Rocky Mountain Power
Docket No. 20-035-04
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of David G. Webb

October 2020

Q. Are you the same David G. Webb who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company")?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony discusses the changes to net power costs in this case to align with the adjustments included by other Company witnesses and responds to various issues and adjustments raised in the direct testimony of the Division of Public Utilities ("DPU") witnesses Mr. Robert A. Davis and Mr. Gary L. Smith, the Office of Consumer Services ("OCS") witness Mr. Philip Hayet, and the Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins relating to net power costs ("NPC").

Q. Please summarize your rebuttal testimony.

A. I discuss the Company's response to the various proposals that affect the NPC in this general rate case ("GRC"). I specifically address the following points:

- NPC changes to align with rebuttal adjustments for wind project updates;
- OCS' proposed adjustment to remove market depth constraints;
- OCS' concern about the Day-Ahead/Real-Time adjustment;
- Parties concerns about including production tax credits ("PTCs") in the Energy Balancing Account ("EBA");
- Impacts to the EBA from the Subscriber Solar II proposal; and,
- DPU's concern about the EBA base revenue update proposal.

II. NPC ALIGNMENT WITH WIND PROJECT IN-SERVICE DATES

Q. Please explain the changes reflected in your revised NPC request.

A. The Company made one change to NPC to reflect the updated timing of the in-service dates of the Pryor Mountain and TB Flats II wind projects as discussed by Company witnesses Mr. Robert Van Engelenhoven and Mr. Timothy J. Hemstreet.

The results of the Company's revised NPC study to align with the wind project changes are provided in Exhibit RMP__(DGW-1R). This NPC revision excludes any of the standard price and contract updates associated with a typical full NPC update. The only revision made was to adjust the Pryor Mountain and TB Flats II wind project in-service dates as model inputs.

Q. How has your NPC recommendation changed from the initial filing?

A. On a total-Company basis, NPC increased by $9.2 million, from $1.421 billion to $1.431 billion. On a Utah-allocated basis, NPC increased from $619.2 million to $622.6 million, a $3.4 million increase from the initial filing but still a reduction of $5.4 million from base NPC of $628.0 million in the last general rate case Docket No. 13-035-184 ("2014 GRC").

Q. Why did the Company forego a full NPC update in its rebuttal filing?

A. The Settlement Stipulation in the 2014 GRC specified that all updates to NPC in future Utah GRCs would be filed at least six weeks prior to the intervenor direct testimony due date.[1] As such, the Company is not updating its NPC at this time.

[1] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Settlement Stipulation at ¶41 p. 12 (June 25, 2014).

III. REBUTTAL TESTIMONY

Modeled Market Depth Constraints

Q. Please summarize OCS' position on the modeled market depth constraints.

A. OCS recommends the Company be required to remove market depth constraints from the High Load Hours ("HLH") in the GRID model. This adjustment reduces NPC by $26.5 million on a total-Company basis or approximately $11.5 million on a Utah-allocated basis.

Q. How does the Company respond to OCS' recommendation?

A. Removing the existing market depth constraint limits—or caps—on market sales will distort the model results in unrealistic ways. As the market caps are derived from actual transactions, they best reflect the actual conditions under which the Company will be hedging and balancing. In actual operations, the Company faces limited counterparty activity and market liquidity at several locations in both the Light Load Hours ("LLH") and the HLH. Those factors are both real and limiting, and they continue to have an effect on optimization efforts and actual NPC. If the caps on market sales are removed, as OCS proposes, none of these current real-world market-limiting characteristics would be represented in the GRID model, which would make the model less accurate.

Q. What market capacity methodology was used in the Company's GRID study in this proceeding?

A. The market capacity in the Company's GRID study reflects a four-year average of historical short term firm transactions, by market, month, and hour class (HLH and LLH). However, no market capacity limits are applied to the Mid-Columbia or the Palo Verde markets because they are the most liquid market points to which the Company has access.

Q. Mr. Hayet argues in favor of removing HLH market caps in GRID because the Public Service Commission of Utah ("Commission") justified its initial 2005 approval of market caps to limit off-peak or LLH sales from coal plants. Has the Commission reviewed market caps at any other point?

A. Yes. While the subject of market caps was initially reviewed before the Commission in the avoided cost docket referenced by Mr. Hayet,[2] the updated methodology, and the basis for adopting it, was originally presented in the direct testimony of Mr. Gregory N. Duvall in the Company's 2010 general rate case,[3] and was also discussed in the direct testimony of Mr. Duvall in the Company's 2014 GRC.[4] The Commission approved market caps in both dockets.

Q. Have the circumstances necessitating market caps in GRID changed dramatically since the Company's 2014 GRC?

A. No. In fact, actual operations provide evidence that the current market caps are sound modeling.

Q. Can you provide an example of some operational data that indicates that the market caps are needed?

A. Figure 1 below compares actual wholesale sales over the period from 2015 through 2019 to the sales forecasted by GRID in the last two GRC proceedings. The approach

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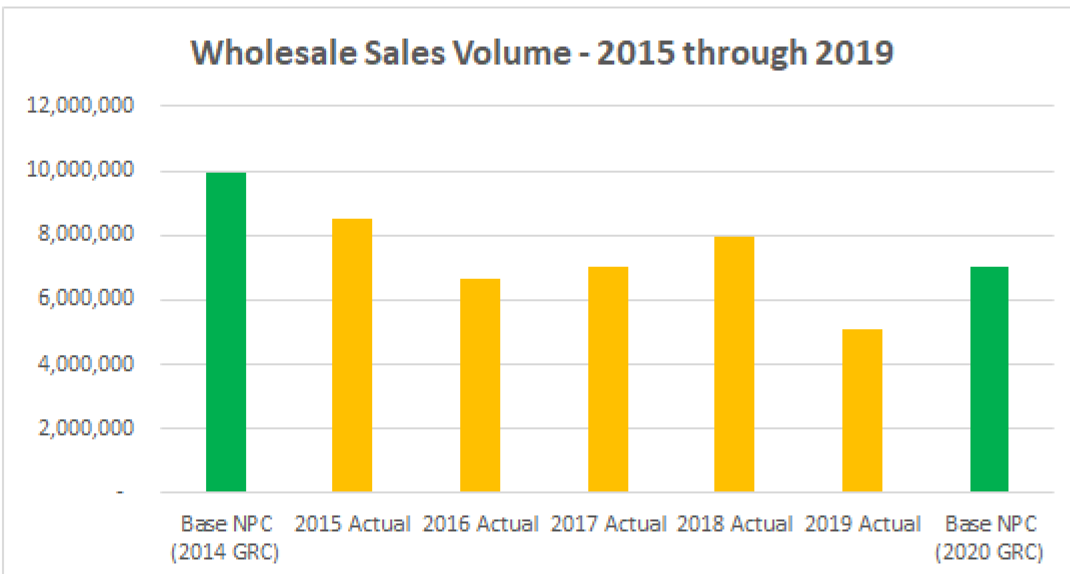
[2] Direct Testimony of Philip Hayet at line 140.

[3] *In the Matter of: the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 10-035-124, Direct Testimony of Gregory N. Duvall, lines 209-263 (Jan. 24, 2011).

[4] *In the Matter of: the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184, Direct Testimony of Gregory N. Duvall, lines 359-419 (Jan. 3, 2014).

to modeling market caps is identical between the two rate case studies. An examination of the figure will illustrate that GRID tends to estimate the Company's ability to sell power into the market with reasonable accuracy—if anything GRID forecasts slightly higher. Without the market caps in place, the model output would be less reflective of actual constraints, which would make the net power cost forecast less accurate as a result.

Figure 1



Q. Mr. Hayet suggests that the removal of HLH market capacity limits represents a reasonable modeling change.[5] Do you agree?

A. No. Mr. Hayet has presented no evidence indicating that the removal of the HLH market capacity limit results in the GRID model producing a more accurate net power cost forecast. In contrast, the history of forecasted sales versus actual sales makes it clear that GRID already projects sales volumes within a reasonable range of actual results. Therefore, I urge the commission to reject the proposed change to market cap

[5] Direct Testimony of Philip Hayet at line 163.

modeling.

Day-Ahead/Real-Time Adjustment

Q. OCS has raised concerns that the Company's "system balancing transaction adjustments" are "complex" and "over-reaching."[6] How do you respond?

A. What OCS refers to as "system balancing transaction adjustments" is in fact the Day-Ahead/Real-Time ("DA/RT") adjustment. The Company incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in GRID. To address this deficiency, the Company uses the DA/RT adjustment to more accurately model system balancing transaction prices and volumes. The Company has been using this adjustment in Oregon, Wyoming, Washington, and California to increase the accuracy of its power cost forecasts.

Q. Please describe how system balancing transactions are included in GRID.

A. System balancing transactions are required to balance the hourly load and resources in the GRID model for the GRC test period. The GRID model calculates the least-cost solution to balance the Company's load and resources each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour.

Q. Please describe the price component of the DA/RT adjustment.

A. To better reflect the market prices available to the Company when it transacts in the

[6] Direct Testimony of Philip Hayet at line 189.

real-time market, PacifiCorp includes in GRID separate prices for forecasted system balancing sales and purchases. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices.

Q. Why is the DA/RT adjustment needed to differentiate the market prices for purchases and sales?

A. In prior NPC forecasts, before including a DA/RT adjustment, the GRID model only used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars were identical within a given month for each weekday of that month. In addition, the prices were input into the model and did not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. While there are exceptions to this rule, the average cost of the Company's daily and hourly short-term firm purchases tends to be higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales tends to be lower than the average actual monthly market price.

Q. Please describe the volume component of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 megawatt ("MW") blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, GRID has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of GRID's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the Company's system.

Q. Can you explain why both a Market Cap adjustment and the DA/RT are necessary even when base NPC is trued-up to actual NPC every year in the EBA?

A. These two adjustments serve different purposes and impact the NPC forecast in different ways. The market cap adjustment exists to account for real operational constraints that limit the amount of sales activity the Company can engage in over time. As noted above, a comparison of forecasted and actual sales indicates that the inclusion of this constraint has made the model more accurate. The DA/RT adjustment applies to both purchases and sales and is in place to reflect a different operational reality faced by the company; specifically, it addresses the fact that the Company cannot balance the system with perfect foresight in a single transaction, at precisely the market average price. The DA/RT adjustment also makes the NPC forecast more accurate when compared to actual operationsand both adjustments serve to mitigate changes in the EBA.

Q. Can you explain why it would be inappropriate to include a line item adjustment based on historical data instead of using the DA/RT?

A. A line item adjustment would make this adjustment less accurate. Historical volumes and prices make up the inputs to the DA/RT calculation, but they need to be applied on an average basis to the forecasted purchase and sale volumes in order to match the Company's expectations regarding the expected system balancing costs over time. In addition, the line item approach misses the opportunity to have GRID optimize using a set of expected prices that more closely match the reality that the Company expects to face when executing balancing transactions. As a result of both of those factors, a line item adjustment would reduce forecast accuracy.

Production Tax Credits

Q. Please explain the Company's proposal to include PTCs in the EBA.

A. PTCs are currently included as a fixed revenue credit in base rates, but since actual PTC recovery is tied to actual generation that is captured in NPC, it is logical to treat PTCs similarly for ratemaking purposes. The PTCs associated with the Energy Vision 2020 projects represent a significant source of additional value for customers. PacifiCorp's proposal to track and true-up PTCs through the EBA is designed to pass back to customers the full and actual value of PTCs.

Q. Please summarize the arguments of the parties against a PTC true-up in the EBA.

A. The DPU recommends that PTCs continue to be included in base rates and excluded from the EBA, claiming that including PTCs in the EBA is not expressly considered by Utah law.[7] DPU further contends that including the PTCs in the EBA

[7] Direct Testimony of Gary L. Smith at lines 185-199.

inappropriately transfers risk from the Company to customers.[8] OCS argues that including PTCs in the EBA insulates the Company from regulatory lag and the risks of construction delays and incentivizes the Company to defer maintenance.[9] UAE recommends the PTCs remain in base rates stating PTC values do not change from year to year in an unpredictable manner and would make the potential benefits to customers from the new large wind investments even more variable than they already are.[10]

Q. Please explain how PTCs are calculated for inclusion in the rate case and why it makes sense to include PTCs in the EBA.

A. The PTCs in this case are derived from the annual wind generation forecast as part of the base NPC. In other words, the annual wind generation forecast in the base NPC is then multiplied by the PTC rate and grossed up for taxes to arrive at the total-Company PTC amount that is then allocated to Utah. All other components of base NPC are trued-up in the EBA, and therefore it makes sense that PTCs, which are also derived from the same forecast, should also be included in the EBA.

Q. How do you respond to DPU's statement the PTCs are not expressly included in Utah's Energy Balancing Account statute?

A. It is my understanding that Utah's Energy Balancing Account statute allows for the recovery of incurred actual power costs.[11] Not all components currently included in the EBA mechanism are described in the statute, such as wheeling revenues. My understanding is that the statute language is not necessarily all-inclusive and does not

[8] Direct Testimony of Gary L. Smith at lines 247-249.
[9] Direct Testimony of Philip Hayet at lines 714-718.
[10] Direct Testimony of Kevin C. Higgins at lines 1185-1187.
[11] Utah Code § 54-7-13.5.

limit other expenses from being included. PTCs vary based on the amount of generation produced by the Company's wind facilities, and so they are intrinsically tied to power costs. Furthermore, they are included in many of the NPC mechanisms that PacifiCorp has in other states including Oregon, California and Idaho.[12] In fact, the Commission has previously contemplated in past orders that it was appropriate to consider the treatment of PTCs in a general rate case.[13]

Q. Do you agree with DPU's characterization that the inclusion of PTCs in the EBA would transfer risk to customers?

A. No. The inclusion of PTCs is not about transferring risk to customers, but rather about ensuring that customers' rates reflect the full costs and benefits of these wind resources. As I discussed above, PTCs are intrinsically tied to the generation output of wind facilities. In fact, all other variable benefits and costs that are tied to the actual generation of the Company's wind facilities are included in NPC. Including PTCs is not shifting risk or harming customers; rather, it ensures that the Company's actual operations are aligned with customer rates.

Q. How do you respond to UAE's assertion that including PTCs in the EBA adds to customer's risk exposure?[14]

A. As I stated above, the inclusion of PTCs is not about increasing variability for customers but about ensuring that customers' rates reflect the full costs and benefits of these wind resources

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[12] PacifiCorp has proposed this treatment in Washington and Wyoming in currently ongoing general rate proceedings.

[13] In 2017, the Commission declined to include PTCs in the EBA but determined they "remain open to reconsider the issue either at the conclusion of the EBA pilot period or during the next GRC." *In the Matter of: the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Order at 9 (Feb. 16, 2017).

[14] Direct Testimony of Kevin C. Higgins at lines 1176-1177.

Q. Do you agree with UAE that PTC values are not variable enough to justify inclusion in the EBA?[15]

A. No. While the value per kilowatt-hour ("kWh") produced is set in the Internal Revenue Code, the amount of the kWh produced by the PacifiCorp's wind facilities is variable, and it is exactly this type of generation variability that net power cost mechanisms are intended to track. Additionally, inclusion of PTCs in the EBA will allow for a timely update of the PTC rate in the event it is updated for inflation. UAE also ignores similar items like renewable energy credits that have a generation-based benefit.

Q. How do you respond to OCS's assertion that including PTCs in the EBA would insulate the Company from construction delays and incentivize the deferral of maintenance?[16]

A. The Company's EBA is audited on an annual basis in order to determine the prudence of its actions. That review includes the ability to review the outages and comment upon decisions regarding the execution or deferral of maintenance activities. Any argument that the Company is insulated from construction delays or could defer maintenance is unjustified because parties and the Commission have a full opportunity to review the prudence of any outages that occur in the EBA.

Additionally, there has been no evidence that the structure of the EBA affects the Company's operations. When the DPU evaluated PacifiCorp's wind generation before and after the EBA, it was determined that there was no evidence to conclude

[15] UAE contends that because the value of PTCs are set that "[t]here is no PTC price volatility to justify recovery through an adjustor mechanism." Direct Testimony of Kevin C. Higgins at lines 1173-1174.
[16] Direct Testimony of Philip Hayet at lines 714-718.

that any deterioration in wind reliability was a result of the EBA.[17] Similarly it is inappropriate to conclude that the inclusion of PTCs in the EBA will have an effect on the Company's operations.

Subscriber Solar

Q. Please summarize your rebuttal testimony with regards to the Company's proposed Subscriber Solar program.

A. The Company proposes a redesign of the existing Subscriber Solar program to allow for new subscribers, which was described in detail by Company witness Mr. William Comeau in direct testimony. The DPU, OCS and Utah Clean Energy ("UCE") filed testimony with various recommendations regarding the redesigned program, the majority of which are addressed in the rebuttal testimony of Mr. Kyle T. Moore, who has adopted Mr. Comeau's testimony. My rebuttal testimony addresses the parties' questions regarding the implications of the redesigned program on NPC and the EBA.

Q. What concern did the parties raise with respect to NPC?

A. DPU witness Mr. Robert A. Davis recommends that the Company confirm the impacts the migration might have on the EBA.

Q. How do you respond?

A. Any unrecovered costs or unsubscribed portion of the proposed updated Subscriber Solar Program will impact the EBA and be allocated to all Utah customers.

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[17] *See In the Matter of: the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, DPU Final Evaluation of PacifiCorp's EBA at page 34 (May 20, 2016).

Update to EBA Base Revenues

Q. Why does DPU witness Mr. Smith recommend the Commission not approve the Company's proposal to update the base EBA in each annual EBA filing?

A. Mr. Smith's only rationale for this recommendation is his belief that it is inconsistent with the statute enabling the EBA. He argues that Utah Code § 54-7-13.5(2)(f)(ii) allows the EBA collection to "be incorporated into base rates in an appropriate commission proceeding" and that the only appropriate commission proceeding is a general rate case. He then reasons that the Company's proposed change is inconsistent with the law, because it would change base EBA rates outside of a general rate case.[18]

Q. Do you agree with Mr. Smith's conclusion concerning the Company's proposed change to the EBA?

A. No. Mr. Smith may misunderstand the Company's proposed change. The Company does not propose updating base EBA rates in each annual EBA filing, and the Company agrees that base EBA rates should not be changed outside of a general rate case. The Company's proposal is to use the actual revenue collected from base EBA rates established in a rate case instead of the forecast revenue collection from the test period in the rate case in its annual EBA filings. The Company is not recommending that base EBA rates themselves would change outside of rate cases; therefore, the proposed change is not inconsistent with the law. Company witness Mr. Robert M. Meredith will respond to Mr. Smith's recommendation in more detail in his rebuttal testimony in the cost of service/pricing phase of this docket.

[18] Direct Testimony of Gary L. Smith at lines 173-184.

IV. CONCLUSION

Q. Please summarize your testimony.

A. The Company's NPC as modeled in the test period in this case are reasonable and have been aligned with the changes to the wind projects using the most recent data available. NPC have increased slightly from the initial filing but have decreased by $5.4 million on a Utah-allocated basis, since the 2014 GRC. Additionally, I recommend that the Commission approve and adopt the proposed base NPC for the test period of $1.431 billion on a total-Company basis and $622.6 million on a Utah-allocated basis.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DGW-1R)
Docket No. 20-035-04
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BEFORE THE PUBLIC SERVICE COMMISSION
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ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of David G. Webb

Pryor Mountain and TB Flats II In-service NPC Revision

October 2020

PacifiCorp

Net Power Cost Analysis

12 months ended December 2021	01/21-12/21	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,505,785	737,196	563,577	510,677	345,626	371,342	595,055	746,190	736,430	730,562	717,386	703,085	748,658
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	8,780	732	732	732	732	732	732	732	732	732	732	732	732
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	110,091	6,811	7,295	10,304	5,026	5,690	5,945	16,774	16,065	12,717	8,713	6,709	8,041
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,624,656	744,739	571,604	521,713	351,384	377,763	601,732	763,696	753,226	744,011	726,831	710,526	757,431
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	1,127,840	371,000	356,160	400,680	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,870,100	1,646,150	1,524,600	1,699,350	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	5,997,940	2,017,150	1,880,760	2,100,030	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	31,881,523	3,020,200	2,579,436	2,474,810	1,162,453	1,739,822	1,877,226	2,197,159	2,677,109	2,715,413	3,861,799	3,685,397	3,890,698
Four Corners	48,545,245	6,210,978	3,680,010	2,826,755	2,276,103	1,883,355	3,186,455	4,518,645	4,327,539	4,528,690	4,812,456	4,650,612	5,643,646
Mead	29,361,275	3,592,938	3,678,098	1,720,957	973,216	1,054,497	1,519,723	1,957,983	3,157,818	2,577,326	3,095,418	2,858,626	3,174,673
Mid Columbia	29,813,703	1,884,558	1,099,010	542,032	1,638,076	2,266,821	1,113,520	6,059,592	5,195,629	3,188,940	3,150,704	1,965,722	1,709,098
Mona	21,569,797	2,757,569	1,406,112	422,603	721,905	946,669	1,619,485	1,743,951	1,810,503	4,141,864	2,098,885	1,561,602	2,338,650
NOB	6,524,288	440,983	444,265	438,899	617,873	145,307	312,102	1,103,234	1,118,879	582,109	75,206	411,762	833,670
Palo Verde	41,859,367	1,715,707	574,779	1,367,312	2,427,272	2,713,993	4,520,068	7,031,232	8,045,662	5,096,377	2,708,516	2,593,441	3,065,009
Trapped Energy	631	-	-	-	-	-	-	-	-	-	-	631	-
Total System Balancing Sales	209,555,829	19,622,932	13,461,709	9,793,368	9,816,898	10,750,465	14,148,580	24,611,799	26,333,138	22,830,718	19,802,984	17,727,793	20,655,444
Total Special Sales For Resale	223,178,425	22,384,821	15,914,073	12,415,111	10,168,283	11,128,228	14,750,313	25,375,494	27,086,365	23,574,730	20,529,815	18,438,319	21,412,876

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	11,723,273	1,348,849	1,095,201	1,032,244	1,016,035	830,825	743,881	742,782	585,990	827,498	1,090,534	1,068,343	1,341,093
Cedar Springs Wind III	8,908,095	1,025,294	832,067	784,236	772,110	631,271	565,348	564,366	445,200	628,830	828,668	811,823	1,018,881
Combine Hills Wind	5,369,068	372,723	451,621	547,613	547,338	465,612	400,323	451,804	378,748	357,771	372,201	456,360	566,954
Cove Mountain Solar	3,863,906	185,318	194,698	339,380	369,458	425,244	457,335	443,628	419,763	359,961	289,769	208,202	171,150
Cove Mountain Solar II	343,571	28,534	28,675	28,713	28,701	28,534	28,701	28,624	28,624	28,609	28,624	28,609	28,624
Deseret Purchase	32,990,071	2,935,583	2,832,069	2,635,138	2,359,940	2,344,792	2,741,178	2,948,207	2,948,207	2,917,910	2,897,712	2,519,000	2,910,336
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,615,653	156,892	141,048	125,873	128,817	154,170	284,603	436,745	407,435	241,073	156,349	153,679	228,968
Gemstate	1,717,824	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152	143,152
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	7,122,324	374,917	425,031	647,514	675,791	770,602	797,429	758,093	712,635	664,479	567,050	402,182	326,602
Hurricane Purchase	160,742	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395	13,395
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	5,084,680	421,050	425,060	421,050	421,050	421,050	421,050	409,020	429,070	429,070	429,070	429,070	429,070
Milican Solar	2,646,179	68,661	138,221	204,961	257,983	306,199	333,290	375,334	331,656	266,914	174,771	111,940	76,250
Milford Solar	7,081,219	358,636	412,994	609,192	677,611	796,634	839,927	747,990	720,080	671,702	541,717	394,020	310,716
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	1,795,505	82,013	91,830	136,171	171,397	203,430	221,430	249,362	220,343	177,331	116,113	74,370	51,717
Rock River Wind	3,949,010	647,624	502,957	528,679	435,960	284,843	262,621	181,185	193,222	262,771	490,382	158,766	-
Sigurd Solar	2,905,571	-	-	-	-	-	23,671	660,236	605,234	565,052	458,516	322,228	270,634
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,662,796	2,790,663	1,806,921	2,135,557	1,618,738	1,425,615	1,202,984	807,052	950,561	1,186,424	1,734,559	2,352,376	2,651,346
Top of the World Wind	40,686,138	5,436,527	3,612,759	4,244,151	3,270,658	2,907,364	2,399,806	1,720,417	1,872,120	2,296,841	3,513,203	4,491,632	4,920,662
Tri-State Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
West Valley Toll	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek Wind	10,259,065	760,539	888,633	1,132,686	1,040,512	787,596	844,716	669,522	637,857	752,718	827,852	962,861	953,573
Long Term Firm Purchases Total	197,183,561	19,425,256	16,311,261	17,984,592	16,223,533	15,215,276	14,999,759	14,625,854	14,318,208	15,066,368	16,948,509	17,376,932	18,688,012
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	2,459,726	215,701	236,633	267,245	312,697	302,769	244,243	166,228	138,407	130,335	133,735	138,107	173,627
QF Idaho	8,526,070	665,205	622,486	675,919	549,840	791,695	853,072	804,323	706,952	676,893	710,906	692,910	775,869
QF Oregon	50,659,824	2,918,983	3,102,799	4,070,906	5,035,956	5,468,588	5,691,241	5,542,450	5,239,793	4,548,585	3,590,005	2,663,496	2,787,021
QF Utah	11,686,984	799,972	834,747	994,336	1,035,869	1,137,833	1,155,642	1,078,323	1,069,390	1,006,203	958,094	845,641	770,935
QF Washington	208,630	-	-	-	3,598	16,682	34,292	47,832	51,603	41,039	13,584	-	-
QF Wyoming	149,045	14,566	13,067	14,455	11,422	10,419	8,672	12,538	12,397	9,613	12,059	12,545	17,290
Biomass One QF	14,325,868	1,137,736	1,170,257	1,267,946	1,426,566	928,933	496,148	1,441,224	1,430,184	1,394,481	1,437,697	1,443,413	751,283
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	119,066	3,390	6,084	5,901	4,769	4,661	7,241	17,585	19,050	24,343	12,375	6,980	6,686
Enterprise Solar I QF	12,563,411	617,060	756,870	980,643	1,117,038	1,257,240	1,382,198	1,554,604	1,501,679	1,181,692	957,986	710,651	545,749
Escalante Solar I QF	11,601,502	565,498	685,084	883,730	1,015,842	1,191,044	1,306,249	1,436,464	1,391,659	1,094,914	874,125	648,324	508,570
Escalante Solar II QF	10,921,713	531,489	645,513	832,362	955,502	1,126,572	1,235,898	1,359,761	1,304,268	1,031,738	818,007	606,453	474,150
Escalante Solar III QF	10,520,640	517,551	627,997	806,129	929,679	1,098,975	1,206,563	1,321,201	1,268,974	1,003,181	750,305	555,442	434,642
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,399,980	515,184	843,295	749,871	802,885	485,845	529,260	630,392	591,216	751,568	738,975	881,157	880,334
Foote Creek III Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	10,913,761	548,826	618,770	895,198	990,554	1,158,651	1,258,453	1,338,832	1,261,328	978,568	810,799	585,874	467,909
Granite Mountain West Solar QF	7,220,477	363,517	409,549	593,815	657,017	766,608	830,760	887,222	834,460	645,109	536,218	387,167	309,035
Iron Springs Solar QF	11,200,371	634,276	666,108	897,183	1,017,893	1,130,820	1,283,100	1,346,598	1,318,721	1,006,219	817,161	582,281	500,011
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,674,740	1,007,477	917,570	1,126,955	897,120	856,897	745,979	673,722	567,152	616,686	799,252	709,690	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,916,080	1,397,705	1,044,898	869,816	693,034	479,607	498,327	410,860	440,933	454,827	672,574	927,984	1,025,515
Mountain Wind 2 QF	13,895,033	2,038,485	1,566,199	1,352,529	1,078,715	750,861	890,296	761,455	734,168	757,712	1,009,557	1,435,299	1,519,756
North Point Wind QF	18,786,576	1,081,867	1,817,411	1,672,826	1,801,611	1,084,057	1,202,040	1,464,551	1,465,394	1,786,186	1,717,960	1,871,542	1,821,132
Oregon Wind Farm QF	12,468,790	729,863	971,742	1,115,635	1,312,368	1,260,505	1,201,740	1,261,216	1,114,406	919,426	735,727	801,716	1,044,447
Pavant II Solar QF	4,310,019	177,389	225,179	346,901	399,215	454,358	476,933	558,197	543,942	425,101	330,218	205,953	166,635
Pioneer Wind Park I QF	10,668,383	1,307,976	927,722	1,190,414	907,777	706,052	651,560	651,076	681,633	452,761	823,624	1,265,841	1,101,946
Power County North Wind QF	5,460,338	415,705	548,470	525,351	519,896	350,950	344,576	370,353	360,112	380,493	511,430	530,622	602,381
Power County South Wind QF	4,865,045	367,049	482,868	474,030	482,998	302,560	306,289	327,761	335,462	336,896	447,464	479,428	522,241
Roseburg Dillard QF	1,042,678	52,652	45,323	49,453	117,831	106,620	104,258	164,486	131,433	66,116	76,189	75,916	52,402
Sage I Solar QF	2,270,456	80,679	79,891	190,158	206,003	234,995	262,709	337,883	333,611	208,547	155,711	104,870	75,399
Sage II Solar QF	2,272,891	80,764	79,986	190,360	206,223	235,208	263,006	338,244	333,976	208,784	155,870	105,000	75,469
Sage III Solar QF	1,870,483	68,007	66,563	157,054	167,907	192,623	214,874	275,730	272,050	172,117	130,624	88,886	64,050
Spanish Fork Wind 2 QF	2,754,893	217,428	177,317	204,533	160,626	154,092	210,749	289,636	315,766	271,043	242,505	250,579	260,620
Sunnyside QF	30,904,807	2,757,966	2,577,196	2,680,631	1,719,211	2,720,081	2,750,586	2,752,683	2,714,248	2,577,478	2,367,927	2,749,169	2,537,628
Sweetwater Solar QF	7,797,376	259,240	374,746	567,022	689,492	814,366	985,566	1,121,979	1,038,739	815,928	628,052	300,112	202,134
Tesoro QF	299,767	50,859	22,516	27,152	24,386	45,902	8,670	11,194	17,560	15,953	18,144	18,180	39,251
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,452,878	411,976	477,957	625,721	834,509	860,254	911,132	1,042,848	998,463	794,907	672,624	450,022	372,466
Utah Pavant Solar QF	5,611,720	208,301	240,534	410,490	470,172	563,656	662,527	772,097	721,480	602,883	450,433	279,646	229,501
Utah Red Hills Solar QF	11,565,119	484,032	621,327	787,698	1,034,405	1,204,547	1,240,486	1,530,453	1,463,983	1,326,491	812,004	594,449	465,244
Qualifying Facilities Total	335,365,139	23,244,375	24,504,675	28,500,365	29,590,624	30,255,524	31,455,334	34,102,001	32,724,591	28,714,814	25,929,922	24,005,344	22,337,570
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(373,959)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)	(31,163)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,136,095	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008	178,008
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,762,136	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845	146,845
Total Long Term Firm Purchases	534,310,836	42,816,475	40,962,780	46,631,801	45,961,002	45,617,645	46,601,937	48,874,701	47,189,644	43,928,027	43,025,276	41,529,121	41,172,427

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	1,094,400	360,000	345,600	388,800	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	9,434,282	281,484	816,220	1,244,702	453,644	322,282	1,425,102	1,389,787	1,208,360	673,983	114,725	110,464	1,393,529
Four Corners	16,897,467	1,200,558	2,818,880	3,528,287	1,986,636	851,095	89,282	146,158	493,879	1,320,265	1,155,108	1,369,761	1,937,557
Mead	5,190,983	219,078	466,364	370,617	265,777	323,420	351,704	969,326	264,126	371,135	459,020	678,005	452,410
Mid Columbia	68,268,627	4,139,075	3,242,604	1,369,052	2,313,372	10,893,444	7,183,584	15,906,931	13,285,655	3,013,219	1,280,929	1,707,562	3,933,201
Mona	9,992,776	1,306,811	867,955	178,944	488,856	493,672	27,494	1,078,296	946,763	949,130	1,174,806	1,164,648	1,315,400
NOB	13,024,374	864,832	915,796	660,012	981,779	267,714	474,495	2,228,662	2,487,994	1,142,351	242,011	949,795	1,808,933
Palo Verde	1,150,203	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850	95,850
EIM Imports/Exports	(64,594,041)	(3,477,483)	(3,102,409)	(8,578,822)	(8,746,296)	(8,972,657)	(3,177,393)	(6,964,351)	(7,193,600)	(4,914,121)	(2,979,604)	(2,911,632)	(3,575,674)
Emergency Purchases	520,874	424	750	251,658	136,693	45,864	3,987	56,102	481	67	24,137	711	-
Total System Balancing Purchases	59,885,544	4,630,629	6,122,010	(879,700)	(2,023,687)	4,320,685	6,474,106	14,906,762	11,589,507	2,651,880	1,566,982	3,165,164	7,361,207
Total Purchased Power & Net Interc	600,690,780	48,257,104	47,880,391	46,590,902	44,387,315	50,388,330	53,526,043	64,231,462	59,229,151	47,029,906	45,042,258	45,144,285	48,983,634

Wheeling & U. of F. Expense													
Firm Wheeling	144,697,684	11,749,372	11,482,343	11,451,463	10,034,554	9,720,807	16,198,114	11,657,890	11,684,246	12,376,159	12,210,595	12,829,755	13,302,386
C&T EIM Admin fee	2,022,748	153,010	131,133	172,440	211,710	248,077	216,704	172,436	135,045	153,613	170,764	127,508	130,308
ST Firm & Non-Firm	30,393	8,032	2,366	803	-	20	666	5,204	4,982	3,613	1,130	1,818	1,758
Total Wheeling & U. of F. Expense	146,750,824	11,910,414	11,615,842	11,624,706	10,246,264	9,968,904	16,415,485	11,835,530	11,824,272	12,533,385	12,382,488	12,959,081	13,434,452
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	-	-	-	-	-	-	-	-	-	-	-	-	-
Colstrip	15,189,735	1,782,525	1,424,501	1,318,024	963,508	838,704	1,034,344	1,577,600	1,569,277	1,173,339	513,140	1,482,927	1,511,845
Craig	16,859,969	1,493,436	1,337,931	1,418,923	1,293,890	1,416,942	1,187,805	1,521,572	1,637,126	1,327,347	1,421,111	1,314,012	1,489,873
Dave Johnston	49,911,159	4,724,454	4,360,909	3,625,199	3,047,223	3,300,576	3,667,705	4,771,042	5,227,608	4,469,050	4,449,688	3,796,022	4,471,682
Hayden	14,706,480	1,397,927	1,198,893	995,646	1,014,078	1,014,757	1,326,435	1,321,986	1,225,980	1,329,757	1,212,614	1,322,376	1,346,030
Hunter	93,768,329	11,786,622	9,348,741	6,950,045	3,715,810	4,739,883	5,828,742	8,872,928	8,010,343	6,487,735	5,887,233	10,235,310	11,904,936
Huntington	99,698,837	11,731,837	9,584,631	8,453,741	5,354,501	4,777,665	5,479,369	10,035,555	9,831,446	7,546,122	5,921,391	8,485,425	12,497,154
Jim Bridger	209,704,601	16,250,562	16,830,219	18,961,498	13,739,064	10,461,240	15,356,324	24,350,400	23,879,296	18,714,470	18,002,871	17,337,594	15,821,064
Naughton	77,018,796	7,573,959	6,782,498	6,851,646	4,927,856	4,373,120	5,842,501	6,963,124	7,115,510	7,017,292	6,229,835	6,676,167	6,665,288
Wyodak	25,770,686	2,529,932	2,419,392	1,895,341	1,356,060	2,099,656	1,948,623	2,723,586	2,563,907	2,385,463	2,290,068	2,023,539	1,535,118
Total Coal Fuel Burn Expense	602,628,592	59,271,254	53,287,715	50,470,065	35,411,989	33,022,544	41,671,847	62,137,793	61,060,493	50,450,575	45,927,952	52,673,374	57,242,991
Gas Fuel Burn Expense													
Chehalis	46,626,229	5,218,443	1,829,937	3,244,262	2,356,707	3,551,746	2,883,763	4,658,620	4,756,101	4,557,374	5,319,764	2,897,663	5,351,849
Currant Creek	39,664,652	1,338,872	817,861	1,782,405	2,657,650	2,860,523	4,218,020	4,638,824	4,128,433	4,409,529	4,313,083	4,356,835	4,142,616
Gadsby	3,759,815	-	102,758	204,046	77,285	83,671	255,780	714,416	692,813	398,423	250,763	351,861	627,999
Gadsby CT	1,687,860	9,641	31,960	45,743	15,115	17,708	64,715	350,346	298,062	135,942	124,212	141,289	453,127
Hermiston	22,517,661	2,149,713	1,578,406	1,290,632	1,879,819	935,346	1,168,672	2,046,301	2,241,483	2,186,304	2,385,181	2,522,510	2,133,296
Lake Side 1	55,157,156	3,942,458	3,209,965	3,352,655	4,213,087	4,621,639	4,855,078	5,739,350	5,896,729	5,425,244	4,741,359	4,759,322	4,400,271
Lake Side 2	53,691,415	5,428,615	4,288,358	4,136,432	4,358,945	3,830,085	4,830,794	4,761,506	4,794,580	3,851,109	3,932,704	3,992,455	5,485,831
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	22,964,296	2,803,912	2,016,812	1,386,254	2,377,787	2,548,484	2,035,304	1,679,789	1,489,963	1,015,569	1,838,916	1,394,864	2,376,641
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	246,069,085	20,891,654	13,876,058	15,442,428	17,936,396	18,449,203	20,312,124	24,589,151	24,298,163	21,979,494	22,905,984	20,416,800	24,971,629
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	16,779,163	107,958	574,350	2,058,478	1,780,200	1,935,640	1,733,700	1,348,578	1,323,855	1,392,075	2,341,585	1,468,350	714,395
Clay Basin Gas Storage	(29,961)	(132,136)	(104,285)	(29,237)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(25,669)	(104,331)
Pipeline Reservation Fees	36,317,735	3,030,219	2,915,834	3,039,201	2,993,761	3,034,107	3,009,667	3,074,081	3,071,440	3,015,726	3,050,970	3,014,404	3,068,326
Total Gas Fuel Burn Expense	299,136,021	23,897,695	17,261,957	20,510,869	22,762,599	23,471,193	25,107,733	29,064,052	28,745,701	26,439,537	28,350,781	24,873,885	28,650,019

Other Generation													
Blundell	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Pryor Mountain Wind	-												
Rolling Hills Wind	-												
Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Generation	4,497,520	448,014	356,628	418,112	407,272	415,782	384,237	373,294	385,568	401,632	407,038	225,018	274,926
Net Power Cost	1,430,525,312	121,399,660	114,488,460	117,199,543	103,047,156	106,138,525	122,355,032	142,266,638	134,158,821	113,280,306	111,580,702	117,437,322	127,173,146