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2007

Integrated Resource Plan Update

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

This 2007 Integrated Resource Plan Update (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: Foot Creek 1
Hydroelectric Generation: Yale Reservoir (Washington)
Demand side management: Agricultural Irrigation
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1. INTRODUCTION

This 2007 Integrated Resource Plan (IRP) update report chronicles integrated resource planning activities that occurred subsequent to the filing of the 2007 Integrated Resource Plan on May 30, 2007, and that helped support the development of PacifiCorp's 10-year business plan for the period 2008-2017 ("2008 business plan"). As part of this support, PacifiCorp performed capacity expansion optimization modeling based on updated inputs and assumptions. The outcome of this modeling work was a revised 2008-2017 resource portfolio.

This report first summarizes the significant changes made to inputs and assumptions relative to the 2007 IRP and used for business plan development, covering (1) natural gas and power market prices, (2) forecasted inflation rates, (3) carbon dioxide emission costs and regulatory assumptions, (4) the long-term load forecast, (5) the coincident summer peak capacity load and resource balance ("capacity balance"), (6) new resource assumptions, (7) the transmission topology, and (8) front office transactions. The updated resource portfolio is then presented along with associated changes to the 2007 IRP action plan.

NATURAL GAS AND POWER MARKET PRICE UPDATES

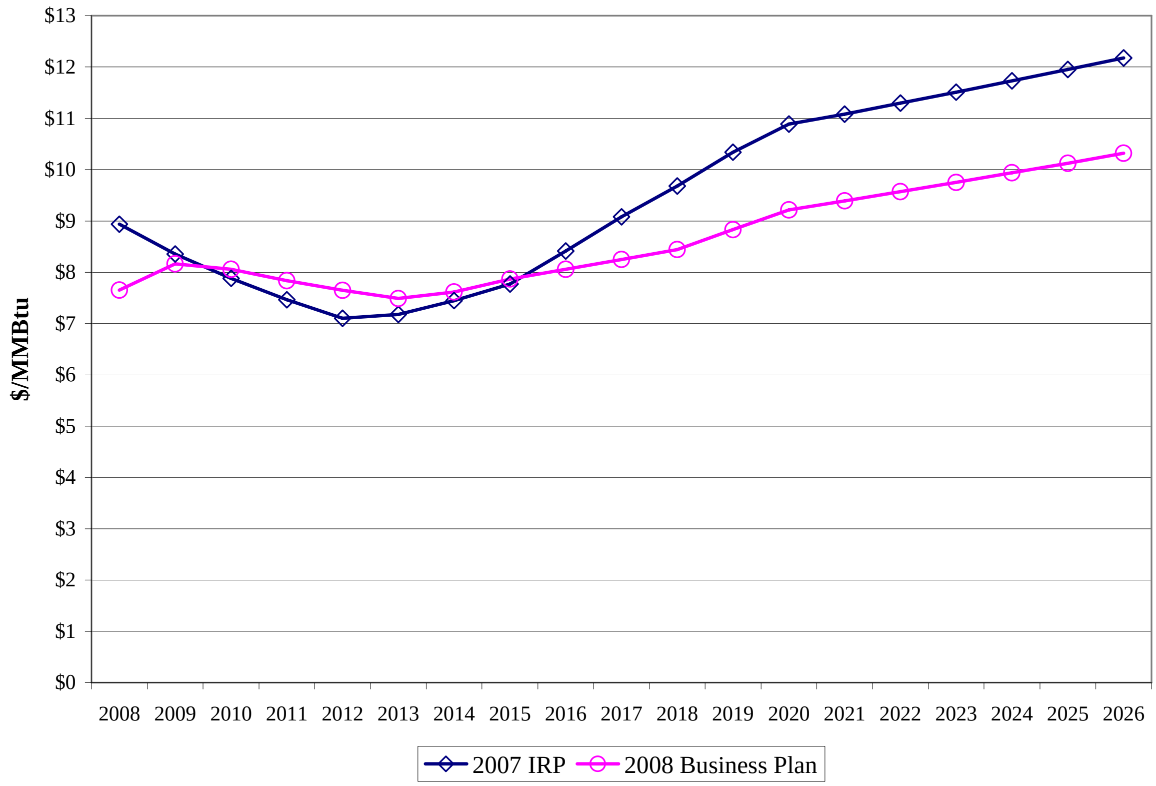
<u>Natural Gas Market Prices</u>

PacifiCorp's natural gas prices are a blend of market forwards and a fundamentals forecast of long-term supply and demand. In both the 2007 IRP and in the 2008 business plan, market forwards are used through the first 72 months of the curve. Over this 72 month period, the 2007 IRP reflects market forwards as of August 31, 2006 and the 2008 business plan reflects market forwards as of September 7, 2007. The long-term portion of the natural gas curve is based upon a fundamentals-based projection from external sources. Each of the external price projections are evaluated routinely to ensure that PacifiCorp's natural gas price curve captures the best available information at any given point in time. A range of factors are considered when selecting the external long-term price forecast. These factors include:

- Underlying supply and demand fundamental assumptions
- Forecast documentation
- Peer-to-peer forecast price comparisons
- Forecast release date
- Forecast horizon

Figure 1 show the Henry Hub natural gas prices used to develop delivered natural gas prices in the 2007 IRP and in the 2008 business plan. Differences through about 2013 are driven largely by movements in the forward markets between August 2006 and September 2007. Variations in long-term prices beyond the market period reflect a migration from one external price forecast issued in August 2006 to another external projection issued in July 2007 consistent with the approach described above.

Figure 1 – Henry Hub Natural Gas Prices (Nominal)



Electricity Market Prices

Electricity prices are a blend of 72 months of market forwards and a fundamentals price projection developed with MIDAS – an hourly chronological dispatch model for the Western Electricity Coordination Council (WECC). As with natural gas prices, the 2007 IRP reflects market forwards for electricity as of August 31, 2006 and the 2008 business plan reflects market forwards as of September 7, 2007. Beyond the market portion of the electricity curve, the MIDAS price forecast reflects the same fundamentals natural gas price projections described in the Natural Gas Markets section above.

Figure 2 shows the average annual flat electricity price at Mid-Columbia as used in the 2007 IRP and in the 2008 business plan. Figure 3 shows average annual flat electricity prices at Palo Verde. For both markets, price differences through about 2013 are driven largely by movements in the forward electricity markets between August 2006 and September 2007. Over this period, the relative increase in electricity prices was larger than the increase in natural gas prices, indicating growth in implied market heat rates. Variations in long-term prices beyond the market period are largely influenced by the changes to long-term natural gas prices between August 2006 and September 2007.

Figure 2 – Average Annual Flat Mid-Columbia Electricity Prices

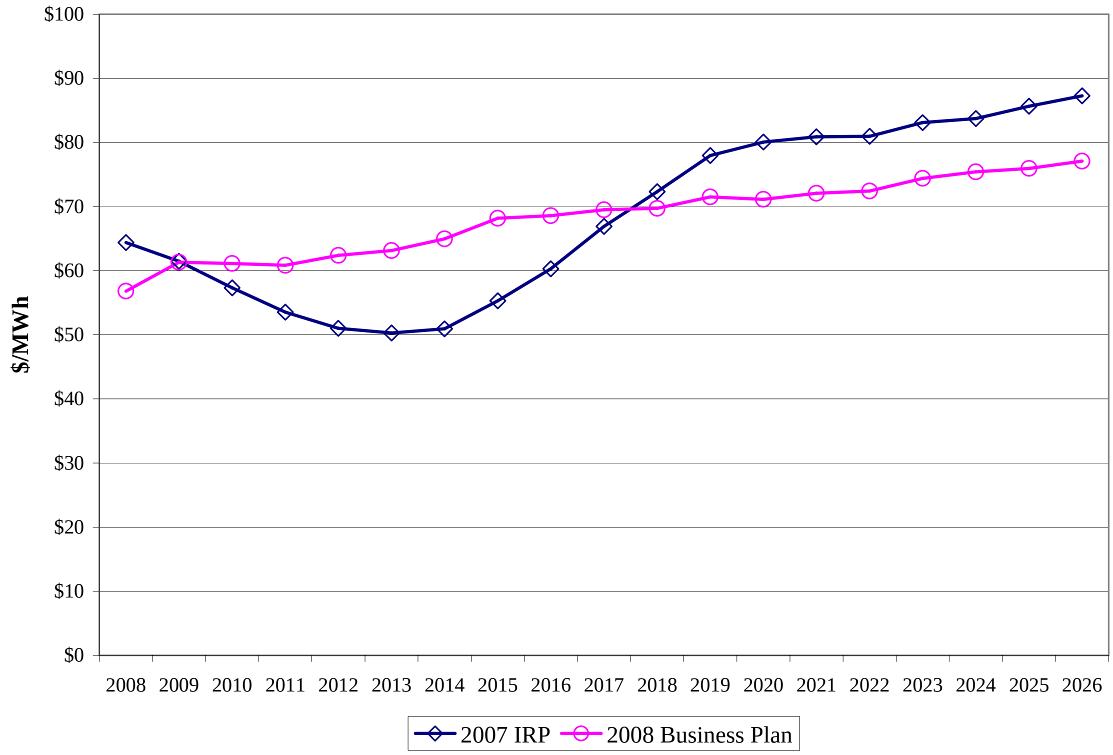
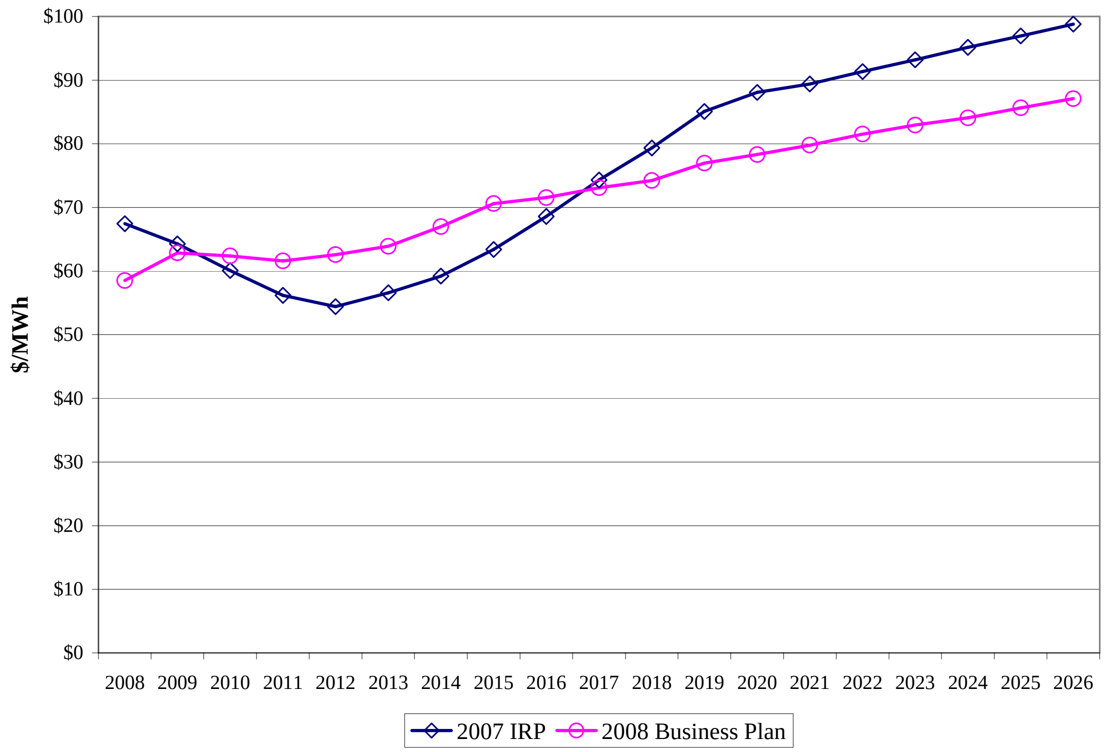


Figure 3 – Average Annual Flat Palo Verde Electricity Prices



INFLATION RATES

Where price forecasts and associated escalation rates were not established by external sources, IRP simulations and price forecasts were performed with PacifiCorp's June 2007 inflation rate schedule (See Table 1 below).

Table 1 – Inflation Rate Forecasts

2007 IRP	
Calendar Years	**Average Annual Rate (%)**
2007-2013	1.86
2014-2020	1.80
2021-2026	1.88

2008 Business Plan	
Calendar Years	**Average Annual Rate**
2008-2014	1.96
2015-2021	1.90
2022-2027	1.90

CARBON DIOXIDE EMISSION COSTS AND COMPLIANCE ASSUMPTIONS

For the 2008 business plan, the assumed carbon dioxide (CO_2) compliance mechanism for resource portfolio analysis is a cap-and-trade system. Subsequent to the filing of the 2007 IRP, PacifiCorp acquired a new module of the System Optimizer capacity expansion model that includes representation of cap-and-trade regulatory policies. The cap-and-trade functionality was used for business plan modeling.

Cap-and-trade assumptions include the following:

- Emissions peaking in 2011 (54.9 million tons) and declining to 2007 emission levels by 2025, assuming straight-line annual decreases for modeling purposes
- Straight-line annual emissions decreasing to 1990 levels by 2030[1]
- An initial CO_2 allowance price of $8.62/ton starting in 2012 (in 2008 dollars), and increasing at PacifiCorp's annual inflation rates

In comparison, for the 2007 IRP, PacifiCorp simulated both CO_2 tax and cap-and-trade policies. For stochastic production cost modeling, PacifiCorp modeled buying and selling of CO_2 emission allowances as an off-line set of spreadsheet calculations assuming a year-2000 emission cap, a $4.14/ton (2008 dollars) allowance price starting in 2010, a $6.34/ton (2008$) allowance price in 2011, and a $8.62/ton (2008$) allowance price in 2012, with prices escalated at PacifiCorp's forecasted inflation rates.

[1] The emission cap in 2027, the last year of the 20-year study period, was 47.4 million tons.

2. RESOURCE NEEDS ASSESSMENT UPDATE

LOAD FORECAST

PacifiCorp updated its load forecast in October 2007. Relative to the 2007 IRP load forecast prepared in March 2007, PacifiCorp system sales and coincident summer peak are virtually unchanged from 2008 through 2016. 2017 and beyond sales and peak are revised slightly downward. The main drivers of the change in 2017 and beyond are an increase in Demand-Side Management (DSM) impacts and a decrease in the Wyoming new Industrial forecast. Although the Wyoming new Industrial forecast is still very strong, there is a decrease from the March 2007 forecast because of a lower growth forecast for the oil and gas sector.

Tables 2 and 3 report the October 2007 annual load and coincidental peak load forecasts, respectively. Tables 4 and 5 show the forecast changes relative to the March 2007 load forecast used for the 2007 IRP.

Table 2 – Annual Load Growth in Megawatt-hours Forecasted, 2008 through 2017

Year	Total	OR	WA	WY	CA	UT	ID[2]
2008	**60,492,210**	15,339,034	4,522,631	9,462,260	938,784	24,622,561	5,384,698
2009	**62,189,571**	15,377,514	4,539,415	10,423,043	943,430	25,261,101	5,421,129
2010	**63,271,762**	15,334,009	4,565,640	11,019,325	951,074	25,719,727	5,456,965
2011	**64,268,367**	15,317,970	4,596,175	11,400,485	958,144	26,288,439	5,481,831
2012	**65,506,284**	15,299,183	4,622,603	11,938,797	965,419	26,929,156	5,524,656
2013	**66,893,227**	15,284,852	4,644,877	12,689,116	973,643	27,515,113	5,557,774
2014	**67,930,143**	15,267,788	4,685,033	13,067,586	983,053	28,103,923	5,593,585
2015	**68,880,593**	15,250,377	4,736,761	13,397,459	994,755	28,643,793	5,627,175
2016	**69,789,986**	15,228,100	4,762,639	13,553,616	1,006,312	29,349,829	5,659,159
2017	**70,464,218**	15,213,956	4,786,162	13,606,094	1,018,537	29,936,986	5,672,011
AAG 2008-2017	1.7%	(0.1)%	0.6%	4.1%	0.9%	2.2%	0.6%
AAG 2017-2027	1.1%	0.6%	1.2%	(0.1)%	1.3%	2.4%	0.7%

Table 3 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	WY	CA	UT	ID	SE-ID
2008	9,776	2,422	731	1,167	147	4,419	578	331
2009	10,068	2,455	739	1,314	149	4,560	583	276
2010	10,276	2,477	744	1,378	151	4,656	584	305
2011	10,446	2,490	749	1,418	153	4,760	580	311
2012	10,745	2,502	757	1,485	148	4,975	576	367
2013	11,021	2,545	769	1,575	151	5,058	585	371
2014	11,239	2,598	778	1,614	153	5,182	586	355
2015	11,357	2,585	790	1,651	156	5,295	588	300

[2] Idaho megawatt-hours include the Company's Southeast Idaho third-party load obligation.

Year	Total	OR	WA	WY	CA	UT	ID	SE-ID
2016	11,591	2,573	788	1,686	158	5,497	582	342
2017	11,758	2,643	805	1,664	154	5,602	583	365
AAG 2008-2017	2.1%	1.0%	1.1%	4.0%	0.5%	2.7%	0.1%	1.1%
AAG 2017-2027	1.8%	1.2%	1.8%	(0.1)%	1.8%	2.7%	0.6%	0.4%

Table 4 – Annual Load Growth Change: October 2007 Forecast Less March 2007 Forecast (Average Megawatts)

Year	Total	OR	WA	WY	CA	UT	ID
2008	**489,083**	564,893	(54,663)	(573,071)	(10,175)	552,086	10,012
2009	**365,301**	564,458	(69,474)	(734,001)	(10,371)	607,918	6,770
2010	**(667,669)**	406,941	(255,364)	(1,000,073)	(28,435)	225,718	(16,456)
2011	**(1,370,049)**	276,015	(304,351)	(1,441,729)	(30,699)	173,737	(43,022)
2012	**(1,521,152)**	141,506	(321,503)	(1,409,041)	(32,953)	161,441	(60,603)
2013	**(1,411,634)**	10,594	(344,090)	(1,029,301)	(34,527)	61,262	(75,573)
2014	**(1,595,718)**	(124,029)	(348,258)	(923,515)	(35,125)	(71,261)	(93,531)
2015	**(1,895,830)**	(259,873)	(340,928)	(848,524)	(33,610)	(294,320)	(118,575)
2016	**(2,515,536)**	(401,472)	(363,051)	(1,158,557)	(32,300)	(395,836)	(164,320)
2017	**(3,465,022)**	(535,864)	(387,954)	(1,632,102)	(30,571)	(663,950)	(214,580)
AAG 2008-2017	**(0.6)%**	(0.8)%	(0.7)%	(0.6)%	(0.2)%	(0.5)%	(0.4)%

Table 5 – Annual Coincidental Peak Growth Change: October 2007 Forecast Less March 2007 Forecast (Megawatts)

Year	Total	OR	WA	WY	CA	UT	ID
2008	**354**	347	29	22	(0)	10	(53)
2009	**324**	220	37	32	(10)	140	(95)
2010	**34**	223	15	(38)	10	(64)	(112)
2011	**(28)**	176	(8)	(55)	25	(172)	7
2012	**(26)**	182	(9)	(84)	(7)	2	(110)
2013	**64**	217	2	(38)	(5)	(3)	(108)
2014	**109**	267	5	(34)	(5)	(2)	(122)
2015	**69**	259	16	(18)	(15)	(42)	(131)
2016	**7**	259	13	(47)	(5)	(50)	(163)
2017	**(291)**	253	7	(131)	(8)	(288)	(124)
AAG 2008-2017	**(0.7)%**	(0.6)%	(0.4)%	(1.1)%	(0.6)%	(0.6)%	(0.7)%

The primary drivers for load forecast growth changes by customer class are summarized below.

Residential
- Increases in cooling load are expected, driven by central air conditioner saturation and larger homes
- Where natural gas is available, decreases in heating saturation are forecasted

Commercial
- Increasing growth in the office and health care sectors are expected

Industrial
- Wyoming oil and gas is still forecasted to be the fastest growing sector, even though PacifiCorp is expecting slower growth from the previous forecast
- The Wyoming industrial sales peak decreases slightly from 2017 to 2027 because several of the oil and gas fields will be depleted, and energy sales to those fields will be reduced
- New oil and gas industry growth is expected near Vernal, Utah
- Oregon sales to wood product sectors are weaker, but sales to specialty food manufacturing, metal, and glass still have a strong outlook

RESOURCES

Significant Changes to Existing Resources

For the 2008 business plan, PacifiCorp reclassified two renewable energy projects from the planned to existing resource category due to these projects entering commercial service in 2007. These projects include the Marengo I wind project, a 78 turbine wind facility near Dayton, Washington with a capacity of 140.4-megawatts, and the Blundell geothermal expansion project, an 11-megawatt bottoming-cycle enhancement to the Company’s existing geothermal facility.

The other significant resource change was removal of the 33-megawatt Cove Fort geothermal power purchase agreement as an existing resource.

Significant Changes to Planned Resources

Thermal

In the company's effort to meet the growing demand for generation, and given the advancing technological improvements in steam turbine design and manufacturing, the most recent "dense pack" turbine upgrade initiative is included in the 2008 business plan. This turbine upgrade initiative is intended to further enhance PacifiCorp's overall generation capability and cycle efficiency for each of the large thermal units in the generation fleet currently exceeding 300 megawatt in rated capacity.[3] Table 6 shows the thermal upgrade schedule included in the 2008

[3] Previous thermal plant upgrades performed by PacifiCorp over the last decade were referred to "aero-derivative steam path" (ADSP) technology, and was installed in most of the same large thermal units being considered for the current dense pack turbine upgrades. The ADSP upgrades also introduced minor capacity upgrades and improvement in efficiency through advancement in turbine technology beyond original equipment design.

business plan. The total increase in capacity from 2009 through 2013 is 202 megawatts. These upgrades are scheduled to occur during each unit's next major planned overhaul.

Table 6 – Thermal Upgrade Schedule

Plant	Megawatt Capacity Increase				
	2009	**2010**	**2011**	**2012**	**2013**
Hunter		19	12	19	
Huntington			18	18	
Johnston				18	
Naughton	21				
Wyodak			9		
Jim Bridger		17	17	17	17
Cumulative Total	**21**	**57**	**113**	**185**	**202**

The generation increase available by installing new dense pack-designed high-pressure / intermediate-pressure turbines, and in some cases low pressure turbine components, is derived entirely through more efficient utilization of existing steam inlet conditions entering each of these turbine sections. Dense pack turbine technology until recently was only offered by a select few turbine manufacturers. Technology refinements that have occurred since the initial introduction of the dense pack design have developed to a point that they are fairly robust and considered a well established offering for large power turbine upgrades. These improvements allow for an additional 1.5 percent to 2.5 percent improvement in generation over previous upgrade designs for each applicable unit without requiring any increases in fuel consumption or heat input in order to achieve the additional generation. In as much as there is no requirement for additional fuel consumption to achieve the capacity and efficiency improvements, emission inventories remain unchanged and do not impact any of the existing environmental or regulatory limits established for the candidate units.

Wind Projects

Table 7 profiles new wind generation projects that have been reclassified from generic IRP resources to planned resources for the 2008 business plan. (Planned resources are those approved by the MidAmerican Energy Holdings Company (MEHC) board for inclusion in a capital budget.) Note that the expected in-service dates in table 7 reflect expectations at the time the 2008 business plan was prepared.

Table 7 – Recent Wind Resource Additions

Resource Name	Location	Nameplate MW	Expected In-Service Date
Goodnoe Hills	Near Goldendale, Washington	99.0	2008
Marengo Expansion	Near Dayton, Washington	70.2	2008
Rolling Hills	12 miles north of Glenrock, in Converse County, Wyoming (the Glenrock Mine site for the Dave Johnston plant)	99.0	2008
Glenrock	12 miles north of Glenrock, in Converse County, Wyoming (the Glenrock Mine site for the Dave Johnston plant)	99.0	2008
Seven Mile Hill	Eastern Carbon County near Medicine Bow, Wyoming	99.0	2008
High Plains	Spans Albany County and eastern Carbon County, Wyoming	99.0	2009

Hydroelectric Plants

Both the 2007 IRP and 2008 business plan included upgrades to the Swift No. 1 hydroelectric plant, totaling 75 megawatts by 2015. This project was reclassified from an existing resource to a planned resource for reporting in PacifiCorp's capacity balance.

While PacifiCorp's hydro turbine generator overhaul program is expected to provide incremental improvements to the overall generating capacity of the hydro portfolio, the upgrade potential at the Swift No.1 project has been identified as a significant opportunity to provide an economic alternative for helping to address the expiring Mid-Columbia capacity and energy purchase contracts. The Swift No.1 project is also expected to be an increasingly important resource to PacifiCorp, providing the majority of the system's load control and reserve support. This upgrade project will enhance the Swift No.1 plant's ability to provide that support.

As envisioned, the project will consist of a major hydraulic turbine overhaul with runner replacement, an electrical generator winding upgrade, a generator bus upgrade, generation step-up transformer upgrades (two units), installation of dedicated generator breakers, possible civil upgrades to the penstock and surge tank, and related plant system upgrades. This project will increase the total generating capability of the Swift No. 1 hydroelectric plant to 315 megawatts.

Kern River Recovered Energy Generation Project

PacifiCorp is teaming with Kern River Gas Transmission Company, a subsidiary of MEHC, to develop waste heat recovery/electric generation facilities at several compressor stations along Kern River's gas pipeline in southwestern Wyoming and Utah. The project will employ the ORMAT Energy Converter system (developed by ORMAT Technologies, Inc.), an organic Rankine cycle technology that produces no air emissions due to the closed-loop nature of the system. These combined heat and power facilities, expected to be in service by 2010, will provide 19 megawatts of nameplate generation capacity.

Demand-Side Management Resources

Two key DSM planning developments that occurred after the filing of the 2007 IRP was the completion of a third-party system-wide demand-side resource potential assessment study made available to PacifiCorp in June 2007[4], and the passage of Oregon Senate Bill 838, which created an opportunity for funding increased amounts of cost-effective energy efficiency resources in the State of Oregon. As a result of these developments, PacifiCorp made significant changes to the forecasts for dispatchable load control (Class 1) and energy efficiency (Class 2) DSM programs originally used for the 2007 IRP. These updated forecasts were incorporated in the 2008 business plan.

For dispatchable load control programs, the new forecast is for 272 megawatts by 2012, compared with 258 megawatts by 2013 for the 2007 IRP. To arrive at the new figures, PacifiCorp used non-resource-specific, high-end estimates based on 2007 IRP modeling work. Tables 8a and 8b report the original 2007 IRP annual Class 1 DSM program amounts along with the incremental increases assumed for the 2008 business plan. (Cumulative and percentage changes between the 2007 IRP and 2008 business plan are shown at the bottom of the table.)

For energy efficiency programs, the new 2008 business plan load reduction forecast is 4.6 million megawatt-hours by 2017, compared with 1.8 million megawatt-hours for the 2007 IRP. To arrive at the adjusted forecast, PacifiCorp used the information provided in the DSM potentials study and applied adjustments to account for recent program implementation experience and market conditions. The Company first applied an economic screen to the energy efficiency potential amounts based on the 2007 IRP decrement values plus 15 percent.[5] An increase to the assumed achievable potential—from 55 percent to 70 percent—was also made, as well as a slight acceleration in the 20-year acquisition timeline. For the Oregon targets, the Company worked with the Energy Trust of Oregon to develop a revised forecast of energy efficiency opportunities. Table 8a and 8b report the original 2007 IRP annual Class 2 DSM program amounts along with the incremental increases assumed for the 2008 business plan. (Cumulative and percentage changes between the 2007 IRP and 2008 business plan are shown at the bottom of the table.) The Class 2 DSM targets are applied as decrements to the load forecast as was done for the 2007 IRP.[6]

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[4] The DSM potentials study, conducted by Quantec LLC, provided PacifiCorp more information on the opportunities for demand-side resource investments should they be found to be cost-effective through the 2008 IRP modeling process.

[5] Preliminary resource screening for cost-effectiveness was performed as part of the original potentials estimation project.

[6] Resource supply curves will be used for portfolio development for the 2008 IRP to determine the cost-effective magnitude and value of energy efficiency programs as compared to supply-side resource options.

Table 8a – Demand-Side Resource Forecast Comparison by Year, 2008-2012

	2008	2009	2010	2011	2012
Class 1 Load Management - 2007 IRP	163	163	163	163	210
Incremental Additions (MW)	37	47	57	67	62
Total Class 1 Load Management - 10-yr Plan	**200**	**210**	**220**	**230**	**272**

Class 2 Energy Efficiency (MWh) - 2007 IRP	247,207	214,532	207,262	200,429	198,239
Class 2 Capacity Impact (MW) - 2007 IRP	47	41	39	38	38
Incremental energy efficiency (MWh)	103,018	178,967	242,914	273,487	288,029
Incremental capacity Impact (MW)	20	34	46	52	55
Class 2 Total Energy Efficiency (MWh) - 10-yr Plan	**350,225**	**393,499**	**450,176**	**473,916**	**486,268**
Class 2 Capacity Impact (MW) - 10-yr Plan	**67**	**75**	**85**	**90**	**93**

Cumulative Forecasts & Percent Change

Class 1 Load Management (MW) 2007 IRP	163	163	163	163	210
Class 1 Load Management (MW) 10-yr Plan	200	210	220	230	272
% change capacity	23%	29%	35%	41%	30%

Class 2 energy efficiency (MWh) 2007 IRP	247,207	461,739	669,001	869,430	1,067,669
Class 2 energy efficiency (MW) 2007 IRP	47	88	127	165	203
Class 2 energy efficiency (MWh) 10-yr Plan	350,225	743,724	1,193,900	1,667,816	2,154,084
Class 2 energy efficiency (MW) 10-yr Plan	67	142	227	317	410
% change forecast	42%	61%	78%	92%	102%

Table 8b – Demand-Side Resource Forecast Comparison by Year, 2013-2017

	2013	2014	2015	2016	2017
Class 1 Load Management - 2007 IRP	258	258	258	258	258
Incremental Additions (MW)	14	14	14	14	14
Total Class 1 Load Management - 10-yr Plan	**272**	**272**	**272**	**272**	**272**

Class 2 Energy Efficiency (MWh) - 2007 IRP	197,801	189,917	185,274	182,296	-
Class 2 Capacity Impact (MW) - 2007 IRP	37	36	35	35	-
Incremental energy efficiency (MWh)	288,467	296,350	300,994	303,971	487,144
Incremental capacity Impact (MW)	55	56	57	58	92
Class 2 Total Energy Efficiency (MWh) - 10-yr Plan	**486,268**	**486,267**	**486,268**	**486,267**	**487,144**
Class 2 Capacity Impact (MW) - 10-yr Plan	**92**	**92**	**92**	**93**	**92**

Cumulative Forecasts & Percent Change

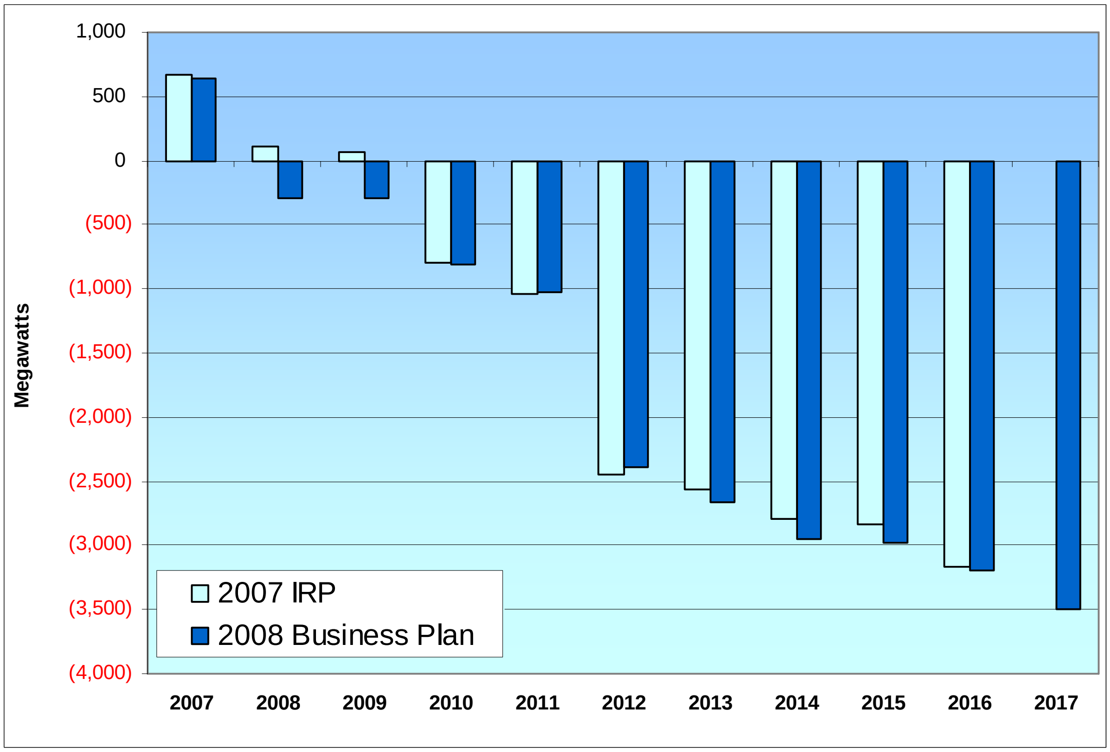
Class 1 Load Management (MW) 2007 IRP	258	258	258	258	258
Class 1 Load Management (MW) 10-yr Plan	272	272	272	272	272
% change capacity	5%	5%	5%	5%	5%

Class 2 energy efficiency (MWh) 2007 IRP	1,265,470	1,455,387	1,640,661	1,822,957	1,822,957
Class 2 energy efficiency (MW) 2007 IRP	240	276	311	346	346
Class 2 energy efficiency (MWh) 10-yr Plan	2,640,352	3,126,619	3,612,887	4,099,154	4,586,298
Class 2 energy efficiency (MW) 10-yr Plan	502	594	686	779	871
% change forecast	109%	115%	120%	125%	152%

UPDATED CAPACITY BALANCE

Figure 4 compares the annual capacity positions for the 2007 IRP and the 2008 business plan. Both positions assume a 12-percent planning reserve margin (PRM). For the 2008 business plan, the system capacity position becomes deficit two years earlier relative to the position reported in the 2007 IRP. The early-year position differences are attributed to the higher relative projected loads in the Western Control Area. After 2010 the differences between the two capacity positions are relatively small.

Figure 4 – Capacity Position Comparison, 2007 IRP versus the 2008 Business Plan



Figures 5 through 7 show the 2008 business plan's capacity peak load and resource gaps for the system, Eastern Control Area, and Western Control Area, respectively. Table 9 reports the detailed load and resource line items for the capacity balance.

Figure 5 – System Coincident Peak Loads and Resources, 2008 Business Plan

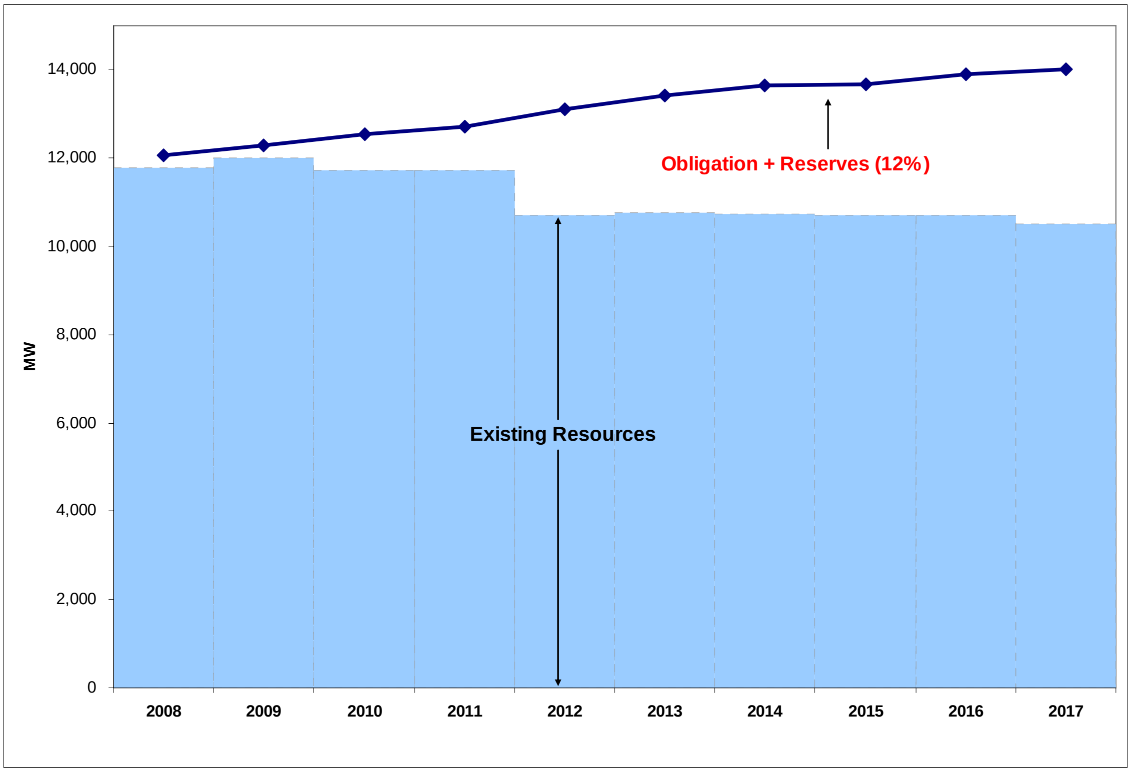


Figure 6 – East Coincident Peak Loads and Resources, 2008 Business Plan

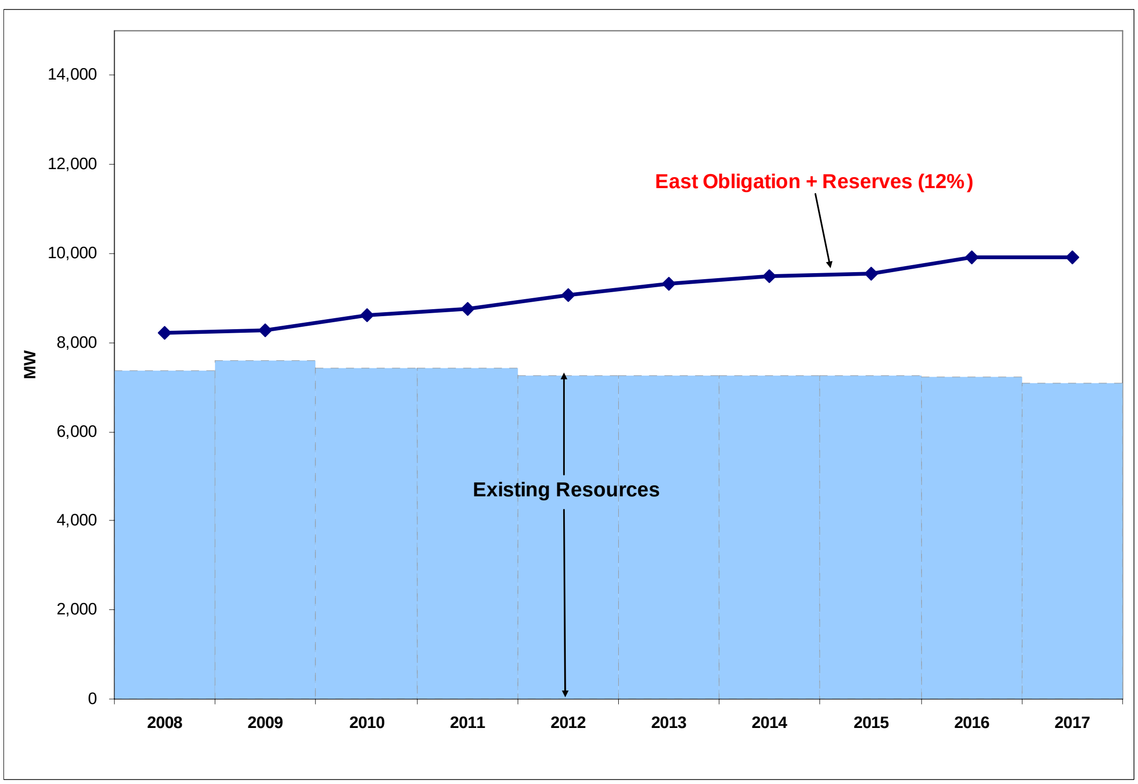


Figure 7 – West Coincident Peak Loads and Resources, 2008 Business Plan

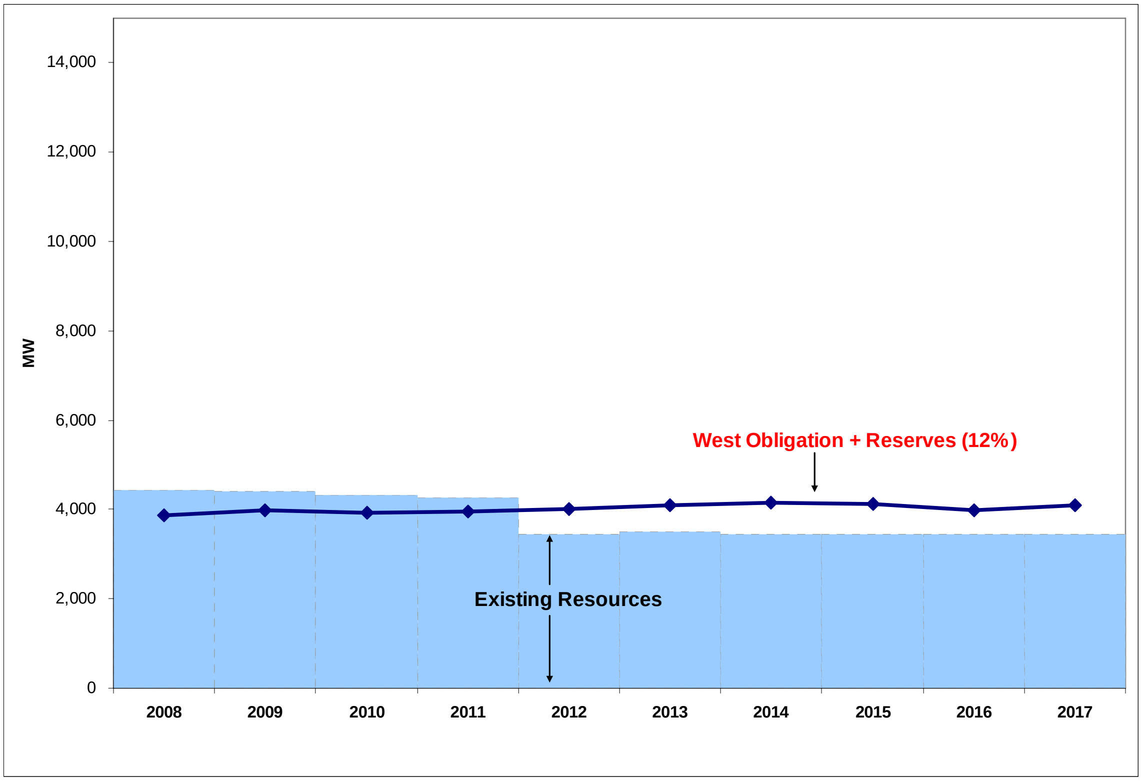


Table 9 – Load and Resource Capacity Balance

Planning Reserve Margin Target = 12%

Calendar Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East										
Thermal	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	163	163	163	163	163	163	163	163	163	0
Renewable	109	109	109	109	109	109	109	105	105	105
Purchase	704	828	648	668	493	493	493	493	472	472
QF	106	106	106	106	106	106	106	106	106	105
Interruptible	212	328	328	328	328	328	328	328	328	328
East Existing Resources	7,361	7,601	7,421	7,441	7,266	7,266	7,266	7,262	7,241	7,077
Load	6,547	6,725	6,975	7,130	7,404	7,612	7,782	7,827	8,147	8,208
Sale	836	752	766	756	745	745	745	745	745	659
East Obligation	7,383	7,477	7,741	7,886	8,149	8,357	8,527	8,572	8,892	8,867
Planning reserves (12%)	756	739	792	807	860	885	905	911	951	968
Non-owned reserves	71	71	71	71	71	71	71	71	71	72
East Reserves	827	810	863	878	930	955	976	981	1,022	1,040
East Obligation + Reserves	8,210	8,287	8,604	8,764	9,079	9,312	9,503	9,553	9,914	9,907
East Position	(850)	(686)	(1,183)	(1,323)	(1,813)	(2,046)	(2,237)	(2,291)	(2,673)	(2,830)
East Reserve Margin	0%	3%	(3%)	(5%)	(10%)	(12%)	(14%)	(15%)	(18%)	(20%)
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,414	1,328	1,332	1,175	1,174	1,168	1,169	1,168	1,177
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	118	118	118	118	94	94	94	94	94	94
Purchase	800	800	800	750	112	141	107	107	107	107
QF	40	40	40	40	40	38	38	38	38	38
West Existing Resources	4,425	4,401	4,314	4,268	3,450	3,493	3,454	3,455	3,453	3,441
Load	3,228	3,343	3,302	3,316	3,341	3,409	3,457	3,531	3,444	3,550
Sale	299	299	290	290	258	258	258	158	108	108
West Obligation	3,527	3,642	3,592	3,606	3,599	3,667	3,715	3,689	3,552	3,658
Planning reserves (12%)	327	341	335	343	418	423	433	430	413	426
Non-owned reserves	7	7	7	7	7	7	7	7	7	8
West Reserves	334	348	342	349	425	430	439	436	420	434
West Obligation + Reserves	3,861	3,990	3,933	3,955	4,024	4,097	4,154	4,125	3,972	4,091
West Position	564	411	381	314	(575)	(603)	(700)	(670)	(518)	(651)
West Reserve Margin	28%	23%	23%	21%	(4%)	(4%)	(7%)	(6%)	(3%)	(6%)
System										
Total Resources	11,786	12,002	11,735	11,710	10,716	10,760	10,721	10,717	10,695	10,517
Obligation	10,910	11,119	11,333	11,492	11,748	12,024	12,242	12,261	12,444	12,525
Reserves	1,161	1,157	1,204	1,227	1,355	1,385	1,415	1,417	1,442	1,473
BP Obligation + Reserves	12,071	12,276	12,537	12,719	13,104	13,409	13,657	13,678	13,886	13,998
BP System Position	(294)	(285)	(813)	(1,020)	(2,398)	(2,664)	(2,950)	(2,975)	(3,202)	(3,495)
Reserve Margin	9%	10%	5%	3%	(8%)	(10%)	(12%)	(12%)	(14%)	(16%)

Table 10 reports the annual line item differences between the capacity balances for the 2008 business plan and 2007 IRP. For the Eastern Control Area, significant changes included the addition of a Public Service Company of Colorado exchange contract, modification to the Monsanto interruptible load contract, and a decrease in the Wyoming load forecast. For the Western Control Area, changes included an increase in forecasted loads and reclassification of the Swift No. 1 upgrade and wind projects.

Table 10 – 2008 Business Plan Capacity Balance Less 2007 IRP Capacity Balance

Planning Reserve Margin Target = 12%

Calendar Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
East									
Thermal	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Hydro	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0
Renewable	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Purchase	25	50	100	125	150	150	150	150	150
QF	0	0	0	0	0	0	0	0	0
Interruptible	(21)	20	20	20	20	20	20	20	20
East Existing Resources	(5)	61	111	136	161	161	161	161	161
Load	32	68	(162)	(159)	(191)	(126)	(113)	(199)	(219)
Sale	25	50	100	125	150	150	150	150	150
East Obligation	57	118	(62)	(34)	(41)	24	37	(49)	(69)
Planning reserves (12%)	6	6	(22)	(21)	(25)	(18)	(16)	(26)	(29)
Non-owned reserves	0	0	0	0	0	0	0	0	0
East Reserves	6	6	(22)	(21)	(25)	(18)	(16)	(26)	(29)
East Obligation + Reserves	63	124	(84)	(55)	(66)	6	21	(75)	(98)
East Position	(68)	(63)	195	192	228	155	140	237	259
East Reserve Margin	(1%)	(1%)	2%	2%	3%	2%	2%	3%	3%
West									
Thermal	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	(25)	(50)	(75)	(75)	(75)	(75)
DSM	0	0	0	0	0	0	0	0	0
Renewable	10	10	10	10	10	10	10	10	10
Purchase	0	0	0	0	0	0	0	0	0
QF	0	0	0	0	0	0	0	0	0
West Existing Resources	10	(7)	(6)	(32)	(57)	(64)	(64)	(64)	(64)
Load	304	248	178	117	101	158	195	260	192
Sale	0	0	0	0	0	0	(0)	(0)	(0)
West Obligation	304	248	178	117	101	158	195	260	192
Planning reserves (12%)	37	30	21	14	12	19	23	31	23
Non-owned reserves	0	0	0	0	0	0	0	0	0
West Reserves	37	30	21	14	12	19	23	31	23
West Obligation + Reserves	341	278	200	131	113	177	218	291	215
West Position	(330)	(285)	(206)	(163)	(170)	(241)	(283)	(356)	(279)
West Reserve Margin	(12%)	(9%)	(7%)	(5%)	(4%)	(6%)	(7%)	(9%)	(7%)
System									
Total Resources	5	54	104	105	104	97	97	97	97
Obligation	361	366	116	83	60	182	232	211	123
Reserves	43	36	(1)	(7)	(13)	1	7	5	(6)
Obligation + Reserves	404	402	116	76	47	183	239	216	117
System Position	(408)	(358)	(22)	18	48	(101)	(157)	(133)	(31)
Reserve Margin	(4%)	(3%)	(0%)	0%	1%	(0%)	(1%)	(1%)	0%

3. NEW RESOURCE ASSUMPTIONS

CAPITAL COSTS

Capital costs for supply-side resources were adjusted to reflect recent escalation trends, and in the case of coal, studies used to support benchmark resource development for the 2012 base load Request for Proposals. Table 11 shows the per-kilowatt and percentage increases in average capital costs by technology type relative to those costs assumed for the 2007 IRP.

Table 11 – Resource Supply Side Options Capital Cost Increases

Average Capital Increases by Resource Type 2008 Business Plan versus 2007 IRP		
Type	**$/kW**	**Percent**
Coal	1,221.5	49%
Gas	87.4	12%
Renewables	459.9	21%

TREATMENT OF COAL RESOURCES

PacifiCorp excluded supercritical pulverized coal and Integrated Gasification Combined Cycle (IGCC) as resource options for 2008 business plan portfolio modeling. This resource selection constraint reflects PacifiCorp's view that for the 10-year business planning horizon, coal resources are not viable resource options given (1) cost uncertainty associated with potential CO_2 regulations, (2) new state energy policies in California, Oregon, and Washington, (3) permitting issues and challenges, and (4) uncertainty regarding the availability and costs of clean coal technologies.

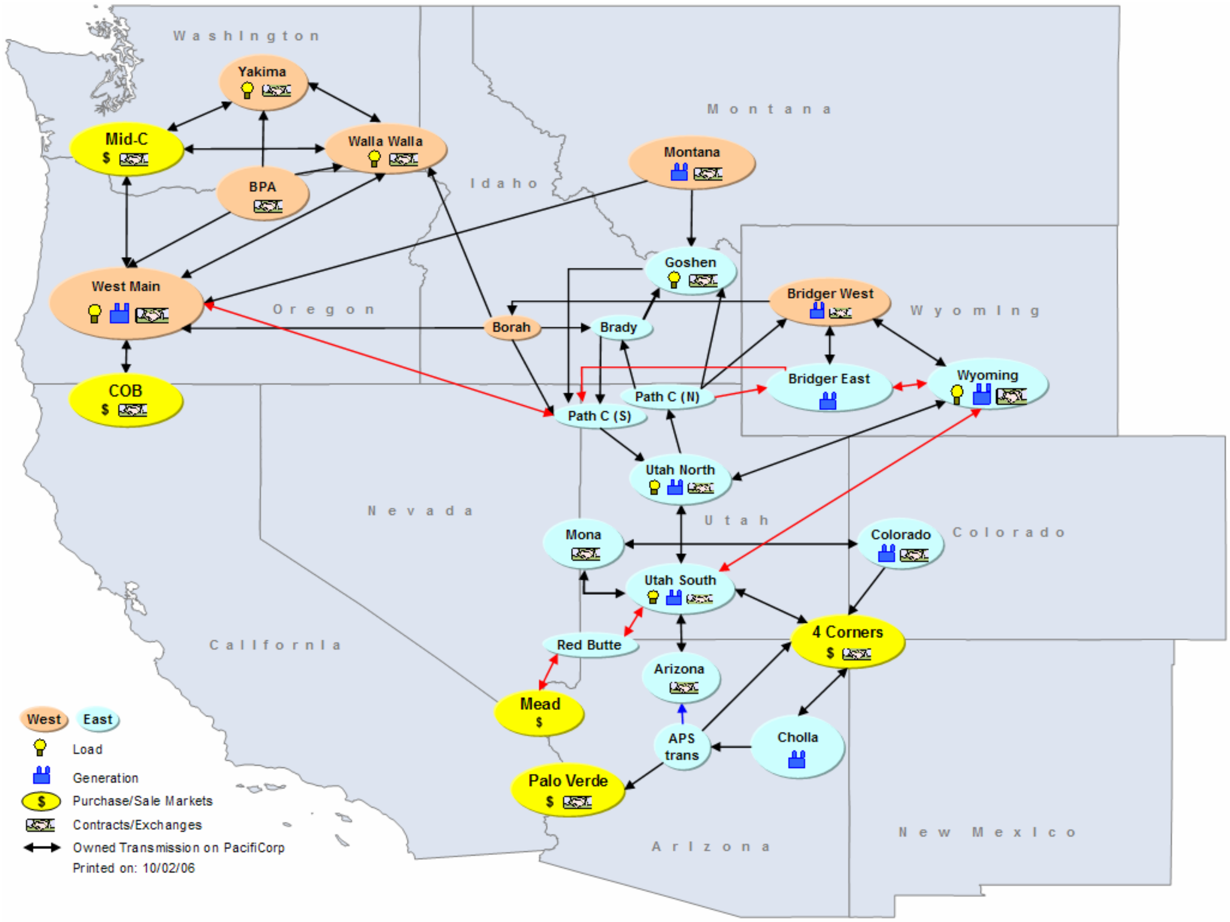
RENEWABLE RESOURCES

The wind resources reflected in the 2007 IRP preferred portfolio, procured in the 2008 through 2013 period, were updated to match 2008 business plan assumptions for start dates, sites, and capacities. These updated wind resources, totaling 1,270 nameplate megawatts, were fixed in the System Optimizer model. These fixed wind resources are shown in the 2008 business plan resource portfolio (Table 12).

4. TRANSMISSION RESOURCES

Figure 8 shows the modeled transmission system topology used for 2008 business plan portfolio modeling. This topology incorporates the Energy Gateway Transmission Expansion project as announced on May 30, 2007. The seven new transmission links associated with the expansion project are identified with red arrows in the topology diagram.

Figure 8 – Modeled Transmission System Topology



5. FRONT OFFICE TRANSACTIONS

For the 2008 business plan, a number of changes to front office transaction assumptions were made.[7] These changes relate to the products selected as proxy resources in some of the markets, and the annual maximum quantities available at each market. The changes—incorporated in the System Optimizer model—were prompted by an updated assessment of market product and supporting transmission availability, as well as the impact of the Energy Gateway Transmission Expansion project. The front office transaction specifications, by market area, are profiled below.

- Mid-Columbia Market
  - Third-quarter, heavy-load-hour (HLH) product (previously modeled as a flat annual product for the 2007 IRP)
  - Maximum annual amount: 400 megawatts for 2007-2026

[7] Front office transactions are proxy resources representing forward firm purchases used to help Pacificorp meet its load and planning reserve requirements.

- California Oregon Border Market
  - Flat annual product
  - Maximum annual amount: 400 megawatts for 2007-2026

- Mona Market
  - Third-quarter HLH product
  - Maximum annual amount: 200 megawatts for 2007-2026

- Mead Market
  - Third-quarter HLH product
  - Maximum annual amount: 0 megawatts for 2007-2012, 600 megawatts for 2013-2026

- Four Corners
  - Third-quarter HLH product
  - Maximum annual amount: 0 megawatts for 2007-2017, 500 megawatts for 2018-2026

6. BUSINESS PLAN PORTFOLIO

PacifiCorp used the System Optimizer to develop a resource portfolio based on the updated inputs and assumptions described above. While 20-year optimizations were conducted, the focus of portfolio development was to refine the selection and timing of gas resources and front office transactions for the business plan time horizon, 2008-2017.

Table 12 shows the resulting supply-side resource portfolio that was used for development of the 2008 business plan. (The business plan DSM resources are shown in Tables 8a and 8b.) Note that resources are shown by their in-service years rather than the years they first are available to meet summer peak load requirements. For example, most renewable resources are assumed to enter commercial service by December of a given year.

Table 12 – 2008 Business Plan Supply-Side Resource Portfolio

			Nameplate Capacity, MW [1/]									
	Resource	**Type**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
East	Upgrades - thermal generation	Various east coal-fired units	-	21	36	38	37	-	-	-	-	-
	Combined cycle CT	2x1 F class with duct firing	-	-	-	-	1,096	-	-	-	-	-
	Geothermal	Blundell	-	-	35	-	-	-	-	-	-	-
	Combined heat and power	Generic east-wide	-	-	19	-	-	-	-	-	-	-
	Renewable	Wind, Wyoming	300	100	100	200	-	200	-	-	-	-
	Front office transactions [2/]	Heavy load hour, 3rd quarter	-	-	-	-	115	633	746	800	800	783
West	Upgrades - thermal generation	Jim Bridger coal-fired units	-	-	17	17	17	17	-	-	-	-
	Upgrades - hydro generation	Swift Hydro	-	-	-	-	-	25	25	25	-	-
	Renewable	Wind, North-central Oregon	-	-	200	-	100	-	-	-	-	-
	Renewable	Wind, Southeast Washington	70	-	-	-	-	-	-	-	-	-
	Front office transactions [2/]	Flat annual product	400	400	389	389	400	400	400	388	338	400
	Front office transactions [2/]	Heavy load hour, 3rd quarter	-	-	268	347	400	59	144	101	334	548
	Annual Additions, Long Term Resources		370	121	408	256	1,250	242	25	25	-	-
	Annual Additions, Short Term Resources		400	400	657	736	915	1,092	1,290	1,289	1,472	1,731
	Total Annual Additions		770	521	1,065	992	2,165	1,334	1,315	1,314	1,472	1,731

1/ Resources are shown by their in-service date as opposed to the year for which they meet the system peak.
2/ Front office transaction amounts reflect purchases made for the year, and are not additive.

7. ACTION PLAN UPDATE

This section provides the updated IRP Action Plan, modified as a result of 2008 business planning activities. The Action Plan update is presented as Table 13. Changes to the original plan have been highlighted. PacifiCorp's update to the 2007 IRP Action Plan covers Demand Side Management, Resource Procurement, and IRP Acknowledgement.

Table 13 – Updated Action Plan

Action Item	Category	Action Type	Calendar-Year Timing	**Size** (rounded to the nearest 50 MW for generation resources)	Location	Action
1	Renewables	New Renewables	2007 - 2013	2,000	System	Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, such as natural gas, to integrate new wind resources. **PacifiCorp has initiated two RFPs in 2008 to support this acquisition plan.**
2	DSM	Existing and New Class 2 programs	2007 - 2014	450 MWa	System	~~**Use decrement values to assess cost-effectiveness of new program proposals.**~~ Acquire the base Class 2 DSM (Pacific Power and ETO combined, including energy savings in Oregon beyond that funded by the ETO) of ~~250~~**300** MWa and 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. Will reassess Class 2 objectives upon completion of system-wide DSM potential study. Will incorporate potentials study findings into the 2007 IRP update and 2008 integrated resource planning processes, **including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.**
3	DSM	New Class 1 programs	2007 - 2014	100	East - 50 West - 50	Targets were established through potential study work performed for the 2007 IRP. **Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified.** A new potential study **was** ~~**is expected to be**~~ completed ~~**by**~~ June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, **including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.**

Action Item	Category	Action Type	Calendar-Year Timing	Size (rounded to the nearest 50 MW for generation resources)	Location	Action
4	DSM	Existing and New Class 3 programs	2007 - 2014	To be determined	System	Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.
5	Distributed Generation	Combined Heat and Power (CHP)	2007-2014	100	System	Pursue at least 75 MW of CHP generation for the west-side and 25 MW for the east-side, to include purchase of CHP output pursuant to PURPA regulations and from supply-side RFP outcomes. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes
6	Distributed Generation	Standby Generators	2007-2014	To be determined	System	Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes
7	Supply-Side	Base Load / Intermediate Load / **Summer Peak**	2012 - **2016**	~~550~~ **2,000**	**System** ~~East~~	Procure base load / intermediate load / **summer peak** resources **system-wide** ~~in the east~~ by the summer of 2012 **through 2016**. This is part of the requirement included in the **2012** Base Load RFP **and the 2008 All Source RFP**
~~8~~	~~Supply-Side~~	~~Base Load / Intermediate Load~~	~~2012~~	~~350~~	~~East~~	~~Procure a base load / intermediate load resource in the east by the summer of 2012. This is part of the requirement included in the Base Load RFP~~
~~9~~	~~Supply-Side~~	~~Base Load / Intermediate Load~~	~~2014~~	~~550~~	~~East~~	~~Procure a base load / intermediate load resource in the east by the summer of 2014. This is part of the requirement included in the Base Load RFP~~

Action Item	**Category**	**Action Type**	**Calendar-Year Timing**	**Size** (rounded to the nearest 50 MW for generation resources)	**Location**	**Action**
~~**10**~~	~~**Supply-Side**~~	~~**Base Load / Intermediate Load**~~	~~**2016**~~	~~**350**~~	~~**East**~~	~~**Investigate a base load / intermediate load resource in the east by the summer of 2016. This is not part of the requirement included in the Base Load RFP**~~
~~**11**~~	~~**Supply-Side**~~	~~**Base Load / Intermediate Load**~~	~~**2011**~~	~~**600**~~	~~**West**~~	~~**Procure a base load / intermediate load resource in the west by the summer of 2011 - 2012**~~
~~**12**~~	~~**Supply-Side**~~	~~**Base Load / Intermediate Load**~~	~~**2010-2014**~~	~~**350-650**~~	~~**East / West**~~	~~**Procure base load / intermediate load resource beginning in the summer of 2010, use the Base Load RFP as appropriate to fill the need in the east**~~
13	Transmission	Transmission	2010 and beyond	Various	System	Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate
14	Climate Change	Strategy and Policy	Ongoing	Not applicable	System	Continue to have dialogue with stakeholders on Global Climate Change issues
15	Carbon-Reducing Technology	Strategy and Policy	Ongoing	Not applicable	System	Evaluate technologies that can reduce the carbon dioxide emissions of the company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power. **For the 2008 IRP, include IGCC plants with carbon capture and sequestration as a resource option for selection.**
16	IRP Planning	Modeling and Analysis	2007-2008	Not applicable	System	Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system

Action Item	Category	Action Type	Calendar-Year Timing	Size (rounded to the nearest 50 MW for generation resources)	Location	Action
17	IRP Planning	Modeling and Analysis	2007-2008	Not applicable	System	Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions
18	IRP Acknowledgement	Policy and cost recovery	2007	Not applicable	System	Work with states to gain acknowledgement or acceptance of the 2008 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs
19	**IRP Planning**	**Modeling and Analysis**	**2008**	**Not applicable**	**System**	**In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk**
20	**IRP Planning**	**Modeling and Analysis**	**2008**	**Not applicable**	**System**	**For the 2008 IRP, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard**
21	**IRP Planning**	**Modeling and Analysis**	**2008**	**Not applicable**	**System**	**For the 2008 IRP, further develop with stakeholders, use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.**
22	**IRP Planning**	**Modeling and Analysis**	**2008**	**Not applicable**	**System**	**For the 2008 IRP, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios**
23	**IRP Planning**	**Modeling and Analysis**	**2008**	**Not applicable**	**System**	**Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emission rates to short-term market transactions.**

ACTION PLAN IMPLEMENTATION

Demand-Side Management

Since the May 2007 IRP filing, PacifiCorp began incorporating results from the DSM potential study into the DSM program planning process, and, by the fall of 2007, identified opportunities to include in the 2008 business plan. The initial impact resulted in the resetting of the 2008 resource targets identified in the 2007 IRP by 23% for Class 1 load management resources and 42% for Class 2 energy efficiency resources. To assist in meeting 2009-2017 adjusted 10-year plan forecasts and in anticipation of 2008 IRP refinements, work is underway on the development of a 2008 DSM Request for Proposal (RFP) for new DSM programs. The RFP is expected to be released later this summer (2008). The company's 2007 actual resource acquisitions against the 2007 IRP resource targets were exceeded by 22% for Class 1 load management resources and 18% for Class 2 energy efficiency resources. The company still needs to determine how to incorporate the potential assessment of Class 3 DSM, price responsive programs, and Class 4 DSM, energy education into the IRP planning process.

Supply-Side Resource Procurement Activities

To help address the resource needs identified in the 2007 IRP, PacifiCorp issued a 2012 Base Load Request for Proposals (RFP) on April 5, 2007. The Company identified a final short list of bids, and is currently negotiating with short list bidders on final bid prices and terms. For 2008, PacifiCorp has issued, or is planning to issue, three additional RFPs to meet the resource needs identified in both the 2007 IRP and 2008 business plan. These RFPs are described below.

Renewable Request for Proposals (RFP 2008R)

The purpose of this RFP, issued January 31, 2008, is to support the acquisition of renewable resources identified in the 2007 IRP (See Action Item no. 1 of Table 8.2, page 224). The scope of this RFP is for system wide (Eastern Control Area and Western Control Area) new renewable resources that are capable of delivery in or into PacifiCorp's network transmission system. The RFP specifies a target quantity of up to 200 megawatts for 2008 and up to 100 megawatts for 2009. Individual bids are limited to (1) less than 100 megawatts in generating capability, or (2) for a term of less than five years if greater than 100 megawatts in generating capability. Renewable categories include wind energy, solar, hydrokinetic (wave, tidal, and ocean thermal energy), biomass/biomass byproducts, geothermal, certified low-impact hydroelectric energy, and waste gas/waste heat capture or recovery. Bidders also have the option of submitting renewable resources with energy storage, such as pumped hydro, compressed air, or battery technologies.

Renewable Request for Proposal (RFP 2008R-1)

This renewables RFP, currently being drafted, is intended as a "shelf" RFP under which subsequent periodic RFPs will be issued to comply with current regulatory rules, orders, and any applicable resource procurement state laws. The 2008R-1 RFP is for renewable resources that can reach commercial operation during the 2008 through 2011 time period, and are limited in size to no more than 300 megawatts.

Request For Proposal – 2008 All Source RFP

The "All Source RFP" was initiated on February 1, 2008 with a required pre-draft conference and focus on procuring resources to fill need from 2012 though 2016 as stated in the 2007 IRP. The RFP is seeking capacity and energy resources to serve PacifiCorp's entire system. Bidders may propose any of seven different proposal structures covering power purchase agreements, tolling agreements, asset purchase and sales agreements, and purchases of existing facilities (load curtailment, Qualifying Facility, and geothermal and biomass projects are also covered.) The bid categories are also separated into Base Load, Intermediate Load and Summer Peak resources.

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

June 11, 2008

VIA ELECTRONIC FILING AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capital Street NE, Ste. 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins,
Administrator – Regulatory Operations

Re: Docket LC 42 - 2007 Integrated Resource Plan Update

Enclosed are an original and five (5) copies of PacifiCorp's 2007 Integrated Resource Plan (IRP) Update. This 2007 IRP Update is documentation of the plan that was presented and discussed at the Company's February 29, 2008, IRP public input meeting. Copies of the report are available electronically and will be posted on PacifiCorp's website, at www.pacificorp.com. The Company's 2007 IRP was filed in the above-referenced docket with the Public Utility Commission of Oregon ("Commission") on May 30, 2007. On April 24, 2008, the Commission issued Order No. 08-232 that acknowledges, with exceptions, the 2007 IRP.

The 2007 IRP Update is submitted to the Commission pursuant to the IRP guidelines issued in Docket No. UM 1056, Order No. 07-002, as corrected by Order No. 07-047. Guideline 3(f) states that once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filings its next IRP. The guideline also states that the utility may request acknowledgment of changes in proposed actions identified in an update. Since the Company expects to file its next IRP in March 2009, it does not request acknowledgment of its 2007 Update.

It is respectfully requested that all Staff requests regarding this filing be addressed to the following:

By E-mail (preferred):	datarequest@pacificorp.com
By Fax:	(503) 813-6060
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

If there are informal inquiries concerning the filing please contact Pete Warnken, Manager, Integrated Resource Planning at (503) 813-5518 or Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea L. Kelly
Vice President, Regulation

cc: LC 42 (w/enclosures)

CERTIFICATE OF SERVICE

I certify that I have cause to be served the foregoing **PacifiCorp's 2007 Integrated Resource Plan Update** in OPUC Docket No. LC 42 by electronic mail and overnight delivery to those parties who have not waived paper service on the attached service list.

DATED this 11th day of June, 2008.

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