PLANNING RESERVE MARGIN STUDY UPDATE
Agenda

- Planning reserve margin (PRM) recommendation and study results
- Methodology update overview
Planning Reserve Margin
Recommendation and Results
PRM Recommendation

- PacifiCorp recommends maintaining a 13% PRM
  - The study shows relatively flat cost/reliability trade-offs between 12% and 15%
  - Reserve margin study shows significant cost increase with PRM above 15%
  - The PRM study does not account for stochastic variability of wind generation
  - Although a 12% PRM may be least cost, the study does not account for capacity held in reserve for variable generation resources; therefore, a 13% PRM is recommended
Study Conclusions

- Planning reserve margin should be less than 16%; substantial cost increase at this level due to exhaustion of FOT possibilities that drives combined-cycle resource selection.
- Given reasonable PRM range of 12%-15%, no PRM level stands out as better than another.
- Duration-based LOLP results indicate that PRMs investigated provide adequate reliability based on one day in 10 years criterion.
### Principal Study Results

<table>
<thead>
<tr>
<th>Reserve Margin</th>
<th>Physical Plant Additions</th>
<th>Front Office Transactions</th>
<th>Total</th>
<th>Expected Total Cost</th>
<th>Expected Unserved Energy (fitted)</th>
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</thead>
<tbody>
<tr>
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<td>(MW)</td>
<td>(MW)</td>
<td>(MW)</td>
<td>($ '000)</td>
<td>(MWh)</td>
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</table>

Combining results of Reliability Model and Production Cost Model yields a reliability-cost schedule.

### Expected Unserved Energy (fitted)

<table>
<thead>
<tr>
<th>Reserve Margin</th>
<th>Expected Total Cost With NWPP Reserve Pool</th>
<th>Expected Total Cost Without NWPP Reserve Pool</th>
<th>Expected Incremental Cost</th>
<th>Incremental Cost of Reliability</th>
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</thead>
<tbody>
<tr>
<td>(percent)</td>
<td>($ '000)</td>
<td>($ '000)</td>
<td>($/kWh EUE)</td>
<td>($/kWh EUE)</td>
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</table>
Standard Stochastic Production Cost Model

- Use standard detailed topology to capture expected market access
- FOT cost is entirely a production cost. Combined-cycle additions have relatively low production cost, but significant capital cost, producing downward kink in production cost but upward kink in total cost
- Any extrinsic value (optionality) to new combined-cycle units is captured in stochastic production cost run
Incremental Cost of Reliability

$/MWh of EUE Reduction

Reserve Margin Levels (%)
Reliability Impact of NWPP Reserve Sharing Arrangements

- Reserve sharing reduces PRM by 2 to 4 percentage points depending on PRM starting point

![Graph showing the impact of NWPP Reserve Sharing on Reserve Margin and EUE (MWh)]
Simulated and Regression LOLP Results

- Duration based LOLP: Ten-year Loss of Load Probability computed as number of hours of Loss of Load in 1-year run, times ten, divided by 24 (Method used by Public Service Company of Colorado for their LOLP study)
Simulated and Regression LOLP Results

- **Event based LOLP**: Ten-year Loss of Load Probability (LOLP) is computed as number of expected Loss of Load episodes in 1-year run, times ten (Similar to the method used for 2011 IRP)
  - Does not incorporate Reserve Sharing, which is a duration-based impact
Methodology Update Overview
Methodology Update Overview

- Calibrated specification of load stochastics
- Simplified Outage Model for convergence analysis; i.e., point where number of draws does not change
  Expected Unserved Energy (EUE) results
  - Incorporates simplified transmission topology
- PaR Reliability Model uses full Monte Carlo for multiple-iteration simulation of resource outages, with post-simulation regression for trend smoothing
- Standard Monte Carlo production cost simulation with original detailed transmission topology
Updated Study Components and Workflow

- **Base Portfolio**
- **Range of PRM levels**
- **Reliability Resources (SCCT, DSM, CCCT, FOT)**

**System Optimizer**

**Portfolio Stochastic Simulations with Simplified Topology (PaR Model)**

- Minimum recommended number of Monte Carlo iterations

**Portfolio Stochastic Simulations with full market access (PaR Model)**

- Reliability Measure (Expected Unserved Energy, EUE)
- Expected Production Cost

**System Optimizer Portfolios (one per Reserve Margin level)**

- Capital Costs

**Compare costs and reliability outcomes of different Planning Reserve Margins (PRMs)**

- Marginal Cost of Reliability

**Select PRM Level**
Calibrated Load Volatility Parameters

• Objective: Align stochastic load draws with the July 2012 1-in-20 load forecast to be used for System Optimizer portfolio development
  – Applied a 0.4 Mean Reversion coefficient
  – Calibrated short-run load volatilities to generate random load draws that hit or exceed the July 1-in-20 peaks with a frequency comparable to production cost runs obtained with PacifiCorp’s original 1-in-10 peak load forecast
Modeling Full Monte Carlo Station Outages

• Thermal station forced outage rates:
  – Reliability resource options use equivalent forced outage rates (EFOR) applied for the 2011 IRP Update
  – For existing resources, EFOR configured from outage probabilities at different capacity levels based on inspection of daily unit outage histories

• Weekly draws, one per resource, from a uniform distribution from 0 to 1

• Each resource’s outage draw is independent from all other draws

• If draw is less than the resource’s configured outage rate, then station is placed on outage for the week
Reliability Model Topology

- Need for large number of iterations of full Monte Carlo simulation presents a problem with respect to production cost model run-times using the original transmission topology.
- Consolidated transmission zones ("bubbles") into five zones within which transmission constraints pose primarily cost (not reliability) consequences; in particular, the production cost model includes significant dispersed purchase markets that supplement own resources during adverse outage combinations.
Reliability Model Topology Diagram

- Bubbles merged into five zones with consolidated transmission links between zones.