacted]	[redacted]	[redacted]						11/06/2007	[redacted]	[redacted]	[redacted]	[redacted]
Middlefork Irrigation District	[redacted]		[redacted]	09/07/2006		[redacted]	[redacted]	[redacted]		10/13/2006			11/09/2006		[redacted]	[redacted]	[redacted]	[redacted]
Monroe Hydro	[redacted]	12/02/2011	[redacted]	02/08/2012	03/01/2012	[redacted]	[redacted]	[redacted]	03/27/2012	03/29/2012			04/04/2012		[redacted]	[redacted]	[redacted]	[redacted]
Mountain Energy	[redacted]		[redacted]			[redacted]	[redacted]	[redacted]		04/07/2007			11/20/2007		[redacted]	[redacted]	[redacted]	[redacted]
Mule Hollow Windfarm LLC [6]	[redacted]	05/23/2011	[redacted]	05/23/2011	06/14/2011	[redacted]	[redacted]	[redacted]	08/02/2011	08/07/2011	11/08/2011	11/08/2011	11/17/2011	11/17/2011	[redacted]	[redacted]	[redacted]	[redacted]
OM Power I	[redacted]	03/13/2012	[redacted]	03/13/2012	03/14/2012	[redacted]	[redacted]	[redacted]	03/28/2012	03/28/2012	03/29/2012	03/29/2012	04/05/2012		[redacted]	[redacted]	[redacted]	[redacted]
Oregon Environmental Industries	[redacted]	11/25/2002	[redacted]			[redacted]	[redacted]	[redacted]		09/07/2005			05/12/2006		[redacted]	[redacted]	[redacted]	[redacted]
Oregon Institute of Technology	[redacted]		[redacted]	05/12/2009	05/13/2009	[redacted]	[redacted]	[redacted]		06/16/2009	07/13/2009		08/18/2009		[redacted]	[redacted]	[redacted]	[redacted]
Oregon State University	[redacted]	04/21/2009	[redacted]	01/25/2010	02/05/2010	[redacted]	[redacted]	[redacted]		03/17/2010	07/26/2010				[redacted]	[redacted]	[redacted]	[redacted]
Oregon Trail Windfarm LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
Pacific Canyon Windfarm LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
Pine City Windfarm LLC [6]	[redacted]	05/23/2011	[redacted]	05/23/2011	06/14/2011	[redacted]	[redacted]	[redacted]	08/02/2011	08/07/2011	11/08/2011	11/08/2011	11/17/2011	11/17/2011	[redacted]	[redacted]	[redacted]	[redacted]
RES Ag- Oak Lea	[redacted]	09/23/2009	[redacted]	11/12/2009		[redacted]	[redacted]	[redacted]	11/13/2009	11/19/2009	09/19/2011	10/04/2011	10/24/2011	10/25/2011	[redacted]	[redacted]	[redacted]	[redacted]
Roseburg LFG	[redacted]	01/24/2011	[redacted]	02/09/2011	03/28/2011	[redacted]	[redacted]	[redacted]		03/29/2011			04/21/2011	05/11/2011	[redacted]	[redacted]	[redacted]	[redacted]
Rough & Ready Lumber	[redacted]		[redacted]		01/09/2012	[redacted]	[redacted]	[redacted]		02/15/2012			02/17/2012	02/20/2012	[redacted]	[redacted]	[redacted]	[redacted]
Roush Hydro, Inc	[redacted]		[redacted]			[redacted]	[redacted]	[redacted]					11/20/2007		[redacted]	[redacted]	[redacted]	[redacted]
Sand Ranch Windfarm LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
Stahlbush Island Farms	[redacted]		[redacted]			[redacted]	[redacted]	[redacted]		02/10/2011			04/15/2011	04/25/2011	[redacted]	[redacted]	[redacted]	[redacted]
Swalley Irrigation District [1]	[redacted]	04/04/2007	[redacted]		4/4/2007, 4/8/2008, 7/14/2009	[redacted]	[redacted]	[redacted]							[redacted]	[redacted]	[redacted]	[redacted]
Threemile Canyon Wind I LLC [4] [5]	[redacted]	5/3/2006 [4], 12/19/2008	[redacted]	9/21/2006 [4], 3/5/2009	9/27/2006 [4], 4/7/2009	[redacted]	[redacted]	[redacted]	05/03/2009	05/17/2009	06/17/2009	06/17/2009	06/17/2009	06/18/2009	[redacted]	[redacted]	[redacted]	[redacted]
TMF Biofuels	[redacted]	05/18/2005	[redacted]	11/15/2010		[redacted]	[redacted]	[redacted]		08/25/2011	12/05/2011	12/13/2011	02/06/2012	02/06/2012	[redacted]	[redacted]	[redacted]	[redacted]
Wagon Trail LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]
Ward Butte Windfarm LLC	[redacted]		[redacted]	05/02/2008	05/22/2008	[redacted]	[redacted]	[redacted]	06/05/2008	08/14/2008					[redacted]	[redacted]	[redacted]	[redacted]

Notes:

[redacted]

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May 21, 2013

Via Electronic and FedEx

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing
Docket No. UM 1610

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the Renewable Energy Coalition's Cross-Examination Exhibits REC/400-407.

The Coalition is also providing confidential copies of Confidential Exhibit REC/407 to parties that have signed the protective order in this proceeding. The Coalition is not providing confidential copies to Portland General Electric Company and Idaho Power Company.

Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely,

Karen Zolka

Karen Zolka

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Cross-Examination Exhibits on behalf of the Renewable Energy Coalition upon the parties on the service list by causing the same to be sent via electronic email to each individual's last-known e-mail address, as listed below.

Dated at Portland, Oregon, this 21st day of May, 2013.

Sincerely,

Karen Zolka

Karen A. Zolka

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