APPENDIX A--Modeling

Model Description

Model Logic

ABB developed the MarketSimulator model to predict the economic and physical performance of large power networks on an hourly basis. The application was designed to produce:

- Market clearing prices – produces estimated forward price curves that vary by location (bus or node), including spot energy and shadow transmission price curves
- Generating resource dispatch – estimates the lowest cost dispatch for the Western Interconnection
- Estimated congestion – demonstrates where transmission bottlenecks may occur
- Transmission expansion – shows system-wide effects of proposed transmission development
- Various sensitivities – allows the user to examine events/scenarios that would introduce volatility in bulk power prices.

For this SSG-WI report, MarketSimulator is used to simulate transmission congestion and to estimate congestion costs at the nodal level on a West-wide basis. The model accomplishes this through means of an algorithm that dispatches generating resources such that total West-wide production costs are minimized. This dispatch algorithm matches hourly generation to hourly loads and losses while taking into account:

- transmission constraints; and
- capacity, energy constraints (hydro, wind), outages, and minimum up and down periods of generating resources.

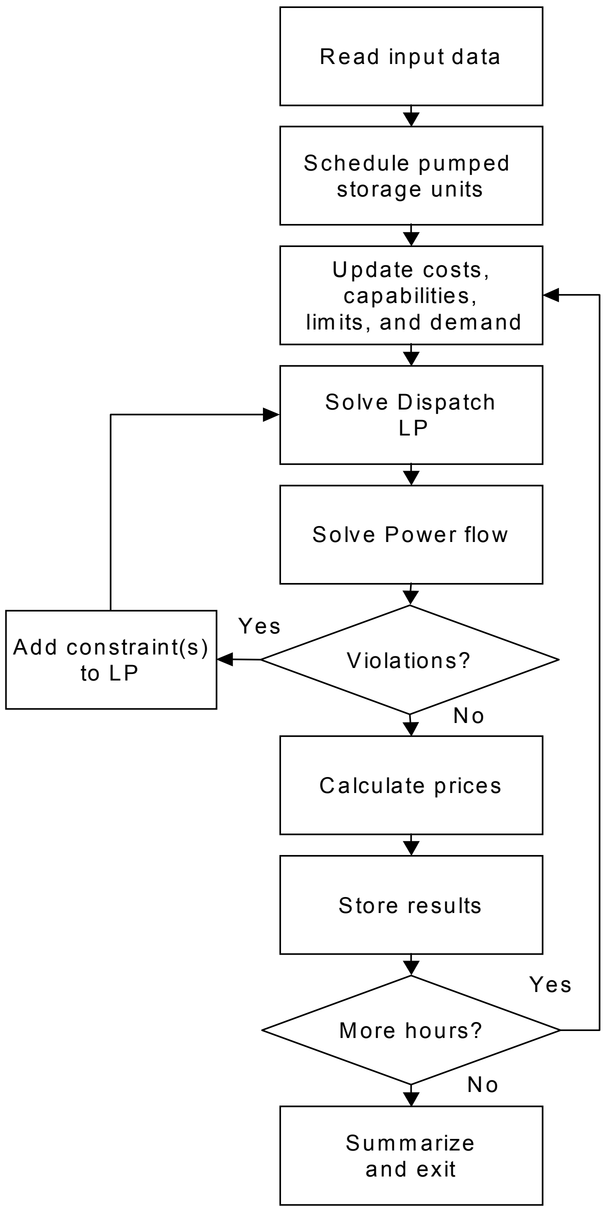
To minimize system production costs, the model takes into account variable fuel costs, heat rates (thermal plants), and variable O&M costs. Production costs and nodal prices are catalogued for each hour of the study year.

The model yields an optimal dispatch of generation, corresponding power flows, and resulting nodal price information. Specifically:

- Hourly dispatch for each generating unit;
- Hourly production costs
- Hourly flows and flow duration curves
- Net import, load and generation for each area
- Congested paths/lines
- Transmission Shadow Prices
- Locational marginal prices for loads and generators; and
- Locational shadow prices.

Large amounts of load and resource data are required to model West-wide system operations on an hourly basis at the nodal level. To keep the modeling efficient and flexible, certain simplifying assumptions were made to data inputs and modeling. For

Figure A-1: MarketSimulator Algorithm



example, contractual terms and conditions for power purchases and sales and for wheeling were not taken into account. Simplified heat rate factors rather than detailed, plant-specific heat curves were applied to thermal units. Bidding behavior was not modeled. The simplifying assumptions do not, however, detract from the screening purposes being served.

As noted earlier, the scope of this SSG-WI study does not consider the capital costs of generation or demand-side alternatives to mitigate congestion. The study also does not evaluate the risks associated with future fuel prices or environmental regulation.

Figure A-1 depicts the logic flow of the MarketSimulator algorithm. The dispatch algorithm solves each hour's dispatch through a technique known as delayed constraint generation, iterating between a linear programming (LP) solver and a power flow calculator, as shown. The LP solver produces a candidate dispatch, which then is evaluated for feasibility by the power flow calculator. If the associated power flow violates any transmission constraints, the constraints are added to the LP formulation, and the process continues until convergence is obtained.

Model Inputs

Monthly peak and energy forecasts are obtained for each area modeled in the power flow. Historic hourly load shapes are used to transform the monthly load data into an hourly loads fit to this peak and energy forecast. Nodal demand is determined at each hour by imposing/fitting a set of load distribution factors obtained from a WECC power flow case onto load shapes selected to describe control area demand patterns.

Economic preference for each thermal generating unit is specified by a piecewise linear incremental heat rate model, time varying fuel costs and variable O&M costs. Capacity and outage information for each unit are also specified as input data. The previous material describes the economic dispatch capabilities and algorithm of Market Simulator. Dispatch determines the loading of resources; predicting the on/off schedule of the thermal units is known as unit commitment. At run time, the user has two options regarding unit commitment:

- Disabled: In this mode, all units not on outage are assumed available for dispatch. Units on must-run status have dispatch lower bounded by the normal unit minimum level. Units on fixed dispatch are locked to their assigned schedule. All other thermal units are made available for dispatch from 0 MW to normal unit maximum capacity.
- Enforced: The current version of MarketSimulator features a multi-area priority list unit commitment method that reflects known transmission constraints when the transportation model is invoked to model the WECC. Both minimum up- and down-times are considered.

Transmission constraints take the form of thermal limits on AC lines and bi-directional security constrained flow limits on interfaces. Interfaces are sums of flows on sets of lines, known elsewhere as branch groups or nomograms.

Hydro Modeling

MarketSimulator is limited when it comes to hydro modeling and optimization. However, the model accepts hourly hydro shapes and treats them as fixed values. For the SSG-WI studies, an external algorithm was used to shape hydro.[1]

The external algorithm used for hydro shaping can be described as a mix of peak shaving and "pseudo" run-of-the-river. It uses hydro resources to level the load shape without regards to the existence of other resources. The run-of-river hydro energy is modeled as base load energy; whereas the dispatchable "monthly" hydro energy dispatches to shave system peak load. Hydro power plants are scheduled one at a time over the horizon of the week, subject to hourly constraints for minimum and maximum generation, weekly constraints for ramp rates, and total energy.

A price-leveling algorithm is used to schedule pumped storage units before the economic dispatch algorithm commences. While respecting pond capacity limits, each pumped storage plant is scheduled in alternating 'blocks' of generation and pumping energy until the expected local marginal price ratio does not compare favorably with the cycle efficiency of the unit.

Wind Modeling

The output of the Foote Creek wind project in Wyoming formed the initial basis of wind data entered into the model. Based on a statistical analysis of the wind resource distribution pattern over a typical year of the project we developed a probability distribution curve showing the probability of output for each hour, calculated as a percentage of the wind farm's capacity. In order to reflect inherent electrical and mechanical system losses the maximum output of the wind plant was limited to 86% of rated nameplate capacity.

The capacity factor for wind generation is highly site specific. Therefore, using best available data, each wind plant modeled was assigned a series of values for its capacity factor, depending on the diurnal and seasonal variations in the wind resource at that location. These were defined in a 4 x 4 matrix of values for each plant, detailing specific values for four time periods during the day (midnight to 6 am, 6 am to noon, noon to 6 pm, and 6 pm to midnight) for each of the four seasons. Then, based on the characteristics of the standard probability distribution curve, each of these "average" capacity factors was randomized to generate a unique hourly time series with 8,760 values per year, as required for input to the model. In this way, all of the sites will exhibit a similar shape to their output distribution curve, but with a temporally and geographically specific average capacity value. The total hourly output of all wind plants

[1] Simulating the dispatch of hydro units on cascaded river systems is significantly more difficult than predicting thermal system operation for several reasons. First, the pondage storage capability and low incremental cost result in a scarcity of energy and not capacity. Market Simulator solves each hour's dispatch sequentially and independently. To properly account for the load leveling capabilities of the river units, require linking the dispatch problems from multiple periods. Further, run-of-river simulation requires that water time delay effects be predicted. Finally, exogenous factors such as fish, recreation and irrigation place demands on hydro dispatch that are not directly associated with power market economics. For all these reasons, and because good historical/forecasted dispatch data for large WECC river systems is available, Market Simulator requires that hourly dispatch for hydro units be specified as input.

in each geographical region was aggregated, and interconnected to the grid at a spot that represented the modelers' views of the "center of gravity" of the various wind farms in that region.

While this process sounds very precise, it is important to understand that it is extremely difficult to generalize the behavior of individual wind farms across <u>any</u> geographic region, and that the raw wind resource data used to generate these time series over this broad geographic scope is not robust. There are several fundamental weaknesses we have identified in this modeling approach. First, because of the random way in which hourly output was generated, there is no correlation between output values from nearby sites or from prior time intervals. In actuality, the best predictor of wind output in any one hour is the output in the last hour. Using a random method to determine the hourly output limits the number of contiguous hours that wind is either at a high level or low level. It also does not model the likelihood that the wind output from a wide area may increase or decrease simultaneously because of synoptic weather patterns. Therefore, the results may show wind's contribution to congestion to be lower than it actually is at some times and higher than it actually is at other times.

Second, the probability distribution curve created was based on the wind characteristics for a single site, and does not necessarily represent the distribution curve that would be expected at any other location. For this approach to gain greater validity, additional distribution curves would have to be developed for each site that is subject to a unique wind regime.

As the primary goal of this analysis is to identify the impact that wind generation could have on transmission congestion, we felt that it was important to in some manner represent the intermittent nature of the wind resource, rather than using steady-state, average output values. Given the relative lack of sensitivity of the overall modeling results to these specific assumptions, this treatment is directionally correct and suitable for this screening exercise. However, uncritical use of this data set for more targeted evaluations of specific projects or follow on detailed planning is not recommended.

<u>Distributed Generation/Demand Response</u>

Distributed generation and/or demand response is not explicitly modeled. Non-wires alternatives are considered qualitatively using some of the studies run for this evaluation.

Model Limitations

LMP Costs may be too Low

In MarketSimulator, the LMP differences become muted when looking across cases because the program looks only at variable costs and does not factor in costs associated with bid behavior (e.g., when the snow pack is low, market prices would likely be more than variable costs). In addition, the hydro peak shaving algorithm schedules a considerable percentage of the hydro hours at the minimum output level from the hydro power plants, which does not typically reflect actual hydro operations. Thus, peak shaving may underestimate the use of thermal peaking units, thus lowering peak hour LMP estimates. On the other hand, hard-wiring hydro generation may underestimate the flexibilities of hydro generation resulting in LMP costs that are too high.

Competitive Market Assumption

The model assumes a fully competitive market in which all generators bid their marginal cost into a market clearing price IFM (Integrated Forward Market), do not engage in strategic bidding, withholding of any generator capacity or otherwise exercise market power or influence prices in the market. Likewise, it is assumed that all demand is price inelastic, and buyers do not engage in strategic or price influencing behaviors. Modeling such behavior is beyond the capabilities of available software, and in any event would be subjective and an invitation for unnecessary debate.

Never-the-less, it is only reasonable to assume there is or will be some strategic behavior in the market, which will reduce overall market efficiency and increase overall market costs. Transmission capacity, however, is the great equalizer. To the extent there is congestion on the grid, almost by definition there are opportunities for strategic behaviors and some inefficiencies that are not modeled. Since the thrust of the SSG-WI/sub-regional modeling efforts is the evaluation of new transmission, the construction of which will eliminate or mitigate congestion to some degree. A more robust transmission will tend to mitigate strategic behaviors. Therefore, there are benefits of the transmission upgrades, which are not captured and quantified by the analysis.

Must Run Generation Not Modeled

The RMR (Required-Must-Run) generators are not modeled as must-run generators, which might underestimate the production costs of more expensive, less efficient generators in an import zone. In other words, the simulation may over-estimate the amount of more expensive, less efficient generation that could be displaced by cheaper imports if a new transmission line were built. The efficient OPF (optimal power flow) dispatch simulation would dispatch the RMR generation to serve load whenever the cost of this generation is low enough to include in an efficient dispatch. However, RMR generation may be required to be dispatched even when this results in an inefficient dispatch for the following reasons:

- They are in an import load pocket or a load pocket that would exist after an N-1 contingency;
- Voltage constraints require that they be operated.

The OPF will instead dispatch more efficient resources, some of which will be imports made possible by the proposed new line, when this would not actually be acceptable if all operating constraints were taken into account.

Lower voltage line limits were not active in the model. Activating them might address part of the problem, but omission of RMR N-1 security and voltage constraints may still raise questions. However, it is possible that excess economical power dispatched from import resources would be present in the base case before addition of the proposed new transmission line such that the incremental benefits of the new line are not distorted or over-estimated. It is also possible that the proposed new lines themselves, or that network upgrades that will be needed to deliver additional imports associated with the new lines will reduce the need for RMR contracts and produce an economic benefit that has not been captured.

The OPF Dispatch Not Security-Constrained

In California, the Cal ISO's MD02 market is going to use a security-constrained dispatch and unit commitment. This means the dispatch will not only be constrained to prevent loading transmission lines beyond their normal (continuous) rating, but the dispatch will be constrained to prevent, for example, N-1 contingency loading beyond the overload (emergency) rating of lines. For example, suppose there are 2 parallel lines with supply at one end and demand at the other. Both lines are rated 100 MW normal with a 120 MW emergency rating. A dispatch that is not security-constrained will dispatch the system to send 200 MW over the parallel lines, if this is the economic solution. A security-constrained dispatch will only dispatch 120 MW over the parallel lines since following an N-1 contingency of one of the lines, this is the maximum that could be reliably carried by the remaining line.

Although the simulation software does not determine security constraints, individual path constraints associated with the WECC Path Ratings (e.g. Path 15, 26, 46, 49, etc), are included in the simulation--i.e. the limits of "rated paths" in the model include dynamic and thermal limits to prevent post contingency conditions from exceeding safe and reliable operating conditions. Non-rated internal paths such as those that are known to cause intra-zonal congestion in the market, such as the West of Devers and North of Miguel systems, are modeled. Likewise, operating nomograms are included in the simulation. All critical constraints known to exist at this time have been modeled.

Failure to consider all operating security constraints could cause the analysis to over-estimate the benefits of import lines since the model may overestimate the amount of internal, less efficient generation that would be displaced by imports. However, no omissions are known to exist at this time, and it is assumed the results are valid in this regard.

Unit Commitment Module Not Available

Absent unit commitment constraints, the OPF program assumes all generators are immediately available, and if the output of a unit is less expensive, it might be dispatched for as few as a couple of MW and/or for as few as a couple of minutes. In actuality, a generator is not started to run under these kinds of conditions. Generators take a finite length of time to start, have a minimum output level, should be operated a minimum length of time before shutdown and should be shut down a minimum length of time before restart can be initiated.

While the lack of a unit commitment module causes the program to tend to underestimate the total cost of production, this does not necessarily imply that the calculated benefits of proposed transmission projects are overstated. The incremental benefits of new transmission may be over- or understated. Hopefully, any error introduced in this way would be present in both the base case and the case with the proposed new transmission project so that the calculated incremental benefits are valid. This problem cannot be corrected given the current software.

Some Proposed Generation not Included

The addition of new, efficient generators inside an area that is currently constrained from securing import generation due to transmission limitations will tend to reduce the benefits of proposed new import transmission lines. For example, some proposed generation facilities in California (e.g. Mountain View, Otay Mesa, and the Pastoria Expansion) did not meet the criteria for inclusion in the simulation but might have a significant impact on the analysis results, if constructed. Mountain View, for example, could have an adverse impact on the economic benefits of the D-PV#2 line. Therefore, sensitivity studies will need to be performed to evaluate the potential impact of these generation projects on the economic analysis results.

Locational gas price differences Included, but Transmission Losses and Wheeling Charges Not Included

The price of gas to generators inside of import areas such as California was assumed to be higher than the price to generators at the border or outside of California and closer to the gas fields. This raises the cost of power from internal generators relative to external generators and causes the OPF to dispatch more power from resources external to California and less from internal generators. Thus, reflecting the locational price of gas tends to increase the economic benefits of the proposed new lines. However, transmission loss factors that are around 5% at external locations such as Palo Verde, and which would effectively raise the cost of generation external to an import area by up to 5% relative to internal generators was not modeled. Wheeling charges that could raise the cost of external generation by $1 or $2 per MWH were also not modeled. This would also cause the OPF to dispatch more power from external resources to meet

California load and less from internal generators, tending to increase the calculated economic benefits of proposed new transmission lines.

The net effect of these modeling assumptions tends to increase the incremental benefits of proposed new transmission projects such as those extending from California to Arizona and Nevada. It might be possible to add a constraint to the OPF formulation to add a hurtle for use of designated lines for imports to simulate the effect of these charges when more detailed studies are performed.

Similar Generators are assumed to have Similar Cost Curves

In the real world, different generators would likely have different incremental cost curves. However, the market bid price of generators cannot really be known, irrespective of actual cost. Therefore, it is reasonable to assume that similar vintage and technology generators have identical, flat incremental cost curves because in a competitive market, actual cost information and biding strategy is not publicly disclosed. A flat cost curve will tend to result in a step function dispatch of generators, which is unlikely to occur. A sloped cost curve is perhaps more realistic. It is difficult to evaluate whether this assumption has any impact on calculated benefits, but since even a large new 500 kV line is a marginal change on a system as large as the Western Interconnection, it might be safe to conclude there would be no significant impact.

Transmission Losses are estimated as a Fixed Percentage

In a real alternating current transmission/distribution system, losses vary with the square of the power transmitted over the line. Although the sub-regions such as California may estimate energy losses under different loading conditions and include them with the demand, the model estimates energy losses by summing up the load at all busses and then applying a fixed percentage adder. This seems to be a satisfactory approach from the standpoint of a production cost model.

Generator Forced Outages Not Modeled

Generator forced outages are not modeled. However, in an incremental comparison, the difference in costs with and without a transmission project would tend to cancel out the impact of omitting forced outages. Thus, this omission should not have much if any impact on the calculation of incremental benefits associated with a possible new line.

Phase shifters

Phase shifters in the model will maintain a fixed angle unless they are activated in the model. For example, the Nelway phase shifter on the BC-NW East Path was not activated in the 2008 case. Use of this phase shifter would have shifted the power flows to the west side of the path, better balancing the flows in the system. However, the representation of the phase shifters is adequate for a planning study.

Consumer and Producer Benefits/Losses

The cost of power to consumers is calculated for each of 8760 hours in the year by summing the LMPs at each bus times the load at each bus in an area (e.g. Arizona, San Diego, etc). The gross benefits of a new line to the consumer are deemed to be the cost of power before the upgrade minus the cost of power after the upgrade project is completed. A reduction in the cost of power is assumed to be an increase in consumer benefit. The producer benefit/loss is calculated in a similar fashion by summing the LMPs at the generator minus the unit production cost of the generator times the number of MWH of energy production in each hour, with and without the upgrade project to find the incremental producer benefit/loss. Consumer benefits may be offset by generator losses when the generator experiencing the loss is tied to the consumer in an economic sense (e.g. is in the rate base of the utility serving the consumer). Thus, it is important that region for which benefits of a new line are to be determined encompasses economically connected producers and consumers.

The benefit of most interest is the net consumer benefit in an import region. If the net benefit that results from a new transmission line is greater than the cost of the new line, there is an economic case to be made for proceeding with the line. The cost of constructing generation resources is ignored in this analysis because it is assumed that such construction has already occurred thus making the capital cost of generation a sunk cost. If the construction of new generation is tied to the construction of new transmission then both sets of capital costs need to be included in the cost/benefit analysis.

With respect to congestion revenues, the construction of a new transmission line may reduce or eliminate the flow of congestion revenues to consumers that existed before the new line was built. Just as a reduction in supplier benefit is netted against an increase of consumer benefit in the same region, a reduction in congestion revenue must also be netted against an increase in consumer benefit, if the market is set up to pay congestion revenues.

Validation of Model Results

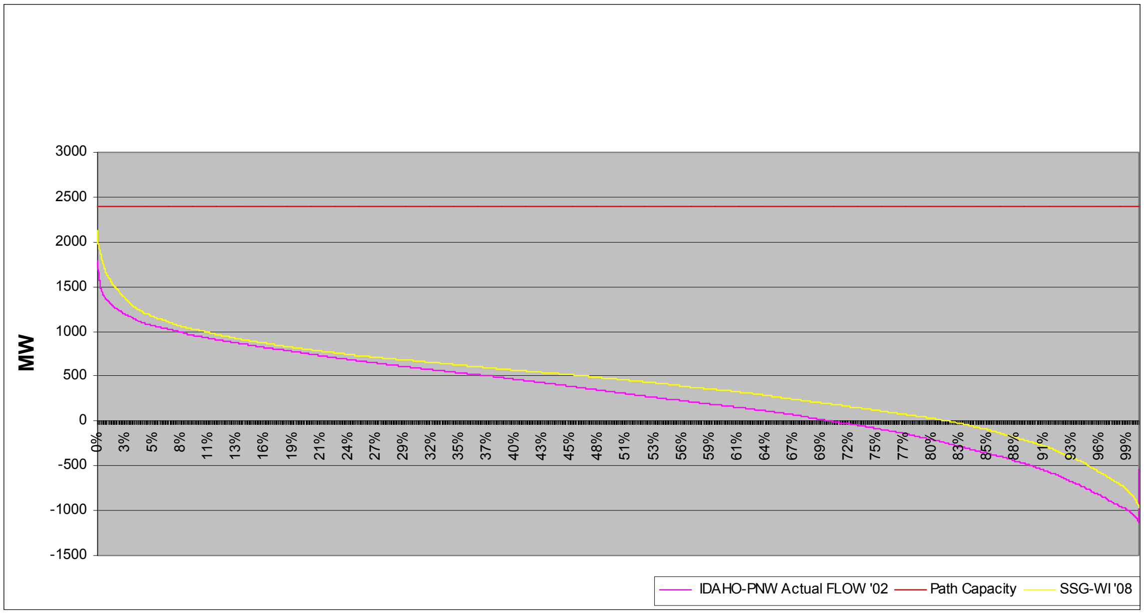
The results of the simulations were validated using the following approach:

- A graphical comparison of Path Duration Flows (PDF) comparing the results of the SSG-WI to historic flows was done.
- The objective of this comparison was a matching of trends with consideration given to:
  - Market Simulator models a single control area
  - A comparison of SSG-WI 2008 to 2002 actual involve different load levels; considerable new resource additions; varied transmission topology

- The similar shape of the actual PDFs and the SSG-WI 2008 PDFs help to validate the results of the simulations (See Figure A-2). Specifically,
  - CAISO confirmed the SSG-WI result to be consistent with what they are seeing for EOR and SCIT. The SSG-WI result for EOR is valid when the significant number of additional resources are taken into account for the 2008 case (i.e., additions at Panda and Gila alone were about 2000 MW; thousands of MWs were added in Arizona and in Nevada.)
  - Path 26 compared favorably.
  - COI Deviation is due to the fair amount of gas added in the Northwest, attempting to move south.
  - "Idaho – PNW" and "Montana to PNW" compared incredibly close; though, thinking about those areas one can say the profile of resources has not changed much. Consistently, the comparison for the "West of Hatwai" should have resulted in greater correlation. The sensitivity runs performed with reduced DSI loads in Montana showed a direct impact to the flows on the "WOH" path. This leads to the conclusion that the continued discrepancy has to do with the level of loads modeled.
  - The "TOT2" discrepancy has to do with reversed economics caused by the glut of generation in Arizona.

Figure A-2

Idaho to PNW Cut Plane



APPENDIX B—Generation Assumptions

Generation Scenarios

2008 Generation Scenario

The power plants likely to be on line by mid-2004 produce enough power to meet expected loads plus reserve requirements in 2008. Plants added between 2000 and mid-2004 are primarily gas-fired.

2013 Natural Gas Scenario

The 2013 natural gas scenario adds 18,200 MW of combined-cycle combustion turbines to the level assumed in 2008. These are located based on load growth and proximity to gas and electric transmission lines.

All three 2013 scenarios add 6,500 MW (nameplate) of wind generation. These wind plants are placed in areas with good resources. These wind resources are placed closer to loads than the additional 12,000 MW wind added in the renewable scenario.

2013 Coal Scenario

This scenario adds 16,300 MW of coal plants to the level assumed in 2008. These plants are located at or near coal mines. Representatives of the Western coal industry helped develop this scenario. This scenario also adds 1,900 MW of combined-cycle gas-fired plants in the Southern California and Northern Baja Mexico areas.

2013 Renewable Scenario

In this scenario, the majority of the new generation in the region is supplied by renewable energy sources, with 9,500 MW of new combined-cycle gas-fired generation added as well. By 2013, this scenario adds 34,300 MW of additional nameplate capacity to the region above the level assumed in 2008. The renewable generation is assumed to be composed of the following resources: 18,500 MW is wind, 2,500 MW is solar and 3,800 MW is baseload biomass and geothermal. This shows 54% of new capacity additions coming from wind, 18% from the combination of geothermal, biomass and solar, and the remaining 28% from natural gas. On an energy basis, this shows wind providing 64,824 GWh/year or 36% of new supply; geothermal and biomass 29,959 GWh/yr or 17%; solar 4,818 GWh/yr or 3%; and combined-cycle gas 77,395 GWh/yr or 44% of total new energy.[2] West-wide, this would increase the percentage of non-hydro renewable generation capacity from 2.6% of the total resource mix in 2008

[2] Wind plant capacity factors are estimated to average 42% in the Mountain states (MT, WY) and 34% in the coastal states (WA, CA, NV), with approximately 80% of new capacity additions planned in the Mountain states to 2013. This equiates to an average wind capacity factor of 40% across the entire WECC region.

to 13.2% in 2013. This is enough renewable energy generation to meet all of the renewable portfolio standard targets of California, Arizona, Nevada and New Mexico currently in place.

Representatives of the American Wind Energy Association (AWEA) and Western Resource Advocates (WRA) participated in developing this scenario. AWEA took the lead on providing the wind capacity added in the scenario and WRA provided the inputs on the non-wind renewables based on the analysis in its forthcoming " Interior West Clean Energy Plan". Many of the performance assumptions for non-wind resources derive from the Energy Information Administration's Annual Energy Outlook 2002 (AEO 2002) and other publicly available sources. These assumptions were further refined based on input from the California Energy Commission, industry experts, and other regional studies.

It proved difficult to establish a clear base-line of the renewable generation on-line as of 2003, the starting point of the study. Historically, renewable sources have tended to be smaller and not as well documented as other types of power plants, which has resulted in discrepancies in the plant data drawn from different sources. For this study, the starting values were derived by inventorying incremental resource additions for 2001 to 2003, and adding them to the year 2000 values listed in WECC's Existing Generation and Significant Additions and Changes to System Facilities report (SigAdds). Although we have not yet been able to reconcile the differences, the values listed in SigAdds for renewables are somewhat lower than in other sources. Because of this, we estimate that there may be as much as 800 MW more non-wind renewable generation currently on-line in the region than is included in this study.

All parties to the Report agreed that the Renewables scenario should model the addition of 20,000 MW of wind added to the region by 2013. The first plan developed by AWEA and its member companies showed 8,000 MW coming on-line in 2002-2007 (with an additional 12,000 MW added 2008-2013). It was later determined that, in addition to currently operating projects, all wind plants under construction and expected to be on-line by the end of 2003 should be treated as "existing" wind capacity. This had the effect of reducing the 8,000 MW of AWEA projected would be developed between 2002 and 2008. The overall result is that the report now models the addition of 18,500 MW of wind instead of 20,000 MW. This discrepancy is insignificant on a 225,000 MW WECC grid ten years out.

Wind, geothermal and biomass plants are located in areas where those resources are prevalent. Given the widespread availability of solar power across the West, whenever possible solar capacity was located near transmission capacity or load centers, or ideally both. The additional gas plants in the renewables scenarios are located near load centers.

In the model the biomass and geothermal plants are run at full output when not down for maintenance, because of their low variable operating costs relative to gas and coal units. The variable output of wind and solar plants is determined outside the model, based on hourly availability of the resource, while gas and coal-fired plants are dispatched within the model to follow the remaining loads.

Wind

Capacity – Wind generation additions were based on the current AWEA forecast for the western United States. As shown in the table below, this projects a total of 20,000 MW of new installed capacity to come on-line between 2003 and 2014. This estimate is based primarily on projects planned or proposed by wind development companies to supply identified customers and markets. This number is consistent with the amount of wind capacity that will have to be installed to meet the targets of the state Renewable Portfolio Standards (RPS) now in place in AZ, CA, NM and NV. This amount of wind saturates no major market in the region, and represents less than 10% of the wind resource potential in the WECC that is economic with current technology when gas prices are $4/mmbtu or greater.[3]

Location – Wind development companies identified the approximate injection points of their planned or proposed projects onto the grid to AWEA. The distribution of these projects by state is consistent with RPS targets, and also shows that each state obtains some wind development. In the 2003-2008 period, as shown on the table below, wind development is projected to be quite equally spread throughout the region, with seven states each receiving 500 MW-800 MW of new projects and three states 900 MW-1,300 MW of projects. In the 2008-2013 period, the great majority of wind additions as proposed by developers is projected to be in MT and WY, with small amounts in the other nine states. In preparing its overall wind development plan for the WECC, AWEA sought to match proposed projects to existing transmission, while also recognizing that development of some resource areas will require new transmission to be built.

[3] Testimony of James H. Caldwell, AWEA, to the U.S. Senate Committee on Energy and Natural Resources, Subcommittee on Water and Power, August 7, 2001.

WECC Wind Development Plan

Nameplate Capacity, MW

State	On-Line	2002-2007	2008-2013
AZ	-	200	100
CA	1,716	1,300	500
CO	61	900	100
ID	-	500	100
MT	-	800	2,900
NV	-	500	700
NM	1	800	700
OR	157	800	100
UT	-	600	400
WA	178	1,000	100
WY	141	600	6,300
WECC Total	2,254	8,000	12,000

Capacity factor – projected capacity factor for each new plant was modeled on an hourly basis, as described in the wind modeling section. The average annual capacity factor of the plants ranged between 34% in the coastal/western states (AZ, CA, ID, NV, OR, WA) and 44% in the Mountain states (CO, MT, NM, UT, WY). Because the largest amount of wind development is proposed for the windier states, the weighted average capacity factor of the total proposed new wind capacity is estimated to be 40%. This notwithstanding, the model runs for this report used an average wind capacity factor of 34%. This will be corrected in subsequent model runs.

Wind Capacity Factor versus Capacity Credit

There is sometimes confusion on the use of the terms capacity factor and capacity credit as it is applied to intermittent sources of energy, such as wind power. This section describes the assumptions and methodologies used to determine these values for the report, and highlights the differences between the two. Much of the work in this field has been conducted by Michael Milligan, of the National Renewable Energy Laboratory. (see Milligan, M. R. (2002). Modeling Utility-Scale Wind Power Plants, Part 2: Capacity Credit. 67 pp.; NREL Report No. TP-500-29701)

WIND CAPACITY FACTOR

Capacity factor is calculated as the amount of energy actually produced during a year, divided by the theoretical maximum output that could be generated over that same period, based on the unit's nameplate rating. For conventional power plants, this is an historical measure of how often the plant is shut down for maintenance, either routine or unplanned, as well as how often the plant's output is reduced because other lower variable cost generation is available to meet load at any point in time.

Commercial wind plants typically have annualized capacity factors of 30-40%. From a mechanical standpoint, the availability of individual wind turbines is warranted by manufacturers to be 95% or greater, and because wind farms consist of many individual turbines the "wind farm availability" is even higher. This availability is superior to that of conventional power plants, reflecting the performance of modern wind plants as extremely reliable generators. However, wind is an intermittent resource – during windy periods there is adequate "fuel" to produce very low cost energy, but during lulls the output may drop to zero. Net wind availability has sometimes been represented as an "Effective Forced Outage Rate," (EFOR) just as mechanical outages are treated with conventional units. Expressed this way "effective forced outage rate" is the inverse of capacity factor, or 60-70%. It is, however, misleading to characterize wind availability as EFOR since the system reliability impacts of wind variability are very different from conventional plant forced outages. Modern wind farms are producing at least some energy over 80% of the time and very, very rarely experience instantaneous changes in output that rival "routine" startup and shut down of conventional plants.

WIND CAPACITY CREDIT

The capacity credit of a plant is a measure of the increase in load carrying capability that a given generator can provide to an electrical system meeting a specific system reliability target. This target can be specified using alternative measures of reliability, such as loss of load probability (LOLP) or expected unserved energy (EUE). A standard criteria in general use is an LOLP of one day in ten years. The capacity credit represents the generator's contribution to the total portfolio of all generation resources that must be able to meet minute-by-minute load requirements as required by the system operator. Therefore, unlike capacity factor, which simply quantifies the overall average energy delivery of a plant, capacity credit indicates both the plant's availability and the correlation of this availability with time differentiated system requirements for the capacity to deliver energy. The value depends heavily (but not exclusively) on events during high load hours for the utility system.

Capacity credit is defined as the change in effective load carrying capability (ELCC) of the system with the addition of the subject generator at a given level of system reliability. The ELCC cannot be calculated simply by specifying the generator average capacity factor or by measuring the plant output during last year's system peak load hour – it must be determined by considering hourly loads and generating patterns, plus a statistical treatment of other generator forced outage rates, and the probability of unusual events such as an unseasonal weather event during e.g. a planned nuclear plant refueling outage, using an appropriate production-cost or reliability model. Many detailed studies have found wind to have a higher "capacity value" to the system during shoulder months of the year when most routine system maintenance is performed rather than during peak seasons /maximum load levels. Because ELCC calculations can be very time consuming and data intensive, it is often estimated by averaging the capacity factor during the top 1,000 load hours during a typical year.

Robust data on which to base a detailed ELCC analysis simply does not exist on a WECC-wide geographic scale. This report assumes a standard capacity credit of 20% for each wind plant. This assumption that capacity credit amount to, on average, roughly 60% of the wind capacity factor is judged to be conservative. Study results are not sensitive to precise measurement of wind capacity credit, which is provided only to ensure the overall "resource adequacy" of the generation portfolios and some assurance that overall system reliability is comparable between the various generation scenarios.

Geothermal

Capacity – Initial geothermal estimates were based on the NEMS geothermal resource assessment. The geothermal units include all potential units with busbar costs of $60/MWh or less. In order to reflect environmental and developmental concerns, the projected geothermal development at each site was limited to those included within Steps 1 and 2 of the NEMS data, where the four possible steps demonstrate increasing difficulty in extraction.

Location – Web-based maps of geothermal resources produced by SMU were used to correlate the geothermal sites to transmission control areas.

Capacity factor – Between 80% and 95%, depending on location. Geothermal plants run at full output when they are not down for routine or unplanned maintenance.

Biomass

For this study biomass facilities are broken down into two categories – 1) dedicated combined cycle facility and 2) biomass (landfill gas).

Capacity – Capacity additions were based on an analysis of biogas potential completed by the Tellus Institute, as included in the Interior West Clean Energy Plan. In addition, 250 MW of landfill gas plants were included throughout the West.

Location – The biomass combined cycle facilities were allocated to transmission service areas on the basis of load.

Capacity factor – 80% for combined cycle plants, and 90% for landfill gas plants. Biomass plants run at full output when they are not down for routine or unplanned maintenance.

Because of their similar capacity factors and operating characteristics as base-load plants, geothermal and biomass plants were combined and treated as a single fuel source.

Solar

Solar estimates were based on an assessment of the economic viability of two technologies during the study period – centralized, solar thermal plants, and distributed photovoltaic arrays. In Arizona, New Mexico, and Southern Nevada, 40% of solar power comes from solar thermal stations while 60% comes from photovoltaics. In the rest of the region solar power is generated exclusively from photovoltaics.

Location – Plant locations were based on a review of the solar insolation and the control area maps in the Renewable Energy Atlas of the West, produced by the WRA and Northwest Sustainable Energy for Economic Development. Whenever possible, the stations were located near transmission capacity or load centers, or ideally both.

Capacity Factor – An 8,760 element time series of capacity factors was developed to describe operating characteristics of solar systems, based on input from Frank Vignola of the University of Oregon. The capacity factor varies daily between 0 and the daily maximum (up to 100%), with an average annualized capacity factor of 22%.

Non-Wires Alternatives

There are non-wires alternatives for relieving transmission congestion. Generation, including distributed generation, can be located on the load side of a transmission constraint; demand-side actions can reduce demand during periods of transmission congestion; and remedial Action Schemes (RAS) and new transmission technologies, such as flexible AC transmission systems (FACTS), can also increase transfer capacity without requiring the construction of new wires.

Non-Wires Alternatives Under Consideration

BPA has initiated a process to incorporate non-wires alternatives into its planning process. BPA's actions are based on a consultants report, "Expansion of BPA Transmission Planning Capabilities," that considers the potential benefits to BPA from looking at other alternatives to complement transmission. The forum for BPA's consideration of non-wires alternatives is the Round Table, a group comprised of regulators, utility representatives, BPA staff, and public interest groups. To date, BPA has analyzed two projects with respect to whether non-wires alternatives could delay the need for construction. The Kangley-Echo Lake line was found to be too close to being needed to allow for contributions from non-wires alternatives. The Olympic Peninsula line is currently being evaluated. Initial work appears to indicate that non-wires alternatives may be able to help delay the investment in that line. One set of issues that the Round Table is grappling with is the institutional barriers that affect the ability of non-wires solutions to be used in a planning context.

Under the emergency conditions of 2000-2001, the California ISO also considered non-wires alternatives.

Strategic Importance of Non-wires Alternatives to Transmission Planners

The future is unknown. New technology, volatile and sustained high fuel prices, and drought are examples of conditions that could fundamentally and quickly change how a region chooses to meet load. During the Western energy crisis of

2000-2001— under conditions no one in the interconnection foresaw – many providers relied on emergency programs to buy back power from customers, and customers' installed on-site generation. While the buyback prices were much higher than the price of power purchased from the utilities, the prices were often much less than the market prices of the time. One lesson from this period is that demand reduction programs can reduce demand given sufficient incentives.

A demand response package and a distributed resources strategy that are a part of every day utility practice could be refined and implemented to reduce the need for transmission expansion and meet demand during a crisis. Deferring big transmission investments *without jeopardizing grid reliability* may lower costs to consumers, as it allows more of the unknown future to unfold itself. Capital investments in the electric industry tend to be big, lumpy, and long-lived. There is the risk that new technologies can turn such investments into "white elephants." New technologies, such as economical fuel cells, could radically reduce the presently perceived need for new transmission.

Non-wires solutions allow planners to determine, and in some cases delay, the need for transmission construction. They also can help to alleviate "economic congestion" at lower costs than new transmission. However, load-based generation and demand-side actions are not substitutes for transmission, which also allows for diversity of generation sources and the inclusion of resources located remotely from load centers.

By illustration, the transmission congestion studies for 2008 and 2013 in this report assume a peak load growth rate of approximately 2% beginning today. If load growth could be reduced to 1%, no additional transmission would be needed in 2013 beyond that assumed in the 2008 study. That is, the load in 2013 would be equal to the loads assumed in 2008[4]. A reduction in peak load growth and local generation of the magnitude required to halve the growth rate of power delivered through the transmission grid is not infeasible.

The concept of non-wires alternatives is not new. FERC has recognized the value of non-wires alternatives as complements to transmission construction and requires equal consideration of non-wires alternatives in its RTO orders and proposed SMD rule. The California ISO and BPA have undertaken initiatives to consider non-wires alternatives in-lieu of new transmission investment. Consideration of non-transmission alternatives was part of the planning process adopted by former Western regional transmission groups (NRTA, SWRTA, WRTA). Also, the existing WECC regional planning process requires the consideration of "alternatives."

There are three groups of non-wires alternatives contemplated here: (1) location of generation on the load side of a transmission constraint; (2) demand-side actions; and

[4] Current (mid-2003) WECC peak summer loads are approximately 138,000 GWe. Peak summer loads in 2008 and 2013 are assumed in the modeling to be approximately 150,000 and 167,000 GWe, respectively. Thus, the assumed load growth from now until 2013 is 2%. If the load growth instead were 1%, today's load of 138,000 GWe would grow to 152,000 GWe by 2013, approximately the assumed load for 2008.

(3) non-wires transmission options such as Remedial Action Schemes (RAS) and flexible AC transmission systems (FACTS).

New generation, including central power plants, combined heat and power (CHP) and other distributed generation, can be located on the load side of a constraint and thereby relieve congestion. Existing backup generation on the load side of a transmission constraint can also be used (e.g., PGE's Dispatchable Standby Generation Program).

There are a variety of demand-side actions that can reduce the need for transmission, including more timely and accurate price signals to consumers that better reflect wholesale market congestion costs, demand buy-back programs (e.g., price-based dispatch, interruptible/curtailable and demand response contracts), and certain measures generally considered only as energy savers[5].

RAS and new transmission technologies, such as FACTS, can be used to increase transfer capacity on existing wires and thereby reduce transmission congestion. RAS schemes are widely used in the Western Interconnection to increase transfer capacity on transmission paths. The cost and impacts on reliability must be considered with these alternatives.

Non-wires alternatives to reduce transmission congestion and help manage future risks should be considered at all levels of transmission planning. The specificity of the analysis of non-wires alternatives should increase as one moves from interconnection-wide planning, to RTO or sub-regional planning, to planning by load serving entities (LSE). At SSG-WI's high level of planning it would be very difficult to specify each of the non-wires alternatives that might be employed to meet transmission needs. As the planning becomes more specific to regions and LSEs, specific measures will need to be considered.

However, even at the SSG-WI level of planning some high-level statements can be made about the impact of non-wires solutions. For example, there are at least two ways to model the effectiveness of non-wires alternatives in relieving congestion and delaying construction of wires.

The impact of successful demand-side measures in reducing transmission congestion can be estimated by extrapolating the lower load in 2008 to the 2013 scenarios[6]. This result can be achieved, for example, by halving the assumed load growth between today and 2013 to 1%. (See footnote above for calculation.) If demand-side measures were able to hold 2013 peak load to levels forecasted for 2008, one could conclude that

[5] For example, compact fluorescent lights reduce peak loads at a fraction of the cost of serving peak loads with gas-fired generation, and they save energy at less than a penny per kWh.

[6] A downside of this approach is that the difference between 2008 and 2013 is only one possible result. Non-wires alternatives may be available to meet this difference and more. However, the appropriate level of non-wire alternatives cannot be determined in this way. At this high level of SSG-WI planning one can gain insight by doing this analysis, and possibly create a target for non-wires contributions between now and 2013.

the same resources[7] and transmission system that met loads in 2008 would meet loads in 2013.

Another way to measure the effects of non-wires solutions at this high level of analysis is to model sensitivity to load variations. For example, one could arbitrarily drop loads by 10% or 20% in an area on the congested side of a constraint and then estimate changes in production costs to determine whether the availability of non-wires solutions is practically and economically feasible. These sensitivities have not been undertaken here. If performed, such analysis would give planners at the subregional or LSE levels guidance as to the amount of non-wires solutions that would have to be available to effectively manage congestion.

The impact of RAS and FACTS could be estimated by increasing the carrying capacity of specific paths in the 2013 scenarios that were modeled and estimating the costs associated with those non-wires investments.

When planning for western subregions or utilities, standards, criteria and metrics should be developed to support analysis and comparison of alternatives. Metrics would include discount rates, assumed facility lifetimes, and other parameters that can be used to compare alternatives on a standard basis. One approach to considering non-wires alternatives on a sub-regional basis has been documented in a report prepared for BPA, *Kangley Echo Lake Economic Screening and Sensitivity Analysis Report*, November 8, 2002.

[7] Some resources would have been retired and replaced by other, perhaps more efficient resources, but the total number of GWe would be the same.

APPENDIX C

Long-term Model Improvements

The following model improvements have been identified to increase the accuracy of existing production costing model simulations. The SSG-WI Modeling Improvements Group will be pursuing the potential solutions listed below.

Modeling Hydro

Opportunity for improvement: Hourly hydro generation is a fixed input to ABB's optimized power flow program (OPF) and is simply netted against the hourly bus bar load at each dam site.

Hydro inputs are determined in the following manner:

Step 1. BPA, BCH, WAPA, CEC and PacifiCorp provided monthly average hydro generation at all major hydro sites assuming high, medium and low water conditions. BPA's data was derived from "Hydsim", a hydro regulation model that simulates the monthly average generation at all federal and Mid-Columbia hydro facilities for various water and load conditions and subject to system operating constraints.

Step 2. The monthly hydro generation at each dam site was shaped into hourly data using a peak shaving algorithm that operates within each dam's minimum and maximum constraint limits to serve the WECC's system-wide hourly load shape.

This two-step approach tends to flex hydro operations beyond operating limits, and is for all practical purposes, is blind to transmission constraints. In addition, this approach creates a "rigid" dispatch scenario that does not interact in a dynamic manner with hourly OPF transmission constraints and thermal unit dispatch.

In addition, chain-linking models is time-consuming and prone to error because the analyst must exercise great care to ensure that Hydsim, the peak shaving algorithm and ABB's MarketSimulator are consistent with regard to model assumptions, loads, thermal displacement markets and transmission constraints.

Potential Solutions:

The existing approach can be improved upon by:

1) Resolving proprietary issues and replacing the peak shaving algorithm with outputs from BPA's Hourly Operation System Simulator (HOSS).

2) "Tuning" the peak shaving algorithm, e.g., adjusting the monthly maximum and minimum limits until the algorithm produces hourly generation shapes that more accurately reflect actual operations.

Future improvements might also include:

Incorporating regional cascaded multi-dam hydro regulation logic directly into the OPF formulation and simulating hydro operations with historical unregulated inflow data or synthesizing inflows that are derived from the historical inflow records and correlated across space and time.

Modeling Wind Generation Characteristics

Opportunity for improvement: The temporal characteristics of the wind resource at geographically specific locations has been poorly documented, and can not be easily modeled as an hourly time series of the nature needed for this study. Each hour of the year was treated as a random event, with no correlation to the changes in wind at nearby locations or during prior time intervals.

Potential Solutions:

Gathering additional historical data on site specific temporal characteristics of the wind, as well as developing more sophisticated models to simulate the performance of wind plants on an hourly basis, which would provide a more meaningful understanding of the impact that a non-dispatchable resource can have upon transmission congestion.

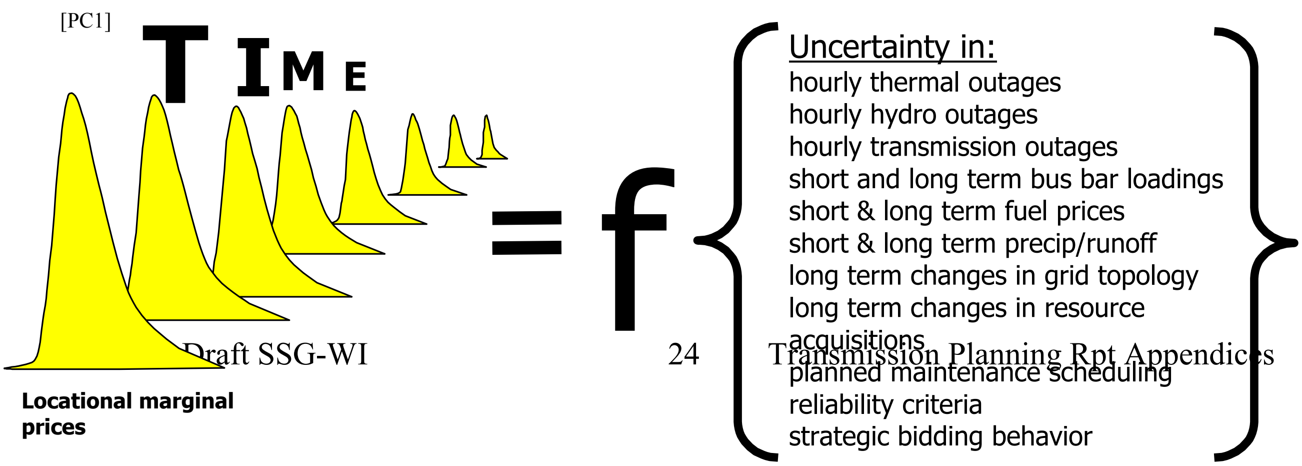
Modeling Uncertainty

Opportunity for improvement: This analysis incorporated uncertainty by simulating the least cost hourly operation of the Western electrical system for 2008 and 2013 across a very limited set of pre-configured outcomes for resources, loads, fuel prices and hydro inflows. While lacking in sample size, this approach can provide useful insights into the relative costs and benefits of alternative scenarios.

However, resource allocation decisions are actually based on uncertain *forecasts* of these quantities and prices. These forecasts can be represented mathematically as a continuum of probability distributions (see diagram below). For example, a LMP forecast is actually a series of probability distributions, each of which is a function of many uncertain variables.

Hence, a more thorough treatment of uncertainty would incorporate these distributions directly into the decision logic of our models, (e.g., decision logic that affects unit commitment, reservoir management and resource/transmission acquisitions.

[PC1]



Potential Solutions:

It would improve the usefulness of the current approach to:

1) Simulate sufficient numbers of scenarios that more adequately represent the range of future possibilities.

2) Create scenarios that are based on consistent input data, e.g., heating and cooling loads that are correlated to snow-pack and runoff.

3) Streamline the entire study process of running a study, from data collection through the report-writing phase.

However, these are quick fixes and of limited value. A more useful approach would be to incorporate uncertainty directly into the decision logic of our models, which may be beyond the capabilities of many existing tools. Hence, we may want to investigate and consider other modeling techniques and formulations.

Modeling New Resource Acquisitions

Opportunity for improvement: Transmission and generation are both substitutes and complements. The economic factors and reliability issues that drive transmission acquisition decisions will also affect resource acquisition decisions, and vice versa, so both strategies should be developed in a consistent manner so as to not introduce a bias in study results.

For example, it is extremely difficult to "manually" create a consistent set of resource and transmission acquisition scenarios for a multiple scenario study in which fuel prices, capital costs, hydro inflows and load growth trajectories are continually varying over time.

Potential solutions:

Hardwiring new resource capacity is a viable option when analyzing only a few scenarios and when the simulation is limited to a single year. However, this approach becomes unwieldy and probably infeasible when the study horizon spans more than a single year or if we adopt a Monte Carlo approach in simulating uncertainty. A more practical solution may be to allow the model to acquire new resource capacity based on long run system economics, maintaining a minimum reliability standard and resource operating and supply curve data.

Modeling Bus Bar Loads

Opportunity for improvement: The existing methodology for estimating hourly bus bar loads is a complicated and arcane process that fails to capture the temporal and spatial variability we would actually expect to see over time horizons of up to 20 years. In addition, no attempt is made to correlate bus bar load data to weather related hydro inflow and runoff data.

The existing methodology is also inflexible in that it is ill-suited for studying specific "events" such as extreme heat wave or cold wave scenarios.

And to complicate things further, historical load data is proprietary and access is usually restricted.

Potential solutions:

Bus bar loads are an important part of the dispatch equation so it is important that these data be modeled with the same degree of precision used in modeling transmission flows and hydro-thermal dispatch. Hence we may want to explore the possibility of:

1) Improving access to historical data.

2) Utilizing historical hydro inflow data and bus bar loadings that are synthesized from chronologically consistent historical weather/temperature year data.

3) Stochastically synthesizing hourly bus bar loads and hydro inflows such that they are correlated across space and time.

Modeling Game Theory and Market Behavior

Opportunity for improvement: Most existing models simulate perfect competition, which maximizes total social benefits. However, in reality, prices can exhibit much greater price volatility when firms attempt to maximize profits by withholding generation.

Potential solutions: Develop a better understanding of how economic equilibrium concepts such as proposed by Cournot and Nash work and incorporate these features into future models.

Modeling Marginal Losses

Opportunity for improvement: Marginal losses can create large LMP differentials that, when ignored, lead to inefficient dispatch and resource siting decisions.

Potential solution: Incorporate marginal loss methodologies within the OPF formulation.

Modeling Transmission and Generation Rights/Ownership

Opportunity for improvement: Most existing OPF models do not have the capability to disaggregate area and nodal costs and benefits to the level of the individual market participants who own or lease property rights to existing and new generation and transmission assets.

This means decision makers are limited in their ability to answer one of the most important questions being asked, i.e., *Who are the winners and losers and how much are they impacted by any given resource allocation or operating decision?*

However, tracking the flow of dollars with this level of precision significantly increases data collection efforts, proprietary data issues, modeling complexity and run times.

Potential solutions: The most commonly used approach for assigning costs and benefits to individual market participants is to make after-the-fact allocations of area or nodal benefits based on simple approximations and rules of thumb.

However this approach often leads to inaccurate and misleading conclusions. Hence, we may want to identify the technical requirements and weigh the costs against the benefits of adding an ownership "dimension" to OPF modeling.

Modeling: The "Curse" of Dimensionality

Opportunity for improvement: Some existing modeling algorithms may be challenged by the huge dimensionality of the problem of simultaneously modeling large nodal networks of thermal generators, hydro plants, loads, transmission elements and storage reservoirs and their ownership, with hourly detail over periods of up to twenty years while representing all of the uncertain variables across many possible future scenarios.

Potential solutions: To overcome this challenge several techniques are commonly employed:

1. Reducing or "equivalencing" the electrical grid into a simpler representation. This technique allows the analyst to aggregate transmission lines, nodes, loads, generators as well as ownership.

2. Reducing the number of future outcomes or scenarios to a manageable number that can be analyzed with existing software and computer processing capabilities.

3. Aggregating time intervals into fewer periods or blocks.

However, these techniques invariably reduce the resolution or precision of the results and compromise our ability to answer the detailed questions decision makers are asking.

Hence, we may need to conduct a thorough review of the underlying methodologies and formulations, especially with respect to their practical ability to handle the huge dimensionality of this problem.

APPENDIX E—WGA & SSG-WI Studies

Conclusions from the WGA Technical Study

Two bookend generation 2010 expansion scenarios were reviewed and transmission expansion plans proposed for both.

- If generation expansion results in mostly gas-fired generation located in or close to loads, transmission expansion that is already under construction or committed to be on line in by 2004 is probably adequate. This conclusion is highly dependent on the assumptions made for gas prices.

- If generation expansion includes significant new coal, wind, hydro, and geothermal resources that are typically located in the more electrically remote regions of the system, $8 to $12 billion (in 2010 dollars) of new main grid transmission infrastructure and generation integration transmission may be needed. However, fuel savings and reductions in market clearing prices as compared with the gas case may justify the additional transmission, depending on assumptions of delivered gas prices, the capital cost of generation, and coal price assumptions. The difference in annual average variable cost savings between the Gas scenario and the Other-Than-Gas scenario is approximately $3 billion to $4 billion. In the high gas price sensitivity study, these annual savings jumped to over $5 billion.

- The initial cost of the Other-Than-Gas case transmission expansion could be reduced by $1 billion to $4 billion (all 2010 dollars) with further study or if main grid transmission plans influence optimum location of generation expansion.

- Capital costs of new generation were analyzed briefly in the spreadsheet study, but were not factored into the production cost model results. Depending on the treatment of capital costs and other fixed costs, including the capital costs of pipelines and fuel delivery systems, either “bookend” generation and transmission expansion scenario appears to be economical.

- Mitigation of market power and policy choices such as decreasing reliance on gas or developing indigenous renewable or coal resources will be important in deciding how much transmission expansion is needed.

WGA Study Recommendation for Additional Work

The WGA study recommended that additional work should be completed to refine the modeling analysis by:

1) Evaluating alternative load growth scenarios that reflect implementation of end-use load management, energy efficiency and distributed generation resulting from consumers receiving closer-to-real-time signals on electricity price;

2) Expanding the sensitivity analysis to examine the impacts of natural gas prices on electricity prices and load growth;

3) Conducting an incremental transmission addition study to better quantify transmission levels and costs;

4) Expanding the analysis by including DC transmission options;

5) Evaluating the market power mitigation and operational flexibility benefits of either (a) additional generation in transmission-constrained areas or (b) the addition of more transmission; and

6) Evaluating additional generation scenarios including combinations of wind and peaking resources.

7) Evaluate the use of additional emerging technology-based solutions in increasing transfer capacity in the existing transmission system where applicable.

Comparison of WGA and SSG Technical Studies

	WGA Study	Proposed SSG Study
Scenarios Studied	1- All-Gas (25,000 MW) 2- Other than Gas (18,000 MW of coal, 4,000 MW of wind, and 1,500 MW of geothermal)	1- Gas Scenario 2- Coal Scenario 3- Renewables Scenario
Years Studied	2004 and 2010	2008 and 2013
Analysis Tool	GE MAPS	ABB Market Simulator
Hydro Sensitivities	Yes – high, average, and low	Yes – high, average, and low
Gas Price Sensitivities	Yes – high, average, and low	Yes – high, average, and low

Benefits of SSG Study over WGA:

1) Additional scenario that studies large amounts of wind generation
2) Updated load, generation, and gas price assumptions
3) Updated estimate of future congested interfaces.
4) More refined and better optimized transmission expansion plans (consideration of DC)

APPENDIX F—Sub-regional Planning Groups

Subregional Planning Groups (SPG), working in cooperation with the SSG-WI Planning Work Group, will play a significant role in Planning of the Western Interconnection transmission system. It is envisioned these groups will be a key part of the RTO planning processes once they form. Through SPGs, stakeholders will evaluate, coordinate, and plan their future transmission needs. The SPGs as well as SSG-WI will also work to facilitate the development of future transmission projects.

SSG-WI and the SPGs will develop a cooperative, supportive and complementary working relationship. Both SSG-WI and the SPGs will work together to develop models and databases for production costing planning studies. SSG-WI will focus on interconnection wide needs. Results of SSG-WI studies will provide important data and information to SPGs for further economic analysis and detailed planning studies.

The SPGs are involving transmission providers, generation developers, marketers, local entities and other stakeholders. The processes are open to all stakeholders. The SPGs will also work with other SPGs on projects that are of concern or impact them. Results of SPG studies will feed into SSG-WI to facilitate its process. SSG-WI focus will be to evaluate interconnection wide benefits beyond the local level.

Several SPGs have already formed and others are in the formative stages. The following is a brief summary of those SPGs.

Central Arizona Transmission System (CATS)

The CATS SPG initially focused on development of the transmission system between the Phoenix and Tucson areas in Arizona. It addressed transmission concerns related to load growth in this area and proposed generation additions in this area of approximately 10,000 MW. The first participants included Arizona Public Service, Salt River Project, Tucson Electric Company, Southwest Transmission Cooperative, Citizens Communications Company, WAPA, and the Arizona Corporation Commission staff. Early on, participation in CATS was opened up to all stakeholders, which widened the interest and scope of the work.

CATS is also working with the STEP SPG to explore transmission alternatives that go from Arizona to Southern California.

Through 2003, the CATS study area encompassed an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station to the west and the Arizona/New Mexico border to the east. During this period a transmission long range plan was developed, a State wide coordinated 10 year study was completed, an ACC “Reliability Must Run” study was coordinated among the stakeholders, and several new transmission projects facilitated by the CATS work were started and are in various stages of development.

The initial CATS meeting was held in March 2000. Reports documenting the long range transmission plan for central and southern Arizona (Phase 1), the integration of several Phase I alternatives and proposed transmission projects in Arizona that were not included in first CATS phase (Phase II), and the 10 year coordinated plans of the transmission entities within Arizona (Phase III), were prepared after each phase was completed. Each study phase took about 1 year.

Discussion are underway to explore the possibility of expanding the CATS study area to include western Arizona, New Mexico, and west Texas for 2004.

Web Site for the CATS Subregional Planning Group is http://www.azpower.org/.

Southwest Transmission Expansion Plan (STEP)

STEP is a collaborative ad-hoc sub-regional planning group that was formed in October of 2002 to meet the following goal:

> *To provide a forum where all interested parties are encouraged to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. The wide participation envisioned in this process is intended to result in a plan that meets a variety of needs and has a broad basis of support.*

STEP is an ad-hoc voluntary organization whose membership is open to all interested stakeholders. STEP has no staff and utilizes its members (stakeholders, project sponsors, transmission owners, regulatory agencies, and RTO/ISO's) to complete the required work. Generally, members that want specific studies conducted are responsible for the completion of the work. STEP's focus is on economically driven expansion projects that support the development of seamless west-wide markets while satisfying established reliability standards. In evaluating the economic benefits of transmission projects, STEP considers all potential aspects of economic benefits including the potential for mitigating market power. In addition, when requested, STEP will work with project sponsors to help assess the benefits (connecting generation, serving load, marketing power, etc.) of their independent transmission proposals.

STEP contains the following planning functions:

1. STEP has developed a biennial planning process that will produce a long-term bulk transmission expansion plan.

2. STEP identifies current and future transmission congestion that is an impediment to the efficient operation of the western market. In addition, the impacts on congestion of potential new generation facilities or new transmission projects will

be considered. Generation currently developing in California, Mexico, Nevada and Arizona is expected to heavily congest the transmission facilities into those areas.

3. STEP is developing, through a collaborative process, strategic transmission options and specific alternative plans for reinforcing the transmission system and for reducing or eliminating congestion. This information is being provided to the marketplace. Specific projects that are being evaluated include:

    a. Upgrading the series compensation in the existing 500 kV transmission lines between California and Arizona.
    b. A new line between Imperial Valley and Rainbow
    c. A second Palo Verde-Devers Line
    d. A second Southwest Power Link (SWPL) line between Hassayampa and Imperial Valley and possibly on to Miguel.
    e. Upgrading the Mead-Phoenix-Adelanto Project to DC.
    f. A new line from the Eldorado Valley (Mead, Marketplace, Eldorado) to southern California (Lugo, Victorville, Adelanto).
    g. A Palo Verde-Mead line

4. STEP will review project sponsor studies if requested by the project sponsor. The review may include:

    a. Assessing the technical system impacts of the proposed project (transmission and non-transmission).
    b. Assessing the projects cost and benefits

5. STEP will rely as much as possible on the technical studies conducted by project sponsors and studies conducted in other forums (primarily CATS, and the ISO Control Area Study).

6. The studies completed for STEP will:

    a. Focus on regional needs.
    b. Consider a variety of alternatives.
    c. Consider the flexibility of alternatives.
    d. Comply with established standards, guidelines, procedures and policies (primarily NERC and WECC).
    e. Be made available to all STEP members following applicable data availability guidelines.
    f. Utilize an economic methodology that has been adopted by STEP to evaluate the economic benefits of transmission system additions such as the one under development at the California ISO.
    g. Consider viable non-transmission alternatives

7. STEP will perform technical study work that is not duplicative of work done by others. Technical studies done by STEP shall be identified in an approved study plan that will include items, such as:

    a. Purpose and need
    b. Objectives
    c. Development of base cases and other data
    d. Methodology
    e. Schedule
    f. Assignment of study work

8. Members of STEP will share the study work. In general, members will study the areas where they have an interest. The results of the individual work will be shared with STEP and will normally be documented in a STEP report.

9. STEP will provide a forum to facilitate stakeholder development of projects through the planning effort. It will be up to those participating in a project to determine the specifics of a project such as the scope of the project, lead entity or entities, project participants, and funding for a project.

10. Once the long-range transmission expansion plan is developed, the focus of STEP will temporarily shift to facilitating the phased implementation of the plan. Implementation may involve a variety of short-term projects that will ultimately support the development of the long-term plan. The long-term plan will be periodically revised as desired by STEP.

11. STEP works closely with regulatory and governmental agencies (CEC, CPUC, ACC, etc.) in developing facility plans, in order to:

    a. Gain their input and insights concerning energy policy and other issues.
    b. Provide input to the various regulatory and governmental agencies primarily through the involvement of the regulatory and governmental personnel who participate in the STEP processes.
    c. Enhance and streamline the permitting of these facilities and help reduce the amount of analysis required by siting agencies.

12. STEP closely coordinates with the following planning and coordination functions:

    a. The west-wide expansion planning function that is being filled by the SSG-WI-PWG.
    b. The planning functions and responsibilities of the individual RTOs. Specifically, this activity will take advantage of the work products produced in the annual grid expansion planning processes that are in place at the California ISO and in other entities (i.e., STEP could use base cases that are jointly developed by CATS and the California ISO).

c. The planning functions and responsibilities of coordination activities such as CATS and WATS.
d. The planning coordination function of the WECC.

STEP provides a forum for the discussion of different approaches for funding potential transmission projects.

Additional information on STEP is available at the web site http://www1.caiso.com/docs/2002/11/04/2002110417450022131.html.

Rocky Mountain Subregional Planning Group

The Rocky Mountain SPG is an effort initiated by the Governors or the states of Wyoming and Utah. The Goal is: "To identify in an open and public process, the most critical electric transmission and generation project needs in the Rocky Mountain subregion, and with broad stakeholder involvement provide a framework for regional collaboration to improve the Western interconnection with technical, financial and environmentally viable projects identified for developmental consideration.

Electric transmission in the rocky Mountain region is constrained and as a result, the region's vast wind, natural gas and coal resources are underutilized. RTOs are years from effective operation and there is no current collaborative Rocky Mountain planning g effort to consider transmission expansion from a holistic perspective.

Those to be involved include Western Interconnection electric utilities, IPPs, rural electric generation and transmission cooperatives, municipalities, federal power, transmission and marketing agencies, project developers, entrepreneurs, power brokers, state and federal regulators, state energy office representatives and anyone interested in regional electric generation and transmission planning.

Additional information on the Rocky Mountain Subregional Planning Group may be found at their web site http://psc.state.wy.us/htdocs/subregional/home.htm.

Northwest Sub-regional Planning Group (NTAC)

FOLLOWING IS THE AGREED UPON SCOPE OF WORK FOR NTAC:

<u>Mission</u>

NTAC will be the open forum to address forward looking planning and development for robust and cost effective NWPP area transmission system.

Background

The electric utility industry continues to change with new issues, proposed regulations, new forums, and an emerging market influence. However, with all these changes the fundamental needs of end-use customers remain the same. Utilities serving these customers struggle to address their individual requirements as well as to analyze and address reliability needs.

Discussion during various meetings have identified a view that the NWPP geographic area is lacking a forum to address the further planning and development of a robust NWPP area transmission system. This planning and development would identify future transmission needs by performing studies to identify solutions. The forum will consider transmission and non-transmission alternatives. This would mean more than reliability planning or maintaining current capability. To fill the existing void in the geographic area of the NWPP associated with the planning of a robust transmission system, the NWPP TPC has broadened its scope of activities to include expansion planning dealing with commercial issues. This forum would need to exist until its functions were assumed by a different forum or through a comprehensive RTO planning function. The goal is to avoid duplication now and into the future.

This Scope of Work outlines a forum and structure where participants can engage in regular and detailed discussions about the further planning and development of a robust NWPP area transmission system.

Goals and Objectives

The overall goals of this effort are:

1. To provide necessary information to maintain and/or enhance the reliability of the transmission system under the operation and planning control of the NWPP area participants.
2. To develop a transmission assessment that identifies transmission constraints under a range of scenarios and suggests possible solutions to relieve those constraints, including alternatives such as transmission additions, DSM, distributed generation, Special Protection Systems (safety nets such as load shedding, Remedial Action Schemes) provided by NTAC participants, or through other transmission planning efforts.
3. To provide information to identify the options to support the continual electric requirements including load growth of the end use customers within the area of the NWPP.
4. To develop a transmission assessment that will also identify options to increase the competitive supply of electricity.
5. To coordinate with other transmission planning efforts within the Western Interconnection.
6. To use an open and transparent process. The transmission assessment will be available to any interested party.

General Approach

In order to meet the goals of this effort, the planning process must integrate the planning activities that provide for ongoing load growth, interconnecting new generation, and ensuring reliability standards are met. The goals look forward into the future, the process must be proactive in nature.

The NTAC will develop and publish an annual Transmission Expansion Assessment for the NWPP region for the 10 year planning horizon. The Transmission Expansion Assessment will identify costs, benefits, impacts, and other relevant information regarding transmission expansion for reliability, transmission for new resources, and additional expansion to support a competitive supply of electricity for the NWPP region. The NTAC will not allocate benefits and/or costs of the Transmission Expansion Assessment. The Transmission Expansion Assessment will be a unified regional transmission plan ("one utility concept") and will not replace or supercede existing tariffs or other existing legal obligations.

All participants are expected to provide necessary information (studies, options, expansion plans, etc.) to NTAC on a sufficient and timely basis, including issues that may have potential effects on the transmission system.

NTAC will use consensus to identify necessary and feasible studies to be performed. The studies performed will be completed within the limitations of resources provided by the participants. If additional funds or resources are requested by NTAC from the TPC in order to perform these studies then TPC will have the responsibility of approving or disapproving that funding. The TPC admits new members who are willing to share the TPC's costs on a pro rata basis.

The following are the responsibilities of the participants in this process:

- **NWPP TPC** – oversight, review, and funding. The TPC will select the NTAC Chairman.
- **NTAC** – NTAC participants will provide input and resources to perform all the necessary studies, work and analyses necessary to develop the annual Transmission Expansion Assessment. NTAC will select the Vice Chairman.
- **NWPP Staff** – provide facilitation, coordination, and dissemination of information.
- **Transmission Providers** – retain local planning responsibilities within the NWPP area to ensure reliability of their systems.

NTAC Expected Duties

1. The NTAC will coordinate the development of a consistent Load and Resource database in cooperation with other related groups such as CREPC's WRAT, PNUCC, and the NWPCC.
2. The NTAC will provide a list of committed transmission additions in its Transmission Expansion Assessment.

3. The NTAC will coordinate the development of a consistent database and methods to support economic and production cost studies and resource adequacy. This will include data support for northwest hydro modeling.
4. The NTAC will refine Northwest data used in the SSG-WI path utilization report, and suggest/develop improvements or enhancements to the report to ensure understanding of uses of the Northwest transmission system.
5. Represent the NW Sub-Regional study effort at the SSG-WI PWG. Information submitted for support of the SSG-WI studies will be derived from NTAC's methods and database.
6. The NTAC will perform annual assessment of the NWPP transmission system by performing studies to:
    a. Estimate future transmission usage and congestion patterns with new resources and load growth scenarios. A broad participant involvement process will be used to identify the necessary scenarios.
    b. Estimate the costs of expansion and assess effects of proposed transmission and resource expansion scenarios on future transmission use patterns and congestion.
    c. Evaluate additional transmission expansion options and other alternatives proposed by participants.

Process

Define existing System - Capability

Base Case

- Decide Base Year
- Committed Transmission Projects
- Committed Resource Additions
- Common Load Forecast
- Established a Capacity Floor
- Is the System Adequate
- Identify existing desired interconnection points for new generation

Problems/Needs

- Existing Transmission Constraints and Needs
- Potential Resources to Loads (IRP)
- Solicit Resource Plans
- SSG-WI Planning Group Needs
- Northern California
- Rocky Mountain

- IPPs to potential Loads
- Renewables

Solutions/Ideas

- Solicit Transmission Plans
- Solicit Alternatives including non-wires
- Renewables

Audience

- PNUCC-TIG
- SSG-WI
- RRG/RTO West
- Regulatory Bodies
- Individual Participants
- WGA

Schedule

To be determined.

Additional information on the Northwest Sub-regional Planning Group will be posted under the Northwest Power Pool's web site at http://www.nwpp.org.

APPENDIX G—Glossary of Terms

Ancillary Services	Interconnected Operations Services identified by the Federal Energy of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.
Available Transfer Capability (ATC)	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Biomass	Any organic material not derived from conventional fossil fuels. Examples are animal waste, agricultural or forest by-products, and municipal refuse.
Capability	The maximum load which a generator, turbine, transmission circuit, apparatus, stations, or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress.
Capacity	Capacity is the maximum load of electricity that equipment can carry. Synonymous with capability.
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.
Combined-cycle combustion turbine (CCCT)	A electrical generation device powered by fossil fuel (natural gas), that combines a combustion turbine with a steam turbine to produce electrical generation.
Combined Heat and Power (CHP)	The use of a single prime fuel source such as reciprocating engine or gas turbine to generate both electrical and thermal energy to optimize fuel efficiency. Also known as cogeneration.
Congestion	Refers to when transmission paths are constrained, which limits power transactions because of insufficient capacity. Congestion can be relieved by increasing generation or by reducing load.
Congestion Costs	Costs that arise from re-dispatching thermal generation to enforce transmission constraints.

Control Area — A geographical area in which a utility is responsible for balancing generation and load.

Daily Peak — The daily peak is the greatest amount of electricity demanded during a one-hour period in a day.

Demand — The rate at which electric energy is required by a system, part of a system, or a piece of equipment expressed in megawatts, megavolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time.

- Average — The demand on, or the power output of, an electric system or any of its parts over any interval of time, as determined by dividing the total number of kilowatt-hours by the number of units of time in the interval.

- Coincident — The sum of two or more demands that occur in the same demand interval.

- Firm — The maximum 60-minutes coincident load for the month specified. It includes transmission system losses and standby demand, and excludes station service, self load, load management, and interruptible loads.

- Maximum (Peak) — The greatest of a particular type of demand occurring within a specified period.

Demand-side Management (DSM) — Methods of managing electrical resources that affect use, rather than generation, of electricity, e.g., energy efficiency or load control measures.

Discount rate — An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value.

Distributed generation — Locating of small amounts of generation located on a distribution system for the purpose of meeting local peak loads, and/or displacing the need to build/upgrade larger-scale, centralized generation facilities.

EHV — Extra-high voltage. Refers to transmission lines with voltage levels higher than high voltage (HV) but lower than ultra-high voltage (UHV) levels, and generally considered to range from the 345 kV class through the 800 kV class of voltages.

Electric demand	The instantaneous electric requirement of a power system, usually expressed in units such as megawatts (MW) or kilowatts (kW).
Energy	Electric energy is usually measured in gigawatt hours.
Generation	The act or process of producing electric energy from other forms of energy; also the amount of energy so produced.
Gross Generation	The total amount of electric energy produced by a generating station or stations, measured at the generator terminals.
Hydro	A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is falling water.
Net Generation	Gross generation less station use.
Independent Power Producer Generation (IPP)	A general term embracing facilities named in the Public Utility Regulatory Policies Act (cogenerators and small power producers) and any other independent power producer generating facilities connected to the utility system (excluding self generation). External IPP resources are those which are located outside of the service area of the utility purchasing the generation. A wheeling utility provides transmission service for the external IPP. Internal IPP resources are those which are located within the service area of the utility purchasing the generation or are radially connected to the purchasing utility and do not require wheeling by another utility.
Pumped Storage Plant	A power plant utilizing an arrangement whereby electric energy is generated for peak load use by utilizing water pumped into a storage reservoir usually during off-peak periods. A pumped storage plant may also be used to provide reserve generating capacity.
Thermal	A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is heat.
Cogeneration	Equipment used to produce electric energy and forms of useful thermal energy, such as heat or steam, used for industrial, commercial, heating or cooling purposes, through

sequential use of energy. Combined Cycle generation is not considered cogeneration.

Gigawatt	1000 Megawatt
Grid	The grid is the network of transmission facilities over which electricity travels.
Heat rate (Average)	Measure of generating station thermal efficiency, generally expressed as Btu per (net) kWh. Computed by dividing total Btu content of fuel burned (or heat released from a nuclear reaction) by the resulting net kWh generated.
Incremental heat rate	Amount of thermal energy needed to produce the next kilowatt-hour of electric energy for any given level of electric power generation.
Integrated Gasification Combined Cycle (IGCC)	Power generation technology that produces electrical power by combusting coal in the absence of sufficient oxygen to produce a low-Btu fuel gas, which is burned in a combined cycle combustion turbine.
Kilowatt	A kilowatt is a measure of electrical power equal to 1,000 watts. A watt is the rate at which electricity is generated or consumed. Ten 100-watt bulbs use one kilowatt of electricity.
Kilowatt –hour	A kilowatt-hour is a basic unit of electricity equal to one kilowatt or 1,000 watts of power used for one hour.
Levelized costs	The expression of costs on an equal, per-unit basis, taking into account an appropriate interest rate. A home mortgage payment is an example of a levelized cost.
Line loss	The electric energy lost (dissipated) in transmission and distribution lines and their associated equipment, usually through heat and vibration. Varies with the current (amperes) of the line. If the current doubles, the losses will increase by a factor of four.
LMP	Locational Marginal Price. The marginal cost of supplying the next increment of demand. Also: shadow price of hourly load resource balance operating constraint.
Load	The amount of electric power delivered or required at any specified point or points on a system. Load originates

primarily at the power consuming equipment of the customers. See DEMAND.

Firm Load — Electric power load (including standby demand) intended to be served at all times during the period covered by a commitment, even under adverse conditions.

Interruptible Demand (Load) — Electric power load (including load management) which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement. In some instances, the demand reduction may be affected by direct action of the system operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as interruptible demand.

Direct Control Load Management — A procedure in which customer demand can be controlled through the direct action of the system operator through actual interruption of power supply to individual appliances or equipment on the customer's premises. This type of control usually reduces the demand of residential customers.

load factor — The ratio of average load to the peak load during a specified period of time; expressed in percent.

Load Management — The management of load patterns in order to better utilize the facilities of the system. Generally, load management attempts to shift load from peak use periods to other periods of the day or year.

Losses — The general term applied to energy (kilowatt-hours) and power (kilowatts) lost when operating an electric system, occurring mainly as energy turns to waste heat in electrical conductors and apparatus.

LSE — Load Serving Entity

Marginal cost — The cost of producing the marginal, or next, unit of power to be generated.

Marginal cost pricing — As applied in the utility industry, a method of pricing whereby the price for each unit of energy is set equal to the cost of producing the next or most recent unit.

Marginal energy costs	1) The cost of producing or saving the last unit of energy; 2) For a generating resource, the cost to produce one more kilowatt-hour of electricity.
Megawatt	A megawatt is one million watts or 1,000 kilowatts.
Nameplate rating	The full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.
Net	The gross capacity of a generating unit as measured at the generator terminals less the power required for the auxiliary equipment (such as fan motors, pump motors, and other station service equipment essential to operate the unit).
Net Dependable Capability (Net Capability)	The maximum load which a generating unit, power plant, or system can supply under specified conditions for a given interval, without exceeding approved limits of temperature and stress. When used in reference to a system or plant, capability includes all generating units except those whose sole function is to supply emergency power for startup and shutdown. It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage, or other reasons, or only operable at less than full output. It excludes power required for plant operation.
Net energy	The electric energy requirements of a system. It is defined as system net generation plus energy received from others less energy delivered to others. It includes system losses but excludes energy required for "pumping up" pumped storage plants.
Network	A network is a system of transmission and distribution lines cross-connected to provide multiple power feeds to an area. A network is usually installed in urban areas. Networks make it possible to restore power quickly to customers by switching them to another circuit.
Nominal discount rate	An interest rate that includes inflation

Nomogram	Graph for displaying data (i.e., transfer capability) based upon certain variable values such as temperature, loads, generation, and line conditions.
Outage	The period during which a generating unit, transmission line, or other facility is out-of-service.
Forced outage	The shutting down of a generating unit, transmission line, or other facility, for emergency reasons.
Scheduled outage	The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.
Peak demand	Peak demand is the maximum amount of electricity necessary to supply customers. Peak periods fluctuate by season. Peak demand generally occurs in the morning during the winter and in the afternoon during the summer.
Phase shifter	Piece of electrical equipment that acts as a "one-way valve" for electricity, allowing it to pass along a conductor in one direction but increasing the resistance to flows in the other.
Planning Margin	The Planning Margin selected is 15% of the annual peak hour when the loads plus long-term firm sales minus long-term firm purchases result in the largest requirement on the system. This target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves regulatory margin, and demand growth uncertainty.
Power pool	Two or more interconnected power systems operated as a system and pooling their resources to supply the power and energy requirements of the systems in a reliable and economical manner.
Present value	1) The value of current dollars of a flow of cash over time; 2) In bond financing, the value in current dollars of debt service payments or reductions over the remaining life of the bonds.
Real discount rate	An interest rate adjusted to remove the effect of inflation
Reliability	Reliability is the assurance of a continuous supply of electricity for customers at the proper voltage and frequency.

Reserve margin	For a power plant or transmission facility, extra capacity above the amount projected to be needed, to allow for unanticipated demand for power, equipment failure, or other unforeseen events. Measured as percentage of peak load, or simply a megawatt number.
Resource adequacy	The sufficiency of generation/demand-side management (DSM) resources to serve loads and meet operating reserve requirements within the constraints of the transmission system and the operation of the generating resources. The timeframe for a resource adequacy standard generally needs to be two to three years out because the construction of new generation generally requires a two, or more, year timeframe.
RPS	Renewable Portfolio Standards. RPS seeks to ensure that a minimum amount of renewable energy is included in the portfolio of electricity resources serving a state or country. Portfolio standards have been primarily a result of state-based electric restructuring efforts. Texas, Arizona Nevada and California have adopted various non-mandatory standards.
Series capacitor bank	An installation of capacitors with fuses and associated equipment in series with a line. Generally located near the center of a line (but can be located at any point). Used to increase the capability of interconnections and in some cases to achieve the most advantageous and economical division of loading between lines operating in parallel.
Shadow Price	The shadow price of a constraint (e.g., a transmission capacity constraint) is the dollar amount by which the optimal objective function (e.g., minimizing total production costs of the system) is improved when the constraint limit is increased by one unit. Synonymous with marginal price, marginal cost, or opportunity cost.
Simple-Cycle Combustion Turbine (SCCT)	A combustion turbine, fueled with fossil fuel(natural gas) used for the generation of electricity without the recovery of waste heat.
Spot Market	As conventionally defined, the spot market refers to day-ahead and real-time purchases and sales of electricity. .The IRP defines spot market more broadly to include market purchases and sales, outside of existing long-term contracts and pursuant to the model dispatch logic.

SSG-WI	Seams Steering Group–Western Interconnection SSG-WI serves as the discussion forum for facilitating the creation of a Seamless Western Market and for proposing resolutions for issues associated with differences in RTO practices and procedures.
Substation	A substation is a facility, generally a small building with a fenced-in yard containing switches, transformers and other equipment used to adjust voltages and monitor circuits.
Summer peak period	The summer peak period begins on June 1 and runs through September 30.
System	The physically connected generation, transmission, distribution and other facilities operated as an integral unit under one control, management or operating supervision, often referred to as "electric system," "electric power system" or "power system."
System peak	The System peak is the maximum load on an electrical system during a given period of time.
Thermal Rating	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.
Transfer	The transfer of electrical energy across a point or points of interconnection during a stated period.
Transmission lines	Transmission lines are heavy wires that carry large amounts of electricity over long distances from generating stations to substations. Transmission lines are held high above the ground on tall structures called transmission towers.
Transmission access	Rights granted to non-owners and non-operators of transmission facilities to deliver energy along transmission lines to wholesale customers.
Transmission congestion	Condition that exists when market participants seek to dispatch generation in a pattern which would result in power flows that cannot be physically accommodated by the transmission system.

Transmission congestion contract — Financial instrument that provides a hedge against congestion price differences between zones.

Transmission interconnection — 1) A system consisting of two or more individual power systems operating with connecting lines to make a larger system, thus permitting the sharing of generation reserves and providing alternative transmission paths to serve customers during line outages; 2) The connection between two power systems.

WGA — Western Governor's Association. WGA addresses important policy and governance issues in the West, advances the role of the Western states in the federal system, and strengthens the social and economic fabric of the region. WGA develops policy and carries out programs in the areas of natural resources, the environment, human services, economic development, international relations and state governance. WGA acts as a center of innovation and promotes shared development of solutions to regional problems.

Water Conditions (as defined in the SSG-WI study)

Low Hydro — Runoff and storage regulation which reflects operation under the lowest quartile of streamflow conditions that have occurred during a specified period, usually the period of historical record. 1930 inflows were used for the PNW system.

Medium Hydro — Runoff and storage regulation which reflects operation under average streamflow conditions across all four quartiles and that have occurred during a specified period, usually the period of historical record. 1953 inflows were used for PNW inflows.

High Hydro — Runoff and storage regulation which reflects operation under the highest quartile of streamflow conditions that have occurred during a specified period, usually the period of historical record. 1948 inflows were used for PNW inflows.

Watt — A watt is the measure of work that electricity can do. Watts are commonly used to rate appliances.

WECC — Western Electricity Coordinating Council (formerly known as the Western Systems Coordinating Council, or WSCC); an organization that works with its members to assess and enforce compliance with established criteria and policies for ensuring the reliability of the region's electric service.

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[PC1] “Boom-Bust” usually refers to construnction cycles. This needs clarification.