SSG-WI 2005 Transmission Planning Program
2015 Reference Case Key Assumptions Matrix

2015 Reference Case includes both production cost modeling (using Gridview) and economic analysis (outside the model) which combines production cost modeling results with incremental annualized fixed costs. Assumptions used in both are documented in this matrix.

Key Assumptions

Load Forecast

- The WECC's 2005 L&R load forecast is used for the 2015 studies, with three large exceptions:
  (1) For Oregon, Washington and parts of Idaho, the Northwest Power Planning Council supplied data from GENESYS/HELM models. The models rely on historical load shapes for the Northwest and a historic relationship between load and temperature for each month. The net result is hourly demand for 2015 given 2002 temperatures (2002 is considered medium water year)
  (2) For Colorado, parts of Idaho, Montana, Utah, Wyoming, and northern Nevada the load forecast in the RMATS study (Sept 2004) is used, escalated from 2008 to 2015 using rates provided by regional representatives
  (3) For California, the latest CEC load forecast is used (Sept, 2005).
- The topology adopted for this planning process is more detailed in some sub-regions than the WECC topology: two bubbles instead of one for NW, and multiple additional bubbles for Rocky Mountain states and California. The load forecast is disaggregated for the SSG-WI topology to create monthly peak and energy loads for each SSG-WI topology bubble. These monthly peak and energy load amounts are then distributed to the bus bars using the WECC power flow case. *The methodology for disaggregating the total load forecast for SSG-WI topology is an area requiring improvement.*
- The monthly peak and energy loads are converted to hourly shapes developed using FERC Form 714. Hourly load shapes are an important factor in modeling transmission congestion. Load shapes are determined for each bubble (all buses within a bubble use the same hourly shape). With two exceptions, hourly shapes for each bubble are "normalized" using 2002 actual loads as the sample year.
  Exceptions:
  (1) hourly shapes developed in RMATS are used for Colorado, parts of Idaho, Montana, Utah, Wyoming, and northern Nevada;
  (2) hourly shapes produced by the NWPCC/BPA's HELMS model are used for Oregon, Washington and parts of Idaho.
- California loads and mapping to buses are adjusted to capture the unique characteristics of pumping plants in California.
- Transmission losses are included in the load forecast. Currently, WECC does not have information to separate loss amounts. This is an area of improvement.
- Existing and some forecasted demand side management (DSM) and energy efficiency programs are embedded in the load forecast. *Currently WECC does not have information to separate these amounts. This is an area of improvement.* In addition, new DSM programs are modeled as dispatchable resources in 2015 studies.
- No load forecast sensitivities are run for the 2015 Reference Case.

Load Forecast as Modeled in Gridview

AREA	ANNUAL ENERGY MWh	Annual Peak MW
IMPERIAL	4,212,776	1,091
LADWP	33,314,726	6,249
MEXICO-C	15,278,260	3,209
PG&E_BAY	51,987,840	10,919
PG&E_VLY	79,993,555	19,549
SANDIEGO	22,962,706	5,058
SOCALIF	134,936,173	25,462
ARIZONA	104,761,526	22,626
NEVADA	29,345,006	7,276
NEW MEXI	27,245,822	4,730
WAPA L.C	1,590,561	252
ALBERTA	77,291,069	10,794
B.C.HYDR	74,158,753	12,457
NW_EAST	74,310,368	12,355
NW_WEST	107,629,066	17,913
B HILL	6,588,272	976
BHB	3,695,185	506
BONZ	1,242,519	237
COL E	62,135,625	10,727
COL W	6,440,916	993
IDAHO	18,631,181	3,694
IPP	-	1
JB	-	1
KGB	6,826,263	1,429
LRS	3,996,419	581
MONTANA	10,807,468	1,698
SIERRA	11,728,413	1,995
SW WYO	4,553,805	637
UT N	42,173,311	7,999
UT S	6,057,463	1,189
WYO	2,454,859	356
YLW TL	-	1
Total	1,026,349,907	192,959

Network Representation and Topology	• WECC's 2008 Heavy Summer power flow case (HS2A) is used for year 2015 with the following modifications to reflect incremental transmission additions between 2008 and 2015: - Palo Verde – Devers #2 - Tehachapi Wind transmission – 2 lines - Navajo/Desert Rock; Four Corners – Moenkopi - Moenkopi to Market Place - Coronado to Silver King line including series comp - 4 Corners to Phoenix - West of Devers upgrade - North Phoenix (Raceway) - Capacity upgrade at N. Gila - Pinal Project - Amps Phase Shifter (Mill Creek Phase Shifter) - Added transmission to integrate Montana incremental transmission, increasing Montana to Northwest transfer by 750 MW (series compensation on the 500 kV lines) - Added transmission from Wyoming to Utah to integrate Bridger #5 and SW WY wind - Added transmission configured for the San Francisco Bay Area Project - Imperial 500 kV line (one to San Diego and one to LA) - Added transmission connection Kansas to Colorado, to integrate the 2-700 MW coal plants - Modified the connectivity of PDCI to reflect improvements applied in California (Reconfigured Sylmar to SCE) • Criteria for line additions in the 2015Reference Case: Use conservative transmission assumptions in the 2008 base case, with minimal additions; add only committed projects and necessary transmission to integrate new resources. The purpose of the Reference Case is to expose transmission problems. • The power flow case takes into account differences in time zones. • Topology: the WECC 22-bubble topology is used, with these exceptions: - The single NW bubble is split into west and east NW bubbles - The single PG&E bubble is split into two bubbles, to accommodate variations in load types and shapes - The RMATS topology is used for the Rocky Mountain states, except that the Montana bubbles are reduced from 2 to 1 With these changes, the SSG-Wi topology includes a total of 33 bubbles. ***See Attachment 1 for SSG-WI topology diagram and Attachment 2 for changes to branches in 2015 Reference Case***
Transmission Path Ratings & Nomograms	• The Transmission Subgroup started with the WECC path rating catalog and applied modifications to capture operating limits for a number of key paths. • Derates to recognize historical OTC limitations are applied. • Nomograms take seasonal derates into consideration. ***See Attachment 3 for path ratings used in 2015 Reference case and Attachment 4 for a map of major paths***
Transmission Forced Outages	Grid View's ability to model transmission forced outages is not used in this study. Reason: transmission maintenance outages typically occur during off peak usage only (low impact) and forced transmission outages occur infrequently.
Wheeling rates	Wheeling rates are not included in the 2015 study. 2008 studies included sensitivities with wheeling rates on an inter-area basis. A decision was made to exclude the wheeling rates from 2015 studies. Reason: lack of sufficient data to include both non-firm and firm wheeling rates; most firm

	transactions include wheeling as a sunk cost. *This is an area that requires improvement.*
Transmission Losses	The transmission loss capability of Gridview is not used in this study. *This is an area that requires improvement.*
Reserves	The Gridview model allows modeling of reserves at a regional level. The 2015 Reference Case includes 4% reserves (3% for spinning and 1% for contingency) for each of the 5 regions, which approximates 50% of the WECC reserve requirement (after forced outages) – 7% for thermal and 5% for hydro.
Generating Resources	Resource information is collected at the unit level of detail. Existing resources • Existing resources are resources assumed to be online by 12/31/2008. These resources were identified through the WECC power flow case (HS2A PF) and the SSG-WI 2003, CEC, RMATS, and other data bases. The states reviewed the list of resources and capacities, and their comments are included to the extent possible. Generating resource capacities are based on the power flow case. Thermal unit capacities are net of station service. *Net to grid generation of cogeneration resources is not explicitly modeled except in Alberta. This is an area of improvement.* The power flow capacities are compared to CEC, Platts, and other data sources and the majority of differences are minimal where material difference are noted by experts, capacities are edited. Incremental resources • Incremental resources are resources expected to be placed in service between 2009 and the 2015 (inclusive) as well as a few pre- 2009 resources omitted from the 2008 study. • Generation subgroup collected data from utilities' IRPs and coordinated with state representatives, NTAC and NWPCC. RPS requirements and NREL's recommended wind generation additions are also considered. ***See Attachment 5 for a list of incremental resources by area and fuel type and Attachment 6 for 2015 Reference Case Load and Resource Balance***
Thermal Unit Operational Info	• Thermal unit commitment is modeled in the study. • Data requirements for unit commitment include capacity information, planned and forced outage assumptions, heat rate curves, ramp rates, minimum up/down times, start-up costs, non-fuel variable O & M costs (Emission rates/constraints and must-run status are capabilities in GridView but are not modeled at this time). • The NWPCC's database supporting the Council's Fifth Power Plan, CEC information, Platts database, and other sources are used to develop generic assumptions for various thermal technologies and locations. Thermal units are broken into categories on the basis of fuel type, technology type, vintage, and capacities. A set of assumptions is developed for each unit category, with more detailed data included for gas-fired units. Most incremental resources added in the 2015 Reference case fit into one of the existing categories. • No resource sensitivities around 2015 Reference Case are done at this time. ***See Attachment 7 for thermal unit generic characteristics by technology type and Attachment 8 for heat rates by fuel and technology***

<table>
<tr><td>Thermal forced and scheduled outages</td><td>

- Database supporting EIA's energy Outlook 2005 is used to develop forced and planned maintenance outages rates
- Occurrences of forced outages are modeled probabilistically using GridView's Monte Carlo capability.

	Forced (%)	Planned (%)
Existing Coal	6.6	7.1
New Coal Plant	6.0	6.5
Oil/Gas Steam	7.1	10.5
Combustion Turbine	3.6	4.1
Combined Cycle	5.5	4.1
Existing Nuclear	7.0	7.5
Advanced Nuclear	3.8	6.1

</td></tr>
<tr><td>Thermal start-up costs; minimum up/down time; ramp-rates</td><td>

- Start-Up costs are based on IRP and expert input, and include fuel, O&M and other costs to reach point of synchronization. Minimum up and down times are provided by SSG-WI members.
- Ramp rates are provided by experts.
- Non-fuel variable O&M rates

	Start-Up Costs $/Unit per Start	Min Up/Min Down Hrs
Combustion Turbine	$ 2,000	8/8
Combined Cycle	$10,000	8/8
Oil/Gas Steam	$3,100	8/8
Coal Steam	$15,000	8/8

Ramp rate	MW/Min
Combustion Turbine	1
Combined Cycle	1
Oil/Gas Steam	1
Coal Steam	2.5

</td></tr>
</table>

Fuel Prices	Gas prices:
	• Several Henry Hub price sensitivities are used (2005$/MMbtu): $5, $7, and $9. $5 is the base assumption in the Reference Case.
	• The NW Power and Conservation Council's methodology in the Fifth Power Plan is used to estimate Western gas market hub and burner tip area differentials.
	• Fixed transportation cost (capacity charge) of delivering gas from regional hubs to burner tip areas is included with other fixed costs of the scenario. The fixed transportation charge was calculated using data from CEC Integrated Energy Policy Report 2005.
	See Attachments 9,10,11
	Coal prices:
	• The coal price forecast in the EIA's "Annual Energy Outlook 2005" is used. This forecast is based on historical trends. The EIA forecast of transportation costs includes two tiers of transportation adders:
	  - Tier 1 (based on historical trends)
	  - Tier 2 (tier 1 plus additional transportation for high demand areas)
	• The tier adders are applied to each coal plant taking into account the sources of coal supplies and the demand area (generator location). The transportation adders are then added to the coal price to get the total price at each plant. The combined price is then averaged over all plants within each SSG-Wi topology bubble, and the averages are entered in GridView.
	Other fuels:
	• Assumptions for other fuels are based on RMATS study.
	See Attachment 12 for coal and other fuels pricesau

Hydro Generation	• The following sources of hydro data are used for the study:
	  - NW federal, Mid-C Nonfederal, and PacifiCorp: recent historical hourly hydro generation that is reasonably reflective of latest Biological Opinion. Actual hourly hydro data from three historical years is chosen: Medium (2002), Low (2003) and High (2000). The Reference Case run reflects the Medium hydro case only. Sensitivities are not run for the Low and High cases.
	  - Other NW nonfederal: actual hourly data is lacking. Fallback is monthly actual data, to which peak shaving algorithm is applied
	  - Central Valley Project: Due to difficulty of disaggregating hourly forecasted data to individual plants, CAISO historical hourly data is used
	  - Other California: CAISO has provided hourly historical hydro data aggregated by river system.
	  - Colorado: Bureau of Reclamation--Upper and Lower Colorado Regions provided monthly forecasted data, which reflects recent severe drought in terms of updated hydrology and operational algorithms, to which GV peak shaving algorithm is applied. Still need to obtain non-Federal Hydro data.
	  - Canada: BC Hydro provided monthly hydro for adverse, average and above average hydro conditions grouped by their coastal, Peace River and Columbia River facilities. Data is shaped using year 2002 actual loads and hourly flows in and out of BC Hydro territory (BCH-US and BCH-Alberta paths), combined with treating the thermal generation as a block resource. Peak shaving algorithm is utilized for incremental hydro resources added for 2015 study. *BC Hydro modeling is an area of improvement.*
	  - Arizona/Desert SW: Non-Federal hydro data from Salt River Project and other projects is used.
	• Originally, SSG-Wi planned to use the Council's GENESYS model to simulate hydro generation. Data and other technical issues arose that prevented this. However, ABB is working to include this algorithm in the GridView model for the region's future use. This is an area of improvement.

Renewable Generation	• Hourly wind shapes used to model all wind generating resources are supplied by National Renewable Energy Lab (NREL). Exception: CAISO provided wind shapes for its areas based on actual data. Wind is treated as a fixed input to the model. • Geothermal plants are modeled as base load plants as confirmed by Clean and Diversified Energy Initiatives Geothermal Task Force. Data to model

specific plants in CA is provided by CAISO.

- Solar production profiles are provided by NREL.

DSM/Energy Efficiency

- Existing and some forecasted DSM and energy efficiency programs are embedded in the load forecast. These amounts are not explicitly collected by WECC.
- In addition, some new DSM programs are modeled as dispatchable resources in 2015 studies.

Incremental Resources' Capital Costs and Fixed O&M (not part of production cost modeling)

- Generic capital cost and fixed O&M assumptions from the NWPCC 5th Power Plan are used where specific resource costs are not available. NREL provided assumptions for capital costs of solar resources. Initial investment costs include a resource's development, construction, and interconnection costs (interest during construction, AFUDC, was calculated separately using a rate of 7.5%). Specific capital costs were used for resources from PacifiCorp IRP, BC Hydro, Alberta. Capital costs for Alberta cogeneration facilities were calculated using net to grid MW instead of nameplate capacity.
- DSM costs for new programs are assumed to be incentive payments for commercial and industrial customers to participate in the program (included as part of fixed O&M line item in the table). Costs for DSM and energy efficiency programs embedded in the load forecast are not captured in this analysis. *This is an area of improvement.*

Resources:	Initial Investment $/kw	Fixed O&M $/kw/yr
Coal	1,373	44
Gas		
SCCT	663	9
CCCT	580	8
Wind	1,116	22
Geothermal	2,021	106
Solar		35
Solar CSP	3,040	38
Solar PV	7,732	35
Biomass	2,196	91
DSM (program costs)		60
AFUDC		7.5%

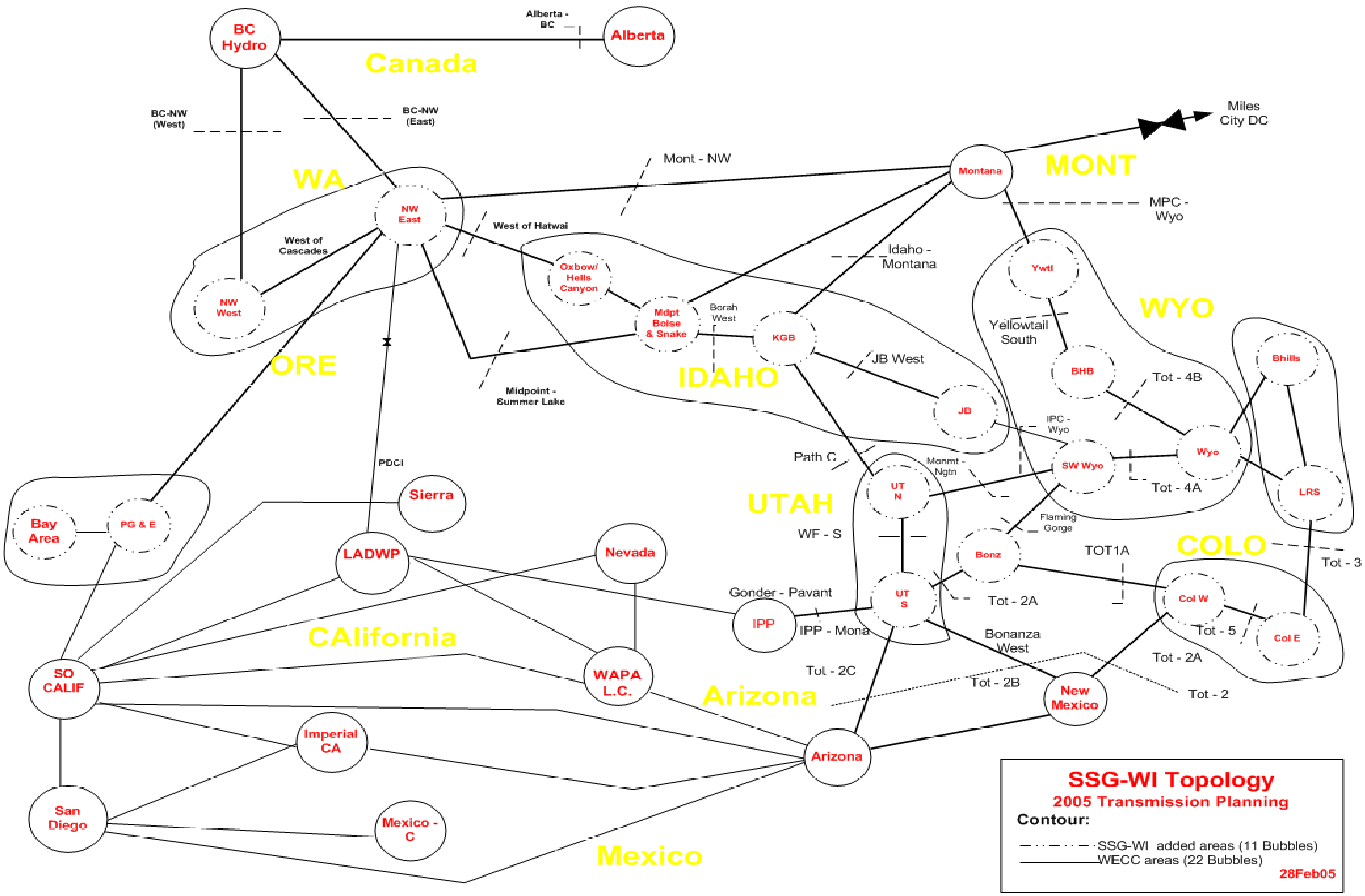
See Attachment 13 for detailed capital costs assumptions for incremental resources by technology type

Incremental Transmission Capital Costs and Fixed O&M (not part of production cost modeling)

- Generic capital costs provided by Transmission subgroup are used in all instances where specific capital cost estimates were not provided. Work done by NTAC, BPA and RMATS served as a source of generic assumptions. Initial investment estimates for transmission include planning, materials and construction, land, overheads, interest during construction, etc.
- Fixed O&M is assumed to be 2% of initial investment (source RMATS).

See Attachment 14 for detailed capital costs assumptions for incremental transmission by area

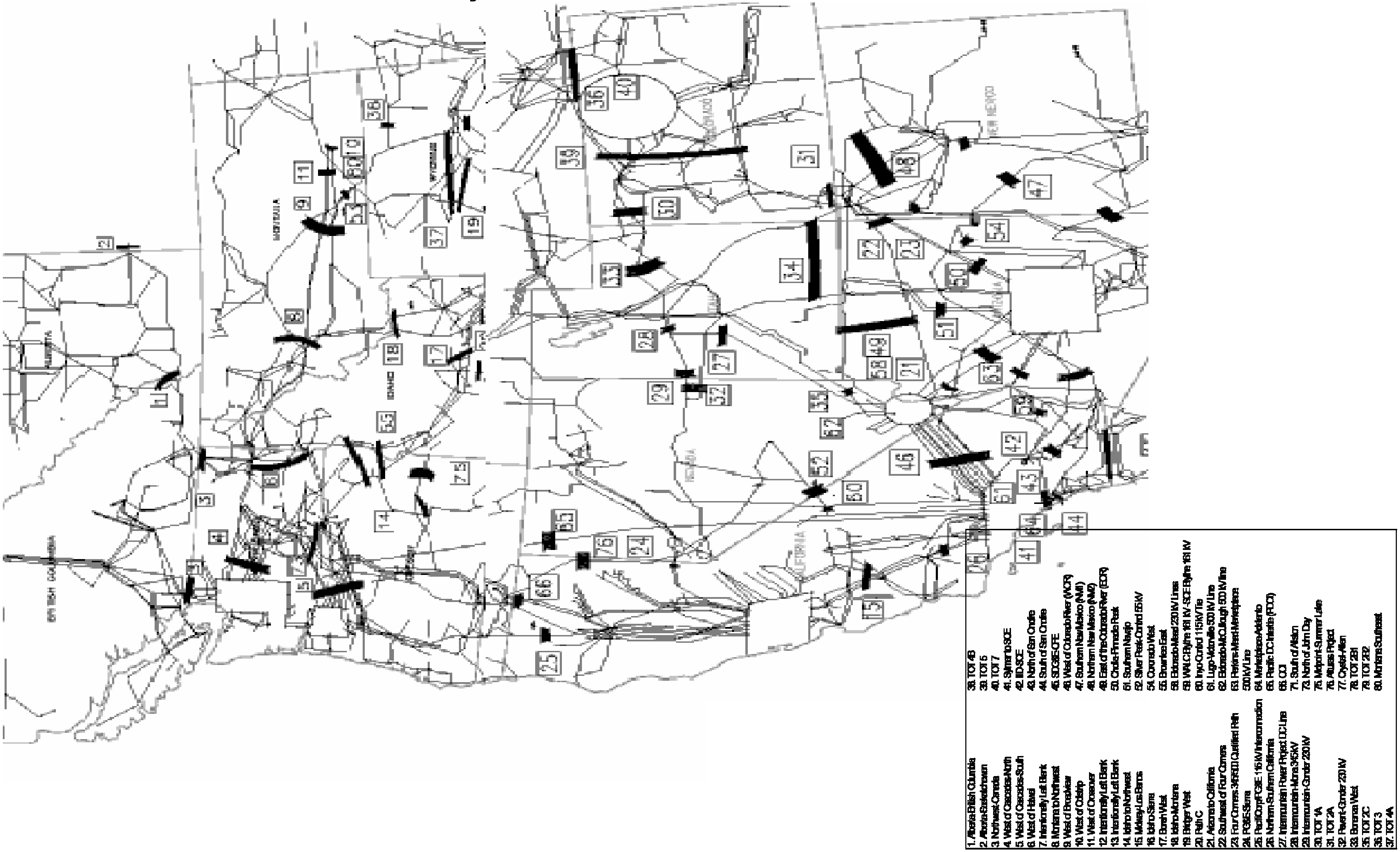
Attachment 1 – SSG-WI Topology



Attachment 2 – Branch Changes in 2015 Case

Interface	Changes applied
Gregg to Hentap1	▪ Doubled line capacity by changing the impedance (previously, new generation had been adde without transmission)
Hassayampa to North Gila	▪ Changed line ratings to reflect capacitor upgrade
Imperial Valley to San Diego	▪ Removed one of the two IV San Diego 500kV lines
North Gila to Imperial Valley	▪ Changed line ratings to reflect capacitor upgrade
Miguel Bank Monitoring	▪ Now monitoring the 500/300 kV banks
PV to Devers	▪ Both CAISO and Imperial submitted data in their respective change files to add PV to Devers #2. Correction was made to eliminate duplication ▪ Changed line ratings to reflect capacitor upgrade
Panoche to Helm	▪ Removed line monitoring (previously, generic generation had been added without transmission)
Poe to Rio Oso	▪ Removed line monitoring (previously, hydro had been added and artificially aggregated at POE)
Rosefill to Folsom	▪ Removed line monitoring (previously, generic generation had been added without transmission)
Warner to Wilson	▪ Removed line monitoring (previously, generic generation had been added without transmission)
West of Devers Upgrade	▪ Upgrade single circuit to double circuit: 1) Devers to San Bernardino and 2) Devers to Vista

Attachment 3 – Western Interconnect Major Paths



Attachment 4 – WECC Path Catalogue Operating Limits & Other Adjustments Made by SSGWI
Part 1 of 4

Interface Name	Forward Limit (MW)	Reverse Limit (MW)
ALBERTA - BRITISH COLUMBIA	700	-720
ALBERTA - SASKATCHEWAN	150	-150
ALTURAS PROJECT	300	-300
BONANZA WEST	785	
BORAH WEST	2557	
BRIDGER WEST	2200	
BROWNLEE EAST	1850	
CHOLLA - PINNACLE PEAK	2700	
COI	4700	-3675
Combined 4a 4b	1096	
CORONADO - SILVER KING - KYRENE	1600	
Crystal - H Allen 500 kV PS	1300	
Crystal - H Allen230 kV PS	950	
Devers - San Bernardino 1(Post Outage)	317	
Devers - San Bernardino 2 (Post Outage)	458	
Devers - Vista 1 (Post Outage)	458	
Devers - Vista 2 (Post Outage)	494	
Devers Bank No. 1	1120	-1120
Devers Bank No. 1 (Post Outage)	1230	
EAGLE MTN 230_161 KV - BLYTHE 16	72	-218
East of PV	6970	
Eldorado - Lugo	1386	-1386
ELDORADO - MCCULLOUGH 500 KV	2598	-2598
ELDORADO - MEAD 230 KV LINES	1140	-1140
EOR	10255	
Hassayampa - N. Gila	1905	
IDAHO - MONTANA	337	-337
IDAHO - NORTHWEST	2400	-1200
IDAHO - SIERRA	500	-360
IID - SCE	1500	
Imperial Valley - La Rosita	797	-797
Imperial Valley to Miguel	2200	
INTERMOUNTAIN - GONDER 230 KV	200	
INTERMOUNTAIN - MONA 345 KV	1400	-1200
INYO - CONTROL 115 KV TIE	56	-56
IPP DC LINE	1920	-1400

Interface Name	Forward Limit (MW)	Reverse Limit (MW)
Jojoba - Kyrene	1732	-1732
LUGO - VICTORVILLE 500 KV LINE	2400	-900
Market Place - Adelanto	1636	-1636
Mccullgh - Victorville	1385	-1385
MIDPOINT - SUMMER LAKE	1500	-600
MIDWAY - LOS BANOS	5400	
Miguel - Tijuana	912	-912
Miguel Bank No. 1	1120	-1120
Miguel Bank No. 2	1120	-1120
Moenkopi - El Dorado	1900	-1645
Mohave - Lugo	1386	-1386
MONTANA - NORTHWEST	2950	-1350
MONTANA SOUTHEAST	600	-600
N. Gila - Imperial Valley	1905	
Navajo - Crystal	1900	-1900
Navajo - Moenkopi	1411	
NORTH OF JOHN DAY	8600	-8600
North of Miguel	2000	
NORTH OF SAN ONOFRE	2440	
NORTHERN NEW MEXICO (NM2)	1800	
NORTHWEST - CANADA	2000	-3150
NW to Canada East BC	400	-400
NW to Canada West BC	2000	-2850
PACIFIC DC INTERTIE (PDCI)	2800	-2100
PACIFICORP_PG&E 115 KV INTERCON.	100	-45
Path 26	4000	-3000
Path 45	408	-800
PATH C	775	-850
PAVANT INTRMTN - GONDER 230 KV	440	-235
Peacock - Mead	508	-508
Perkins - Big Sandy	1238	-1238
PERKINS - MEAD - MARKETPLACE 500	1400	
PG&E - SPP	160	-150
PGE-Bay	50000	
PV to Devers	4676	

Interface Name	Forward Limit (MW)	Reverse Limit (MW)
PV West	3600	
SCIT	17700	-17700
SDGE Import Limit	4000	
SILVER PEAK - CONTROL 55 KV	17	-17
South of Alston	3050	
South of Lugo	6100	-6100
South of Navajo	2264	
SOUTH OF SAN ONOFRE	2500	
SOUTHERN NEW MEXICO (NM1)	1048	-1048
SOUTHWEST OF FOUR CORNERS	5325	
SYLMAR - SCE	1600	-1600
TOT 1A	800	-800
TOT 2A	690	-690
Tot 2a 2b 2c Nomogram	1570	-1600
TOT 2B	780	-850
TOT 2B1	560	-600
TOT 2B2	265	-300
TOT 2C	300	-300
TOT 3	1800	-1800
TOT 4A	810	-810
TOT 4B	680	-680
TOT 5	1675	-1675
TOT 7	890	
WEST OF BROADVIEW	3323	
WEST OF CASCADES - NORTH	10500	-10500
WEST OF CASCADES - SOUTH	7000	-7000
WEST OF COLSTRIP	3348	
WEST OF CROSSOVER	3348	
WEST OF HATWAI	4277	
WOR	11823	
WOR - IID230	600	-600
WOR - N.Gila	1861	
WOR -n- El Dor to Lugo	2754	
WOR -n- Mc-Vic	2592	
WYOMING TO UTAH	1700	

Attachment 4 – WECC Path Catalogue Operating Limits & Other Adjustments Made by SSGWI Part 2 of 4

Note Path 1: Alberta-BC was decreased from 1000 to 700 MW to reflect operational limits.

Note Path 3: The Canada-Northwest limit was not reduced from the 3150 MW rating however a nomogram was included that decreased the Westside limit (2850 MW) by 1 MW for each MW of Northern Puget Sound generation.

Note Path 4: West of Cascades North was increased from 9800 to 10500 MW due to the upgrade of the PSE 230-kV line.

Note Path 6: West of Hatwai was increased from 4000 to 4277 MW to reflect the accepted rating that was recently obtained.

Note Path 8: Montana to Northwest was increased from 2200 to 3000 MW due to upgrades to the series compensation.

Note Path 9: West of Broadview was increased from 2573 to 3323 MW due to upgrades to the series compensation.

Note Path 10: West of Colstrip was increased from 2598 to 3348 MW due to upgrades to the series compensation.

Note Path 11: West of Crossover was increased from 2598 to 3348 MW due to upgrades to the series compensation.

Note Path 15: Path 15 was increased from 3900 to 5400 MW due to the addition of the third Midway-Los Banos line.

Note Path 17: The West of Borah path rating used was 2557 MW to reflect a planned upgrade to increase this path by 250 MW by summer 2007.

Note Path 19: Bridger West was maintained at 2200 MW. The addition of the Bridger-Wasatch Front line will be rated separately.

Note Path 20: Path C was increased from 1000 to 1075 MW due to a planned upgrade of this path.

Note Path 21: The Arizona-California Rating was ignored in this study.

Note Path 22: Southwest of Four Corners was increased from 2325 to 5325 MW due to Four Corners-Moenkopi (Navajo Project) and Four Corners to Pinnacle Peak Project.

Attachment 4 – WECC Path Catalogue Operating Limits & Other Adjustments Made by SSGWI Part 3 of 4

Note Path 26: Path 26 was increased from 3400 to 4000 MW due to the addition of a new SPS.

Note Path 36: TOT3 was decreased from 1605 to 1450 MW to reflect seasonal derates.

Note Path 41: Sylmar-SCE path has been uprated from 1200 to 1600 MW due to the addition of a new transformer at Sylmar.

Note Path 44: South of San Onofre was increased from 2200 to 2500 MW to reflect the actual capability on this path.

Note Path 46: WOR was increased from 10118 to 11823 MW due to the addition of the EOR SC upgrades and the Palo Verde-IH500-Devers #2 line.

Note Path 48: Northern New Mexico (NM2) rating was changed to 1800 MW to reflect a recent upgrade and match Path Rating Catalog.

Note Path 49: EOR was increased from 7550 to 10255 MW due to the addition of the EOR SC upgrades and the Palo Verde-IH500-Devers #2 line. Addition of Moenkopi to El Dorado contributed 1000 MW additional rating.

Note Path 50: Cholla-Pinnacle Peak was increased from 1200 to 2700 MW due to new 500-kV project from Four Corners to Pinnacle Peak.

Note Path 54: The Coronado-Silver King-Kyrene was increased from 1100 MW to 1600 MW due to upgrades associated with the addition of Springerville Unit 4. The upgrades include increasing series compensation to 70%, addition of a 500/345kV transformer, and thermal increases to the 230kV system west of Silverking.

Note Path 55: Brownlee East was increased from 1750 to 1850 MW due to energizing the second Oxbow-Brownlee line.

Note Path 63: Perkins-Mead-Marketplace was increased from 1300 to 1400 MW due to the removal of the Perkins phase shifter, upgrading the line and adding the Navajo-McCullough line

Attachment 4 – WECC Path Catalogue Operating Limits & Other Adjustments Made by SSGWI Part 4 of 4

Note Path 64: Market Place-Adelanto was increased from 1200 to 1636 MW due to the ability of this line to carry more than its contractual allocation of 1200 MW.

Note Path 65: The PDCI was decreased from 3100 to 2800 MW partially due to seasonal derates similar to the COI (-100 MW) and partially to reflect the lack of modeling losses in the program (-200 MW).

Note Path 66: COI rating was decreased from 4800 to 4700 MW due to seasonal derates. This is an increase from the number used in the 2003 study (4500 MW) due to the impact of the addition of the Schultz-Wautoma line. There is also a COI/North of John Day/Midpoint-Summer Lake nomogram included.

Note Path 71: South of Allston was increased from 1620 to 3050 MW to update the path rating catalogue value and reflect additional facilities that were added in the path definition.

Note Path 73: North of John Day was increased from 8400 to 8600 MW due to the addition of the Schultz-Wautoma line.

Note Path 75: Midpoint-Summer Lake was increased from 400 to 600 MW (West to East) to reflect desired path rating increase.

Note Path 76: The rating of the Bordertown Phase Shifter (between busses 64017 and 64018) should be changed to +/-300 MW so that the Alturas Path can be used to its full +/-300 MW rating.

Note Path 101: SCIT nomogram limit was increased from 13700 to 17700 MW due to the addition of the EOR SC upgrades and the Palo Verde-Devers #2 line.

Note Path 102: South of Lugo was increased from 2264 to 6100 MW due to the addition of a new line and other upgrades.

Attachment 5 – Incremental Resources by Fuel Type and Area (Capacity net of station service)

Part 1 of 2

Includes submitted changes to the 2008 case, whether addition/subtraction of MW in pre-2008 years, or upgrades to older units

Sum of PSSEMaxCap(MW)			Fuel										
Region	**Area Name**	**Comment**	**Bio**	**Coal**	**DSM**	**Gas**	**Geothermal**	**Hydro**	**Oil**	**Solar**	**Wind**	**Nameplate Total**	**Discounted Total**
AZNMNV	ARIZONA	Added		3,400		2,700					1,500	7,600	6,400
	ARIZONA Total			3,400		2,700					1,500	7,600	6,400
	NEVADA	Added				1,446						1,446	1,446
	NEVADA Total					1,446						1,446	1,446
	NEW MEXI	Added	64			1,406						1,470	1,470
		Retired				(149)			(20)			(169)	(169)
	NEW MEXI Total		64			1,257			(20)			1,301	1,301
	WAPA L.C	Added		400						50		450	450
	WAPA L.C Total			400						50		450	450
AZNMNV Total			**64**	**3,800**		**5,403**			**(20)**	**50**	**1,500**	**10,797**	**9,597**
CAISO	IMPERIAL	Added	75			50	425					550	550
	IMPERIAL Total		75			50	425					550	550
	LADWP	Added				300				185	1,030	1,515	743
	LADWP Total					300				185	1,030	1,515	743
	MEXICO-C	Added				1,619	86					1,704	1,704
		Retired							(300)			(300)	(300)
	MEXICO-C Total					1,619	86		(300)			1,404	1,404
	PG&E_BAY	Added				565						565	565
		Retired				(215)						(215)	(215)
	PG&E_BAY Total					350						350	350
	PG&E_VLY	Added	190			2,666	410			280	900	4,446	3,771
		Retired				(334)						(334)	(334)
	PG&E_VLY Total		190			2,332	410			280	900	4,112	3,437
	SANDIEGO	Added				500		40		300	163	1,003	881
		Retired				(689)						(689)	(689)
	SANDIEGO Total					(189)		40		300	163	314	192
	SOCALIF	Added	290			1,768				500	3,500	6,058	3,433
		Retired		(1,580)								(1,580)	(1,580)
	SOCALIF Total		290	(1,580)		1,768				500	3,500	4,478	1,853
CAISO Total			**555**	**(1,580)**		**6,229**	**921**	**40**	**(300)**	**1,265**	**5,593**	**12,723**	**8,528**

Attachment 5 – Incremental Resources by Fuel Type and Area (Capacity net of station service) Part 2 of 2

Sum of PSSEMaxCap(MW)			Fuel										
Region	**Area Name**	**Comment**	**Bio**	**Coal**	**DSM**	**Gas**	**Geothermal**	**Hydro**	**Oil**	**Solar**	**Wind**	**Nameplate Total**	**Discounted Total**
CANADA	ALBERTA	Added		1,420		1,164					1,670	4,254	2,918
		modified		(13)								(13)	(13)
		Retired		(434)		(359)		(317)				(1,110)	(1,110)
	ALBERTA Total			973		805		(317)			1,670	3,131	1,795
	B.C.HYDR	Added				1,173		1,754			897	3,823	2,994
	B.C.HYDR Total					1,173		1,754			897	3,823	2,994
CANADA Total				**973**		**1,978**		**1,437**			**2,567**	**6,954**	**4,788**
NWPP	NW_EAST	Added			144	723		260			1,590	2,717	1,445
	NW_EAST Total				144	723		260			1,590	2,717	1,445
	NW_WEST	Added			384	790					150	1,324	1,204
	NW_WEST Total				384	790					150	1,324	1,204
NWPP Total					**528**	**1,513**		**260**			**1,740**	**4,041**	**2,649**
RMPP	B HILL	Added		100								100	100
	B HILL Total			100								100	100
	COL E	Added		3,150		1,282				8	835	5,275	4,524
	COL E Total			3,150		1,282				8	835	5,275	4,524
	IDAHO	Added			152	30						182	182
	IDAHO Total				152	30						182	182
	JB	Added		500								500	500
	JB Total			500								500	500
	KGB	Added		500		62					590	1,152	680
	KGB Total			500		62					590	1,152	680
	MONTANA	Added		1,268							400	1,668	1,348
	MONTANA Total			1,268							400	1,668	1,348
	SIERRA	Added		703		514	441				601	2,259	1,778
	SIERRA Total			703		514	441				601	2,259	1,778
	UT N	Added						44				44	44
		Retired				(128)						(128)	(128)
	UT N Total					(128)		44				(84)	(84)
	UT S	Added		575								575	575
	UT S Total			575								575	575
	SW Wyo	Added									700	700	140
RMPP Total				**6,796**	**152**	**1,760**	**441**	**44**		**8**	**3,126**	**12,327**	**9,723**
Total Net Change to 2008 Case			**619**	**9,989**	**680**	**16,883**	**1,362**	**1,781**	**(320)**	**1,323**	**14,526**	**46,841**	**35,285**
Total Additions Only			**619**	**12,016**	**680**	**18,757**	**1,362**	**2,098**	**-**	**1,323**	**14,526**	**51,380**	**39,843**

Attachment 6 – Loads and Resources Balance

		2015 Resources		2015 Load			
REGION	AREA	Capacity (1) MW	Discounted Capacity (2) MW	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	Load Coverage within each SSG-Wi Bubble (using discounted capacity)
CALIF ("CAISO")	IMPERIAL	2,108	2,092	4,212,776	1,091	501	92%
CALIF ("CAISO")	LADWP (4)	8,983	8,121	33,314,726	6,249	5,060	30%
CALIF ("CAISO")	MEXICO-C	4,717	4,717	15,278,260	3,209	2,405	47%
CALIF ("CAISO")	PG&E_BAY	7,655	7,274	51,987,840	10,919	10,017	-33%
CALIF ("CAISO")	PG&E_VLY (3)	28,680	27,722	79,993,555	19,549	10,870	42%
CALIF ("CAISO")	SANDIEGO	4,923	4,801	22,962,706	5,058	3,912	-5%
CALIF ("CAISO")	SOCALIF (3)	25,766	22,251	134,936,173	25,462	19,491	-13%
AZNMNV	ARIZONA	30,697	30,697	104,761,526	22,626	14,464	36%
AZNMNV	NEVADA (4)	7,582	7,582	29,345,006	7,276	3,648	4%
AZNMNV	NEW MEXI	5,619	5,427	27,245,822	4,730	4,001	15%
AZNMNV	WAPA L.C	6,389	6,389	1,590,561	252	235	2439%
CANADA	ALBERTA	14,482	13,077	77,291,069	10,362	10,794	26%
CANADA	B.C.HYDR	16,058	13,913	74,158,753	9,248	12,457	50%
NWPP	NW_EAST	36,991	31,402	74,310,368	11,270	12,355	179%
NWPP	NW_WEST	12,508	11,778	107,629,066	15,979	17,913	-26%
RMPP	B HILL	1,120	1,120	6,588,272	972	955	15%
RMPP	BHB	0	0	3,695,185	457	506	-100%
RMPP	BONZ	468	468	1,242,519	237	176	97%
RMPP	COL E	13,979	13,227	62,135,625	10,727	9,521	23%
RMPP	COL W	2,294	2,294	6,440,916	951	993	141%
RMPP	IDAHO	2,575	2,217	18,631,181	3,694	2,850	-40%
RMPP	IPP	1,847	1,847	0	1	1	N/A
RMPP	JB	2,628	2,628	0	1	1	N/A
RMPP	KGB	1,476	952	6,826,263	1,429	1,081	-33%
RMPP	LRS	1,628	1,628	3,996,419	581	567	180%
RMPP	MONTANA	5,579	5,062	10,807,468	1,689	1,698	200%
RMPP	SIERRA	4,137	3,656	11,728,413	1,995	1,642	83%
RMPP	SW WYO	964	321	4,553,805	596	547	-46%
RMPP	UT N	2,438	2,438	42,173,311	7,999	5,368	-70%
RMPP	UT S	3,486	3,486	6,057,463	1,189	819	193%
RMPP	WYO	775	775	2,454,859	331	304	134%
RMPP	YLW TL	288	288	0	1	1	N/A
	Total Capacity	**258,838**	**239,648**	**1,026,349,907**	**186,130**	**155,151**	**29% (5)**

(1) Capacity represents installed capacity net of station service (capacity net to the grid).

(2) Discounted capacity reflects the capacity contribution to peak load. The following capacity credits are used for calculating Discounted capacity:

* Assumed discounts: BC Hydro (25% for hydro, 7.5% for wind), NW hydro credit 89.4%, California wind 25%, Colorado wind 10%, all other wind 20%

(3) SOCAL and PG&E VLY loads include irrigation (pump) load obligations, though they are modeled as negative resources to reflect their particular load shapes.

Pump Load obligations SOCAL (6,926.4 Gwh), PGE VLY (4,398.3 Ghw)

(4) LADWP includes 1,446MW of gas generation submitted by NV, but this is shown in the LADWP topology bubble because of dual allocation of the Crystal bus. The 1,446MW was moved from the NV side of the substation to the LADWP side because of bus overloading issues on the NV side.

(5) Represents percentage covered based on discounted capacity only. This percentage (margin) would also need to cover any requirements for operating reserves.

Attachment 7 – Thermal Resources' Generic Characteristics

These data are all generic assumptions for thermal unit commitment, other than incremental heat rates (shown in Tables 1 and 2)

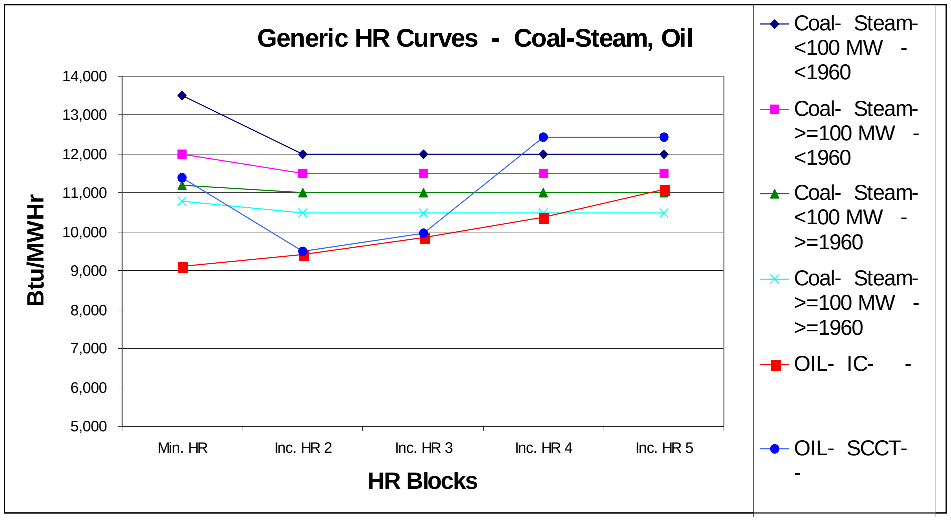
Bucket	Fuel	Technology	Size	Vintage	Variable Non-Fuel O&M ($/MWh)	Forced Outage Rate	Forced Outage Duration (Days)	Min Up Time (Hours)	Min Down Time (Hours)	Ramp Rate (MW/Min)	Summer De-rated Cap	Ave. Maint. Days p.a.	Start-Up Costs $/unit start
1	Gas/Oil	Steam	<100 MW	<1960	5.00	0.071	55	8	8	1.0	97.3%	38	3,100
2	Gas/Oil	Steam	>=100 MW	<1960	5.00	0.071	55	8	8	1.0	97.3%	38	3,100
3	Gas/Oil	Steam	<100 MW	>=1960	5.00	0.071	55	8	8	1.0	97.3%	38	3,100
4	Gas/Oil	Steam	>=100 MW	>=1960	3.00	0.071	55	8	8	1.0	97.3%	38	3,100
5	Gas	SCCT		<1985	8.00	0.036	89	8	8	1.0	88.0%	15	2,000
6	Gas	CCCT		<1985	5.00	0.055	22	8	8	1.0	93.1%	15	10,100
7	Gas	SCCT	<70 MW	>=1985 & <2006	5.00	0.036	89	8	8	1.0	88.0%	15	2,000
8	Gas	SCCT	>=70 MW	>=1985 & <2006	5.00	0.036	89	8	8	1.0	88.0%	15	2,000
9	Gas	CCCT		>=1985 & <2001	2.00	0.055	22	8	8	1.0	93.1%	15	10,100
10	Gas/Oil	CCCT- Frame F		>=2001	2.00	0.055	22	8	8	1.0	93.1%	15	10,100
11	Gas	DT		<1985	5.00	0.055	22	8	8	1.0	93.1%	15	-
12	Gas	DT		>=1985	5.00	0.055	22	8	8	1.0	93.1%	15	-
13	Gas	SynCrude/Canadian Tar Sands			5.00	0.036	89	8	8	1.0	93.1%	15	10,100
14	OIL	IC			13.25	0.036	55	8	8	1.0	97.3%	38	2,000
15	OIL	SCCT			8.00	0.036	55	8	8	1.0	88.0%	15	2,000
16	Coal	Steam	<100 MW	<1960	4.00	0.066	38	8	8	2.5	97.3%	26	15,000
17	Coal	Steam	>=100 MW	<1960	2.00	0.066	38	8	8	2.5	97.3%	26	15,000
18	Coal	Steam	<100 MW	>=1960	3.00	0.066	38	8	8	2.5	97.3%	26	15,000
19	Coal	Steam	>=100 MW	>=1960	2.00	0.066	38	8	8	2.5	97.3%	26	15,000
20	Bio/WH/Ref/Wood	Steam			5.00	0.071	38	8	8	1.0	97.3%	38	15,000
21	GEO	GE			4.00	0.071	16	8	8	1.0	100.0%	38	-
22	URAN	NUCLEAR				0.070	298	8	8	1.0	100.0%	27	-
23	SUN	SL					1	8	8	1.0		38	-
24	PC	Steam			21.00	0.071	55	8	8	1.0	97.3%	38	15,000
25	Gas	SCCT		>=2006	5.00	0.036	55	8	8	1.0	88.0%	15	2,000
26	Gas/Oil	CCCT- Frame G	>450 MW	>=2008	2.00	0.036	22	8	8	1.0	93.1%	15	10,100
27**	Gas	CCG+H		>=2008	2.00	0.036	22	0.041	0.97	0.0	97.0%	15	7,000
28**	Gas	GTC		>=2008	21.00	0.071	55	0.041	0.95	0.0	95.0%	15	7,000

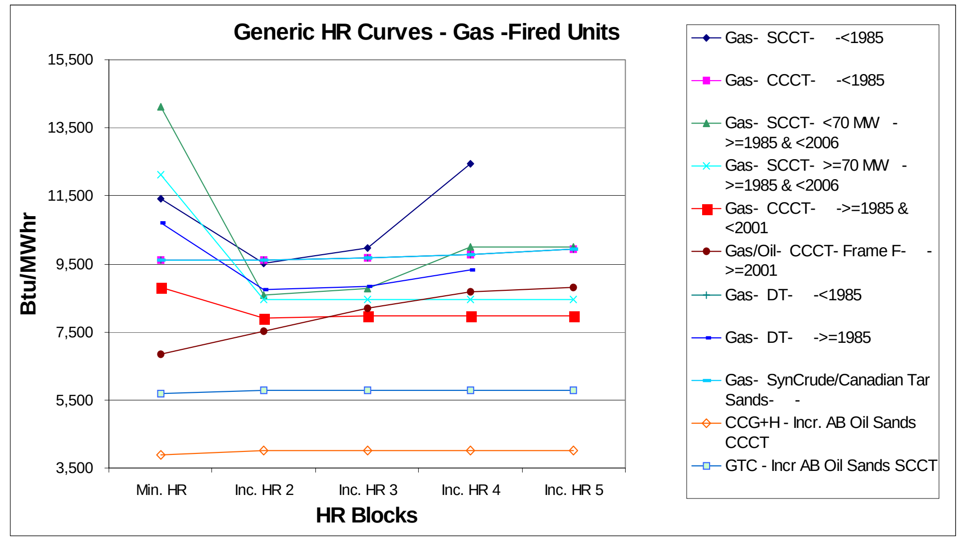
Attachment 8 – Thermal Resources' Generic Heat Rates by Fuel, Technology Part 1 of 2

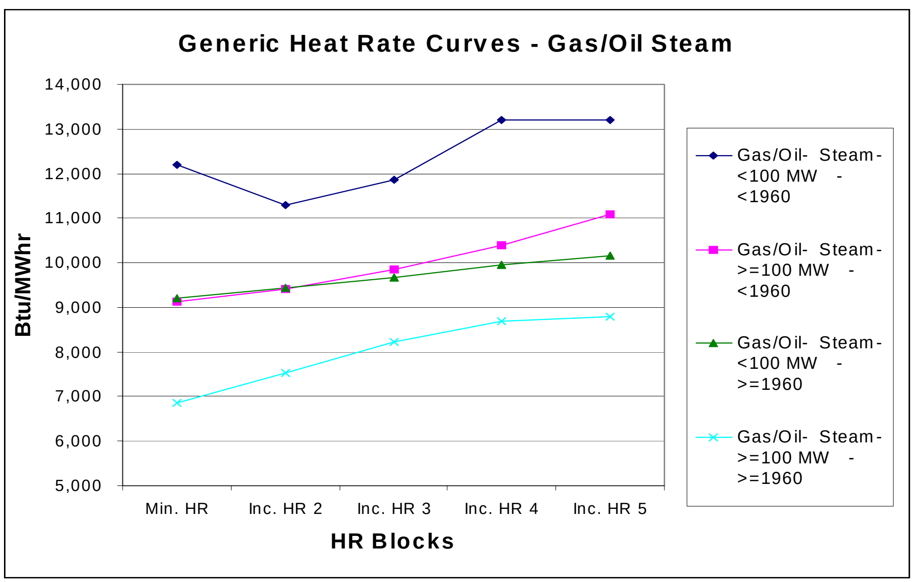
These Incremental Heat Rate data are generic assumptions derived using the Platts database
These data are for units in the SSG-WI database which do not have unit-specific data in the CEC paper (shown in Table 1)
Incremental heat rates are shown in Btu/kWh

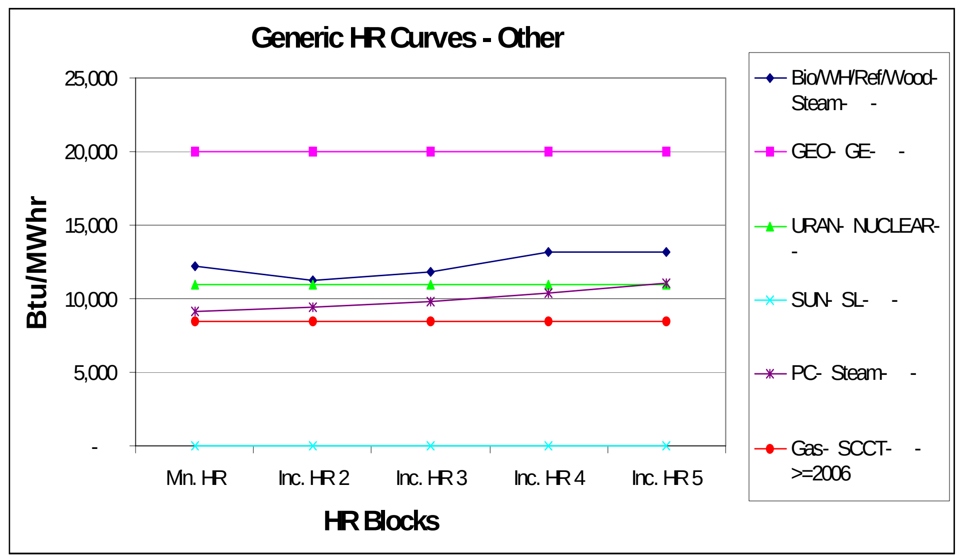
Bucket	Fuel	Technology	Size	Vintage	MinCap % of Nameplate	MinHR	Block2%of Nameplate	IncHR2	Block3%of Nameplate	IncHR3	Block4%of Nameplate	IncHR4	Block5%of Nameplate	IncHR5
1	Gas/Oil	Steam	<100 MW	<1960	30%	12194	20%	11292	30%	11868	20%	13199		
2	Gas/Oil	Steam	>=100 MW	<1960	8%	9125	22%	9421	23%	9846	23%	10388	24%	11078
3	Gas/Oil	Steam	<100 MW	>=1960	26%	9214	20%	9428	20%	9672	20%	9946	14%	10155
4	Gas/Oil	Steam	>=100 MW	>=1960	7%	6856	18%	7520	25%	8212	30%	8692	20%	8799
5	Gas	SCCT		<1985	30%	11403	20%	9507	30%	9980	20%	12430		
6	Gas	CCCT		<1985	13%	9600	19%	9621	22%	9680	19%	9760	27%	9920
7	Gas	SCCT	<70 MW	>=1985 & <2006	45%	14114	25%	8590	20%	8782	10%	9993		
8	Gas	SCCT	>=70 MW	>=1985 & <2006	60%	12106	30%	8451	10%	8459				
9	Gas	CCCT		>=1985 & <2001	60%	8815	35%	7896	5%	7986				
10	Gas/Oil	CCCT- Frame F		>=2001	7%	6856	18%	7520	25%	8212	30%	8692	20%	8799
11	Gas	DT		<1985	13%	9600	19%	9621	22%	9680	19%	9760	27%	9920
12	Gas	DT		>=1985	45%	10695	25%	8747	20%	8842	10%	9335		
13	Gas	SynCrude/Canadian Tar Sands			13%	9600	19%	9621	22%	9680	19%	9760	27%	9920
14	OIL	IC			8%	9125	22%	9421	23%	9846	23%	10388	24%	11078
15	OIL	SCCT			30%	11403	20%	9507	30%	9980	20%	12430		
16	Coal	Steam	<100 MW	<1960	30%	13500	70%	12000		0	0%	0		0
17	Coal	Steam	>=100 MW	<1960	30%	12000	70%	11500		0	0%	0		0
18	Coal	Steam	<100 MW	>=1960	30%	11200	70%	11000		0	0%	0		0
19	Coal	Steam	>=100 MW	>=1960	30%	10800	70%	10500		0	0%	0		0
20	Bio/WH/Ref/Wood	Steam			30%	12194	20%	11292	30%	11868	20%	13199		
21	GEO	GE			100%	20000					0%			
22	URAN	NUCLEAR			100%	11000					0%			
23	SUN	SL			100%	0					0%			
24	PC	Steam			8%	9125	22%	9421	23%	9846	23%	10388	24%	11078
25 **	Gas	SCCT		>=2006	60%	8500		90%	8501		100%	8502		
26**	Gas/Oil	CCCT- Frame G	>450 MW	>=2008		6300			6301					
27**	Gas	CCG+H		>=2008	80%	3900	20%	4000						
28**	Gas	GTC		>=2008	48%	5700	52%	5800						
29	Hydro	Hydro	Non-thermal buckets											
30	Wind	WT	Non-thermal buckets											
31	Not currently being used													
32	DSM	DSM	Non-thermal buckets											
999	Retired	Retired	Non-thermal buckets											

Attachment 8 – Thermal Resources' Generic Heat Rates by Fuel, Technology Part 2 of 2







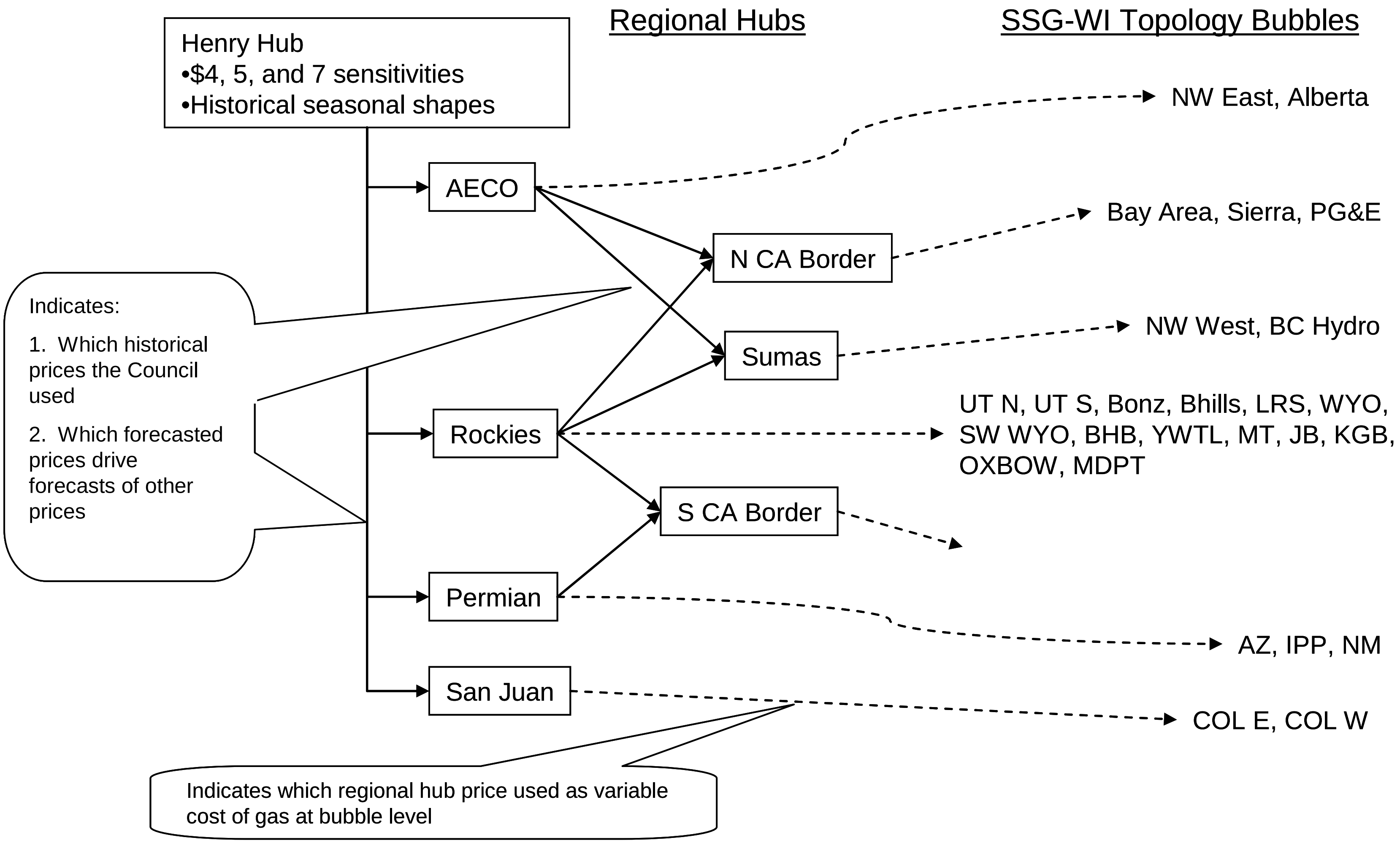


Attachment 9 – Gas prices by SSG-WI Topology

Based on $5.00 2008 annual average Henry Hub
2008 gas price forecast (in 2005$/MMBtu)

Area	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
ALBERTA	$4.89	$4.88	$4.75	$4.05	$3.95	$3.97	$3.99	$4.01	$4.00	$4.01	$4.23	$4.37
ARIZONA	$5.42	$5.40	$5.26	$4.53	$4.43	$4.45	$4.47	$4.49	$4.48	$4.49	$4.73	$4.87
B.C.HYDRO	$5.01	$4.99	$4.86	$4.17	$4.08	$4.10	$4.12	$4.14	$4.12	$4.14	$4.36	$4.49
BAY AREA	$5.70	$5.68	$5.55	$4.86	$4.76	$4.78	$4.80	$4.82	$4.80	$4.82	$5.04	$5.18
BHB	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
BHILLS	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
BONZ	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
COL E	$4.84	$4.83	$4.71	$4.09	$4.01	$4.03	$4.04	$4.06	$4.05	$4.06	$4.26	$4.38
COL W	$4.84	$4.83	$4.71	$4.09	$4.01	$4.03	$4.04	$4.06	$4.05	$4.06	$4.26	$4.38
IMPERIAL CA	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
IPP	$5.42	$5.40	$5.26	$4.53	$4.43	$4.45	$4.47	$4.49	$4.48	$4.49	$4.73	$4.87
JB	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
KGB	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
LADWP	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
LRS	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
MDPT BOISE & SNAKE	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
MEXICO-C	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
MONTANA	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
NEVADA	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
NEW MEXICO	$5.42	$5.40	$5.26	$4.53	$4.43	$4.45	$4.47	$4.49	$4.48	$4.49	$4.73	$4.87
NW EAST	$4.89	$4.88	$4.75	$4.05	$3.95	$3.97	$3.99	$4.01	$4.00	$4.01	$4.23	$4.37
NW WEST	$5.01	$4.99	$4.86	$4.17	$4.08	$4.10	$4.12	$4.14	$4.12	$4.14	$4.36	$4.49
OXBOW/HELLS CANYON	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
PG AND E	$5.70	$5.68	$5.55	$4.86	$4.76	$4.78	$4.80	$4.82	$4.80	$4.82	$5.04	$5.18
SAN DIEGO	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
SIERRA	$5.70	$5.68	$5.55	$4.86	$4.76	$4.78	$4.80	$4.82	$4.80	$4.82	$5.04	$5.18
SO CALIF	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
SW WYO	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
UT N	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
UT S	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
WAPA L.C.	$5.67	$5.66	$5.52	$4.82	$4.73	$4.75	$4.77	$4.79	$4.77	$4.79	$5.01	$5.15
WYO	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36
YWTL	$4.81	$4.80	$4.68	$4.07	$3.99	$4.00	$4.02	$4.04	$4.03	$4.04	$4.23	$4.36

Attachment 10 – Regional hub gas price development diagram



Attachment 11 – Fixed gas transportation cost assumptions

Fixed gas transportation cost calculation - calculated and applied only to incremental gas generation added to SSG-WI Reference Case from 2008 to 2015

Inflation	2.50%
Conversion factor $/mcf to $/mmbtu	1.03
Heat rate of CCCT	8
Heat rate of SCCT	9

SSG-WI Bubble	Corresponding Area from CEC 2005 IERP	Fixed Distribution Cost of Transporting the Gas from regional hub to utility burner tip (2000 $/mcf) from CEC 2005 IERP	Fixed Distribution Cost of Transporting the Gas from regional hub to utility burner tip (2005 $/mmbtu)	Fixed Distribution Cost of Transporting the Gas from regional hub to utility burner tip CCCT (2005 $/KW/yr)[2]	Fixed Distribution Cost of Transporting the Gas from regional hub to utility burner tip SCCT (2005 $/KW/yr)[2]
IMPERIAL	SoCalGas Company.	0.34	0.37	no incremental CCCT added	29.4
LADWP	SoCalGas Company.	0.34	0.37	no incremental CCCT added	29.4
MEXICO-C	SoCalGas Company.	0.34	0.37	22.2	29.4
PG&E_BAY	PG&E	0.176	0.19	11.5	15.2
PG&E_VLY	PG&E	0.041	0.05	2.7	3.6
SANDIEGO	SDG&E	0.34	0.37	22.2	no incremental SCCT added
SOCALIF	SoCalGas Company.	0.34	0.37	22.2	29.4
ARIZONA	SW Desert (Arizona)	0	0.00	0.0	0.0
NEVADA	S. Nevada (Las Vegas)	0.15	0.16	9.8	13.0
NEW MEXI	SW Desert (New Mexico)	0	0.00	0.0	0.0
WAPA L.C	SoCalGas Company.	0.34	0.37	no incremental CCCT added	no incremental SCCT added
ALBERTA	Alberta Demand	0.22	0.24	14.4	19.1
B.C.HYDR	British Columbia Demand	0.66	0.72	43.2	57.2
NW_EAST	PNW (Oregon	0.08	0.09	5.2	6.9
NW_WEST	PNW (Oregon	0.08	0.09	5.2	no incremental SCCT added
B HILL	:Rocky Mtn (Wyoming)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
BHB	:Rocky Mtn (Wyoming)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
BONZ	Rocky Mtn (Utah)	0.24	0.26	no incremental CCCT added	no incremental SCCT added
COL E	Rocky Mtn (Colorado)	0.48	0.53	31.4	41.6
COL W	Rocky Mtn (Colorado)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
IDAHO	Rocky Mtn (Idaho)	0.45	0.49	no incremental CCCT added	39.0
IPP	na	0	0.00	no incremental CCCT added	no incremental SCCT added
JB	na	0	0.00	no incremental CCCT added	no incremental SCCT added
KGB	Rocky Mtn (Idaho)	0.45	0.49	no incremental CCCT added	39.0
LRS	:Rocky Mtn (Wyoming)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
MONTANA	:Rocky Mtn (Mont)	0.24	0.26	no incremental CCCT added	20.8
SIERRA	S. Nevada (Las Vegas)	0.15	0.16	9.8	no incremental SCCT added
SW WYO	:Rocky Mtn (Wyoming)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
UT N	Rocky Mtn (Utah)	0.24	0.26	no incremental CCCT added	no incremental SCCT added
UT S	Rocky Mtn (Utah)	0.24	0.26	no incremental CCCT added	no incremental SCCT added
WYO	:Rocky Mtn (Wyoming)	0.48	0.53	no incremental CCCT added	no incremental SCCT added
YLW TL	na	0.48	0.53	no incremental CCCT added	no incremental SCCT added

[1] Expected fuel usage of each technology type is based upon the technologies anticipated capacity factor: 85% for CCCT, and 10% for SCCT

2) Cost applied only to incremental gas resources added from 2008 to 2015

Attachment 12 – Coal Price by SSG-WI Topology and Other Fuel Price Assumptions

SSG-WI Topology Bubble	**2008 Coal Price** Includes Transportation adder in 2008$/MMBtu, assuming 2.5% yearly inflation rate
ARIZONA	1.49
Big Horn Basin (BHB)	0.44
Colorado East (COL E)	0.97
Colorado West (COL W)	1.10
IPP	1.18
Jim Bridger (JB)	1.06
MONTANA	0.62
NEVADA	1.18
NEW MEXICO	1.47
Northwest West (NW WEST)	1.52
Utah North (UT N)	1.12
Wyoming (WYO)	0.53

FUEL	**$/MMBtu** (RMATS Study)
Biomass*	$2.22
Oil-L, Petroleum Coke Oil-H	$6.62 $4.42
Geothermal, Waste Heat*	$1.105
Refuse*	$4.41
Uranium	$0.60

Attachment 13 – Incremental resources' capital cost assumptions by category

SSG-Wi 2015 Reference Case
Generic Capital and Fixed O&M Assumptions Table for Incremental Resources

2005 Dollars

SSG-WI Technology Types				Fixed Costs		
Fuel	**Technology**	**Size**	**Vintage**	**Based on Size MW**	**Initial Project Investment (Capex) $/Kw (1)**	**Fixed O & M ($/Kw/yr) (2)**
Gas/Oil	CCCT- Frame F		>=2001		580	9
Gas	SynCrude/Canadian Oil Sands			2000	474	0
Gas	SCCT (Simple Cycle CT)		>=2006	94	663	8
Gas/Oil	CCCT- Frame G	>450 MW	>=2008	610 (2x1+df)	580	9
Coal	Steam	>=100 MW	>=1960	400	1,373	44
Coal	IGCC, no CO2 sep.			425	1,546	50
Coal	IGCC, with CO2 sep.			401	1,988	59
Geothermal	GE			50	2,021	106
SUN	SL - Central Thermal CSP	100MW	2005		4,630	59
SUN	SL - PV (Photovoltaic)			0.002	7,732	35
SUN	SL - Central/Thermal CSP	200 MW	2015		3,040	38
DSM	Demand Response				-	60
DSM	Load-reduction				-	0
Wind	Wind Turbine			100	1,116	22
Hydro	Hydro	Based on BC Hydro Site C			2,027	11
Hydro	Generic GMS Upgrades and Generic MCA Upgrades	Based on BC Hydro Mica			266	1
Hydro	Generic Small Hydro	Based on BC Hydro info			2,031	41

(1) Initial Project Investment/Resource Cost (Capex) Includes: Cost for development and construction, interconnection, excluding financing and finance costs during construction. Cost of financing during construction will be calculated for the added resources using a rate of 7.5%.
(2) Fixed O&M (operation & maintenance) includes: Labor, major maintenance, general & overhead, fees and contingency. Excludes startup costs, taxes and insurance.
(3) Biomass plant cost assumptions are a weighted average of several different types because the SSG-Wi data is not consistently supplied to us with sufficient detail about a generator. It is weighted by proportion of the resource stack biomass generators we have information about, (mostly wood-burning steam generators types).

Attachment 14 – Incremental transmission capital cost estimates by area

SSG-WI 2015 Reference Case Incremental Transmission Additions Capital Cost Estimates by Area	Estimates are 2005 $ (All in Costs - includes planning, materials, land, overhead, AFUDC, etc)			Notes
Area	**Line Costs**	**Equipment**	**Total**	
Colorado/Holcomb (Sandsage) additions to incorporate two 700 MW generators includes 345 and 203 KV lines and equipment	747,000,000	11,500,000	**758,500,000**	generic assumptions used
WY/Utah transmission additions				
Bridger - Wasatch Front TX 345 and 230 KV lines and equipment	409,600,000	included in line estimates	409,600,000	
Path C upgrade	65,000,000	included in line estimates	65,000,000	
Amps Phase Shifter		10,000,000	10,000,000	
			484,600,000	
Montana/NW upgrades - Colstrip to Spokane series comp		142,000,000	**142,000,000**	
Arizona/New Mexico				
Four Corners to Pinnacle Peak 500 KV line	577,000,000	included in line estimates	577,000,000	
Four Corners to Moenkopi 500 KV line	560,000,000	included in line estimates	560,000,000	
Moenkopi to Market Place 500 KV	436,000,000	included in line estimates	436,000,000	
Coronado TX system upgrades - series comp		20,000,000	20,000,000	
SRP TX upgrades 500 KV	204,620,100	52,553,500	257,173,600	
Capacitor upgrade		5,200,000	5,200,000	
Arizona Total			**1,855,373,600**	
California				
SDG&E 230 KV	19,500,000	1,000,000	20,500,000	generic assumptions used
Transbay cable	300,000,000	included in line estimates	300,000,000	
Imperial TX additions 500 and 230 KV	429,333,333	16,800,000	446,133,333	generic assumptions used
Other CA 500 and 230 KV	856,800,000	included in line estimates	856,800,000	
Total CA			**1,623,433,333**	
Total Incremental TX added 2008-2015			**4,863,906,933**	

Generic Assumptions	
500-kV single circuit line for NW (eastern, not I-5) and BC	$1.6/mile
500-kV single circuit line for Alberta	$1/mile
500-kV single circuit line for Arizona, CA, I-5 corridor of NW	$1.8/mile
500-kV double circuit line for NW and CA	$3.4/mile
500-kV breaker installation	$2.3 /breaker
500/230-kV transformer	$13.0
500-kV reactor installation	$7.5
500-kV series capacitor installation	$12.0
500-kV shunt capacitor installation	$5.2
345 KV singl circuit	$.9/mile
SVC	$90/kvar
230-kV single circuit line	$0.65/mile
230-kV breaker installation	$1.0 million

Attachment 15 - Economic Comparison Methodology

SSG-WI 2015 Reference Case Fixed and Variable Costs

Fixed Costs are incremental to 2008 Base Case

2015

	Dollars in Millions (2005)	Reference Case $5 Gas		Sensitivity $7 Gas		Sensitivity $9 Gas	
		Initial Investment	Annual Costs	Initial Investment	Annual Costs	Initial Investment	Annual Costs
1	**Production Costs (Fuel & Other VOM)**		**14,778**		**17,594**		**20,242**
2	Change from 2015 Reference Case $5 Gas		-		2,816		5,464
3							
4	**Incremental Resource Costs:**						
5	**Resource Additions Investment [1]**						
6	Wind	17,602					
7	Gas	13,080					
8	Coal	21,789					
9	Other (Solar, Biomass, etc)	11,575					
10	**Resource Investment Sub Total**	**64,047**					
11							
12	**Annualized Fixed Cost of Resource Additions**						
13	Incremental Capital Charge @ 10%		6,405				
14	Incremental Fixed O&M[2]		1,393				
15	**Subtotal Fixed Annualized Cost of Resource Additions**		**7,798**				
16							
17	**Incremental Fixed Gas Transportation Costs[3]**		176				
18							
19	**Incremental Transmission Costs:**						
20	**Transmission Additions Investment**						
21	Line Investment	4,605					
22	Customized Equipment Investment	259					
23	**Transmission Investment Sub Total**	**4,864**					
24							
25	**Annualized Fixed Cost of Transmission Additions**						
26	Incremental Fixed O&M		97				
27	Incremental Capital Charge @ 10%		486				
28	**Subtotal Fixed Annualized Cost of Transmission Additions**		**584**				
29							
30	**Total Annualized Fixed Costs (Line 15 +Line 17 + Line 28)**		**8,557**				
31	Change from 2015 Reference Case $5 Gas				-		-
32							
33	**Total Incremental Investment (Line 10 + Line 23)**	**68,911**					
34							
35	**Annual Net (Savings)/Cost from Reference Case (Line 2 + Line 30)**				**2,816**		**5,464**

[1] Includes resource development, construction, interest during construction and interconnection investment for resource additions FY 2008-2015.
[2] Does not include the cost of DSM and energy efficiency programs embedded in the load forecast.
[3] Includes cost of delivering gas from regional hub to plant burner tip. Based on assumptions used for CEC 2005 Integrated Energy Policy Plan.

NOTE: Detailed Resource and TX additions capital cost assumptions are included in the key assumptions matrix

Key Assumptions

Resources:	Initial Investment $/kw*	Fixed O&M $/kw/yr*
Coal	1,373	44
Gas		
SCCT	663	9
CCCT	580	8
Wind	1,116	22
Geothermal	2,021	106
Solar		35
Solar CSP	3,040	38
Solar PV	7,732	35
Biomass	2,196	91
DSM (program costs)**		60
Transmission:	Initial Investment $millions/mile***	
500KV	1.60	
345KV	0.90	
230KV	0.65	
Interest during construction rate		7.5%
Resource and Transmission Capital Charge Rate (% of initial investment)		10%
Transmission Fixed O&M $/kw/yr (% of initial investment)		2%

* These are generic assumptions used where specific resource investment costs were not provided. Generic assumptions are based on NWPCC 5th Power Plan. Solar assumptions provided by NREL.

** Incentive payments for commercial and industrial customers to participate in the program (included as part of fixed O&M line item in the table)

*** Generic assumptions used where specific transmission investment costs were not provided (estimates include planning, materials and construction, land, overheads, interest during construction, etc)

The methodology below compares the variable (production) and annual fixed costs of resource and transmission expansion scenarios. The comparison takes into account the production (fuel and other variable O&M) costs of scenarios, the initial capital investment requirements in new resources and transmission, and associated annualized fixed costs. The total annual cost for each scenario is then compared to the Reference Case to measure annual net savings or costs.

Annual fixed costs include resource and transmission annual capital carrying charges associated with each incremental investment and fixed O&M. (Lines 12:15 and lines 25:28). This methodology applies a 10% capital carrying charge rate to the initial investment amount to calculate annual capital carrying charges for both transmission and resource additions (lines 10 and 23). This 10% rule-of-thumb was developed by Cambridge Energy Research Associates (CERA). It is determined by:

1)Calculating the present value of the post-investment streams of depreciation, return on capital, property and income taxes, interest, and administrative and general costs.
2) Determining a real discount rate by removing the inflation component from the discount rate.
3) Applying this real discount rate to calculate a levelized payment from the present value of post-investment streams calculated in step 1 over the average expected service life of the assets. This levelized payment represents the real levelized annual cost of the investment.

Fixed O&M costs include routine and major maintenance, operating labor, etc. Fixed O&M amounts are calculated separately for each type of resource (Line 14).
In addition, fixed gas transportation cost associated with delivery of gas from regional hub to the utility plant is included in the analysis. (Line 17).

Transmission fixed O&M is assumed to be 20% of the annual capital charge based on a recent transmission study by CERA. (Line 26).

Resource and transmission capital charges and fixed O&M are combined to produce a total annual cost for each scenario (Line 30). The production costs as well as annualized fixed costs associated with each alternative are then compared the SSG-WI Reference Case and other alternatives to obtain annual net savings and confirm economic viability (Line 35).