BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

In the Matter of the Filing of 2008 Integrated Resource Plan Rocky Mountain Power	) **DOCKET NO. 20000-346-EA-09**)))

COMMENTS OF INTERWEST ENERGY ALLIANCE

I. INTRODUCTION

Interwest Energy Alliance ("Interwest") submits the following comments related to the 2008 Rocky Mountain Power Integrated Resource Plan (the "Plan") filed with the Wyoming Public Service Commission.

Interwest is a trade association of wind and utility-scale solar energy producers and venders operating in Colorado, Wyoming, Utah, Arizona, New Mexico and Nevada. Interwest represents some of the nation's leading companies in the wind and utility-scale solar energy industries and leading regional clean energy advocate groups. Interwest's members will be affected by the Plan. Most are independent power producers with information about available energy resource and who will bid in to the Requests for Proposals used to acquire renewable resources. Interwest members support greater generation diversity, correct incentives, and fair competition to provide the many benefits of developing the most cost-effective, stable rate renewable energy projects to help serve the Company's load. Interwest has previously participated, *inter alia*, in regulatory proceedings throughout the West related to resource planning rules, rules related to renewable energy standards, rulemaking and enforcement in support of wind and solar energy generation and transmission development for renewable energy.

II. WYOMING'S INTEGRATED RESOURCE PLANNING RULE

Rule 253 "Integrated Resource Planning" states:

> Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determinates it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.

The guidelines for staff review published at the time of the rulemaking inform the consideration of the Commission. They include the following:

The Commission's review of the IRP may include, but is not limited to:

A. The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;

B. The utility's strategic goals and resource planning goals and preferred resource portfolio;

C. The utility's illustration of resource need over the near-term and the long-term planning horizons;

D. A study detailing the types of resources considered;

E. Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;

F. The environmental impacts considered;

G. Market purchases evaluation;

H. Reserve Margin analysis; and

I. Demand-side management and conservation options.

III. COMMENTS

Rocky Mountain Power has produced a generally thorough Integrated Resource Plan. The Plan includes a detailed analysis of the relevant information and is relatively easy to understand. However, Interwest members would like to encourage Rocky Mountain Power to incorporate more renewable resources, especially wind resources. The Plan fails to commit to the optimal amount of renewable resources as indicated by the modeling results. The least cost-least risk portfolio (Case 8) includes 2400 MW of wind. Instead of adopting this recommended portfolio, however, Rocky Mountain Power chose the second best portfolio, which includes less than 60% of recommended amount. Incorporating 2400 MW of wind (Case 8) is the most cost-effective and efficient portfolio.

1. Modeling Standards Are Optimized by Increased Integration of Wind Resources.

Twenty-one diverse resource portfolios were selected to reflect stochastic costs, stochastic supply reliability risk, and capital cost performance. See Table 8.1, "Portfolio Capacity Additions by Resource Type, 2009-2018, a copy of which is attached hereto as **Exhibit A;** Table 8.2, "Portfolio Capacity Additions by Resource Type, 2009-2028", a copy of which is attached hereto as **Exhibit B;** and Table 9.1, "Preferred Portfolio Summary Level, attached hereto as Exhibit C, for convenient reference. The top portfolios included significantly wind resources:

> Regarding fuel source diversity, the Case 8 portfolio has a greater proportion of renewable generation – and generation reduction in the case of Class 2 DSM – than for Case 5, particularly in the near term. On the other hand, Case 5 has a greater share of gas generation, and for the first 10 years, more reliance on generation from market purchases. By 2028, the generation mix for the two portfolios look similar. The significant difference is that Case 5 includes a clean coal resource in 2025, which Case 8 depends on much earlier wind investment to meet CO_2 and RPS compliance requirements.

IRP p. 232. The modeling results reflected varied CO_2 taxes ranging from \$20/ton to \$70/ton,[1] in part because no single CO_2 reduction compliance approach has emerged as a consistent front-runner for adoption. *IRP p. 143.* The *\$45/ton tax represents a reasonable intermediate value and* starting point at which significant changes in resource mix over the long term can be expected to occur. IRP p. 143. Case 8, Case 5 and Case 9 rank highest based on the average of the CO_2 tax results. IRP pp.194–195; Table 8.6. Case 8, Case 5 and Case 9 rank the highest in line with the stochastic mean PVRR values. IRP p. 197; See Table 8.3.

Case 8 ranked lowest in cost exposure for carbon dioxide tax outcomes. See Table 8.11. In other words, maximum projected loss is lowest because there is zero cost exposure if carbon is taxed at \$56/ton with no probability weights applied.

2. Present Value Revenue Requirements Also Validate Higher Levels of Stable-Priced Renewable Energy Resources.

A measure of the risk-adjusted PVRR (Present Value Revenue Requirements) by *portfolio indicates Case 8 prevails.*[2] *See Table 8.0 (insert);* IRP p. 197. The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 cost adders. Total resource cost includes all the costs to the utility and to customers for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand side resources as evaluated in the IRP. See IRP p. 170.

Portfolio mixes represented in Case 2, Case 5, Case 8 and Case 9 performed best overall under the PVRR standard. The preference scores vary across CO_2 tax levels.[3] IRP p. 229. Case 2 performed best with tax levels below \$40, while Case 8 portfolio scores best at levels \$50 and above. Both Case 5 and Case 8 are "equally strong contenders" to be the 2008 IRP preferred portfolio. The main difference between the two portfolios is that Case 8 includes 1,150 and more wind in the first ten years (600 MW more overall) and lacks a gas peaking resource in 2016.

[1] IRP, p.194.

[2] The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2009 dollars as of January 1, 2009. IRP p. 170.

[3] Rocky Mountain Power dropped Cases 2 and 9; See p.230

Case 5 also includes more east-side front office (market purchase) transactions in the first 10 years than Case 8.

The assumed CO_2 cost is the key determinant for overall portfolio performance: Case 8 outperformed Case 5 with CO_2 taxes at $45 and above, but the reverse is true with CO_2 taxes below $56. Both Case 5 and Case 8 rely heavier on market purchases than other portfolios although Case 8 ranks better than Case 5. IRP, p.231. Case 8 and Case 5 portfolios were nearly equal with respect to both PVRR average and standard deviation. IRP, p.232.

Rocky Mountain Power opines that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. IRP, p 231. Fixed-rate wind PPAs can fulfill this need.

The greatest variable cost is natural gas fuel prices. Case 5 has a greater share of gas generation (and significantly less wind generation) than Case 8, and in the first 10 years, more reliance on generation from market purchases. IRP, p.232. This subjects ratepayers to the whirlwind of natural gas prices. Natural gas prices will undoubtedly increase from current levels, and have been quite volatile in recent years. This reliance is therefore questionable as compared to investment in wind which includes minimal fuel costs and stable prices over the long term.

The portfolio for Case 8 has both the lowest PVRR and the smallest PVRR variability across the risk scenarios. IRP, p. 233. Case 8 outranks Case 5 on the basis of having the lowest rank sum (16). IRP, p. 233. Case 5 falls to 3rd place in this ranking. Id. Case 5 performs best in low natural gas price assumptions and low CO_2 tax scenarios, but worst in high natural gas price assumptions and high CO_2 tax assumptions. IRP, p.234. Case 8 performed best under the medium/high gas price and medium/ high CO_2 tax scenarios, but performed worst in low gas/low CO_2 scenarios. Public policy considerations indicate a preference for a Case which assumes high natural gas prices will protect consumers. The Commission should assume that any natural gas price recast will likely be wrong, because most historic natural gas price projections have turned out to be incorrect, either too high or too low. Natural gas is an international commodity that is subject to a large number of variables that affect price, including oil prices, speculation, cyclical market conditions, hurricanes, and national policies. If the natural gas price projection is too low, and utilities acquire natural gas-fired facilities and pass gas costs on to consumers through rates, then consumers pay the price of the higher than anticipated gas cost. However, if natural gas price projections are too high, consumers may pay more than ideal amounts for more efficient gas burning equipment, insulation, and renewable energy (particularly wind, which tends to offset gas costs first), but these investments will have the effect of erecting a hedge against the next gas price spike. Therefore, if projections are going to be wrong, public policy considerations indicate that regulators should lean toward being wrong and too high, rather than wrong and too low, to protect consumers.

The scenario risk assessment yielded findings similar to the stochastic mean cost analysis regarding the top-performing portfolio, Case 8. IRP, p.234.[4] Case 8 is the highest-performing portfolio and includes more renewable energy, including nearly twice as much wind as the next-highest performing portfolio. Therefore, Rocky Mountain Power should have preferred Case 8 over Case 5, in part due to external resource portfolio standards which are increasing renewable requirements in several jurisdictions served by PacifiCorp in the near future.

Interwest urges Rocky Mountain Power to find ways to incorporate the greater proportions of wind resources into its systems, by its own development and by working closely with independent power producers to acquire a variety of renewable resources in a cost-effective manner.

Since carbon control legislation is a recent development in these markets, it is difficult to get a long-term perspective on their impact. However, we have significant measurable patterns indicating that natural gas prices will very likely rise and fall unpredictably over time, and in the

[4] Rocky Mountain Power did not find the scenario risk assessment to add value to the discussion, so they indicate "the stochastic risk analysis is sufficient for exploring portfolio cost outcome given a range of input assumptions reflecting uncertainty and risk. IRP p. 235.

recent past has included intolerable spikes that have challenged consumers' ability to pay.[5] Case 5 prolongs that risk for both large and small consumers.

Case 8 provides the foregoing benefits and savings to consumers in a cost-effective manner. Case 8 ranks lowest of all of the modeled portfolios in carbon tax exposure for lowest risk-adjusted PVRR, lowest in overall CO_2 emissions, and the lowest "rank sum".

Interwest urges greater acquisition of wind resources in the early years of this resource plan. Rocky Mountain Power will lose the opportunity to invest in wind in the future once resources have been "sunk" into other types of generation facilities rather than in renewable wind energy (or fixed rate or indexed-rate PPAs for wind energy). This may mean consumers will pay higher costs than they would have in the event that carbon control measures are imposed. The "best" (highest capacity) wind projects, nearest to transmission, including a mix of independent power producer and utility-owned resources should be developed immediately.

3. Rocky Mountain Power's wind integration costs used for modeling purposes appear to be unusually high.

The IRP Appendix F "Wind Integration Cost Update", reflects some analysis in Table F.7 indicating the Total Expected $/Expected MWh ranges from $9.96/MWh to $11.85/MWh. In itself, this is a 16% variance. These costs should be analyzed carefully and substantiated by publicly-available, peer-reviewed studies conducted in transparent processes to obtain the benefit of state-of-the-art research. <u>See</u> list of Wind Integration Cost studies and reports, attached hereto as **Exhibit D**. This list is shown to provide examples of the types of wind integration studies which have been completed by other utilities. The bases for these costs reported by Rocky Mountain Power requires further inquiry. Interwest recommends that when the opportunity arises, the Commission require that Rocky Mountain Power pursue "least cost" integration strategies so that new renewable projects can be added to the system over time without being taxed by outdated operational, scheduling, and forecasting methods.

[5] For history of natural gas prices to commercial consumers, see, e.g. Energy Information Administration, *Monthly U.S. Price of Natural Gas Sold to Commercial Consumers*,:http://tonto.eia.doe.gov/dnav/ng/hist/n3020us3m.htm

Interwest appreciates the opportunity to provide these Comments.

Respectfully submitted this 7th day of August, 2009, by

/s/______________________________
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On Behalf of Interwest Energy Alliance

CERTIFICATE OF SERVICE

I hereby certify that on this 7th day of August, 2009, the original and eight copies of the foregoing Comments to 2008 Integrated Resource Plan were delivered by Federal Express to the Wyoming Public Service Commission, 2515 Warren Avenue, Suite 300, Cheyenne, WY 82002, and copies were placed in the U.S. Mail, postage pre-paid, addressed as follows:

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Table 8.1 – Portfolio Capacity Additions by Resource Type, 2009 – 2018

				Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market Resources) [1/]							
Case	PVRR	Gas Scenario / FPC	CO2 Price	SCPC	Gas	Wind	Dist. Gen	Market Purchases (10-yr Avg)	Other Renewables	DSM Class 1	DSM Class 2
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)											
1	$20,045	Low - June 2008	$0		261		124	748		108	716
2	$21,512	Medium - June 2008	$0	600	261	140	85	646	35	2	890
3	$19,503	High - June 2008	$0	790		3,291	95	530	155	7	982
5	$40,526	Low - June 2008	$45		261	1,050	95	691	35	2	901
8	$41,372	Medium - June 2008	$45			2,400	147	663	120	7	955
9	$40,204	Low - Oct 2008	$45		261	1,280	95	690	35	2	899
10	$40,319	Medium - Oct 2008	$45			2,400	117	679	155	7	949
11	$40,559	High - Oct 2008	$45	600		4,814	103	546	155	7	1,001
14	$39,949	High - June 2008	$45	600		5,355	107	500	155	7	1,018
17	$51,207	Medium - June 2008	$70			3,900	110	613	155	7	985
18	$49,745	Low - Oct 2008	$70			3,900	110	640	155	7	954
19	$50,102	Medium - Oct 2008	$70			4,100	110	620	155	7	975
20	$50,536	High - Oct 2008	$70			5,250	104	602	155	7	1,007
22	$49,983	High - June 2008	$70	600		5,750	101	514	155	7	1,048
24	$60,693	Medium - June 2008	$100			5,739	112	565	155	7	1,009
25	$58,838	Low - Oct 2008	$100			5,250	112	742	155	7	1,000
26	$59,660	Medium - Oct 2008	$100			5,250	112	661	155	7	1,007
27	$60,484	High - Oct 2008	$100			5,750	110	648	155	7	1,045
29	$57,635	High - June 2008	$100			5,750	158	538	155	110	1,079
46	$21,532	Medium - Oct 2008	$8, C&T		174	600	136	641		19	906
47	$20,863	Medium - Oct 2008	$8, C&T		174	822	136	646		29	903
Low Load Growth Core Cases											
4	$34,612	Low - June 2008	$45			300	91	216	35		882
7	$34,582	Medium - June 2008	$45			1,800	91	172	85		920
13	$31,076	High - June 2008	$45	600		4,610	95	121	155		1,004
16	$43,523	Medium - June 2008	$70			3,599	109	116	155		962
21	$40,517	High - June 2008	$70			5,750	95	134	155		1,017
23	$51,692	Medium - June 2008	$100			5,559	111	101	155		1,005
28	$47,806	High - June 2008	$100			5,750	95	242	155		1,017
High Load Growth Core Cases											
6	$48,140	Low - June 2008	$45		1,363	904	192	755	155	126	957
12	$50,146	Medium - June 2008	$45	600	888	1,907	151	748	155	107	994
15	$50,914	High - June 2008	$45	600	261	5,750	153	771	655	114	1,079
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth											
30	$48,541	Medium - June 2008	$45 to $179			4,400	110	621	155	7	1,003
31	$47,552	High - June 2008	$45 to $179			5,750	110	533	155	7	1,072
Sensitivity Case - High Cost Outcome											
33	$69,949	High - June 2008	$100	600	577	5,750	158	662	655	126	1,113
Sensitivity Cases - Clean Base-Load Generation Availability											
34	$40,564	Medium - June 2008	$45			3,183	138	647	85	7	950
35	$39,853	High - June 2008	$45	600		5,000	97	528	120	7	1,015
36	$51,242	Medium - June 2008	$70			4,200	147	681	120	7	1,002
37	$48,949	High - June 2008	$70			5,750	95	595	120	7	1,019
Sensitivity Cases - High Plant Construction Costs											
38	$41,974	Medium - June 2008	$45			1,605	138	665	85	64	968
39	$34,791	High - June 2008	$45	600		3,182	142	493	120	109	1,020
Sensitivity Case - System-wide Oregon CO2 Reduction Targets											
40	$24,761	Medium - June 2008	Hard Cap			1,241	124	677	85	104	920
Sensitivity Cases - Planning Reserve Margin, 15%											
41	$41,542	Medium - June 2008	$45		261	1,934	151	776	155	25	954
42	$51,420	Medium - June 2008	$70		261	3,600	110	764	155		983
43	$60,905	Medium - June 2008	$100			5,750	154	713	155	105	1,036
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)											
44	$21,249	Medium - Oct 2008	$8, C&T	600		1,746	132	632	85	109	900
45	$20,875	Medium - Oct 2008	$8, C&T	600	261	721	89	654	35	2	877
Sensitivity Case - Class 3 DSM for Peak Load Reduction											
48	$41,268	Medium - June 2008	$45			2,400	107	643	85	121	945

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

EXHIBIT A

Table 8.2 – Portfolio Capacity Additions by Resource Type, 2009 – 2028

Case	PVRR	Gas Scenario / FPC	CO2 Price	Cumulative Megawatt Nameplate Capacity by Resource Type (Annual Average for Market and Growth Resources) [1/]											
				SCPC	SCPC w/ CCS	IGCC w/ CCS	Gas	Wind	Dist. Gen	Nuclear	Market Purchases (20-yr Avg)	Growth Resource (8-yr Avg, 2021-2028)	Other Renewables	DSM Class 1	DSM Class 2
Candidate Portfolio Core Cases (Medium Load Growth plus Business Plan Reference Cases)															
1	$20,045	Low - June 2008	$0				261		130		1,102	859		108	1,537
2	$21,512	Medium - June 2008	$0	600			261	941	109		880	524	35	2	1,815
3	$19,503	High - June 2008	$0	790				4,003	95		713	437	155	7	1,992
5	$40,526	Low - June 2008	$45		346		261	1,600	110		1,089	734	35	2	1,835
8	$41,372	Medium - June 2008	$45					2,400	160		1,090	624	120	7	1,942
9	$40,204	Low - Oct 2008	$45		346		261	1,600	110		1,133	623	35	2	1,834
10	$40,319	Medium - Oct 2008	$45					2,600	129		1,124	513	155	7	1,936
11	$40,559	High - Oct 2008	$45	600				5,000	114		717	651	155	7	2,024
14	$39,949	High - June 2008	$45	600		466		6,287	120		711	272	155	7	2,066
17	$51,207	Medium - June 2008	$70		876			3,900	122		1,084	609	155	7	2,020
18	$49,745	Low - Oct 2008	$70		876			3,900	122		1,089	667	155	7	1,974
19	$50,102	Medium - Oct 2008	$70		876			4,100	122		1,094	610	155	7	2,009
20	$50,536	High - Oct 2008	$70		876			6,600	114	1,600	842	651	155	7	2,035
22	$49,983	High - June 2008	$70	600	876			7,200	101	1,600	616	161	155	7	2,115
24	$60,693	Medium - June 2008	$100		876			6,600	122	3,200	802	280	155	7	2,076
25	$58,838	Low - Oct 2008	$100		876			6,175	122		1,070	777	155	7	2,035
26	$59,660	Medium - Oct 2008	$100		876			6,600	122	3,200	783	311	155	7	2,042
27	$60,484	High - Oct 2008	$100		876			6,680	120	3,200	972	650	155	7	2,098
29	$57,635	High - June 2008	$100		876	466		7,200	167	3,200	575	450	155	110	2,183
46	$21,532	Medium - Oct 2008	$8, C&T	600			174	1,388	151		897	468		19	1,825
47	$20,863	Medium - Oct 2008	$8, C&T	600			174	1,344	151		892	469		29	1,822
Low Load Growth Core Cases															
4	$34,612	Low - June 2008	$45		346			300	110		269	125	35		1,801
7	$34,582	Medium - June 2008	$45		346			1,800	110		185	115	85		1,857
13	$31,076	High - June 2008	$45	600				4,800	95		71	81	155		2,038
16	$43,523	Medium - June 2008	$70		876			3,599	122		108	111	155		1,990
21	$40,517	High - June 2008	$70		876			6,202	95	1,600	124	70	155		2,058
23	$51,692	Medium - June 2008	$100		876			6,600	122	3,200	157	85	155		2,045
28	$47,806	High - June 2008	$100		876			5,800	95	3,200	150	67	155		2,036
High Load Growth Core Cases															
6	$48,140	Low - June 2008	$45				1,838	1,600	209		1,181	1,125	155	126	1,983
12	$50,146	Medium - June 2008	$45	600			888	2,299	169		1,186	1,125	155	126	2,082
15	$50,914	High - June 2008	$45	600		466	261	6,599	169	1,600	1,148	572	655	125	2,163
Sensitivity Cases - Real CO2 Cost Escalation with Changing Load Growth															
30	$48,541	Medium - June 2008	$45 to $179		876	466		7,000	122	3,200	743	126	155	7	2,091
31	$47,552	High - June 2008	$45 to $179		876			7,200	122	3,200	815	130	155	7	2,159
Sensitivity Case - High Cost Outcome															
33	$69,949	High - June 2008	$100	600			1,100	7,200	169		762	1,125	655	126	2,294
Sensitivity Cases - Clean Base-Load Generation Availability															
34	$40,564	Medium - June 2008	$45					3,900	152		1,109	539	85	7	1,937
35	$39,853	High - June 2008	$45	600				5,000	97		778	479	120	7	2,022
36	$51,242	Medium - June 2008	$70		876			4,200	169		1,127	762	120	110	2,046
37	$48,949	High - June 2008	$70		876			5,762	95	3,200	468	150	120	7	2,061
Sensitivity Cases - High Plant Construction Costs															
38	$41,974	Medium - June 2008	$45					2,118	151		1,114	535	85	64	1,970
39	$34,791	High - June 2008	$45	600				3,255	149		641	580	120	109	2,113
Sensitivity Case - System-wide Oregon CO2 Reduction Targets															
40	$24,761	Medium - June 2008	Hard Cap		876			2,200	124		999	1,000	85	104	1,880
Sensitivity Cases - Planning Reserve Margin, 15%															
41	$41,542	Medium - June 2008	$45				261	1,934	163		1,168	590	155	25	1,941
42	$51,420	Medium - June 2008	$70		876		261	3,600	122		1,160	679	155		2,017
43	$60,905	Medium - June 2008	$100		876			6,600	163	3,200	907	291	155	105	2,104
Sensitivity Cases - Alternative Renewable Policy Assumptions (High RPS/PTC expiration)															
44	$21,249	Medium - Oct 2008	$8, C&T	600				5,673	149		948	161	155	109	1,811
45	$20,875	Medium - Oct 2008	$8, C&T	600			261	881	110		904	430	120	2	1,795
Sensitivity Case - Class 3 DSM for Peak Load Reduction															
48	$41,268	Medium - June 2008	$45					2,400	122		1,037	679	85	121	1,932

[1/] All portfolios include 1,520 MW of firm planned resources, consisting of Lake Side 2, a 2012 east PPA, 2009-2010 wind resources under development or contract, coal plant turbine upgrades, and Swift 1 hydro upgrades.

EXHIBIT B

- The use of physical and financial hedging for electricity price risk
- Managing gas supply risk
- The treatment of customer and investor risks for resource planning

THE INTEGRATED RESOURCE PLAN ACTION PLAN

Table 9.1 is a summary of the annual MW capacity and timing for the resources contained in the 2008 IRP preferred portfolio. A more comprehensive summary of portfolio resources can be found in Chapter 8.

Table 9.1 – Preferred Portfolio, Summary Level

		Capacity, MW										Cumulative
	Resource	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
East												
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-	570
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-	261
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-	200
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-	128
	Geothermal	-	-	-	-	35	-	-	-	-	-	35
	Wind	99	249	-	100	100	100	150	100	100	50	1,048
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4	30
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4	38
	DSM, Class 1, Utah Cool Keeper Load Control	25	50	40	30	10	10	10	10	10	10	205
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*	Up to 90
	DSM Class 2	42	51	49	52	55	55	56	56	58	59	532
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800	
West												
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-	42
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-	75
	Wind	45	20	200	-	-	-	-	-	-	-	265
	CHP	1	1	1	1	2	2	2	2	2	2	16
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1	12
	DSM, Class 1	*	*	*	*	*	*	*	*	*	*	Up to 30
	DSM, Class 2	35	36	39	39	38	39	39	39	39	29	372
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582	

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.

[2/] The Swift 1 hydro updates are shown in the years that they enter into commercial service.

* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.

The 2008 IRP action plan, detailed in Table 9.2, provides the Company with a road map for moving forward with new resource acquisitions, including major transmission projects needed to support the preferred portfolio and other Company objectives. (More detail on transmission expansion action items is provided in Chapter 10.)

EXHIBIT C

EXHIBIT D
Wind Integration Cost Studies

As a result of discussions between various stakeholders, Bonneville Power Administration recently announced a reduction in its wind integration tariff from over $12/MW to $5.40/MW, as reported by Renewable Northwest Project, July 22, 2009; http://www.rnp.org/News/pr_RNP_BPARateCase_09Jul22.htm.

Final Report, Avista Corporation Wind Integration Study, Prepared by EnerNex Corporation, March 2007, http://www.uwig.org/AvistaWindIntegrationStudy.pdf

Operational Impacts of Integrating Wind Generation in to Idaho Power's Existing Resource Portfolio, Idaho Power, February 2007; http://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm

National Renewable Energy Laboratory, Wind Integration Cost and Ancillary Service Impacts; Michael Milligan (Consultant), WEATS, August 10, 2006; http://apps1.eere.energy.gov/tribalenergy/pdfs/course_wind_milligan1.pdf

"Status of Wind Integration Studies"; National Renewable Energy Laboratory; D.Lew, NREL, Presented at WIEB Board Meeting, November 5, 2007; http://www.nrel.gov/wind/systemsintegration/pdfs/lew_regional_studies.pdf

Wind Integration Study for Public Service Company of Colorado; Addendum, Detailed Analysis of 20% Wind Integration, Prepared for Excel Energy by EnerNex Corporation, *December 1, 2008;* http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPWindIntegrationStudy.pdf

American Wind Energy Association
http://www.awea.org/utility/wind_integration.html
A portion of the AWEA report is repeated here:

To address wind energy's variability, some incremental generation may be required for system balancing. While this is not a reliability issue, it can add a modest amount to the overall cost of electricity service. The costs of this generation include the costs of keeping the generators available and ready to operate, and the fuel costs of operating them. The exact costs depend on the mix of generation on a given system and various other factors. In a document prepared by the Utility Wind Integration Group in coordination with the trade associations of all three utility sectors (investor-owned, public, and cooperative), the studies and experiences with utility wind integration are summarized as follows:

1. **"Wind resources have impacts that can be managed through proper plant *interconnection, integration, transmission planning and system and market* operations.**

EXHIBIT D

2. **System operating cost increases arising from wind variability and uncertainty *amounted to only about 10% or less of the wholesale value of the wind energy.***
3. **A variety of means – such as commercially available wind forecasting – can be employed to reduce these costs.**
4. **In many cases, customer payments for electricity can be decreased when wind is *added to the system,* because the *operating-cost* increases are offset by savings from displacing fossil fuel generation."**

One of the primary conclusion from this survey of studies from different parts of the country is as follows:

"[This study] lays to rest one of the major concerns often expressed about wind power: that a wind plant would need to be backed up with an equal amount of dispatchable generation."

For more information, refer to the Utility Wind Integration Group (UWIG) website at http://www.uwig.org/opimpactsdocs.html