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Writer's E-Mail Address: bkeating@gunster.com

February 25, 2011

BY HAND DELIVERY

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: **Docket No. 110041-EI - Petition for approval of Amendment No. 1 to generation services agreement with Gulf Power Company, by Florida Public Utilities Company.**

Dear Ms. Cole:

Enclosed for filing in the referenced Docket, please find the original and seven (7) copies of Florida Public Utilities Company's Responses to FPSC Staff's First Set of Data Requests to FPUC. We are also submitting, under separate cover, the confidential portions of the Company's response, along with a Request Confidential Classification of Attachment A. Service has been made in accordance with the attached certificate.

Thank you for your assistance with this filing. If you have any questions whatsoever, please do not hesitate to let me know.

Sincerely,

Beth Keating

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 618
Tallahassee, FL 32301
(850) 521-1706

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FLORIDA PUBLIC UTILITIES COMPANY'S
RESPONSES TO
STAFF'S FIRST DATA REQUESTS
DOCKET NO. 110041-EI

1a. Please describe FERC's Market Based Rate Tariff and explain FERC's jurisdiction regarding the Agreement for Generation Services and Amendment No. 1.

Company Response: FERC's Rule, issued June 21, 2007, on Market Based Rates codifies its existing standards for market-based rates for sales of electric energy, capacity, and ancillary services. The rule provides a rigorous up-front analysis of whether market-based rates should be granted, including protective conditions and ongoing filing requirements in all market-based rate authorizations, reinforcing FERC's ongoing oversight of market-based rates. FERC analyzes whether a market-based rate seller or any of its affiliates has market power in generation or transmission and, if so, whether such market power has been mitigated. If a seller is granted market-based rates, as is Gulf Power, the authorization is conditioned on: affiliate restrictions governing transactions and conduct between power sales affiliates where one or more of those affiliates has captive customers; a requirement to file post-transaction electric quarterly reports containing specific information about contracts and transactions; a requirement to file any change of status; and a requirement for all large sellers to file triennial updates. In addition, FERC, through its ongoing oversight of market-based rate authorizations and market conditions, may take steps to address seller market power or modify rates.

FERC has reviewed Gulf Power's filing for Market-Based Rate Tariff and has approved its request to implement said tariff. As such, FERC does not have specific oversight of the Agreement for Generation Services or Amendment No. 1, per se, but instead, FERC, through the process noted above, has granted Gulf Power market-based rate authority. As further defined in the Agreement for Generation Services, Section 9.3, both parties acknowledge that it is a market-based contract and is not contingent on FERC acceptance. Section 9.3 also states that "Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, the Parties waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way."

1b. Given FERC jurisdiction, please describe FPUC's options to improve its negotiation position with Gulf regarding the Agreement for Generation Services and this amendment.

Company Response: As described in the Company's response to Question 1a, FERC's jurisdiction over granting Gulf Power to implement market-base rates does not improve or degrade the Company's negotiation position regarding the

Agreement for Generation Services or the Amendment. FERC has determined that Gulf Power does not have market power and, as such, any contracts negotiated are not subject to FERC acceptance.

2. Regarding FERC's jurisdiction and FPUC's options, please explain:

   a. FERC's standard, policy, or tariff that governed FPUC's power supply agreement with Gulf Power that existed before 2008.

Company Response: The Company believes that FERC's market-based rate policy and standards that existed at the time that FPUC and Gulf Power executed the previous purchased power agreement in 1996 was essentially the same policy that is currently effective. The June 21, 2007 FERC Rule referenced in the Company's response to Data Request No. 1 merely codified FERC's existing policy and standards for market-based rates.

   b. The comparison between the current FERC standard – the Market Based Rate Tariff – and the standard that governed the negotiation of FPUC's power supply agreement with Gulf Power that existed before 2008.

Company Response: See the Company's response to Data Request 2b, above. The most significant difference is the 1996 agreement included transmission service which was not included in the current agreement.

3. In its petition, FPUC requests that the Commission "Review and approve Amendment No. 1 to the Generation Services Agreement between FPUC and Gulf Power Company as being a reasonable and prudent agreement for purposes of purchased power…"

   a. Please define and explain exactly what FPUC means by "Review and approve" and cite applicable Commission jurisdiction and statute.

Company Response: For these purposes, FPUC defines "review and approve" to mean that FPUC seeks a Commission determination that it was prudent for FPUC to enter into Amendment No. 1, and that the associated costs are appropriate for recovery through the Fuel and Purchased Power Cost Recovery Clause, consistent with the Commission's prior decision approving the underlying Agreement for Generation Services (PPA).

In approving similar contracts in the past, the Commission has relied upon its authority in Sections 366.04, 366.041, 366.05, 366.06, and 366.076, Florida Statutes.

By Order No. PSC-07-0476-PAA-EI, the Commission approved FPUC's current purchase power agreement (PPA) with Gulf Power Company.

Therein, the Commission stated that, ". . . [W]e find that the agreement is approved and that the reasonable and prudently incurred costs arising from exercise of the contract are appropriate for purposes of cost recovery through the fuel and purchased power cost recovery clause." Order No. PSC-07-0476-PAA-EI, issued June 6, 2007, in Docket No. 070108-EI.

The PPA had been submitted to the Commission for approval in accordance with Section 9.4.1 of the PPA, which called for FPUC to seek approval by the Commission for FPUC to "recover from its Northwest Division customers all payments required to be made to Gulf Power under this Agreement. . . ." There is also a similar, separate provision of the PPA, Section 17.10, which requires that any Amendments, such as the one that has been submitted in the current Docket, receive all "acceptances or approvals of Governmental Authorities with competent jurisdiction necessary for the effectiveness thereof." Amendment No. 1 to the PPA has been submitted for approval in the instant proceeding in accordance with this provision, as well as the express language contained in Section B. 1. of the Amendment itself, which mandates that FPUC make a filing with the Commission by January 31, 2011, seeking approval of Amendment No. 1, and that FPUC must diligently endeavor to obtain final approval of Amendment No. 1 by July 31, 2011.

In the past, the Commission has undertaken to approve purchased power agreements for purposes of cost recovery. Specifically, in Docket No. 041393-EI, the Commission approved two power sales agreements between Progress Energy and Southern Company. In the Order, the Commission specifically determined that the agreements were approved for cost recovery purposes, and that entering into the agreements was reasonable and prudent. Order No. PSC-05-0699-FOF-EI at p. 11, issued June 28, 2005, in Docket No. 041393-EI. In that same Order, the Commission stated that its jurisdiction to address Progress Energy's petition arose from Sections 366.04, 366.05, and 366.06, Florida Statutes. *Id.* at p. 2.

Likewise, in Docket No. 090169-EI, the Commission approved a purchased power agreement between Gulf Power and Shell Energy. In approving the contract, the Commission stated that it derived its authority from Sections 366.04, 366.041, and 366.076, Florida Statutes. Although the PPA addressed in the case was not with a renewable energy provider, the Commission employed Rule 25-17.0832(3), F.A.C., as a viable guideline for use in analyzing the contract. Upon review, the Commission approved the contract and authorized recovery of the associated costs through the Purchased Power Capacity and Fuel and Purchased Power Cost Recovery Clauses. Order No. PSC-09-0534-PAA-EI, issued August 3, 2009.

In Docket No. 041414-EI, the Commission considered long-term fuel supply and transportation contracts (which are somewhat similar to purchased power contracts) between Progress Energy and BG LNG Services, Southern Natural Gas Company, and FGT. The Commission noted in the Order that Progress Energy was not required to seek approval of the contracts by Commission rule or order, but that approval had been sought consistent with the contract terms. Order No. PSC-05-0721-FOF-EI at p. 2, issued July 5, 2005. The Commission stated that its jurisdiction to proceed arose from Chapter 366, Florida Statutes. *Id.* In rendering its decision, the Commission specifically limited its approval of the contracts to four areas: 1)the market-based pricing index and basis used for gas pricing; 2) the negotiated transportation rates from SONAT and FTG; 3) the volume of gas that Progress Energy would accept under the re-gasified LNG contract; and 4) the duration of the contracts. The Commission found that approval of these terms was necessary and appropriate because approval was a condition precedent in the contracts themselves and avoided regulatory uncertainty associated with the 20-year term of the contracts. *Id.* at pgs. 6 and 7. The Commission also decided to, ". . . permit recovery of these [contract] costs subject to a finding that PEF has managed the contracts in a reasonable and prudent manner." *Id.* at p. 7.

In another somewhat similar case, Docket No. 060793-EI, the Commission considered Progress Energy's request for approval of its long-term fuel and transportation contracts with the Southeast Supply Header Pipeline (SESH). In that case, Progress requested not only a determination of the prudence of entering into the contracts for purposes of cost recovery, but also specific approval of the terms and conditions of the contracts themselves. The Commission denied Progress's request for approval of the specific terms and conditions of the contract, because the Commission did not believe that the same level of risk of regulatory uncertainty was associated with the SESH contracts as had been attached to the contracts addressed in Docket NO. 041414-EI. Order No. PSC-07-0294-PAA-EI at p. 3. Nonetheless, the Commission also determined that Progress had prudently entered into the contracts, and consequently, approved recovery of the associated costs through the fuel and purchased power clause. *Id.* at p. 6.

b. Section B of Amendment No. 1 concerns regulatory approval. In negotiating Section B, which party wanted the provisions of Section B?

Company Response: Both parties acknowledged that the Agreement for Generation Services, in Sections 9.4 and 17.10, required initial approval of the Commission and were desirous of the same treatment for the Amendment in order to avoid regulatory uncertainty.

c. Does Section B allow any modifications by the Commission to Amendment No. 1 or to the Agreement for Generation Services? Please explain.

Company Response: The Commission authority with respect to this Amendment is not affected by the language in Section B of Amendment No. 1. However, in accordance with Section B, if the Commission does undertake to modify the terms and conditions of Amendment No. 1, then Amendment No. 1 is immediately terminated. The parties have negotiated a carefully crafted and balanced amendment to the Agreement for Generation Services and believe that any modification will upset the commensurate economic benefits for both parties.

d. Was FPUC's power supply agreement with Gulf Power Company that existed before 2008 approved by the Commission?

Company Response: No, the previous power supply agreement with Gulf Power Company was not approved by the Commission.

e. Why does FPUC want the Commission to approve Amendment No. 1?

Company Response: The Company seeks Commission approval of Amendment No. 1 for two primary reasons: 1) a portion of the overall reductions of the Capacity Purchase quantity provides savings which serve as the cost-based justification for the recently approved Time-of-Use (TOU) and Interruptible rates; and 2) a portion of the overall reductions also provides savings for non-participating Northwest Division customers compared to the existing Agreement for Generation Services over the remaining term of the agreement. Additional provisions of the Amendment also provide for a reduction of the Capacity Purchase quantity in 2018 and 2019 if the City of Marianna does not continue to receive service from the Company.

f. If the Commission does not approve Amendment No. 1, what will be the result?

Company Response: If the Commission does not approve Amendment No. 1 or seeks to modify Amendment No. 1, then the amendment will be immediately terminated.

4. Amendment No. 1 extends the term of the current Agreement for Generation Services by two years – from the end of 2017 to the end of 2019. Escalation factors for the capacity charges extend for the two additional years.

   a. What is the basis and reason for the escalation of the capacity charges?

   Company Response: The capacity charges for 2018 and 2019 were negotiated. The capacity charges are one of many items that were negotiated, with the result being a carefully balanced amendment which provides for significant savings for the Company from 2011 through 2019, while providing benefits to Gulf Power through the escalation of the capacity charges and the extension period of the Agreement for Generation Services.

   b. Please explain the escalation for the capacity charges in 2018 and 2019.

   Company Response: The escalation of the capacity charges in 2018 and 2019 are consistent with the escalation of the capacity charges, year over year, contained in the Commission-approved Agreement for Generation Services. The capacity charges for 2018 and 2019 were negotiated as one item in the overall Amendment No. 1 contract modifications.

   c. Provide a copy of any analysis that FPUC did to determine the reasonableness of this escalation.

   Company Response: See Attachment A. (This attachment is confidential)

5. Please show the effect this amendment would have on the 1000kWh monthly residential bill for 2010 and for 2011. Include all calculations and assumptions. Please show the estimated effect for a residential customer using TOU rates and for a residential customer not using TOU rates. In presenting this response, use the Schedule E-10 format and make the comparison between the bill with the amendment and the bill with the current rates.

   Company Response: See Attachment B.

6. Under the current Agreement for Generation Services and under Amendment No. 1, please explain what FPUC will do to lower the cost of power to its Northwest Division customers.

   Company Response: The Company is currently evaluating filing for a mid-course correction that would immediately pass through savings to Northwest Division customers. The existing Agreement, and the proposed Amendment, is a "full requirements" contract, and as such, the Company is restricted in purchasing power for other entities (there are a couple of very specific exceptions, as noted in Section 3.4 of the Agreement).

7. Will FPUC be able to shop for lower cost alternatives that could be implemented before 2019? Please explain.

Company Response: No, as explained in the Company's response to Data Request 6, the Agreement is a "full requirements" contract that restricts the Company's ability to shop for lower cost alternatives.

8. Will the existence of the current agreement and the amendment preclude FPUC from finding and implementing lower cost alternatives before 2019? Please explain.

Company Response: For the reasons set forth above, the Company's ability to implement lower cost alternatives prior to 2019 will be very restricted. Nevertheless, there is always a possibility that opportunities may arise at some future date in which FPUC and Gulf may wish to explore other modifications to the PPA. Likewise, there may be as yet unanticipated regulatory changes that could improve the Company's ability to obtain lower cost alternatives. For instance, if the Company were allowed to implement an "open access" tariff, which could enable it to exit the merchant function, then it might be possible for customers to obtain lower cost alternatives in the open market, depending upon the level of market prices at the time. However, as it currently stands, the existing arrangement is the most viable, prudent option available to the Company.

9. Explain FPUC's analysis of its market power for negotiating power supply agreements for its Northwest Division? **Please provide all related documents.**

Company Response: FPU has conducted no study - and knows of no study - of its market power (as a buyer) within the market for generation services in the Southeast region (SERC). In view of the small size of the Northwest Division - approximately 90 MW - compared to the sheer size of the SERC region (installed capacity of 231,000 MW), it is highly unlikely that FPU could in any way influence, through the exercise of market power, regional wholesale power prices.

10. Please provide FPUC's actual annual system peak demand (non-coincident peaks) from 2004 through 2010 and demonstrate how these values are used to determine the system billing demand for 2007, 2008, 2009 and 2010 based on contract provisions of the Agreement.

Company Response: See Attachment C. Please note that the system billing demand for 2007 is not shown, as it was calculated in accordance with the previous contract between FPUC and Gulf. The current Agreement became effective January 1, 2008.

11. Please provide the annual billing demand from 2011 through 2017 based on provisions of the Agreement assuming FPUC's annual non-coincident peaks rises steadily from the 2010 level to 85 MW in 2014, then rises 5 percent per year after that.

    Company Response: See Attachment D.

12. Please provide the annual billing demand from 2011 through 2017 based on provisions of the Amendment assuming FPUC's annual non-coincident peaks rises steadily from the 2010 level to 85 MW in 2014, then rises 5 percent per year after that.

    Company Response: See Attachment E.

13. What is the difference between the current wholesale market conditions for FPUC, when FPUC was negotiating Amendment No. 1, compared with the time when FPUC was negotiating the Agreement for Generation Services in 2006, if any?

    Company Response: The most significant difference in market conditions is the economy and its impact on the availability of generation capacity for the wholesale market. When the Agreement for Generation Services was negotiated in 2006, the economy and growth were strong and electric generators were planning to build additional units to serve the anticipated growth requirements. The current market conditions are significantly different; the economy is in recession, growth is virtually non-existent and generation capacity appears to be plentiful. As noted herein, FPUC is locked into this 2006 Agreement for Generation Services through 2017 with no ability to purchase power elsewhere without a significant penalty. Based upon the significant penalty, the options for negotiating a new agreement were severely limited to amending the current agreement. This resulted in the proposed Amendment No. 1.

14. Are there any additions to transmission capacity (recent or planned for the next 8 years) implemented or planned by any transmission operators (e.g. Southern Company affiliates, Alabama Electric Cooperative or FPUC) that would be relatively close to FPUC's Northwest Division service area?

Company Response: No. There are currently no known transmission additions or upgrades that have the capability to impact the FPUC service territory.

a. If yes to above, has FPUC analyzed how such additions to transmission capacity could affect its ability to acquire power at a lower cost than its current agreement or the amended agreement?

Company Response: Not applicable.

b. If yes to above, what is the analysis?

Company Response: Not applicable.

15. What is FPUC's estimate of Gulf Power's profit margin on the Agreement for Generation Services as amended by Amendment No. 1? Please explain the estimate and assumptions. If FPUC did not estimate Gulf Power's profit margin for the Agreement for Generation Services as amended by Amendment No. 1, please explain why it did not make an estimate.

Company Response: FPUC, based upon available public domain information contained in Gulf Power's FERC Form 1 filings, estimated that Gulf Power's profit margins that it would obtain from the two year extension and capacity charge increases were offset by the reduction of the Capacity Purchase quantities negotiated over the remaining life of the agreement. In other words, the Company has estimated that the benefits to Gulf Power and to FPUC are neutral as a result of Amendment No. 1.

16a. Does FPUC have any recourse with FERC regarding its Agreement for Generation Services with Gulf Power and its negotiations?

Company Response: The Agreement for Generation Services severely limits the Company's ability for any recourse with FERC through the following language contained in Section 9.3, which states that "Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, the Parties waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way."

16b. Can FPUC request FERC review the Agreement for Generation Services and Amendment No. 1?

Company Response: See Company's response to Data Request 16a.

16c. If yes to above, did FPUC consider asking FERC to review the Agreement for Generation Services and Amendment No. 1.

Company Response: Not applicable.

17. Please explain FPUC's understanding of how FERC's Market Based Rate Tariff governs or affects the negotiation of the Agreement for Generation Services and Amendment No. 1.

Company Response: See the Company's responses to Data Request Nos. 1 and 2 above.

Docket No. 110041-EI

Company's Responses to First Set of Data Requests

Attachment A - Response to Question 4c

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capacity Rates	[redacted]									
Percent Increase	[redacted]									
Average Annual Increase (Orig Term)								[redacted]		

Docket No. 110041-EI
Company's Responses to First Set of Data Requests
Attachment B - Response to Question 5

For Monthly Usage of 1,000 KWH

2010	Standard Usage		TOU	
	Unit Cost	Amount	Unit Cost	Amount
Customer Charge ($)	$ 12.00	$ 12.00	$ 12.00	$ 12.00
Energy Charge ($/kwh)	$ 0.01958	$ 19.58	$ 0.01958	$ 19.58
Fuel Recovery Factor ($/kwh)	$ 0.11927	$ 119.27		$ -
On Peak Fuel Recovery Factor ($/kwh)			$ 0.19953	$ 41.90
Off Peak Fuel Recovery Factor ($/kwh)			$ 0.07653	$ 60.46
Energy Conservation Cost Recovery ($/kwh)	$ 0.00080	$ 0.80	$ 0.00080	$ 0.80
Total Revenues***		$ 151.65		$ 134.74
TOU Savings per Month				$ 16.91

2011	Standard Usage		TOU	
	Unit Cost	Amount	Unit Cost	Amount
Customer Charge ($)	$ 12.00	$ 12.00	$ 12.00	$ 12.00
Energy Charge ($/kwh)	$ 0.01958	$ 19.58	$ 0.01958	$ 19.58
Fuel Recovery Factor ($/kwh)	$ 0.11553	$ 115.53		$ -
On Peak Fuel Recovery Factor ($/kwh)			$ 0.19953	$ 41.90
Off Peak Fuel Recovery Factor ($/kwh)			$ 0.07653	$ 60.46
Energy Conservation Cost Recovery ($/kwh)	$ 0.00115	$ 1.15	$ 0.00115	$ 1.15
Total Revenues***		$ 148.26		$ 135.09
TOU Savings per Month				$ 13.17

Assumptions:

On Peak KWH approx. 21% of energy consumption

***Excludes Gross Receipts and Franchise Taxes

Docket No. 110041-EI
Company's Responses to First Set of Data Requests
Attachment C - Response to Question 10

2008

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2004	69.653	2.6%	71.512
2005	74.411	2.6%	76.397
2006	74.679	2.6%	76.672
2007	79.197	2.6%	81.311

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	6.83%
	(b)	0.36%
	(c)	6.05%
		13.24%
(2)	Divided by 3	4.41%

C. Forecasted Northwest Division Annual Peak Demand

(1)	234.380	
(2)	78.127	
(3)	85.169	
		Highest Amt
or		85.169
(1)	157.983	
(2)	78.992	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	97.944	
	or			Least Amount
				97.944
	(b)	(i)	1.0541	
		(ii)	103.243	
(2)	97.944			

2008 Capacity Purchase 97.944 Highest Amount

2009

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2005	74.411	2.6%	76.397
2006	74.679	2.6%	76.672
2007	79.197	2.6%	81.311
2008	72.928	2.6%	74.875

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	0.36%
	(b)	6.05%
	(c)	-7.92%
		-1.51%
(2)	Divided by 3	-0.50%

C. Forecasted Northwest Division Annual Peak Demand

(1)	232.858	
(2)	77.619	
(3)	76.845	
		Highest Amt
or		78.093
(1)	156.186	
(2)	78.093	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	89.807	
	or			Least Amount
				89.807
	(b)	(i)	1.0050	
		(ii)	98.434	
(2)	97.944			

2009 Capacity Purchase 97.944 Highest Amount

2010

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2006	74.411	2.6%	76.397
2007	74.679	2.6%	76.672
2008	79.197	2.6%	81.311
2009	73.203	2.6%	75.157

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	0.36%
	(b)	6.05%
	(c)	-7.57%
		-1.16%
(2)	Divided by 3	-0.39%

C. Forecasted Northwest Division Annual Peak Demand

(1)	233.140	
(2)	77.713	
(3)	77.108	
		Highest Amt
or		78.234
(1)	156.468	
(2)	78.234	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	89.969	
	or			Least Amount
				89.969
	(b)	(i)	1.0061	
		(ii)	98.541	
(2)	97.944			

2010 Capacity Purchase 97.944 Highest Amount

2011

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2007	74.679	2.6%	76.672
2008	79.197	2.6%	81.311
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	6.05%
	(b)	-7.57%
	(c)	-4.95%
		-6.47%
(2)	Divided by 3	-2.16%

C. Forecasted Northwest Division Annual Peak Demand

(1)	227.906	
(2)	75.969	
(3)	72.723	
		Highest Amt
or		73.298
(1)	146.595	
(2)	73.298	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	84.293	
	or			Least Amount
				84.293
	(b)	(i)	0.9884	
		(ii)	96.808	
(2)	97.944			

2011 Capacity Purchase 97.944 Highest Amount

2011

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2007	79.197	2.6%	81.311
2008	72.928	2.6%	74.875
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	-7.92%
	(b)	0.38%
	(c)	-4.95%
		-12.49%
(2)	Divided by 3	-4.16%

C. Forecasted Northwest Division Annual Peak Demand

(1)	221.470	
(2)	73.823	
(3)	67.809	
		Highest Amt
or		73.298
(1)	146.595	
(2)	73.298	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	84.293	
	or			Least Amount
				84.293
	(b)	(i)	0.9684	
		(ii)	94.850	
(2)	97.944			

2011 Capacity Purchase **97.944** Highest Amount

2012

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2008	72.928	2.6%	74.875
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	0.38%
	(b)	-4.95%
	(c)	5.54%
		0.97%
(2)	Divided by 3	0.32%

C. Forecasted Northwest Division Annual Peak Demand

(1)	221.991	
(2)	73.997	
(3)	74.471	
		Highest Amt
or		74.471
(1)	146.834	
(2)	73.417	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	85.642	
	or			Least Amount
				85.642
	(b)	(i)	1.0132	
		(ii)	99.237	
(2)	97.944			

2012 Capacity Purchase **97.944** Highest Amount

2013

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	-4.95%
	(b)	5.54%
	(c)	5.25%
		5.84%
(2)	Divided by 3	1.95%

C. Forecasted Northwest Division Annual Peak Demand

(1)	226.188	
(2)	75.396	
(3)	78.365	
		Highest Amt
or		78.365
(1)	154.75	
(2)	77.375	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	90.12	
	or			Least Amount
				90.120
	(b)	(i)	1.0295	
		(ii)	100.833	
(2)	97.944			

2013 Capacity Purchase **97.944** Highest Amount

2014

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	5.54%
	(b)	5.25%
	(c)	4.99%
		15.78%
(2)	Divided by 3	5.26%

C. Forecasted Northwest Division Annual Peak Demand

(1)	238.062	
(2)	79.354	
(3)	87.922	
		Highest Amt
or		87.922
(1)	162.666	
(2)	81.333	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	101.11	
	or			Least Amount
				101.110
	(b)	(i)	1.0626	
		(ii)	104.075	
(2)	97.944			

2014 Capacity Purchase **101.110** Highest Amount

Attachment D - Page 2

2015

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	5.25%
	(b)	4.99%
	(c)	4.75%
		14.99%
(2)	Divided by 3	5.00%

C. Forecasted Northwest Division Annual Peak Demand

(1)	249.935	
(2)	83.312	
(3)	91.851	
		Highest Amt
or		91.851
(1)	170.581	
(2)	85.291	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	105.629	
	or			Least Amount
				105.629
	(b)	(i)	1.0600	
		(ii)	107.177	
(2)	101.110			

2015 Capacity Purchase **105.629** Highest Amount

2016

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269
2015	89.250	2.6%	91.632

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	4.99%
	(b)	4.75%
	(c)	5.00%
		14.74%
(2)	Divided by 3	4.91%

C. Forecasted Northwest Division Annual Peak Demand

(1)	262.213	
(2)	87.404	
(3)	96.198	
		Highest Amt
or		96.198
(1)	178.901	
(2)	89.451	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	110.628	
	or			Least Amount
				110.628
	(b)	(i)	1.0591	
		(ii)	111.872	
(2)	105.629			

2016 Capacity Purchase **110.628** Highest Amount

2017

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269
2015	89.250	2.6%	91.632
2016	93.713	2.6%	96.214

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	4.75%
	(b)	5.00%
	(c)	5.00%
		14.75%
(2)	Divided by 3	4.92%

C. Forecasted Northwest Division Annual Peak Demand

(1)	275.115	
(2)	91.705	
(3)	100.951	
		Highest Amt
or		100.951
(1)	187.846	
(2)	93.923	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	116.094	
	or			Least Amount
				116.094
	(b)	(i)	1.0592	
		(ii)	117.177	
(2)	110.628			

2017 Capacity Purchase **116.094** Highest Amount

2011

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2007	79.197	2.6%	81.311
2008	72.928	2.6%	74.875
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	-7.92%	
	(b)	0.38%	
	(c)	-4.95%	
		-12.49%	
(2)	Divided by 3	-4.16%	

C. Forecasted Northwest Division Annual Peak Demand

(1)	221.470		
(2)	73.823		
(3)	67.809		
		Highest Amt	
or		73.298	
(1)	146.595		
(2)	73.298		

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	84.293	
	or			Least Amount
				84.293
	(b)	(i)	0.9684	
		(ii)	88.125	
(2)	91.000			

2011 Capacity Purchase **91.000** Highest Amount

2012

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2008	72.928	2.6%	74.875
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	0.38%	
	(b)	-4.95%	
	(c)	5.54%	
		0.97%	
(2)	Divided by 3	0.32%	

C. Forecasted Northwest Division Annual Peak Demand

(1)	221.991		
(2)	73.997		
(3)	74.471		
		Highest Amt	
or		74.471	
(1)	146.834		
(2)	73.417		

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	85.642	
	or			Least Amount
				85.642
	(b)	(i)	1.0132	
		(ii)	92.201	
(2)	91.000			

2012 Capacity Purchase **91.000** Highest Amount

2013

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2009	73.203	2.6%	75.157
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	-4.95%	
	(b)	5.54%	
	(c)	5.25%	
		5.84%	
(2)	Divided by 3	1.95%	

C. Forecasted Northwest Division Annual Peak Demand

(1)	226.188		
(2)	75.396		
(3)	78.365		
		Highest Amt	
or		78.365	
(1)	154.75		
(2)	77.375		

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	90.12	
	or			Least Amount
				90.120
	(b)	(i)	1.0295	
		(ii)	93.685	
(2)	91.000			

2013 Capacity Purchase **91.000** Highest Amount

2014

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2010	69.581	2.6%	71.438
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	5.54%	
	(b)	5.25%	
	(c)	4.99%	
		15.78%	
(2)	Divided by 3	5.26%	

C. Forecasted Northwest Division Annual Peak Demand

(1)	238.062		
(2)	79.354		
(3)	87.922		
		Highest Amt	
or		87.922	
(1)	162.666		
(2)	81.333		

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	101.11	
	or			Least Amount
				96.697
	(b)	(i)	1.0626	
		(ii)	96.697	
(2)	91.000			

2014 Capacity Purchase **96.697** Highest Amount

2015

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2011	73.436	2.6%	75.396
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	5.25%
	(b)	4.99%
	(c)	4.75%
		14.99%
(2)	Divided by 3	5.00%

C. Forecasted Northwest Division Annual Peak Demand

(1)	249.935	
(2)	83.312	
(3)	91.851	
		Highest Amt
or		91.851
(1)	170.581	
(2)	85.291	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	105.629	
	or			Least Amount
				96.460
	(b)	(i)	1.0600	
		(ii)	96.460	
(2)	91.000			

2015 Capacity Purchase **96.460** Highest Amount

2016

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2012	77.291	2.6%	79.354
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269
2015	89.250	2.6%	91.632

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	4.99%
	(b)	4.75%
	(c)	5.00%
		14.74%
(2)	Divided by 3	4.91%

C. Forecasted Northwest Division Annual Peak Demand

(1)	262.213	
(2)	87.404	
(3)	96.198	
		Highest Amt
or		96.198
(1)	178.901	
(2)	89.451	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	110.628	
	or			Least Amount
				96.378
	(b)	(i)	1.0591	
		(ii)	96.378	
(2)	91.000			

2016 Capacity Purchase **96.378** Highest Amount

2017

A. Northwest Division Annual Peak Demand

Year	Peak Season MW	Trans Loss %	Peak Season MW
2013	81.146	2.6%	83.312
2014	85.000	2.6%	87.269
2015	89.250	2.6%	91.632
2016	93.713	2.6%	96.214

Peak Season is defined as May through September

B. Growth Rate

(1)	(a)	4.75%
	(b)	5.00%
	(c)	5.00%
		14.75%
(2)	Divided by 3	4.92%

C. Forecasted Northwest Division Annual Peak Demand

(1)	275.115	
(2)	91.705	
(3)	100.951	
		Highest Amt
or		100.951
(1)	187.846	
(2)	93.923	

D. Capacity Purchase

(1)	(a)	(i)	1.15	
		(ii)	116.094	
	or			Least Amount
				96.387
	(b)	(i)	1.0592	
		(ii)	96.387	
(2)	91.000			

2017 Capacity Purchase **96.387** Highest Amount

CERTIFICATE OF SERVICE

I HEREBY ATTEST that a true and correct copy of the foregoing has been served upon the following by U.S. Mail this 25th Day of February, 2011:

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