Network Open Season
Regional Economic Analysis

December 9, 2008

Background

- The Regional Economic Benefits resulting from adding new generating resources and transmission facilities are part of the Commercial Infrastructure Expansion Policy (CIP) financial evaluation. These benefits, and costs, are taken into account as part of the business case to support financing and construction of new facilities.
- The fourth category of CIFP includes regional economic benefits, which could be evaluated in a similar manner as has and is being done in the west-wide economic transmission expansion analyses performed by Seams Steering Group – Western Interconnection (SSG-WI), previously, and now by Western Electricity Coordinating Council (WECC).

Goal

- Quantify, to the extent feasible, how adding new generation may influence future regional power prices and likely congestion as a result of economic dispatch, and how adding new facilities further affects the future power prices and congestion.
- Assess whether or not the future northwest RPS mandates can be met with or without new transmission facilities.
- The primary indicator of benefits in this type of analysis is the reduction in generation production costs between a base case and a transmission infrastructure improvement scenario. This reduction in production costs indicates that lower cost generation can reach the market in the scenario after additional transmission infrastructure has been built.

Objective

- Identify potential incremental change in annual fuel costs from the addition of NOS generation changes and associated transmission projects (metrics: $$$).
- Estimate relative congestion cost associated with new NOS generation with no new transmission (metrics: hours).
- Estimate relative congestion cost savings from the addition of NOS transmission projects associated with new NOS generation.
- Deliverable: A differential analysis of costs & benefits with and without the proposed transmission additions identified by 2008 NOS cluster studies is the primary deliverable.

Scope

- Phase 1: Using the ABB Gridview Transmission Constrained Flow-Based Production Cost model to estimate future system economic operating performance:
  - Make relative economic comparison by comparing various estimated operating parameters to estimate relative economic effects of adding NOS transmission.
  - For each future scenario estimate a surrogate set of operating economic characteristics including annual production cost (variable costs) for the test year (2017) with:
  - Scenarios:
    - Base case scenario - “as planned” generation & existing transmission path limits
    - System with NOS generation added
    - System with transmission projects associated with NOS generation

Scope (Contd.)

- Phase 1: Continued
  - Identify related relative operation changes for assumed operating conditions
    - Annual saving estimate of hourly dispatch production cost
    - Increase or decrease in transmission congestion costs using following metrics:
      - Difference between estimated production costs with and without the new transmission
      - Frequency and percentage of time path loading levels exceed congestion indicator levels
- Phase 2: Perform sensitivity studies to the above varying:
  - Renewable Portfolio Standards requirements and penalties,
  - CO2 Tax assessment
  - Others as needed

Production Cost Model Application

- The production cost model in this study was used to produce a surrogate future operating year hourly dispatch of the NW and Western power system simulating how might be dispatched each hour given:
  - Forecast loads and load shapes
  - Generation mix and generation operating characteristics including production cost rates
  - Water and wind generation profiles
- Because firm transmission services, other commercial arrangements such as take or pay contracts and credits, firm interconnection schedules are not now know for the future scenario, hourly dispatch and interchange was estimated by assuming a one system operation in which hourly dispatch unit commitment is calculated to best reduce overall variable O&M and fuel costs for the total generation fleet to meet hourly loads.
  - The same dispatch method and assumptions were made in each scenario.
  - The results were then compared to get a relative sense of the economic effects on the variable costs of operation from addition of NOS generation and transmission into the future system.

Production Cost Model - Contd.

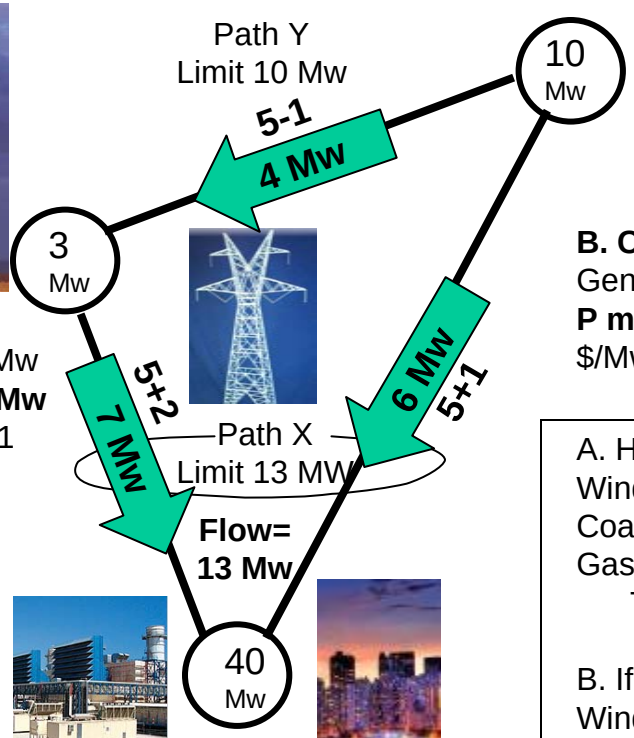
- Generation and loads are represented at their respective buses in the WECC transmission model. Powerflows resulting from the dispatch are computed for all lines represented in the model.
- Dispatch was computed to meet the three object functions:
  - Generate to meet loads
  - Keep powerflows within the flowgate/path limits
  - Minimize variable costs
- The model recognizes respective unit heat rates, unit ramp rates, minimum run times, start-up costs and maintenance requirements
- The database for the western system is from WECC TEPPC and has been prepared by staff from all parts of the western system and is well tested and vetted.

How the Model Works - Example

- Simple One Hour example – Market Simulator would perform dispatch on WECC system topography for 8760 hours in the scenario (future) year
  - Slides 10 – 13 show simple example of how the model dispatches on variable costs as constrained by transmission
  - Slide 10 shows the transmission system required to meet on peak firm N-1 reliability needs – because wind in NW has limited capacity during peak periods, transmission is basically sized for firm capacity
  - Slide 11 shows how wind during off peak periods when wind capacity is high would dispatch down resources on its side of bottlenecks. Also it shows one congestion metric. There still isn't a standard on how congestion should be measured.
  - Slide 12 shows how transmission expansion would reduce congestion but while reducing it on Path X, it increases it on Path Y so additions need to be made carefully.
  - Slide 13 shows how the model would dispatch around the exceeded transmission limit in Slide 13

Reliability Planning

N-1 Capacity for Peak Load Period



A. Wind
Gen 3 Mw
P max 3 Mw
$/Mwhr $1

Max Wind Capacity during NW Peak = P max

B. Coal
Gen 10 Mw
P max 10 Mw
$/Mwhr $10

C. Gas Peaking
Gen 40 Mw
P max 40 Mw
$/Mwhr $30

Import
13 Mw

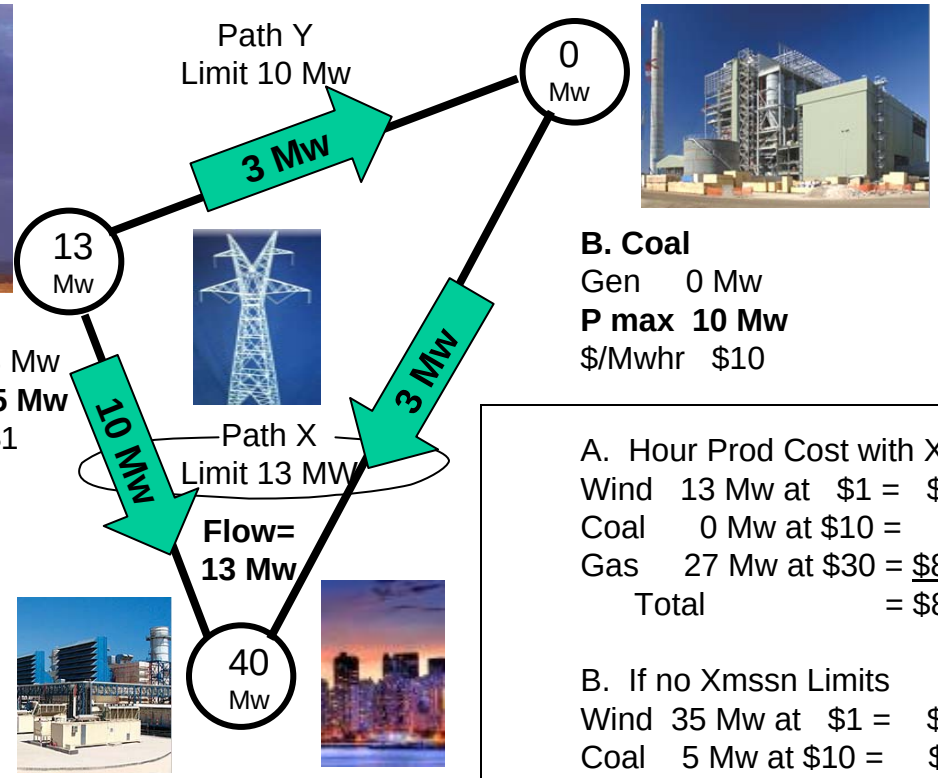
Load
53 Mw

A. Hour Prod Cost with xmssn limits:
Wind 3 Mw at $1 = $3
Coal 10 Mw at $10 = $100
Gas 40 Mw at $30 = $1200
Total = $1303

B. If no Xmssn Limits
Wind 3 Mw at $1 = $3
Coal 10 Mw at $10 = $100
Gas 40 Mw at $30 = $1200
Total =$1303

C. Congestion (metric) from Xmssn Limits
= $1303 - $1303= $0

Economic Dispatch for Off Peak Loads but Forecast Good Wind



A. Wind
Gen 13 Mw
P max 35 Mw
$/Mwhr $1

Max Wind Capacity during NW Peak = P max

B. Coal
Gen 0 Mw
P max 10 Mw
$/Mwhr $10

C. Gas Peaking
Gen 27 Mw
P max 40 Mw
$/Mwhr $30

Import
13 Mw

Load
40 Mw

A. Hour Prod Cost with Xmssn limits:
Wind 13 Mw at $1 = $13
Coal 0 Mw at $10 = $0
Gas 27 Mw at $30 = $810
Total = $823

B. If no Xmssn Limits
Wind 35 Mw at $1 = $35
Coal 5 Mw at $10 = $50
Gas 40 Mw at $30 = $0
Total = $85

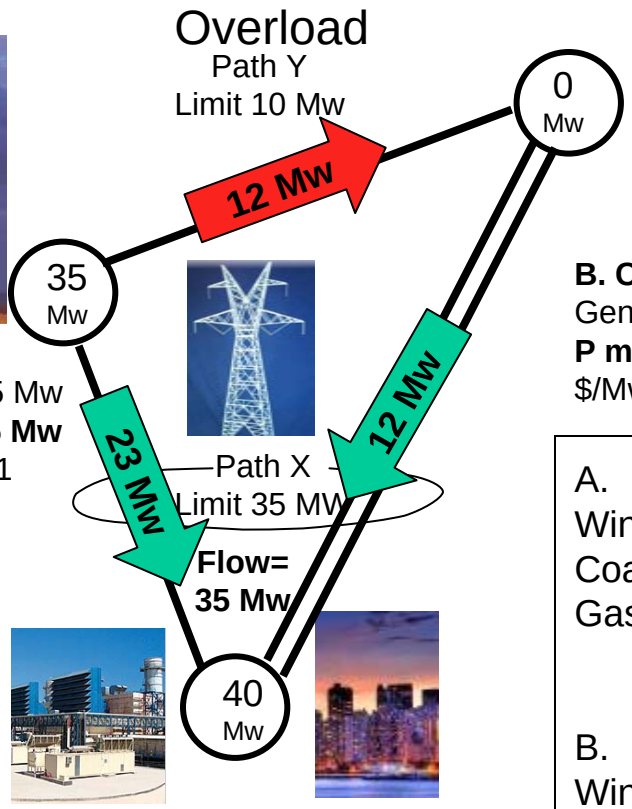
C. Congestion (metric) from Xmssn Limits
= $823 - $85= $738

Build for Firm ATC, Reduce Congestion

A. Wind
Gen 35 Mw
P max 35 Mw
$/Mwhr $1

Max Wind Capacity during NW Peak = P max

B. Coal
Gen 0 Mw
P max 10 Mw
$/Mwhr $10



C. Gas Peaking
Gen 27 Mw
P max 40 Mw
$/Mwhr $30

Import
13 Mw

Load
40 Mw

Note Coal still can't use capacity

A. Hour Prod Cost with Xmssn limits:
Wind 35 Mw at $1 = $35
Coal 0 Mw at $10 = $0
Gas 5 Mw at $30 = $150
Total = $185

B. If no Xmssn Limits
Wind 35 Mw at $1 = $35
Coal 5 Mw at $10 = $50
Gas 40 Mw at $30 = $0
Total = $85

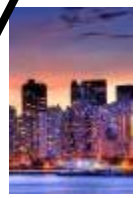
C. Congestion (metric) from Xmssn Limits
= $185 - $85= $100

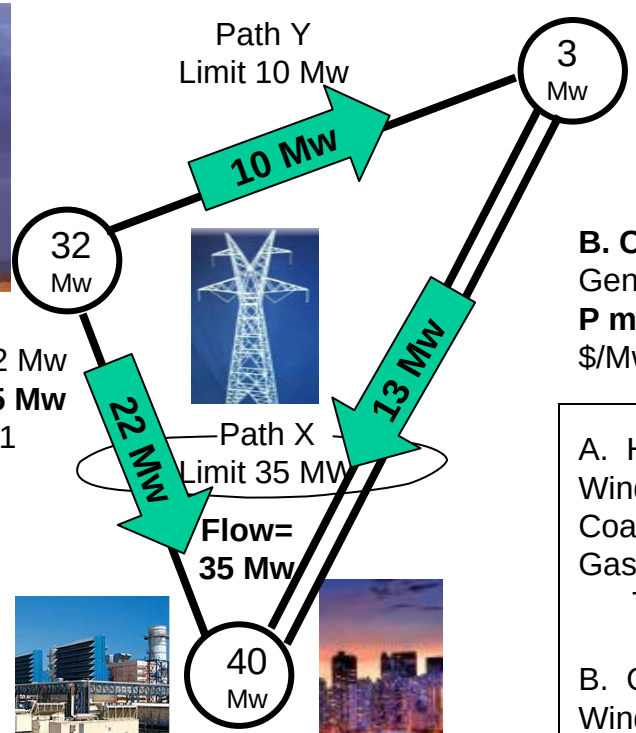
Model Dispatches to keep Within Limits

A. Wind
Gen 32 Mw
P max 35 Mw
$/Mwhr $1

Max Wind Capacity during NW Peak = P max

B. Coal
Gen 3 Mw
P max 10 Mw
$/Mwhr $10





C. Gas Peaking
Gen 5 Mw
P max 40 Mw
$/Mwhr $30

Import
35 Mw

Load
40 Mw

Note: Expansion would have been more effective on wind side

A. Hour Prod Cost with Xmssn limits:
Wind 32 Mw at $1 = $32
Coal 3 Mw at $10 = $30
Gas 5 Mw at $30 = $150
Total = $212

B. Optimum with no Xmssn Limits
Wind 35 Mw at $1 = $35
Coal 5 Mw at $10 = $50
Gas 0 Mw at $30 = $0
Total = $85

C. Congestion (metric) from Xmssn Limits
= $212 - $85= $127

Methodology

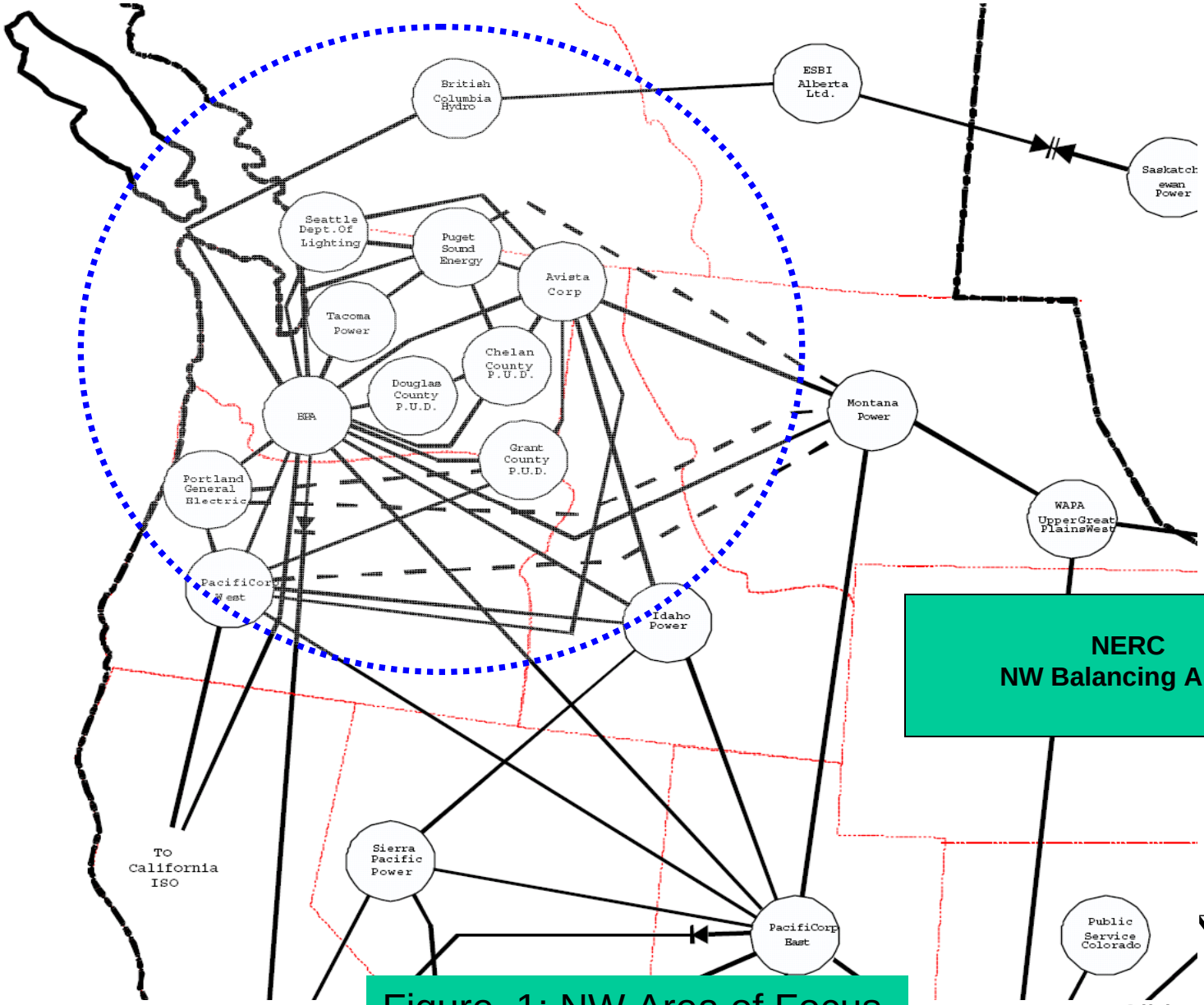
- System operation simulation was performed using the ABB Gridview hourly chronological dispatch model including powerflow representation (impedances and path limits) of the WECC transmission system
  - Model computes the best generation dispatch for each hour in the simulated year, and records resulting powerflow path loadings and production costs
  - Dispatch is calculated from given generation mix using an optimum least cost overall production cost and respecting given flowgate limits.
- The model calculates and tabulates theoretical production fuel costs and path loadings for each hour in each simulated Case
- Production costs and monitored flowgate loadings were compared between scenario cases using Excel spreadsheet-based tools applied to model results to calculate the relative effects of NOS generation and transmission

Methodology (Contd.)

- Model computes theoretical maximum production cost savings for the represented system on a “one system” basis (WECC wide) and generally computes conservative congestion results since dispatch is not restricted by “firm” reservations. This should be used as one bookend in viewing future system performance. The other bookend is the congestion that would be seen from a forecast of firm Transmission System requests and long term reservations.
- Cost differences shown are differences in thermal production costs, in millions of dollars, and in differences in total input generation, in megawatt-hours
- Monitored flowgate loading differences are shown by frequency of transmission loading (number of hours) a path loads to or above 75%, 90%, or 100% of its path flowgate limit

Methodology (Contd.)

- This analysis is a relative comparison study.
  - The theoretical production costs and resulting transmission flows for the various scenarios for the simulation year studied are compared with each other to measure relative differences (savings) or changes in production costs, and transmission loading levels.
  - The analysis is not meant to indicate production cost or market price forecasts
  - The analysis is not meant to be forecasts of actual or expected power system operation



NERC
NW Balancing Areas

Figure 1: NW Area of Focus

Assumptions

- Test year is 2017 to represent the middle of the time frame window when most NOS generation and associated transmission could be operational
- Basecase simulation data was developed from the WECC TEPPC PC1 Production Cost case and WECC PCC 2017 HW1 powerflow basecase
  - TEPPC production cost database use generic fuel costs and other generation attributes for individual unit types
  - Specific commercial arrangements such as “take or pay” fuel contracts, tax credits or other are not included
- Hourly loads are specific to electrical location on the system:
  - Area and bus location,
  - Use seasonal, monthly, weekly, and daily load profile projections for the test year

Assumptions (Contd.)

- Load requirements representative of 2017 levels
- The NOS generation added was approximately 4500 MW
- Generation units are dispatched hourly to meet load requirements:
  - To minimize production costs
  - To respect WECC-Wide flowgate limits as defined in the WECC Path Rating Catalogue and other monitored flowgates (e.g., COI, PDCI, South of Allston, West of McNary, etc)
  - Use given unit commitment and operating constraints including provisions for reserves

Assumptions (Contd.)

- Capital cost allocation and recovery for generation and transmission additions are not part of this analysis.
  - The model does not consider capital costs of generation or transmission additions but assumes once installed they will operate and be dispatched based on economic dispatch principles
  - Market based pricing and bidding as influenced by energy or capacity markets, credits or other are not considered
- Transmission flows resulting from the dispatch are calculated using powerflow transmission distribution factors and are limited by flowgate limits. The model in this analysis is set up to observe flowgate limits based on actual flows and not schedules and reservations

Generation Assumptions

- NW hydro generation
  - Projects with significant flexibility are modeled using a 'proportional load following' (PLF) method
    - Available energy in a month is generated in a shape proportional to loads, which may be modified by wind generation to simulate wind-hydro integration
    - Less or more flexibility to follow load is indicated by an analytically developed monthly "k-factor"
    - Hydro energy is optimally shaped within each month to meet NW loads, or residual loads once wind generation has met some of the load
  - Less flexible projects produce the energy they generated in 2002 – a near-normal stream flow year
  - A few small projects use a base-load sometimes combined with a peak-shaving method, where some part of energy is flat-loaded for the period and remaining energy is placed in peak load hours

Generation Assumptions

- Wind generation
  - Generation at wind plants based on wind profiles unless constrained by transmission flowgate limits
  - NW wind profiles for similarly situated wind plants are used for new NOS wind generation and are based on historical data
  - Only wind for delivery into the BPA control area is integrated with hydro generation
  - A zero incremental production fuel cost is assumed for wind
- Thermal Units
  - The model uses generic fuel cost curves, variable O&M, and other generic attributes for thermal units (confidentiality restrictions prevent the use of unit-specific data)
  - Production costs savings include thermal fuel savings and such other potential variable cost savings as decreases in maintenance costs
  - The model respects ramp times (up & down), minimum run and down time requirements, start up cost and energy, and maintenance

Transmission Assumptions

- Analysis assumes all lines in service
- Future major projects
  - 2017 WECC Transmission Topology
  - No large transmission projects added accept projects associated with NOS transmission scenario case
- WECC-Wide flowgate limits as defined in the WECC Path Rating Catalogue and other monitored flowgates (e.g., COI, PDCI, South of Allston, West of McNary, etc)
- Transmission capital costs is assumed as sunk cost and dispatch is not influenced by wheeling rates. All transmission is deemed available on a comparable basis

Next Steps

- Complete scenario analysis (Dec. 12)
- Complete comparative analysis (Dec. 16)
- Complete sensitivity studies (Dec. 24)
  - RPS Consequences
  - Carbon tax effects (WECC Wide)
- Prepare final report (Jan. '09)