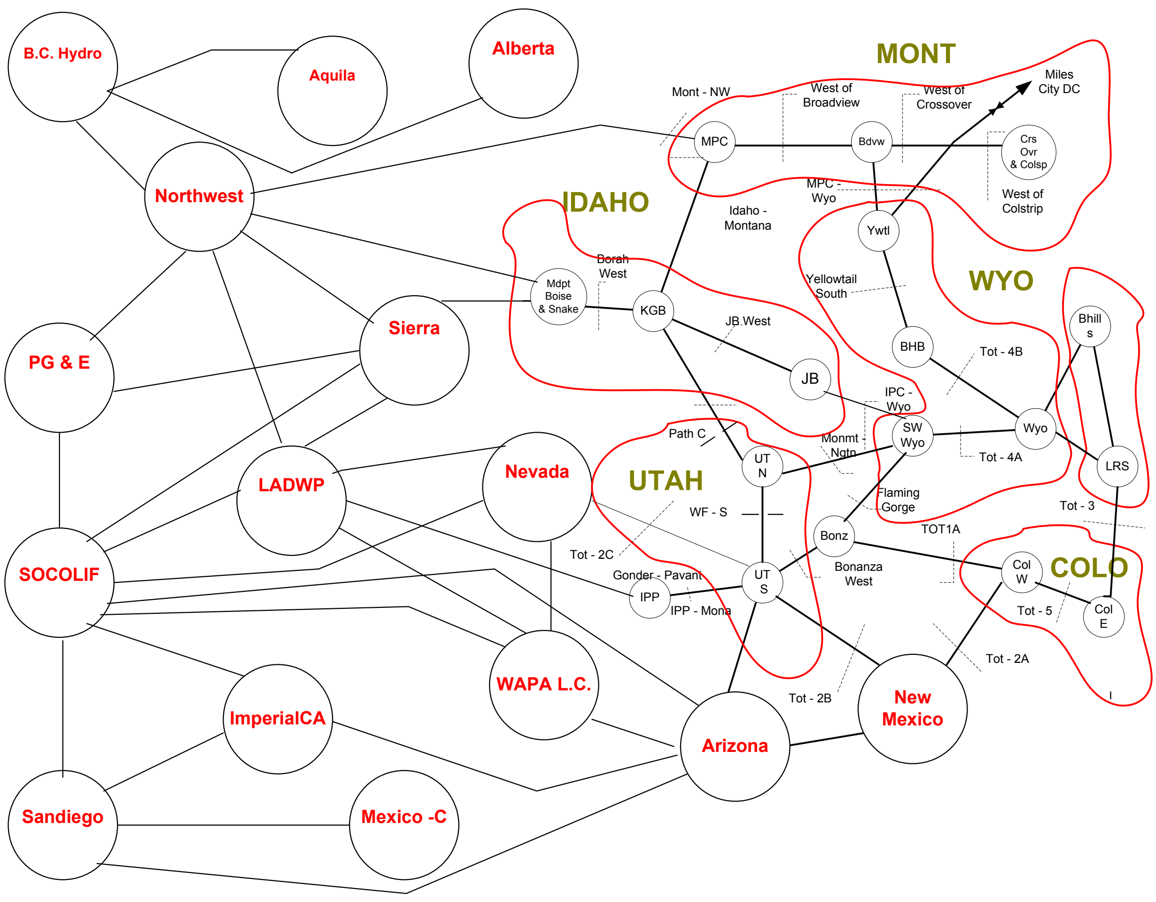
Appendix F.1- Key Assumptions

Transmission

The topology for the Western Interconnect transmission system includes 33 bubbles or areas (as shown in Figure F.1.1). The system is split into bubbles in order to disaggregate monthly load peaks and energy, to identify transfer links (transmission interfaces), and to summarize modeling results. The starting point for the RMATS topology was the WECC 22-bubble topology. Eleven bubbles were added to the WECC topology to increase data granularity for the Rocky Mountain region.

Figure F.1. 1: RMATS 33 bubble topology



Transmission Path Ratings & Nomograms

The study applied the path and nomogram ratings posted in the WECC February 2003 Path Rating Catalog. Paths and nomograms internal to companies were added and rated by the Transmission Additions Work Group (TAWG).

Path ratings are "Maximum Path Transfer Capabilities" based on WECC path rating methodology similar to "First Contingency Incremental Transfer Capabilities" (the method used by NERC councils). Most of the ratings reflect capabilities based on technical limits determined from system studies. These do not necessarily represent Available Transmission Capacity because they do not indicate the degree to which the path transfer capability has been committed.

A nomogram is a graphic representation of operating relationships between transmission paths. On lines where the relationship between variables does not change, a nomogram can be represented simply as a single transmission interface limit. Nomogram relationships are plentiful on the Western Interconnect. Below are some key nomograms in the West:

- TOT 4 A / TOT4B
- East of the Colorado River / West of the Colorado River (EOR/WOR)
- West of Borah versus Path 15 (Central to Southern California)
- AC/DC Pacific Intertie and California Oregon Intertie for South-to-North flows

Transmission added to the 2008 Base Case

The WECC 08 LS P1A1 (light load spring) powerflow case was the starting source for the physical transmission system. RMATS added some transmission facilities to this powerflow case to establish the 2008 base case. A major modification was to close an existing 500 kV line out of Kelly Lake in British Columbia (line was opened earlier due to light hydro flow conditions). Other modifications, as flagged by transmission providers:

- APS
    - Close the following lines:
        - FOURCORN 345 - WESTMESA 345
        - FOURCORN 345 - SHIPROCK 345.
    - Open FOURCORN 230 - SHIPROCK 230

- BPA
    - Remove the second Monroe-Echo Lake 500-kV line
    - Remove the John Day-McNary 500-kV line
    - Remove the Starbuck integrating transmission (Starbuck to Lower Monumental 500 kV line) unless Starbuck generation is being added to the case. (a new radial, no action needed)
    - The Wallula generation has been put on hold but the integrating transmission can remain in the case as it does not impact the transfer impedance through the system.

    - It is our understanding that Grant Co PUD's Priest Rapids-Wahluke-Frenchman-Ptholes 230 line and phase shifter project has been cancelled. Grant Co should be contacted on this. (opened part of new 230kV).

- PG&E
    - Path 15 Upgrade (Conversion of 115 to 230 kV)

Transmission added to the 2013 Scenario

- Harquahah to Devers 500kV
- Sycamore to Carlton Hill 138kV
- Sycamore to Chcarita 138kV
- Transformers at Miguel, Devers, and Sycamore

Transmission Losses

The WECC load forecast includes estimated losses. No further adjustment was made to these assumptions. As noted in Figure F.2.1, the production cost modeling does not take into account loss charges.

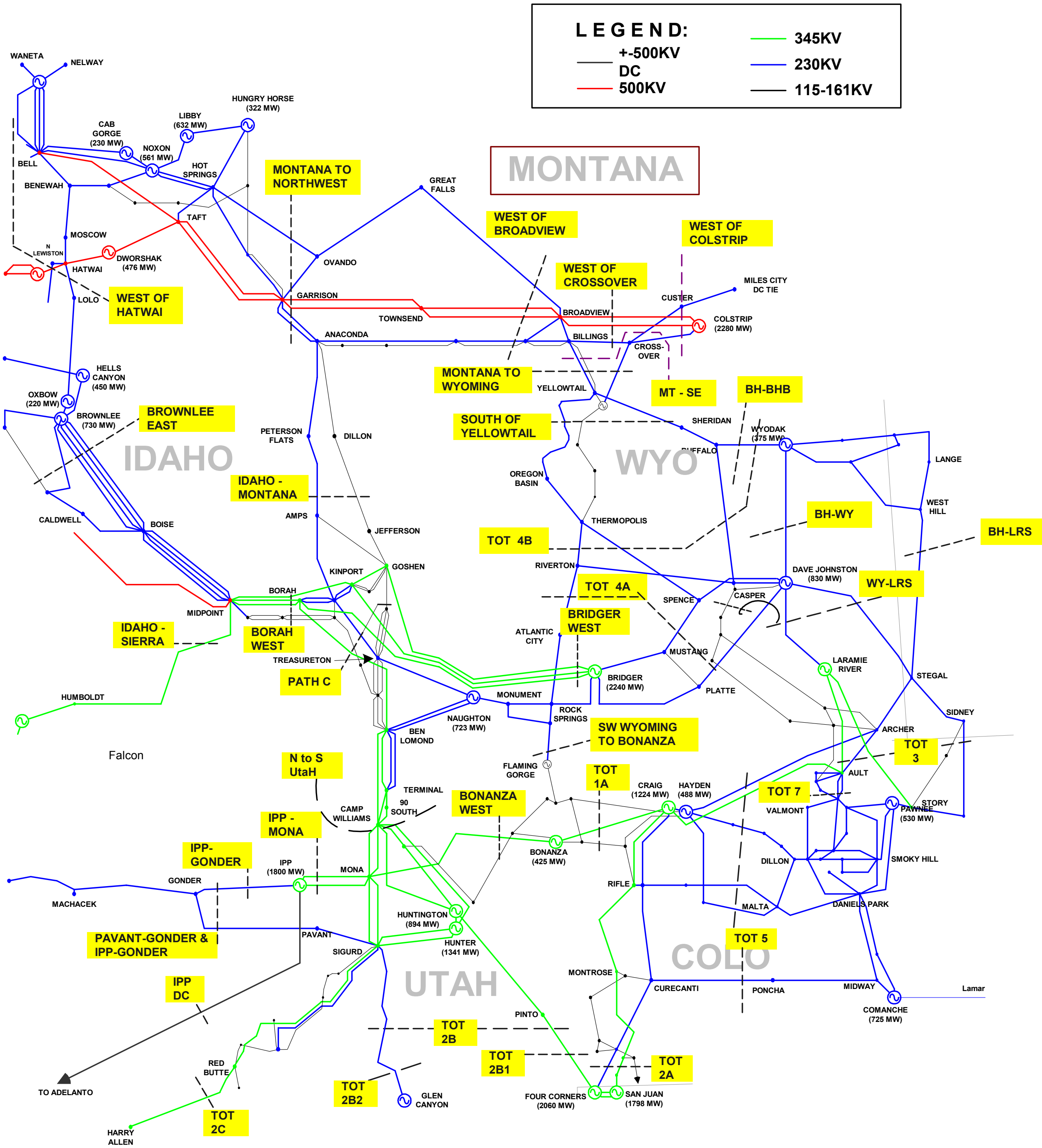
Table F.1.1 outlines the interfaces/paths monitored for RMATS analyses. Figure F.1.2 displays the geographic representation of these interfaces/paths.

Table F.1. 1: Transmission interface/path ratings

Name	From	To	Forward Limit (MW)	Reverse Limit (MW)
MONTANA - NORTHWEST	East	West	2,200	(1,350)
WEST OF BROADVIEW	East	West	2,573	N/A
WEST OF COLSTRIP	East	West	2,598	N/A
WEST OF CROSSOVER	East	West	2,598	N/A
IDAHO - NORTHWEST	East	West	2,400	(1,200)
IDAHO - SIERRA	North	South	500	(360)
BORAH WEST	East	West	2,307	N/A
IDAHO - MONTANA	South	North	337	(337)
BRIDGER WEST	East	West	2,200	N/A
PATH C	North	South	1,000	(1,000)
SOUTHWEST OF FOUR CORNERS	NE	SW	2,325	N/A
IPP DC LINE	NE	SW	1,920	(300)
INTERMOUNTAIN - MONA 345 KV	East	West	1,400	(1,200)
INTERMOUNTAIN - GONDER 230 KV	East	West	250	N/A
TOT 1A	East	West	650	N/A
TOT 2A	North	South	690	N/A
PAVANT, INTRMTN - GONDER 230 KV	East	West	440	(235)
BONANZA WEST	East	West	785	N/A
TOT 2B	North	South	780	(850)
TOT 2C	North	South	300	(300)
TOT 3	North	South	1,424	N/A
TOT 4A	NE	SW	810	N/A
TOT 4B	SE	NW	680	N/A
TOT 5	West	East	1,675	N/A
TOT 7	North	South	890	N/A
BILLINGS - YELLOWTAIL	North	South	400	(400)
BROWNLEE EAST	West	East	1,850	N/A
TOT 2B1	North	South	560	(600)
TOT 2B2	North	South	265	(300)
Combined 4a, 4b	N/A	N/A	1,096	N/A
Tot 2a, 2b, 2c Nomogram	North	South	1,570	(1,600)
Montana - Southeast	North	South	600	(450)
Black Hills to Laramie River	North	South	332	(332)
Black Hills to C Wyoming	East	West	332	(332)
Laramie River to C Wyomong	East	West	640	(640)
SW Wyoming to Bonanza	North	South	200	(200)
N to S Utah	North	South	3,000	(3,000)
SW Wyoming to N Utah	East	West	400	(400)
Black Hills to Big Horn	East	West	332	(332)
Yellowtail South (N-S)	North	South	625	N/A
Yellowtail North (S-N)	South	North	600	N/A
West of Naughton (E-S&W)	East	West	920	N/A
Sierra Import Limits	North	South	1,010	N/A

Ratings do not include seasonal variance i.e., Path C

Figure F.1. 2: Geographic representation of interface/path locations and line representation



Load Forecasting

Data Sources & Methodology

- The Load Forecasting Work Group (LFWG) developed the load forecast for the Rocky Mountain States for years 2008 and 2013. See RMATS Appendix E.
- WECC 2003 monthly peaks and total averages from the WECC 2003 L&R report were used for the remaining regions at the area level in the Western Interconnect (see Figure F.1.1).
  - WECC's 2003 Load & Resource report
    - Lists six Western Interconnect regions (Canada, Northwest, Rocky Mountain, Desert Southwest, California, Mexico)
    - Shows monthly data for the last year (2002), projection of current year (2003), and forecast of next year (2004)
    - Shows annual projection data for years 2005 - 2013 for winter peak, summer peak, and annual energy
- Market Simulator requires loads on an hourly basis at the nodal level. The spatial distribution of monthly loads and energy from the area level to the bus level were formulated using the peak breakdown configuration in the light spring WECC 08 LSP1A1 powerflow case. The spatial distribution of loads is assumed to not change over time; this can be corrected in future modeling by using more than a single season's pattern. The implication of this assumption is that an area will have the same proportion of load levels for all hours of both 2008 and 2013 test years.
- Derivation of 2008 and 2013 monthly estimates outside of the Rocky Mountain region are assembled based on the WECC L&R report forecast into areas.

Planning Margin

Capacity margins for the Western Interconnect regions outside of Rocky Mountain region were projected in SSG-WI's gas resources case to be adequate over the planning horizon 2008 through 2013. The 2008 SSG-WI gas case included projects underway, which add an estimated 25% planning margin over 2003 loads. Beyond 2008, SSG-WI participants agreed to use a 15% planning margin applied to load to cover Western Interconnect operating reserves and plant forced outages. RMATS participants adopted this same target planning margin for Rocky Mountain loads.

Resource adequacy reserves are often called planning reserves and are not the same as 5 and 7 percent operating reserves. FERC has proposed to adopt a 12 percent reserve margin as a minimum regional level for all regions; this 12 percent margin is low by traditional generation adequacy standards. The reserve margin and planning horizon sections of FERC's SMD NOPR are summarized below:

> In order to operate a transmission system reliably, adequate generation must be available to meet load. Some lead time is needed to develop adequate infrastructure for the future.

> Resource adequacy must be assessed at the regional level. Because all customers in a interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region.
>
> A requirement to assure adequate long-term resources is currently needed because spot market prices do not consistently signal the need for new infrastructure in the electric power industry. Most resources take years to develop and spot market prices alone may not signal the need to begin development of resources in time to avoid a shortage.
>
> Each region should take its own characteristics into account when determining the appropriate level of reserves, subject to a minimum level of resource adequacy for all regions. This determination has historically been made by load-serving entities under the oversight of the states, and FERC wants this state oversight to continue. FERC proposes that the level should be set by a Regional State Advisory Committee. States in the region should have a strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. State representatives are in the best position to determine on behalf of retail customers the trade-off between the costs to the customers of extra generation and demand response reserves and the difficult-to quantify benefits to the customers of increased reliability and reduced exposure of the region to effects of the power shortage.
>
> Once the future level of supply and demand resources is determined, the region must assess whether this level is adequate. This requir3es a regional determination of the appropriate level of resources, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent or another level.

The capacity associated with thermal and hydro resources was assumed to be the nameplate capacity. A 20% of nameplate capacity was assumed for wind resources.

Treatment of Resources

Several of the smaller SCCT or IC units were not explicitly modeled; instead, they were lumped into one peaking resource. In addition, multiple units at a plant location were consolidated into one for modeling purposes to speed up the model's run time. Exception: units were not consolidated if they had different heat rates.

All existing generation facilities were assumed to remain in service in 2008, with the exception of the following facilities, which were assumed to be retired as defined by the California Energy Commission;

- Mohave- 1580 MW
- South Bay- 695 MW
- Hunters Point- 219 MW
- Etiwanda 5- 130 MW

In a sensitivity analysis, Mohave's plant life was extended so that it was modeled as operating in 2013.

The actual study used wind profiles developed by the National Renewable Energy Laboratories (NREL) based on location and available wind resource. This established the annual wind generation capacity factor.

Hydro Conditions

RMATS accepted the SSG-WI assumptions for hydro modeling without change. RMATS tested the sensitivity of hydroelectric generation levels on production costs. Base simulations were run with medium hydro, while sensitivities were run at low and high hydro conditions.

For Canada and the Northwest, modified hydrology associated with the following historical years was used to represent the three water conditions:

- 1930 for low water with an annual Columbia River runoff of 93.7 million acre-feet (MAF),
- 1953 for average water with an annual Columbia River runoff of 133.3 MAF, and
- 1948 for high water with an annual Columbia River runoff of 170.3 MAF.

The modified hydrology associated with each of these three water conditions was run through water-power operation studies that modeled the non-power constraints of the reservoir systems and used any flexibility in the reservoirs to shape the generation to meet load. These studies produced monthly estimates of generation as well as maximum and minimum plant capacities.

The California Energy Commission has twenty years of hourly generation records for the hydroelectric plants in California. The limited period of record is not conducive to selecting single years to represent the three water conditions. Instead, the four driest years were averaged to represent the low water condition. All of the years were averaged to represent the average water condition. The four wettest years were averaged to represent the high water condition.

Given the large storage to runoff ratio for hydroelectric power plants in the Desert Southwest, it was assumed that in any one year, hydroelectric generation could be regulated as needed. Therefore, the average hydroelectric generation associated with these plants is deemed representative of all three water conditions. This simplifying assumption was made due to a lack of a historical record of hydroelectric generation by year and because the magnitude of hydroelectric generation is small compared to that in the remaining Western Interconnection.

Maintenance Outages

Outages for existing thermal plants (gas and coal) are consistent with the SSG-WI study, which was based on a (2002) Tabors Caramanis Associates cost-benefit analysis for RTO West. Modifications to the outages were made so that plants in the same geographic location were not modeled to be down for maintenance at the same time. In addition only large new gas plants have an imputed maintenance schedule. Small gas plants are assumed to be maintained when the model is not choosing the resource to run.

Heat Rates and VOM costs

For simplification, all existing and new thermal plants are assumed to have the same heat rate and cost curve if they are of the same age, vintage, type, and class, as shown in Table F.1-2.

Table F.1. 2: Cost curves for thermal plants by type, technology size and vintage

Fuel Type	Technology	Size	Vintage	Heatrate	VOM $/MWh ($2004)
Gas/Oil	Steam	<100 MW	Pre 1960	12,500	$5.00
Gas/Oil	Steam	>100 MW	Pre 1960	11,500	$5.00
Gas/Oil	Steam	<100 MW	Post 1960	10,500	$5.00
Gas/Oil	Steam	>100 MW	Post 1960	9,500	$3.00
Gas	SCCT		Pre 1985	13,500	$8.00
Gas	CCCT		Pre 1985	9,300	$5.00
Gas	SCCT	<70 MW	Post 1985	9,500	$5.00
Gas	SCCT	>70 MW	Post 1985	10,500	$5.00
Gas	CCCT		Post 1985	7,250	$2.00
Coal	Steam	<100 MW	Pre 1960	12,000	$4.00
Coal	Steam	>100 MW	Pre 1960	11,000	$2.00
Coal	Steam	<100 MW	Post 1960	11,000	$3.00
Coal	Steam	>100 MW	Post 1960	10,000	$2.00
Coal	Fluid Bed			10,500	$2.00
Coal	PC- Supercritical	>750	Post 2008	9,500	$2.00
Coal	IGCC	>250	Post 2008	8,000	$2.00
Diesel				11,000	$12.00
Gas/Oil	CCCT- Frame F		Post 2001	7,000	$2.00
Gas/Oil	CCCT- Frame G	>450 MW	Post 2008	6,300	$2.00

Resource Additions 2008

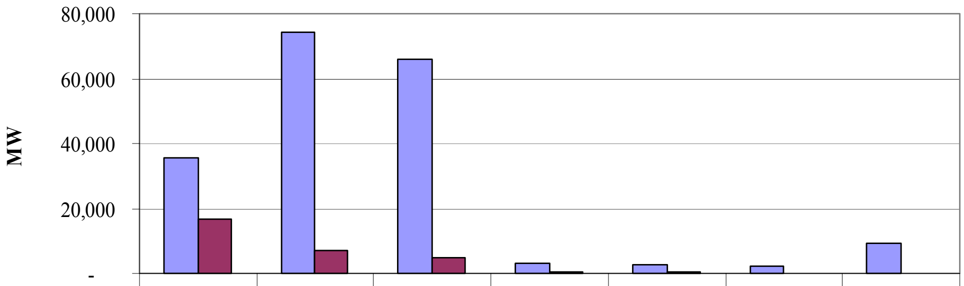
Generating resources that were under construction or that were highly likely to be placed in service by 2008 were included in the 2008 Base Case. The plants added were:

Table F.1. 3: Expected resources to be in service by 2008

Facility	Location	Technology	Capacity (MW)
Springerville Expansion	Arizona	Coal	400
Nebo	Utah	Gas- CCCT	147
Currant Creek	Utah	Gas- CCCT	525
Bennett Mountain	Idaho	Gas- SCCT	167
Pleasant Valley	Wyoming	Wind	144
Additional Colorado Wind Capacity	Colorado	Wind	23
Total			1,406

Figure F.1.3 below depicts a combination of existing resources with the additions assumed in 2008 study by fuel type. The figure demonstrates how the RMATS region stacks up with the Western Interconnect resources.

Figure F.1. 3: Generation capacity by fuel type (MW)- 2008

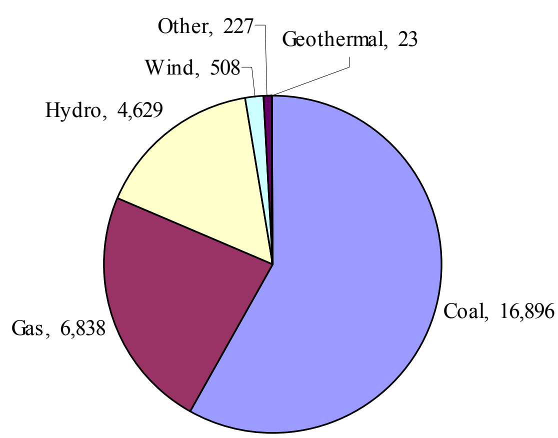


	Coal	Gas	Hydro	Wind	Other	Geothermal	Nuclear
WI	35,682	74,443	65,724	2,958	2,508	2,069	9,262
RMATS	16,896	6,838	4,629	508	227	23	-

Fuel Type

The assumed 2008 generation capacity located within the Rocky Mountain States is 29,121 MW. The diagram below (Figure F.1.4) shows the distribution of generation among the Rocky Mountain States.

Figure F.1. 4: 2008 Rocky Mountain area total resources by type (MW)



Resource Additions 2013

The Resources Additions Work Group (RAWG) developed generation addition scenarios in the Rocky Mountain region for modeling and analysis purposes. The basic thrust of the study was not to favor one company plan over another or one location over another, but to target development of using PRB coal and open range wind generation.

RAWG surveyed developers to determine generation projects that have been committed or proposed within the Rocky Mountain region. The following guidelines were used:

- Each new generation project should be modeled in at least one-generation alternative, either as an individual project or as part of a coherent group.
- Wind generation should be considered as having a contribution toward capacity of 20% of the nameplate rating.
- The total capacity additions in the alternatives would be generally equal to a multiple of load increase between years 2008 and 2013 plus a 15% planning reserve.

The generation alternative groupings or alternatives were based on the load growth plus 15% reserves. After these alternatives were consolidated, it was discovered that the actual load growth was 300 MW higher for 2013 than original projected. Since the expected wind capacity factor was higher than assumed for planning margin purposes, it was felt that there was sufficient generation added to cover this upward change in the load forecast.

The generation additions were placed into four alternatives. Alternative 1 added sufficient generation to cover the load growth plus reserves and was based on either existing IRPs or placement of resources close to loads in areas where there were no IRPs. Alternative 2 was based on the RMATS load growth with the focus being on adding mine-mouth, coal and open range wind mostly in Montana and Wyoming. Alternative 3 is an export case based on adding resources that were equal to twice the load growth plus reserves. Alternative 4, was another export case based on adding resources equal to twice the RMATS load growth plus reserves.

The RAWG and the modeling team worked closely with the TAWG in an iterative process to determine the transmission needed to integrate the new resources alternatives into the system and relieve the resulting congestion.

All four 2013 generation alternatives, called alternatives, included the resources assumed in the 2008 base case. The Table Following outlines the additions.

Table F.1. 4: Resource additions by state and alternative

State	Bubble	Gen Type	Name Plate Generation Values			
2013 ALTERNATIVE CASES			1	2	3	4
Colorado	Colorado East	Coal	1250	500	1540	2500
		Gas	210	210	210	603
		Wind	800	500	800	1500
	Colorado West	Coal				
		Gas				
		Wind			250	250
Idaho	KGB	Coal				
		Gas				
		Wind	125	125	125	125
	Mid Point/Boise/Snake	Coal	575			
		Gas				
		Wind				440
Montana	Montana West	Coal				
		Gas			260	260
		Wind	225	280	500	1000
	Broadview	Coal		250	500	750
		Gas				
		Wind	0		950	1000
	Colstrip/Crossover	Coal		359	609	1109
		Gas				
		Wind		50	100	200
Utah	Bonanza	Coal				
		Gas				
		Wind				
	IPP	Coal	200		950	950
		Gas				
		Wind				
	Utah North	Coal				
		Gas				
		Wind	250	100	200	320
	Utah South	Coal	575	575	575	575
		Gas	525	140	140	140
		Wind			120	250
Wyoming	Big Horn Basin	Coal				
		Gas				
		Wind	250	250	250	250
	Black Hills	Coal				
		Gas				
		Wind				125
	LRS	Coal				
		Gas				
		Wind		500	500	1500
	SW Wyoming	Coal				
		Gas				
		Wind	925	1150	1000	2450
	Wyoming	Coal		700	1400	2100
		Gas	50		50	50
		Wind				800
WYO(IDA)	Jim Bridger	Coal		575	575	575
		Gas				
		Wind			160	230
WYO(MT)	Yellowtail	Coal				
		Gas				
		Wind				
	Total Coal		2600	2959	6149	8559
	Total Gas		785	350	660	1053
	Total Wind Nameplate		2575	2955	4955	10440
	Total Firm Energy		3900	3900	7800	11700

Table F.1.5 displays the 2013 wind additions by Rocky Mountain state and area for each of the alternatives.

Table F.1. 5: Wind resources added for each alternative

	1	2	3	4
Colorado				
East- Colorado	800	500	800	1,500
West- Colorado	-	-	250	250
Subtotal	*800*	*500*	*1,050*	*1,750*
Idaho				
KGB	125	125	125	125
West- Idaho	-	-	-	440
Subtotal	*125*	*125*	*125*	*565*
Montana				
West- Montana	225	280	500	1,000
Broadview	-	-	950	1,000
Colstrip/Crossover	-	-	950	1,000
Subtotal	*225*	*280*	*2,400*	*3,000*
Utah				
Bonanza	-	-	-	-
IPP	-	-	-	-
North- Utah	250	100	200	320
South- Utah	-	-	120	250
Subtotal	*250*	*100*	*320*	*570*
Wyoming				
Bighorn Basin	250	250	250	250
Black Hills	-	-	-	125
Laramie River Station	-	500	500	1,500
SW Wyoming	925	1,150	1,000	2,450
Central- Wyoming	-	-	-	800
Jim Bridger	-	-	160	230
Yellowtail	-	-	-	-
Subtotal	*1,175*	*1,900*	*1,910*	*5,355*
Total Wind	**2,575**	**2,905**	**5,805**	**11,240**

Capital Costs

Generation and transmission capital costs were compiled and approved by the RMATS Resource and Transmission Addition Work Groups (RAWG & TAWG). These cost estimates reflect historical data and professional judgment of the group members. Estimates are added to the production costs for each alternative to determine and compare the full the cost of each such alternative. See appendix B.6 for an explanation of the economic comparison tables (see Appendix B.6).

Resource Capital Costs

The Northwest Power Planning Council's (NWPPC) *New Resource Characterization for the Fifth Power Plan reports*, published on January 5, 2004, and the California Energy Commission report on renewable resources were the starting point for estimating the capital costs of new resources. The following assumptions were used to develop capital cost estimates for each resource category:

- Wind: $760 per installed Kilowatt plus $44,000 per Kilowatt for grid integration
- Gas: $565 per installed Kilowatt plus $13,600 per Kilowatt for grid integration
- Coal: $1,230 - $1,755 per installed Kilowatt, depending upon the nameplate capacity of the plant, plus $13,600 per Kilowatt for grid integration

Transmission Capital Costs

The transmission capital costs were estimated on a line-by-line basis and include land costs, voltage, overhead, and customized equipment costs. These estimates were based on the professional judgment of the members of the RMATS Work Groups with the knowledge of the particular transmission area. The Table F.1.6 below contains transmission line costs used in the RMATS studies.

Table F.1. 6: Transmission line capital cost estimates

Line	From Bus	To Bus	Voltage (kV)	Miles	Cost per Mile ($)	Total Mileage Cost ($000)	Customized Equipment Cost ($000)	Total ($000)
1	Midpoint	Boise	230	106	575,000	60,950		60,950
2	Colstrip	Broadview	500				10,700	10,700
3	Broadview	Ringling	500				30,700	30,700
4	Broadview	Ringling	500	112	775,000	86,800	14,650	101,450
5	Missoula	Taft	500				30,700	30,700
6	Broadview	Great Falls	500	163	775,000	126,325	27,650	153,975
7	Great Falls	Hot Springs	500	200	775,000	155,000	11,150	166,150
8	Hot springs	Noxon	500	68	775,000	52,700		52,700
9	Noxon	Bell	500	96	775,000	74,400		74,400
10	Bell	Ashe	500	145	775,000	112,375		112,375
11	Jim Bridger	Borah	500	240	1,150,000	276,000		276,000
12	Kinport	Midpoint	500	112	775,000	86,800		86,800
13	Kinport	Borah	345	27	750,000	20,250	2,000	22,250
14	Borah	Midpoint	500	85	1,250,000	106,250	28,000	134,250
15	Borah	Midpoint	345	85	750,000	63,750	3,300	67,050
16	Ben Lomond	Borah	500	135	1,629,966	220,045		220,045
17	Treasureton	Borah	345	70	750,000	52,500	9,200	61,700
18	Ben Lomond	Treasureton	345	65	750,000	48,750	2,200	50,950
19	Jim Bridger	Treasureton	345	185	750,000	138,750		138,750
20	Jim Bridger	Naughton	345	103	900,000	92,700	2,200	94,900
21	Naughton	Ben Lomond	345	87	900,000	78,300	12,000	90,300
22	Jim Bridger	Naughton	500	103	1,452,097	149,566	31,550	181,116
23	Naughton	Ben Lomond	500	87	1,629,966	141,807	31,550	173,357
24	Ben Lomond	Midpoint	500	320	1,471,950	471,024	22,498	493,522
25	Midpoint	Table Mtn	500	550	1,500,000	825,000		825,000
26	Table Mtn	Tesla	500	135	2,000,000	270,000		270,000
27	Reno (Ant Mine)	Dave Johnston	345	70	630,359	44,125	19,665	63,790
28	Dave Johnson	Laramie River	345	76	630,359	47,907	5,773	53,680
29	Laramie River	Cheyenne Tap	345	65	630,359	40,973	11,773	52,746
30	Cheyenne Tap	Ault	345	45	630,359	28,366	5,773	34,139
31	Ault	Green Valley	345	70	630,359	44,125	9,719	53,844
32	Reno (Ant Mine)	Laramie River	345	146	630,359	92,032	15,719	107,751
33	Jim Bridger	Miners	345	120	900,000	108,000	9,754	117,754
34	Miners	Cheyenne Tap	345	60	630,359	37,822	9,719	47,541
35	Jim Bridger	Dave Johnston	345	220	900,000	198,000	9,748	207,748
36	Emery	Grand Junction	345	180	900,000	162,000	4,228	166,228
37	Ben Lomond	Mona	500	108	1,649,000	178,092	36,592	214,684
38	Mona	Red Butte	345	225	900,000	202,500	15,000	217,500
39	Red Butte	Crystal	345	102	923,489	94,196		94,196
40	Mona	Red Butte	500	225	1,452,000	326,700	36,592	363,292
41	Red Butte	Crystal	500	102	1,452,000	148,104	50,635	198,739
42	Crystal	Market Place	500	52	1,452,000	75,504	8,404	83,908
43	Midpoint	Grizzly	500	365	1,500,000	547,500		547,500
44	Midpoint	Crystal	500	505	1,000,000	505,000		505,000
45	Ringling	Borah	500	344	775,000	266,600	28,500	295,100
46	Colstrip	Reno	500	162	775,000	125,550		125,550
47	Colstrip	Reno	345	162	630,359	102,118	15,719	117,837
48	DC Wyodak	Tesla	500	1600	700,000	1,120,000	450,000	1,570,000
49	DC Wyodak	Mira Loma	500	1500	700,000	1,050,000	450,000	1,500,000
50	Midway	Vincent	500	113	2,000,000	100,000		100,000
51	IPP Upgrade					65,000		65,000
52	Amps Phase Shifter					10,000		10,000
53	FG Transformer					6,000		6,000

Gas Prices

The Gas Price sub-group to the Resource Addition Work Group (RAWG) approved the gas price forecast, believing:

- The existing forecasts that would have a broad base of support, such as the EIA forecast (dated), were a year old and do not reflect current conditions.
- The forecasts used in the Integrated Resource or Least Cost Plans of the investor owned utilities were based on forecasts developed over a year ago.
- Only one utility had updated its forecast more recently. However, we were unable to verify the methodology used by this utility, and we were therefore somewhat uncomfortable in using these results.
- The $4.00/MMBtu US Average Wellhead price was arrived at through discussion and consensus.
- One member felt that the current NYMEX Henry Hub Price for the calendar year 2008 of about $4.71/MMBtu was not indicative of what the price will actually be since it is at a market high. The member felt that the market would eventually respond with lower prices. After discussion, most members with an opinion also felt that the current price was probably on the high end of the cycle. Since that discussion the HH price have been higher and as of September 16, 2004 it was $4.72.
- The basis differentials that were developed by the Northwest Power & Conservation Council for the 5th Northwest Conservation and Electric Power Plan dated April 22, 2003 are appropriate.

Conclusions of the Gas Pricing Sub-group:

- The 2008 nominal gas price is assumed to be $4.00/MMBtu ($3.60 in 2004 dollars) for the low case and $5.00/MMBtu ($4.50 in 2004 dollars) for the high case. The most recent EIA forecast (December 2003) in nominal dollars for 2008 was $4.22/MMBtu. The consensus of the group was that the forecast comports with the EIA forecast.

- After discussion, the group settled on using the indexed price of $6.50/MMBtu at Henry Hub normalized to 2013 dollars ($5.20 in 2004 dollars.) Sensitivities were also run at $4.50/MMBtu at the Henry Hub ($3.60 in 2004 dollars.) A basis differential was set to match the 5th Northwest Conservation & Electric Power Plan.

- RAWG agreed that the basis differential for California that was adopted by SSG-WI was not realistic. The basis from the California border to-state shown in SSG-WI's modeling was $0.05/MMBtu when it should have been $0.20/MMBtu.

- The basis differential will not be escalated between 2004 and the 2008 and 2013 test years. Since the spread between any two points tends to reflect transportation costs, it is unlikely that the basis spread between two points would grow faster than cost of transportation. Since the capital investment in pipelines tends to be fixed with the initial construction, and the variable costs of operating the pipeline are small, the overall increase in nominal dollars will be negligible.

As for capital costs associated with expanding the capacity of the pipe (compression/new pipe), it was assumed that all incremental expansions would have a net cost comparable to the current rate. It was also assumed that all pipeline expansion would be equal to the incremental demand for natural gas. Since the rates would not materially change and the pipeline expansion would not change the supply/demand balance for pipe line capacity, the basis differentials should remain about the same over time.

Table F.1. 7: Gas prices for 2008 & 2013

	2008		2013	
	$4.00 Case	$5.00 Case	$4.50 Case	$6.50 Case
Average US Wellhead price	$ 4.00	$ 5.04	$ 4.50	$ 6.50
Wellhead w/Fuel use (4%)	4.16	5.20	4.68	6.76
Henry Hub-Wellhead w/fuel use	4.28	5.32	4.80	6.88
AECO	3.83	4.87	4.35	6.43
East-side PNW	4.23	5.27	4.75	6.83
Northern CA	4.61	5.65	4.98	7.06
Station 2	3.93	4.97	4.45	6.53
Sumas - PNW	4.15	5.19	4.67	6.75
West-side PNW	4.52	5.56	5.04	7.12
San Juan	4.02	5.06	4.54	6.62
CO - PSColorado	4.38	5.42	4.90	6.98
Rockies	3.88	4.92	4.40	6.78
UT-PACE	4.23	5.27	4.75	7.13
Wyoming	4.28	5.32	4.80	7.18
Montana	4.21	5.25	4.73	7.11
Idaho	4.23	5.27	4.75	7.13
N. NV-Sierra	4.57	5.61	5.09	7.47
Permian	4.11	5.15	4.63	6.71
Arizona	4.43	5.47	4.95	7.03
New Mexico	4.35	5.39	4.87	6.95
S. Nevada	4.44	5.48	4.96	7.04
CA Border	4.44	5.48	4.96	7.04
Southern CA	4.64	5.68	5.16	7.24

Coal Prices

RAWG collected coal prices for new plants from developers, and these generic prices were used for raw coal resources except in the case of Idaho Power where the company's suggested price was used for the IPP new unit at Intermountain. For coal resources that were not mine-mouth, a transportation surcharge was used to cover the additional rail costs. These numbers were the basis for assembling generic Rocky Mountain coal prices, in Table B.1.3 below.

Table F.1. 8: Coal prices (2004 dollars)

	Dollars per MMBtu
WY/MT Powder River mine mouth	$0.40
WY/MT Powder River transport WY/MT	$0.60
WY/MT Powder River transport to CO	$0.70
MT/ND lignite	$0.55
UT trucked coal	$0.90
UT rail transport	$1.25
SW WY mine mouth	$1.00