Chapter 2: Modeling ofTransmission Needs

Overall Modeling approach
Primary Model
Key assumptions
Alternatives modeled (to be added)

Overall Modeling Approach

In RMATS Phase 1, the modeling evaluated the economic implications of transmission expansion alternatives for the Rocky Mountain States and for the West. The modeling was designed as an economic screening study in order to:

- identify areas of transmission congestion under various load, generating resource, transmission grid, and other assumptions. Transmission congestion affects the cost of serving loads and the ability to reach markets on the West Coast. In many locations, congestion grows as loads grow unless new resources and transmission are added
- quantify the cost of congestion to the region. The cost of congestion is defined as the increase in production (fuel) costs due to transmission constraints and losses
- support the development of resource addition and transmission expansion alternatives to meet future load growth and alleviate congestion
- quantify and compare the variable and fixed costs of resource and transmission expansion alternatives
- estimate whether loads (consumers) and generators may gain or lose economically in the Rocky Mountain States and in other areas of the West with the resource and transmission additions in the alternatives.

The modeling began by identifying areas of transmission congestion and quantifying the costs of congestion with the existing transmission system. Modeling for this "current system" base case was accomplished with a production cost model that includes a detailed representation of the Western Interconnection. Once the base case was completed, the Resource Additions and Transmission Additions Workgroups developed four resource scenarios and associated transmission solutions with an eye to meeting future loads and alleviating congestion. The production costs and then the investment costs and the annualized fixed costs of these alternatives were modeled, and then compared. Finally, estimates were made on where loads (consumers) and generators may gain or lose economically in the Rocky Mountain States and elsewhere in the West. From this analysis, the RMATS Steering Committee formulated two transmission expansion recommendations. The recommendations are expected to undergo technical studies, siting reviews, ownership and financing planning, and additional economic analysis in RMATS Phase 2.

The bulk of the modeling involved simulating production costs for the Western Interconnect. A spotlight was placed on generation and transmission in the Rocky Mountain States. To begin the production cost modeling, key data assumptions were required for loads, resources, and transmission capabilities and power flows. The starting point for these data inputs was the West-wide transmission planning screening study conducted under SSG-WI auspices in 2003. This data base was updated, corrected and otherwise refined by experts in the RMATS Workgroups..

Two test years were modeled. The first test year was the 2008 base case. The objectives of this base case were to identify the incidence and duration of congestion in the current system, and to estimate its costs under certain load, gas price, and wind capacity assumptions,. The base case included the West's existing generating resources and transmission grid, as well as new resource and transmission additions that had already been approved and planned for construction. From this modeling, several areas of congestion were found. "Low hanging fruit" was identified, meaning a few relatively low-cost transmission enhancements were identified that are clearly economic and easily accomplished in the near term.

The second test year was 2013, in which the economics were modeled for the resource addition and transmission expansion alternatives that the Workgroups developed to meet future load growth. The year 2013 was chosen to provide adequate lead time fo any major transmission expansion. The modeling quantified and compared the production costs and the fixed costs of the alternatives for purposes of arriving at economically viable project recommendations.

(To insert a graphic here that shows, on a very high level, key data assumptions going into MS, MS optimization, MS outputs, Econ table –James/Dina)

Production cost modeling

ABB Market Simulator was the production cost model used to simulate transmission congestion, calculate marginal prices at the nodal (bus) level and system-wide fuel and other variable production costs.

Market Simulator is designed to produce:

- Congestion estimates – demonstrating where transmission bottlenecks may occur
- Market clearing prices – estimating forward price curves that vary by location (bus or node), including spot energy and shadow transmission price curves
- Generating resource dispatch – estimating the lowest cost dispatch for the Western Interconnection
- Transmission expansion – showing the production cost effects of proposed transmission development.

n (sometimes called shadow price).

The model seeks to minimize system production costs while matching hourly generation to hourly loads. This optimization takes into account gas and coal fuel prices, resource capacity constraints, energy constraints (hydro and wind resources), heat rates for thermal plants, planned outages, minimum and up and down times, and transmission constraints. The optimization seeks to equalize LMPs across the West.

Large amounts of load, resource, and transmission 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 the model's dispatch engine and to the data. For example, the model assumes a single, seamless west-wide market, with none of the efficiencies of multiple control areas or of rate and loss charged pancaking that exist today. It assumes an optimal one-world dispatch of generating resources. Hydroelectric and wind resource generation is modeled outside Market Simulator, with the results then entered as fixed inputs around which the model dispatches thermal resources. Must run" generation and unit commitments are not modeled, nor are strategic bidding behaviors.

See Appendix X, "ABB Market Simulator", for an expanded discussion of the model's logic, inputs and outputs, and limitations.

Linkage to real-world decision-making
The way decisions are made in Market Simulator differ from the way they are made in the Real World. In both decision processes, the location of new generation drives the determination of the need for new transmission. In the modeling process, the location of new generation is an assumed input. Among the 2013 alternatives that were modeled, only one was linked to available resource plans of three load serving entities in the RMATS footprint (Pacificorp, Xcel, Idaho Power Company). In the Real World process, the decision on what new generation is built is largely determined by choices of load serving entities and their regulators. A significant weakness in the way generation decisions are made in the Real World is that each load serving entity generally makes decisions in isolation. Because transmission additions and some generation additions (e.g., coal-fired) tend to be in lumpy increments (i.e., do not come in capacities sized only to meet near-term incremental needs), and because there tend to be economies of scale in building transmission (a 500 KV line does not cost twice as much as a 230 KV line), a transmission addition may not be economic to meet the demands of a single load serving entity, but would be economic when combined with the needs of other LSEs.

In the RMATS modeling, once the location and type of generation is assumed, the model chooses the dispatch of the existing and new generation based on the lowest variable operating and maintenance (VOM) cost of the generating units without regard to plant ownership or power purchase contracts. In the Real World process in the Rocky Mountain region, the decision on which generation to dispatch is typically made by each LSE based on the lowest operating cost of the units it owns or power purchase contracts it has signed.

Once the model has chosen the units to dispatch, it is assumed that all transmission paths are available to move the power to load centers without regard to contractual rights on the transmission system. The transfer of electricity from the generator to the load is only constrained by the physical capabilities of the transmission system. In the Real World, moving power from a generator to a load can only be done pursuant to schedules over specified transmission paths or pursuant to network service contracts. To execute a schedule, a party must have rights to use specific transmission paths from the generator to the load, even though in actuality the electricity from the generator to the load will flow physically over other paths as well as the paths over which the power has been scheduled. As a result of institutional constraints, capacity on the line is frequently not available even when the line is not fully loaded. In some cases, like the West of Hatwai transmission path, institutional constraints limiting the use of the transmission system have been overcome by building new transmission even though the existing physical assets may have been capable of moving the power.

In the RMATS modeling process, after the generation with the lowest fuel and other variable O&M cost is dispatched over any combination of lines that can physically handle the transfer, the model determines if there are generators with lower operating and maintenance costs which could not be dispatched because of the lack of transmission capacity. In place of the lower cost generation, a higher cost generator is dispatched to meet demand. The model calculates the fuel and other variable O&M cost for all the generation it dispatches in the Western Interconnection, and shows differences in dispatch costs in different areas in the Interconnection. Where the model shows significant differences in costs between the bubbles, the RMATS Transmission Working Group identified transmission additions that would enable power to flow from areas with lower operating and maintenance costs to areas with higher costs.[1] In the Real World, a load serving entity examines whether new transmission would lower the cost of acquiring generating resources to meet the demands of its customers. Traditionally, the decision on what new transmission to build has been made in conjunction with the decision on what new generation to acquire. Typically, only after the LSE has decided it wants to build a project will it inquire whether other parties would be interested in sharing the cost of the line or expanding the line.

Figure 2-X
Comparison of Modeling and Real World Decision-Making
(Doug/Jim – we need to spend time on this)

	Strength of approach	**Weakness of approach**
Location and type of generation		
RMATS modeling: regional resource scenarios that are integrated with regional transmission expansion solutions	May identify lower cost alternatives available through regional planning	Does not reflect most LSE planning today
Dispatch of generation		
Model: Lowest cost generation in Interconnection is dispatched to meet demand.	Supports proposition that identified transmission additions add value for the interconnection regardless of future changes in ownership of plants and LSE configurations.	Does not recognize transmission expansion that may be marginally economic from a global perspective, but makes economic sense for specific parties.
Real World: Generation dispatch optimized for LSE but not across the Interconnection.	Reflects reality faced by LSEs today and thus it is easier to make decisions on financing of transmission projects (i.e., individual LSEs will see the benefits of transmission projects which allow them to save money by optimizing the dispatch of their resources).	Does not reflect future changes in the ownership of plants and their output that would allow more optimal dispatch patterns.
Value of Transmission Additions		
Model: Optimizes use of the transmission system within its physical constraints.	Provides justification for new transmission under future institutional changes, such as the formation of RTOs, and provides a compelling case for new transmission in the permitting process.	May not reflect the incentives faced by those who would finance new transmission.
Real World: Reflects institutional constraints that can result in sub-optimal use of the transmission system.	More likely to result in projects being financed because it reflects both present and foreseeable future rules on transmission system use.	Can result in building transmission that would not be needed if there were system operation rules that allowed more efficient use of the grid. This may make permitting of such transmission more difficult since the need for the line is based on institutional rules, not physical needs.

Capital and other fixed cost modeling
(being drafted)

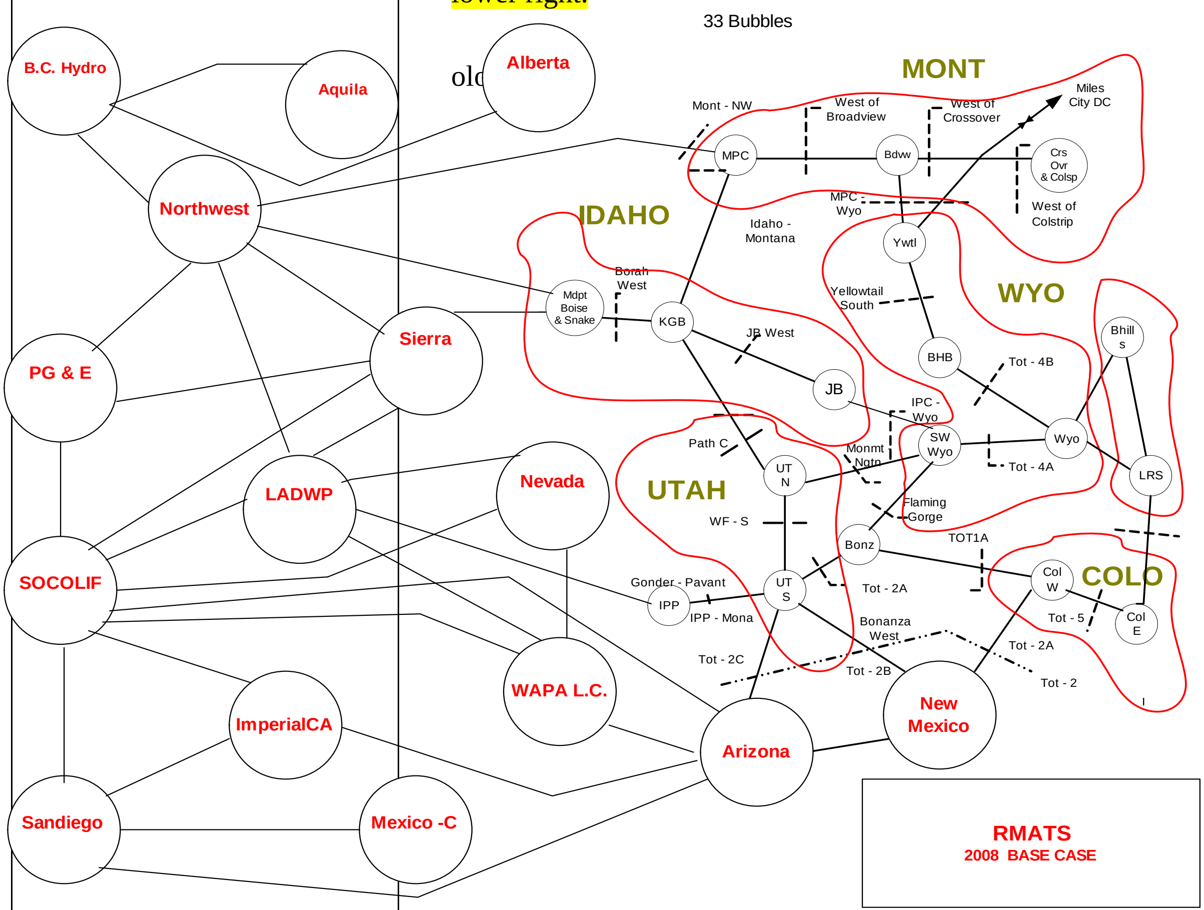
Key data assumptions

To promote consistency with other transmission planning in the West, RMATS used as a starting point the data base for Western Interconnect loads, resources, and the transmission network that SSG-WI compiled through extensive coordination. Updates and corrections to these data were made by the Resource Additions, Load Forecasting, and Transmission Additions Work Groups.

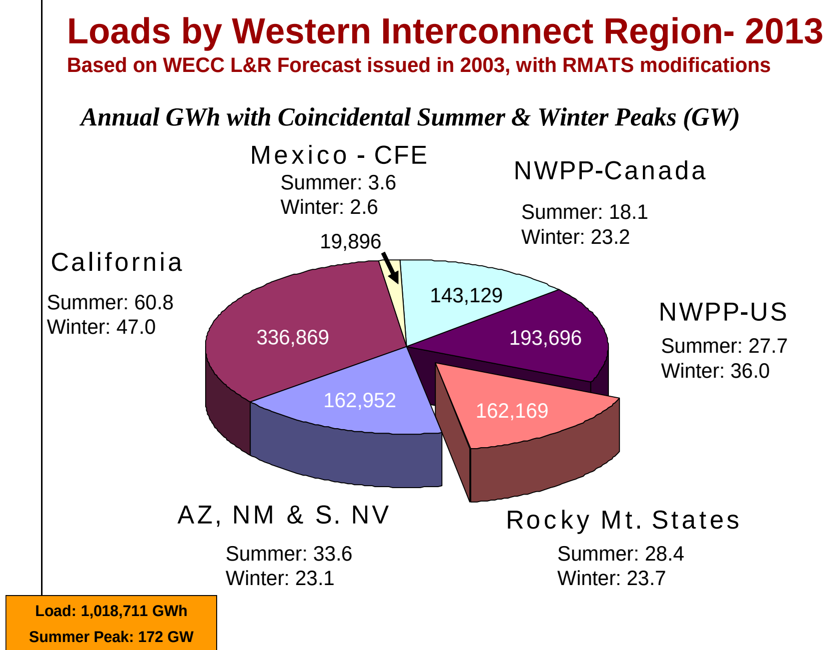
An expanded discussion of key data assumptions is included in Appendix X.

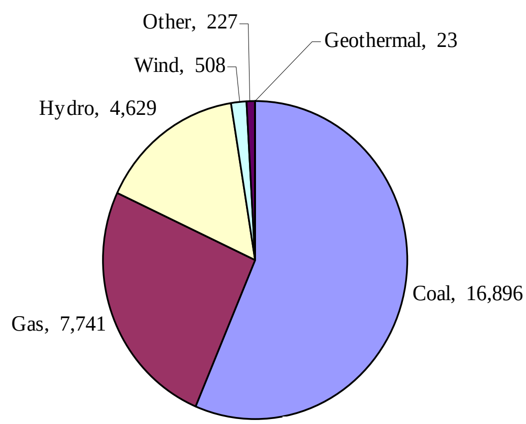
Figure 2-X
2008 Base Case and 2013 Study Assumptions

Assumption	***Description***
Transmission topology	James: include a brief explanation as to the purpose of bubbles (essentially aggregate and report results by area) and logic behind drawing them where we did. Also, let's get rid of the text box at lower right.



Transmission path ratings and nomograms	New transmission includes what is defined in the WECC 2008 LSP case ???, with modifications to provide more in-depth look at the

Assumption	*Description*
	Rocky Mountain region (Jamie)
Power flow	Jamie: source, vintage, mention that same for all cases (to be updated in Phase 2)
RMATS regional loads and average annual load growth	Based on WECC load forecast issued in 2003 with modifications (LFWG needs to summarize modifications). (Mike TBA: explain how moved from the WECC level of detail down to the level required for LMP modeling) 
Natural gas prices	2008 U.S. average wellhead price set at $4.00 and $5.00/MMBtu (in 2004 dollars. Henry hub prices were adjusted to estimate the delivered price of gas using *hourly?* basis differentials developed for the Fifth Northwest Conservation and Electric Power Plan. Range between the low and high case is consistent with December 2003 forecast by the Energy Information Administration. LINK Jamie – see me: The 2013 Alternative Studies were run using an escalated $6.50 price with area deviations
Coal prices	Based on Northwest Power Pool forecast (vintage) , which assumed . . (RAWG). Prices were modified for location. Prices include transportation if coal is railed or trucked
Existing thermal plants	Existing thermal plants as modeled in SSG-WI base case. All existing plants assumed to remain in operation, except plants due to retire as outlined by the California Energy Commission. A sensitivity was performed to include Mohave which is due to retire in at the end of 2005. Maintenance outage assumptions were the same as SSG-WI study, which in turn drew from the TCA cost-benefit analysis for RTO West. That analysis assumed that . . . (Jamie). Modifications made

Assumption	*Description*
	for coordinated maintenance? All plants in each vintage, type and class are assumed to have similar heat rates.
Generating resource additions in Base Case	The 2008 base case includes power plants sponsored by entities that have the ability to secure the proper permits, financing and construction, with more than one-half of the generation subscribed. These represent 1,000 MW of new generation that was not included in the SSG-WI study. These plants were also rolled forward to the 2013 study Figure 2-X Generation Resource Mix in 2008 Western Interconnect (megawatts) 
Hydroelectric resources	All plants currently in operation are assumed to remain in operation. Hydro dispatch is based on medium water year levels. A sensitivity was run based on low hydro conditions
Renewable resources	As modeled by SSG-WI with additions (RAWG needs to summarize modifications) Clarify the (non-wind) types of resources covered here
Wind hourly shapes	Assumptions consistent with SSG-WI study. This included (RAWG explain). The National Renewable Energy Laboratory provided hourly shapes based on (RAWG explain)
Transmission additions in Base Case	I forget – were there any (Jamie)?
Treatment of demand-side management	DSM for 2008 was decremented against forecasted loads assuming (LFWG summarize). Mention sensitivities for 2013
Planning margin	To be added. . *Need to decide whether this should be included here or in appendix or not at all. In early calculations of the load growth in the RMATS sub-region the delta (listed above at 3,657 MW) was erroneously calculated to be 3,380MW. A reserve margin of 15% was added to this figure to arrive at the assumed new generationof 3,900 MW required to meet Rocky Mountain sub-region load growth. When the 2008 to 2013 sub-region was later calculated to be 3,657 MW, the assumed new*

Assumption	Description
	generation requirement was left at 3900 MW by the RAWG. Other assumptions by the RAWG, related to wind generation included in the new generation mix, tended to offset this error and the result was deemed to be "close enough" for a screening study.
Capital investment, capital charge, and fixed O&M assumptions for 2013 resource and transmission alternatives	James/Dina
Inflation rate	2.5% applied to fuel and variable operating and maintenance costs

Resource Addition and Transmission Expansion Alternatives

(TBA)

Sensitivities

- A high wind sensitivity was run, this sensitivity included 1,742MW of additional wind capacity. to base 508 MW for total of 2250 MW in the Rocky Mountain Area
- Did not consider transmission impacts other than on monitored interfaces (feasibility may require significant transmission additions)
- Wind MWhs displaced gas generation over 95% of time
- Some hourly impacts on coal plants

Sensitivities run for 2008
A base case for 2008 was modeled to assess the current system with viable investment already in progress included, identify the incidence and duration of congestion, estimate the costs of congestion, evaluate several load, gas price, and hydro sensitivities, and review plant performance. The analysis helps illuminate opportunities for cost-effective transmission projects by estimating the incremental value of transmission expansion on congested paths.

Figure 3-10

Base Case Runs

	2008 Load	2008 Load with Additional Wind Generation	High Load*
$4 Gas	X	X	X
$5 Gas	X	X	X

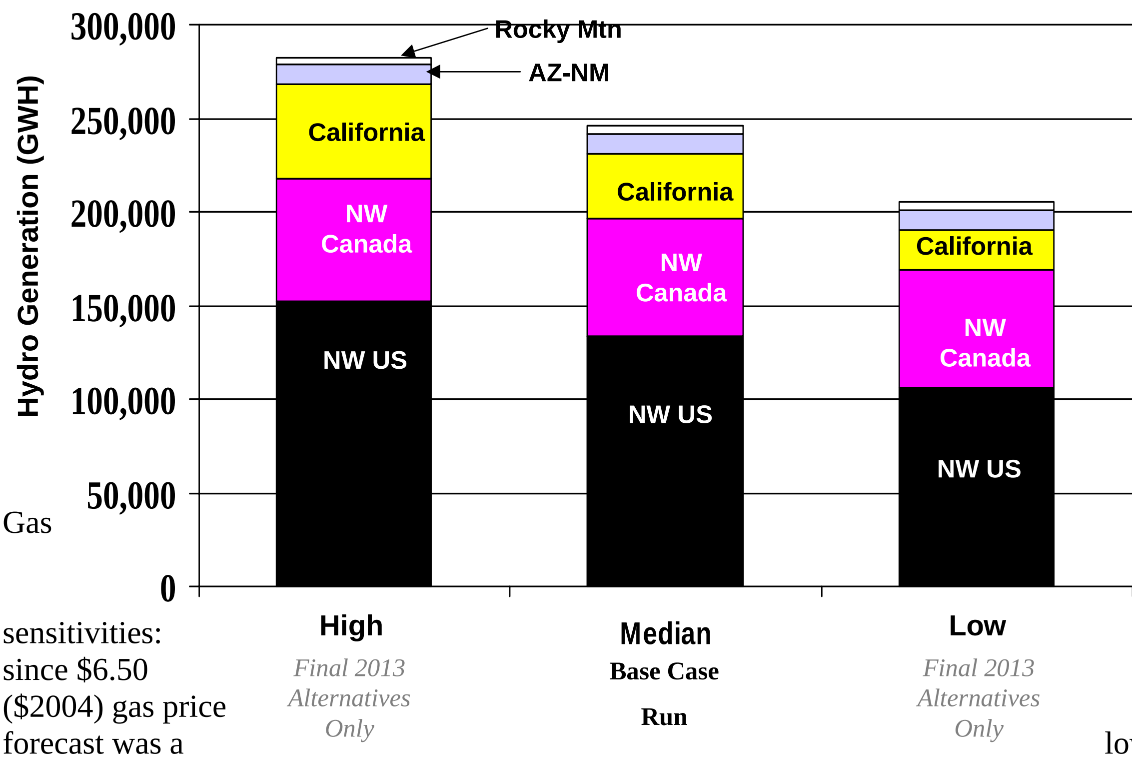
Need explanatory bullets or footnotes for "additional wind generation" and "high load"

Sensitivities run for 2013
Hydro, Gas, Load, Resource sensitivities were modeled for the Alternative 3 resource configuration option 3 only. In addition to these sensitivities, a Carbon Tax affect was determined only on Alternative 3 resource thermal additions.

- Hydro sensitivities: 2013 Alternative were ran using the median hydro condition as was the 2008 Base Case. A high & low sensitivity was ran using Alternative 3- Option 3 which generation as shown in Figure 3-9

Figure 3-11

Hydro Generation



- Gas sensitivities: since $6.50 ($2004) gas price forecast was a lower $4.50 was tested for Alternative 3- Option 3.
- Resource sensitivities: In addition to the resource alternatives, Alternative 3- Option 3 was tested to include Mohave, which is stated to retire at the end of 2005.

- Load Sensitivities: load sensitivities were performed in a DSM case where load does not grow [NEED DSM DETAIL]
- Carbon Tax Sensitivities: A $5 & $15 per CO_2 ton were added to new thermal plants emission levels for each Alternative. These amounts were added to plant emissions levels after the model was ran. It was found that including a fuel adder to the modeling had little impact on which plants generate.

Comparable table

Economics modeling approach/logic - methodology, sources of data, assumptions behind data, capital charge concepts(Dina, coordinating with Kurt)

* 2013 loads applied to 2008 resources and transmission

Note: Need concluding paragraphs on the modeling approach.