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IRP Public Input Meeting

January 29, 2004

Agenda

- » RFP Update
 - RFP 2003A - Supply Side RFP
 - RFP 2003 B – Renewables RFP
 - Demand Side RFP
- » Review of Inputs & Assumptions
- » Topology Update
- » Planning Margin Study
- » Review Primen Study Results – Distributed Energy
- » Resource Addition Logic
- » Next Steps



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RFP Update

Ken Dragoon & Mike Koszalka

RFP 2003-A – Supply-Side RFP

IRP Action Plan Update showed an increase in the need for new resources

- » “SuperPeak” bid category, (seasonal, 2004-2007)
 - Requested 225 MW
 - No transactions in this category that help us serve our load in Utah
- » “Peaker” bid category, (by summer 2005, daily dispatchable)
 - Requested 200 MW
 - Currant Creek
 - ⇒ Currently undergoing certification process in Utah for Currant Creek
 - ⇒ Company would like to begin construction on Currant Creek in January 2004, pending the hearing schedule
 - ⇒ Size & Timing - 280 MW by Summer 2005, 525 MW by Summer 2006
 - Pursuing additional economic supply that could be available as early as Summer 2005
- » “Base Load” bid category (by summer 2007)
 - Requested 570 MW
 - Actively engaged in commercial negotiations

RFP 2003-B – Renewables RFP

- » RFP filed with Oregon PUC October 17, 2003
- » PUC consideration tentatively scheduled February 3, 2004 Commission Meeting
 - Quantities
 - ⇒ 100 MW west side 2005
 - ⇒ 200 MW east side 2006
 - ⇒ 1,100 MW total
 - PPM Energy
 - ⇒ Affiliate bids will not be accepted
 - Proposed Dates
 - ⇒ Bidding expected to open February 4
 - ⇒ Proposals will be due approximately one month later

Demand Side RFP

- » Utah Residential New Construction
 - Provides incentives for builders and homebuyers to build and buy homes meeting efficiency standards above existing energy efficiency building codes
- » Utah Building Recommissioning
 - Provides expertise and incentives to recommission or tune-up existing commercial and industrial customers' existing electrical equipment
- » These two program will result in reducing Utah customer demand for electricity by 5.9 MWa. At peak, Utah loads will be reduced by 24.3MW.



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Review of Inputs and Assumptions

Melissa Seymour

The IRP Process

Regulators & Intervenors



Strategy & Planning



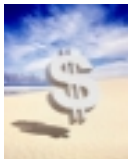
Hydro



Renewables



Financial Products



Forecasts



Transmission



Thermal



DSM

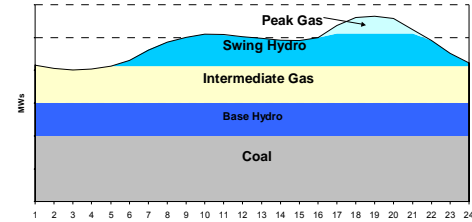


Environmental



IRP Process

Fulfill Customer Obligation



Deliver Economic Solution to Customer & Shareholder



Reduce Commodity Risk



Earn Allowed Rate of Return



Inputs & Assumptions to Review

Environmental



Strategy & Planning



Hydro



Renewables



Forecasts



Transmission



Thermal



DSM



- » **Forecasts** - electric price, gas price, load, hydro availability, etc.
- » **Supply-Side Resources** - existing and proposed hydro, thermal and renewable resources
- » **Transmission** – upgrades, tariffs, new transmission lines
- » **Demand-Side Management (DSM) Resources** - energy-reducing DSM programs modeled by type
- » **Strategy & Planning** - Company's view on outcome of future shifts in operations, such as environmental and renewable legislation

Categories of Updates

- » **Categorizing updates to inputs and assumptions used in the 2002/2003 IRP:**
 - **Refreshed** - inputs & assumptions that will be updated, but will not result in a major assumption change or new methodology
 - **Revised** – reviewing the assumption or methodology used for the input or assumption, which *may* result in a change

Forecasts

Input/Assumption	Refreshed	Revised
Electric Prices	✓	
Natural Gas Prices	✓	
Load		✓
Hydro Availability	✓	
Thermal Outages		✓

Supply-Side Resources

Category	Input/Assumption	Refreshed	Revised
Thermal	Existing Plants	✓	
	New Plants	✓	
Hydro	Existing Plants	✓	
	Relicensing	✓	
Renewables	Existing Facilities	✓	
	New Facilities	✓	
	Wind Capacity		✓
Contracts		✓	
Distributed Energy		✓	

Transmission

Input/Assumption	Refreshed	Revisited
Topology		✓
Transmission Rights	✓	
Tariffs	✓	
Upgrades (associated with supply-side resources)	✓	
New Transmission Lines		✓

Demand-Side Resources

Input/Assumption	Refreshed	Revisited
Existing Programs	✓	
Evaluation of New Programs		✓

Strategy & Planning

Input/Assumption	Refreshed	Revised
SB1149	✓	
RTO	✓	
MSP	✓	
Environmental Assumptions	✓	
RPS – Federal and/or State	✓	
Planning Margin / Resource Adequacy		✓
Market Depth & Liquidity		✓



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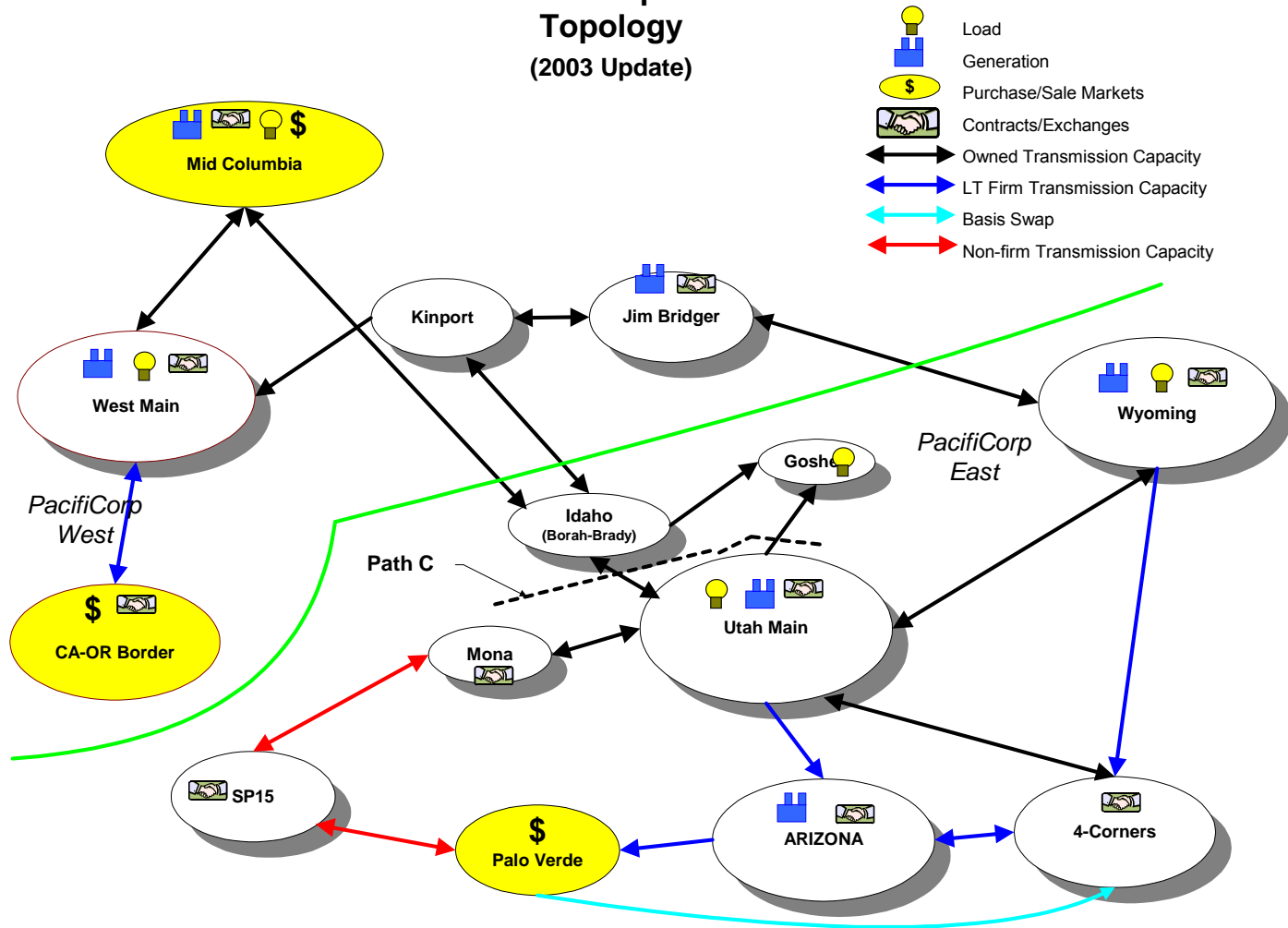
Topology Update

The Utah Split

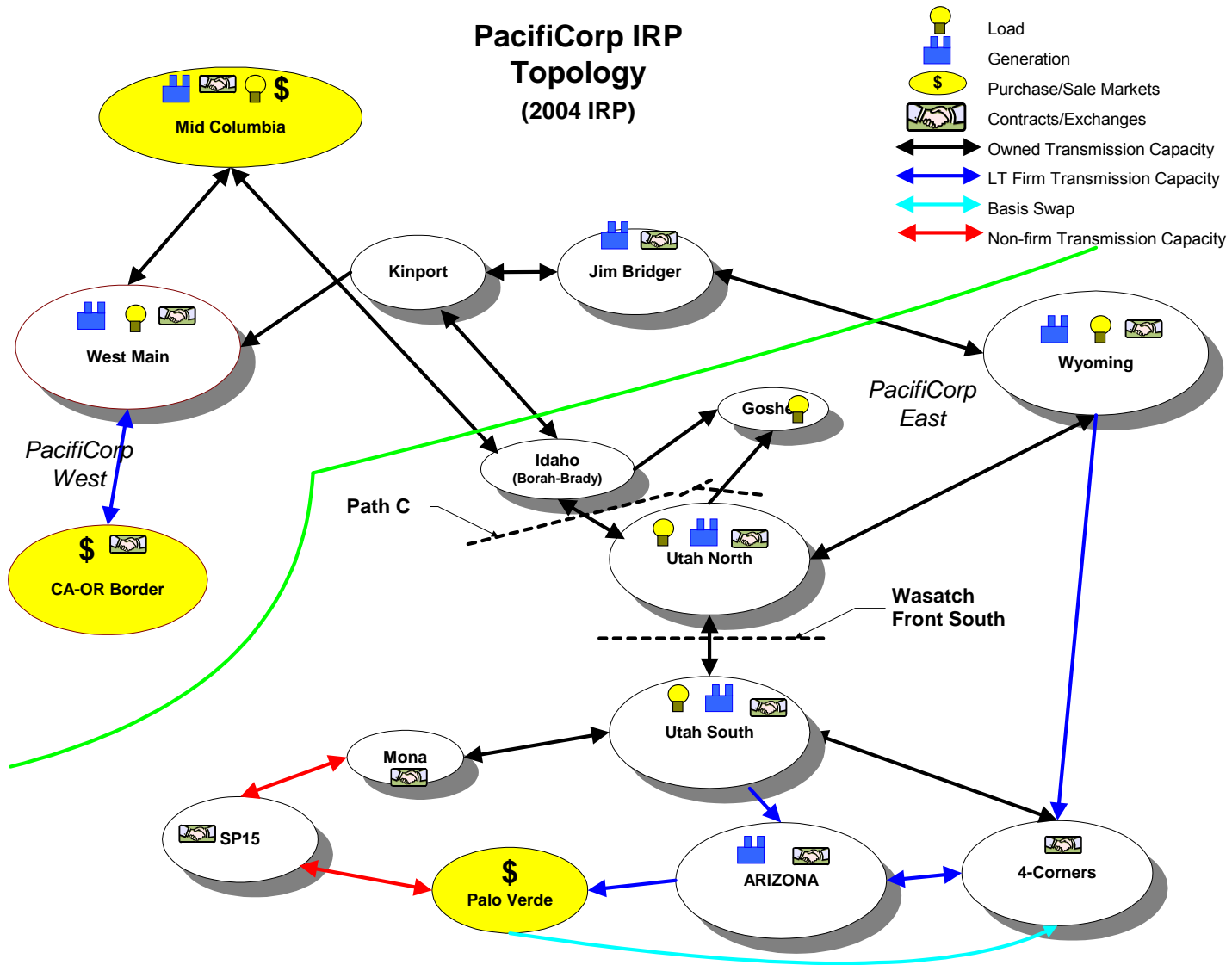
Matt Ruckwardt

Topology – 2003 IRP Update

PacifiCorp IRP
Topology
(2003 Update)

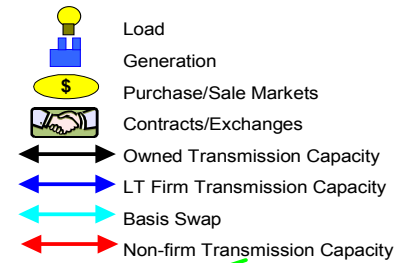


Topology – 2004 IRP



Topology – 2004 IRP

PacifiCorp IRP Topology (2004 IRP)

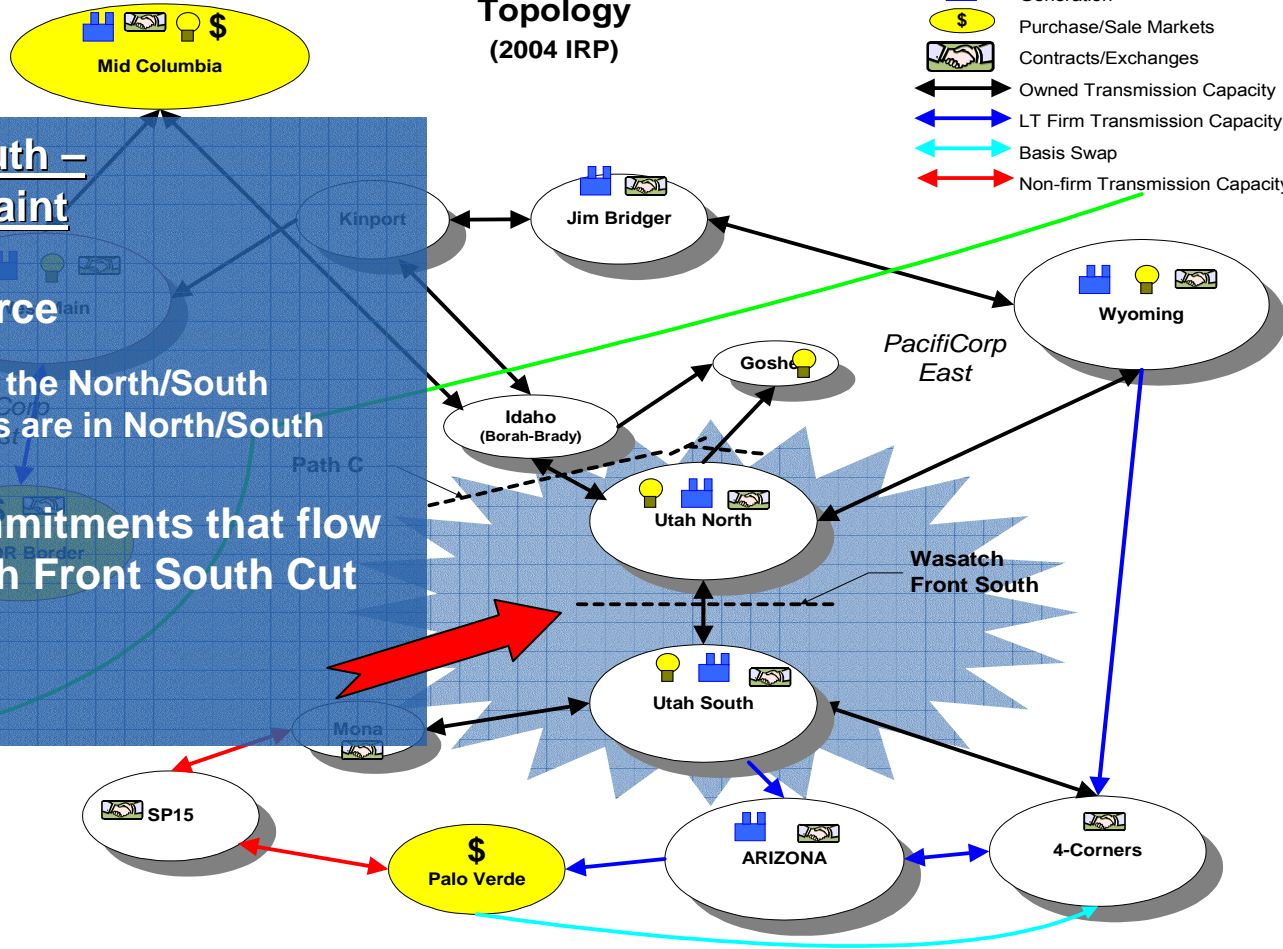


Wasatch Front South – Reason for Constraint

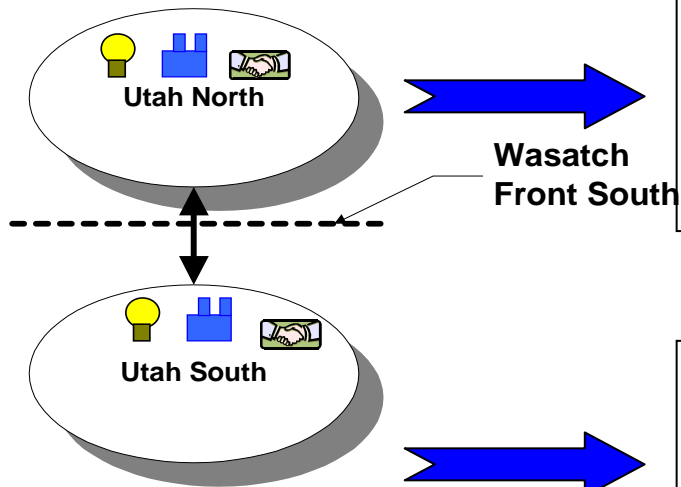
Utah Load / Resource

- 80/20% of Load is in the North/South
- 33/66% of Resources are in North/South

Transmission Commitments that flow across the Wasatch Front South Cut Plane



Wasatch Front South Boundary



UTAH NORTH

Load: ~ 80% of Utah Load

Generation: Gadsby, Naughton, West Valley, Little Mtn., Cove Cutler, Grace, Lifton, Oneida, Soda (~ 1/3 of Utah Capacity)

Contracts: Desert Power, Black Hills, MagCorp

UTAH SOUTH

Load: ~ 20% of Utah Load

Generation: Current Creek, Hunter, Huntington, Blundell, Carbon (~ 2/3 of Utah Capacity)

Contracts: Sunnyside, Utah Municipal Power Systems, Los Angeles Dept of Water & Power, AEP, City of Anaheim

Drivers of Topology Change

Reasons for Changes

- » Greater utilization of transmission across Wasatch Front South (WFS) cut plane
- » By creating a North/South Utah split, the IRP will be able to look at the cost benefits of transmission investments along the WFS cut plane
 - Improvement in cost information regarding:
 - ⇒ Siting of resources
 - ⇒ Dispatch of Utah North/South Units
 - ⇒ Dialog with market
 - ⇒ ENS and Dumped Energy



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Planning Margin Study

John Fritz

Planning Margin Assumption in the 2003 IRP

- » PacifiCorp employed a planning margin of 15%, recognizing that more or less planning margin could be warranted
- » Conducted sensitivities at 10% to test the risk of a divergence from this assumption
- » Rationale behind 15% - Guidance from FERC's SMD NOPR:
 - Proposed that all Load Serving Entities meet a minimum capacity reserve planning margin of 12% or face penalties
 - Proposed that Regional State Advisory Committees could require even higher planning margins
 - 15% is the middle value of 12% to 18% range suggested in SMD and reinforced by the public input process
 - RTO West Order was more flexible in that it encouraged the filers to consider reliability based development of a resource adequacy plan

2003 Benchmark of Other Utilities

» PacifiCorp's planning margin relative to other Western utilities:

Utility	Planning Margin Assumption	IRP/ Least Cost Plan
Avista	10% + 90MW \approx 15%	2003
Idaho Power	330MW \approx 13% [1]	2002
PacifiCorp	15%	2003
Portland General Electric	10-20% [2]	2002
Puget Sound Electric	\approx 8% [3]	2003

- [1] 330 MW/ Peak Load
- [2] Based on WECC region
- [3] (Current Pos. + Add'l Resources) / Peak Load

» **Conclusion:** PacifiCorp's 15% was consistent with industry

Planning Margin Assumption in the 2003 IRP

- » Failure of SMD prompted concern around this assumption
- » Created IRP Action Item #24 in the 2003 IRP Action Plan:
 - “Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP, following the outcome of the FERC’s proposed SMD rule. The analysis for this will include loss of load probability studies.”

No Consensus Achieved Since 2003 IRP

- » PacifiCorp co-hosted Power Supply Adequacy Forum meetings in early 2003, no consensus reached
- » Power Supply Adequacy Forum meetings resuming (tomorrow)
- » In a rare 5-0 vote, CPUC recently ruled utilities must achieve planning margins of 15%-17% by early 2008 and contract for 90% of summer needs at least one year in advance (1/22/04) (Not Applicable to PacifiCorp)
- » Comprehensive energy bill is still stalled in Congress; some lawmakers are pushing to pass reliability legislation separately
- » Consulting firm Henwood Energy has stated no answer yet exists for “what is the right choice of planning margin?”
- » No federal reliability legislation or WECC-wide agreement or standardization achieved since 2003 IRP

This study will therefore further examine issue and add to wealth of debate around resource adequacy.

Scope & Goals of Study

- » Identify and evaluate methods for measuring resource adequacy, including planning margin and LOLP
- » Evaluate industry & regional trends related to planning margin and resource adequacy
- » Recommend a build target that:
 - Procures adequate resources to meet load requirements
 - Avoids physical short exposure to markets
 - Ensures safe, reliable, low cost energy for the consumer
- » This study is a precursor and direct input for the building of 2004 IRP portfolios

Modeling Methodology

- » We have identified two approaches to inform the selection of an appropriate build target:

1. Descriptive analysis of FY2005 to analyze reliability at several scenarios of planning margin

2. Prescriptive “reliability target” analysis of FY2005 portfolio under current operations practice to determine values of several stochastic reliability measures produced under stochastic evaluation of loads and resources

Evaluate use of a stochastic reliability measure as a build target for future portfolios

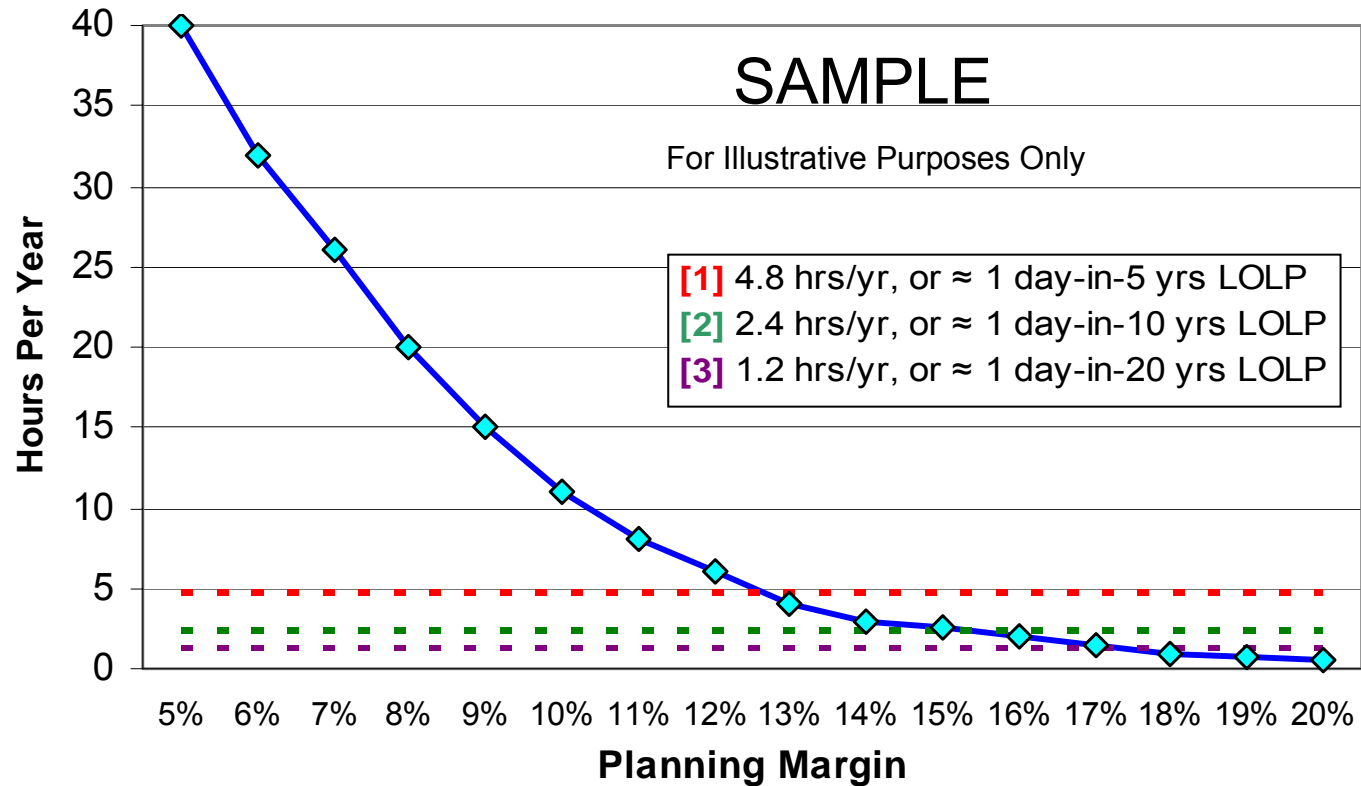
Evaluate resources’ ability to contribute to reliability measures

Descriptive Study Outline

- » Build FY 2005 to several levels of planning margin
 - (e.g., 5%, 6%, 7%, ..., 15%, 16%, 17%, 18%, 19%, 20%)
- » Stochastically simulate each level of planning margin in Prosym
 - Stochastic simulation models iterations of loads and available resources
- » Analyze results at each level of planning margin, to include:
 - Loss-of-Load Probability (LOLP) as a function of planning margin
 - ⇒ Prosym tracks and reports the probability of Loss-of-Load hours
 - ⇒ A Loss-of-Load hour is an hour where demand exceeds supply
 - Expected Unserved Energy (EUE) as a function of planning margin
 - ⇒ Prosym tracks and reports MWh of Energy Not Served (ENS) across all iterations of the stochastic simulation
 - ⇒ The mean value of ENS across all iterations is termed Expected Unserved Energy (EUE)
 - Cost of EUE reductions as a function of planning margin
 - ⇒ The costs of resources added compared to the lower levels of EUE achieved by building to higher planning margins

Sample Results of the Descriptive Study

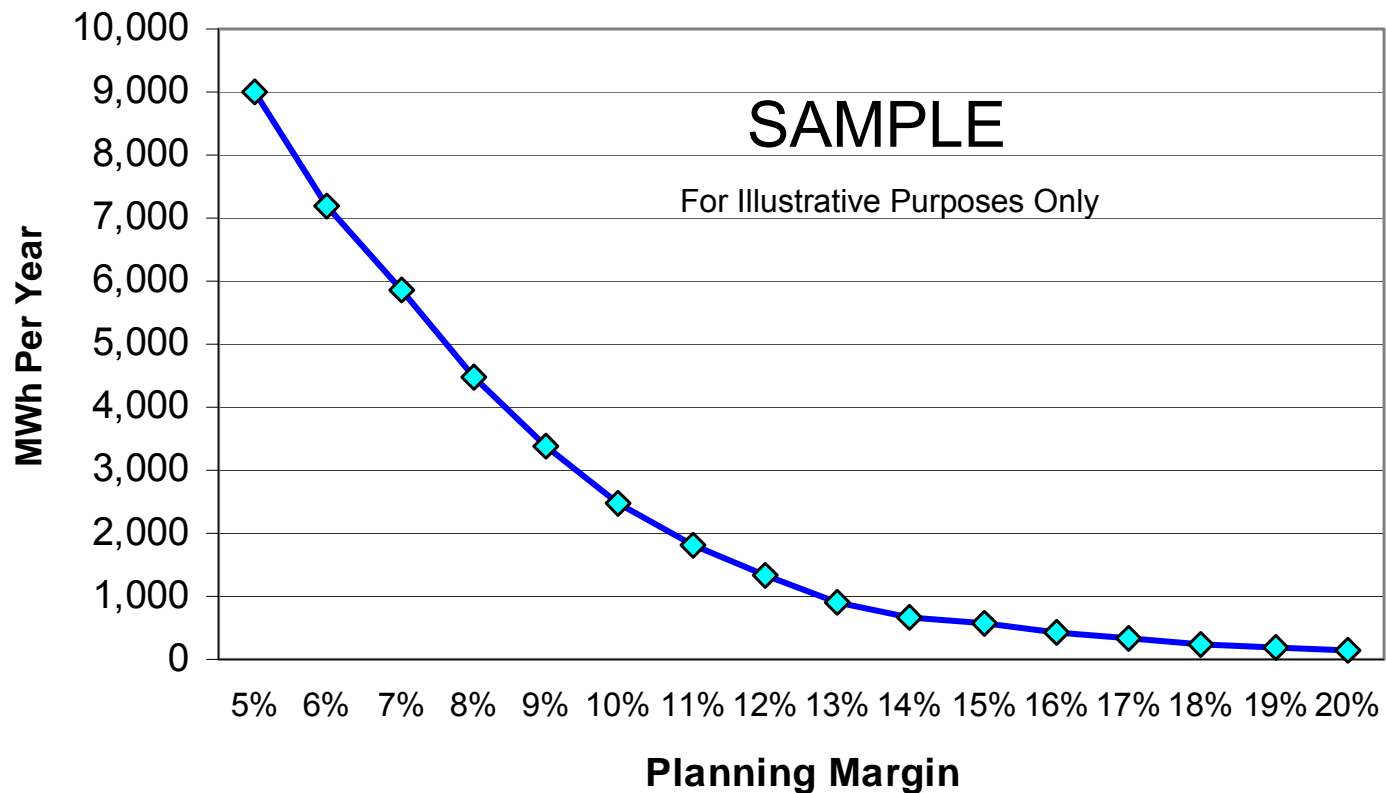
- » Expected Loss-of-Load (LOL) Hours as a function of planning margin



- » Loss-of-load hours are any hours with a loss of load
 - Does not indicate magnitude or duration of the loss-of-load

Sample Results of the Descriptive Study

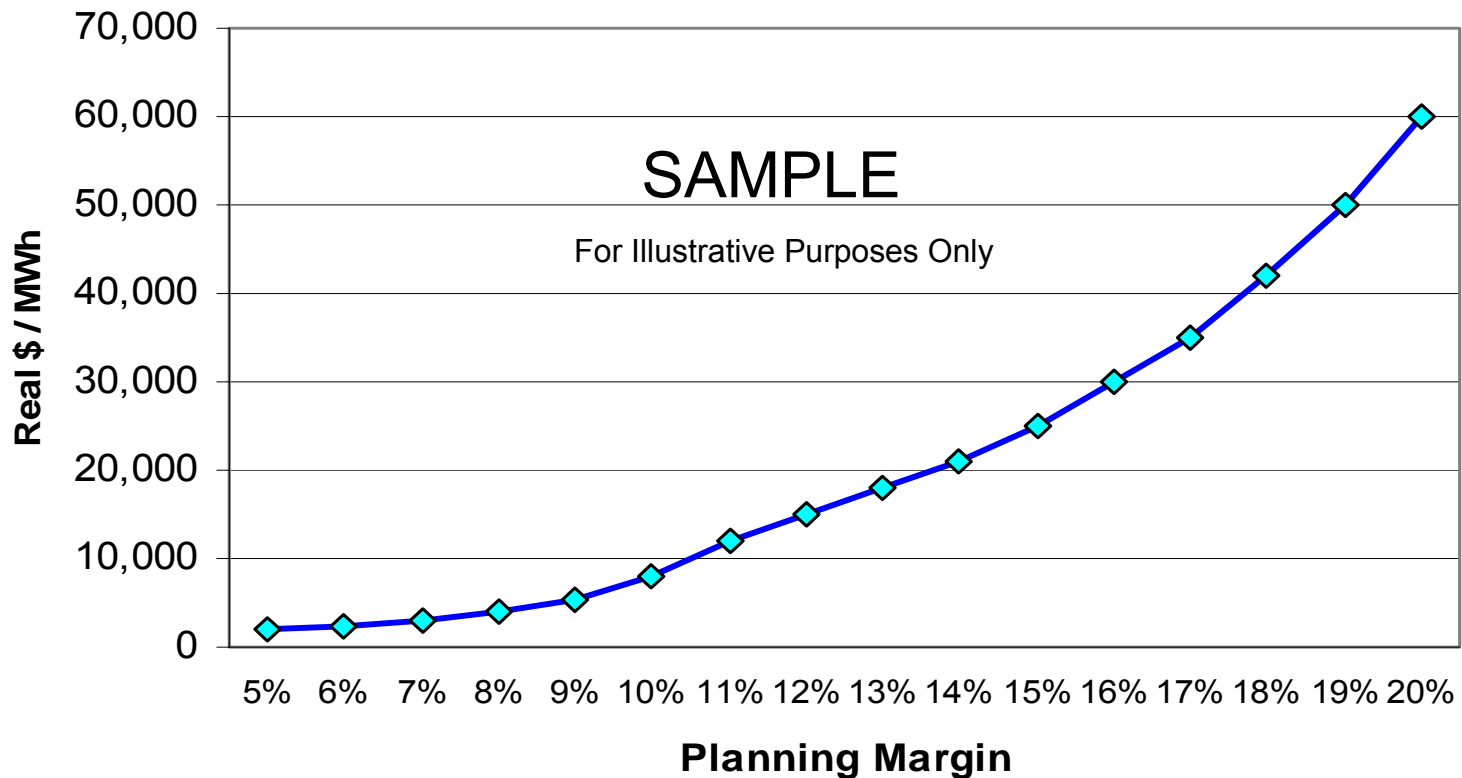
- » Expected Unserved Energy (EUE) as a function of planning margin



- » Expected Unserved Energy (EUE) is the mean value of Energy Not Served (MWh) over all iterations of loads and resources

Sample Results of the Descriptive Study

- » Cost of EUE reductions as a function of planning margin



- » Shows the increasing cost to achieve higher levels of reliability

Reliability Target Study Outline

- » Analyze reliability measures of FY 2005 portfolio under current operations practice
- » FY 2005 portfolio is built to meet Tier 1 and Tier 2 demands:
 - **Tier 1 (Delivery Risks)**
 - ⇒ Risk of insufficient resource capacity within transmission constrained area to meet our maximum firm capacity obligation
 - ⇒ Plan to cover peak hour physical position with expected outage
 - **Tier 2 (Financial Risks)**
 - ⇒ Financial risk associated with meeting our overall energy obligation
 - ⇒ Plan to cover average monthly energy position with expected outage
- » Following these standards, the FY 2005 portfolio is considered adequate by operations staff

Reliability Target Study Outline

- » Stochastically simulate this portfolio in Prosym
 - Stochastic simulation models iterations of loads and available resources
- » Analyze reliability measures (to include EUE, LOLP, etc.)
- » Analyze resources' ability to incrementally improve reliability of portfolio

Reliability Target Study Results

- » Results of this study will provide a reference point on the graphs of the descriptive study
- » Results could potentially be used as a constraint to future portfolios (e.g., FY 2005 as a minimum reliability measure for future portfolios)

Summary and Next Steps

- » We are conducting two parallel modeling analyses:
 - Descriptive study
 - ⇒ Will show Loss-of-Load Probability, Expected Unserved Energy, and Cost of EUE Reductions as a function of planning margin
 - Reliability target study
 - ⇒ Will analyze the reliability of the FY 2005 portfolio PacifiCorp Operations deems adequate to meet Tier 1 (capacity) and Tier 2 (energy) needs
- » We are evaluating industry trends and proposed legislation:
 - Updating benchmark of utilities
 - Analyzing other regions' methods and rulings
- » PacifiCorp will consider modeling results and all available information to recommend appropriate build target for 2004 IRP
- » As this study is a precursor and direct input to the IRP process, it must be completed by April 2004



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Primen Study Results: Distributed Energy

Mike Koszalka

Executive summary -- National Study

- » In 2003, the market for distributed energy (DE) bottomed out and began to rebound
- » About 13% of customers in 100 kW to 10 MW size range are prospects for DE
 - 12,000 North American energy users are strong prospects for DE
- » The top three drivers for DE are:
 - Energy cost savings
 - Improved power reliability
 - Predictable energy prices

Executive Summary (cont.)

- » Energy users have a number of concerns about DE
 - Users want service warranties and service agreements even though they want to retain control
 - User concerns about environmental permitting are greater now than in previous years
 - Users are concerned about rising and volatile natural gas prices even though natural gas remains their preferred fuel
- » Blackouts and other electric service failures create short-lived “moments of opportunity” for closing DE deals

Executive Summary (cont.)

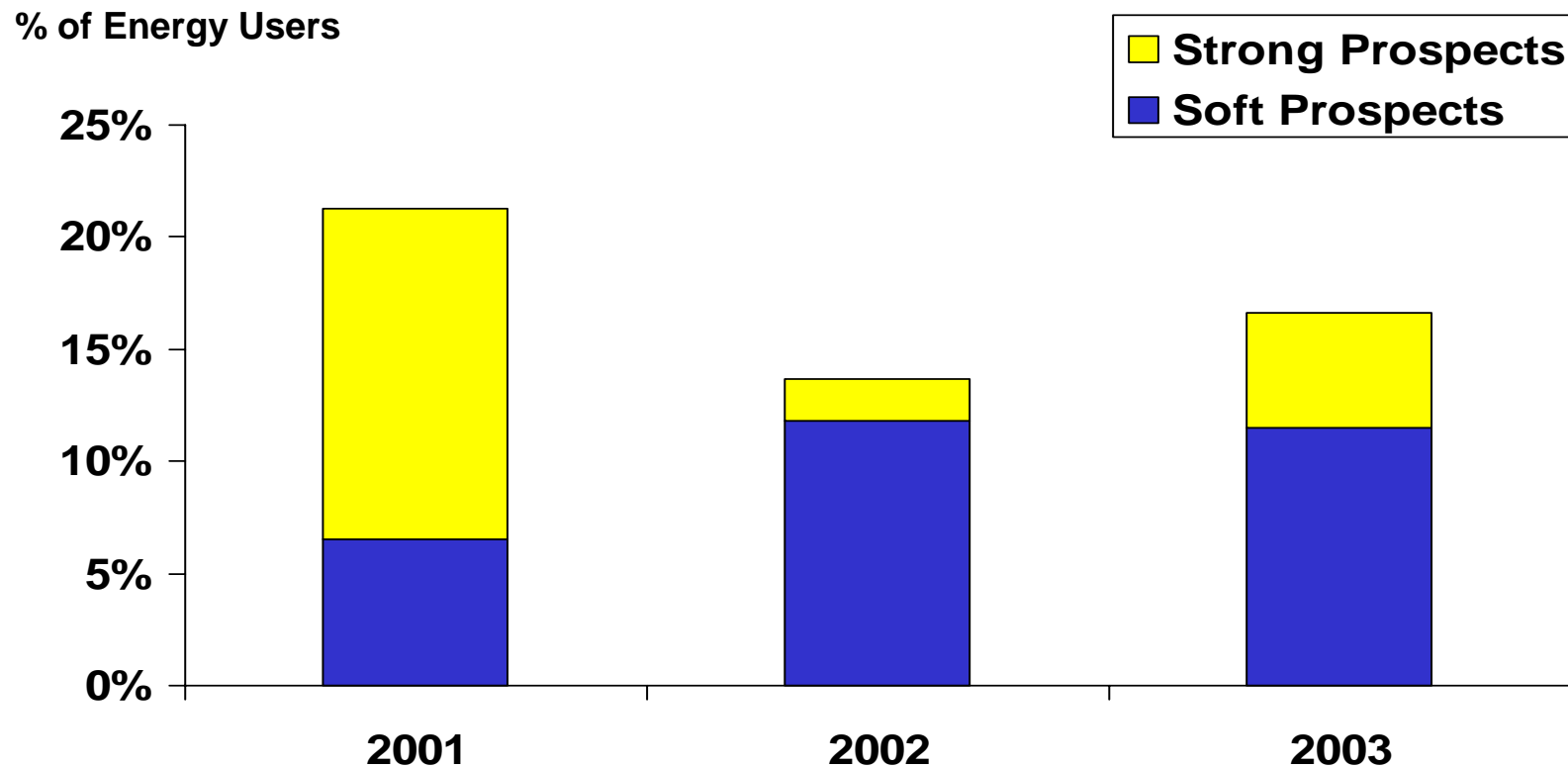
- » Best candidates for DE:
 - Companies that are expanding or relocating facilities
 - Companies that are replacing aging central plant, including boilers, chillers, heating systems and/or generators
- » Companies typically make decisions to acquire DE using a team approach, which results in a lengthy and labor-intensive sales process
- » When it comes to providing DE equipment, electric utilities are deemed less credible than manufacturers or third-party developers by energy users

Research Approach

- » The main *Distributed Energy Market Study 2003* findings are based on Primen proprietary quantitative and qualitative surveys of U.S. and Canadian energy users:
 - 806-respondent quantitative survey (10 kW – 10 MW)
 - ⇒ Pre-August 2003 blackout
 - 100 qualitative interviews
- » The comparisons we present in this report are based on qualitative interviews with 40 energy users from the Salt Lake City region (referred to as “SLC users” below):
 - Recruits for interviews were nominated by Questar Gas and Utah Power, but interviewed by Primen staff
- » Findings are also based on Primen’s on-going research on DE markets, technologies, and regulatory issues

Customer Interest in Distributed Energy

*Nationwide, interest in baseload DE is growing again
(300 kW-to-5 MW demand)*



Source: Primen Quantitative Survey Results

** Not enough quantitative responses in SLC region to statistically portray local trend

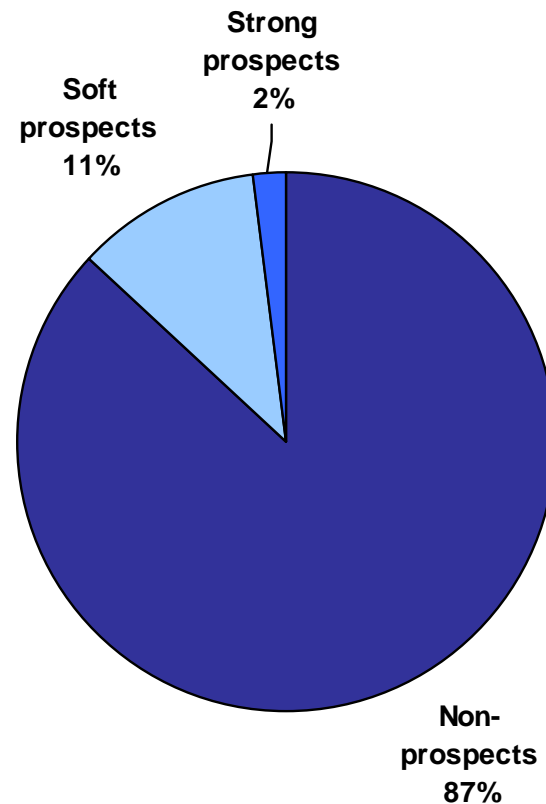


Customer Interest in Distributed Energy

» The market for baseload distributed energy (DE) is far below where it was three years ago, **but significant opportunities remain**

- More than 12,000 business establishments, in the 100 kW to 10 MW demand range, were strong prospects for DE in 2003
- **Strong prospects** say they are more than 50% likely to acquire baseload DE in the next two years *and* they are actively evaluating their options
- **Soft prospects** also say they are more than 50% likely to acquire, but they have not begun to actively investigate their options

13% of national businesses surveyed are DE prospects - 2% are strong prospects



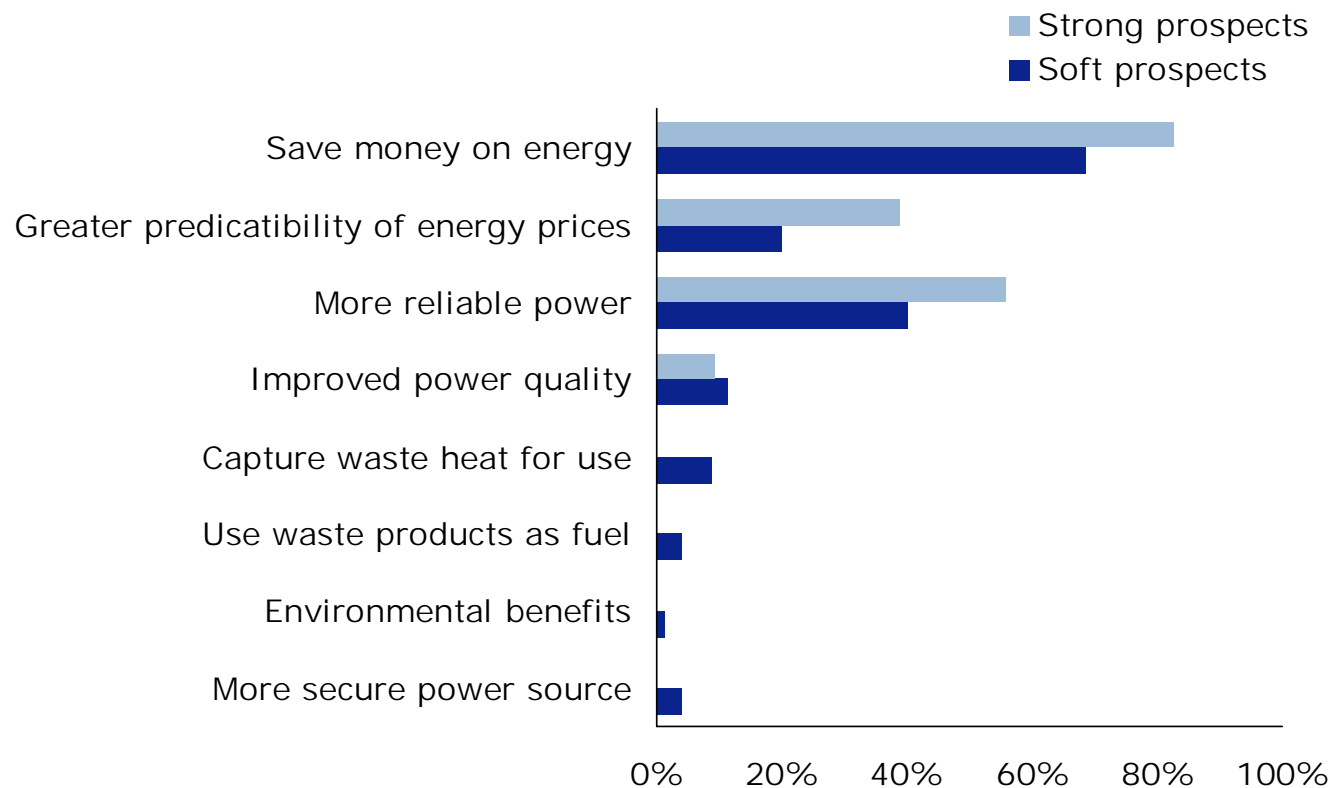
Source: Primen 2003 Quantitative Survey Results

Core Appeal of DE Remains the Bottom Line

- » Nationwide, prospects identify their three top drivers for DE:
 - Energy cost savings
 - Improved power reliability
 - Predictable energy prices
- » For the SLC users, the top three drivers are the same as the nationwide results:
 - Cost savings was the number one reason customers mentioned for considering DE
 - However, predictable energy prices were cited more often than improved power reliability

Drivers for DE (from national quantitative survey)

- » The 2003 quantitative survey results support the thoughts expressed in the qualitative interviews



Source: Primen 2003 Quantitative Survey Results

It takes more than savings to close DE deals

- » Cost savings and enhanced reliability are the fundamental needs driving energy users to DE, but to really sell DE to a user, other criteria need to be addressed, including:
 - The company's financial position and/or the state of the economy
 - Availability of financing from the vendor/project developer
 - Specific warranties or guarantees provided
 - Service agreement included/offered
 - Support for addressing environmental or permitting issues
 - Electric service provider's flexibility, or lack thereof, in resolving tariff and interconnection issues
 - Fuel prices, particularly for natural gas
 - Ability to cogenerate heat, steam, or chilled water along with power

Opportunity for DE Sales

- » DE installations require significant capital expenditures, happen infrequently, and are highly dependent on market conditions at the moment of the sale
- » As a result, correctly timing the sales effort can mean the difference between a successful deal and a fruitless string of contacts
- » An opportunity for DE sales efforts occurs when:
 - Obsolete or failing equipment needs replacement
 - Crises in infrastructure or market conditions occur
 - Electric service failures damage sensitive equipment or cause downtime

Who's behind the DE decision?

- » The process of deciding whether to invest in DE systems is not standardized among energy users
- » That's because DE acquisition represents an infrequent, capital-intensive purchase that requires input and signoff from multiple centers within the purchasing organization
- » Despite the lack of a common protocol, many companies use a team approach
 - An internal, primary “champion” usually shepherds the project along
 - ⇒ For SLC users, the internal “champion” was typically the facility or plant manager, but it could also include executives from the strategic division or financial department
 - The project is then presented to other important stakeholders in the company, where each department provides its “two cents” in the decision-making process

Who's behind the DE decision? (cont.)

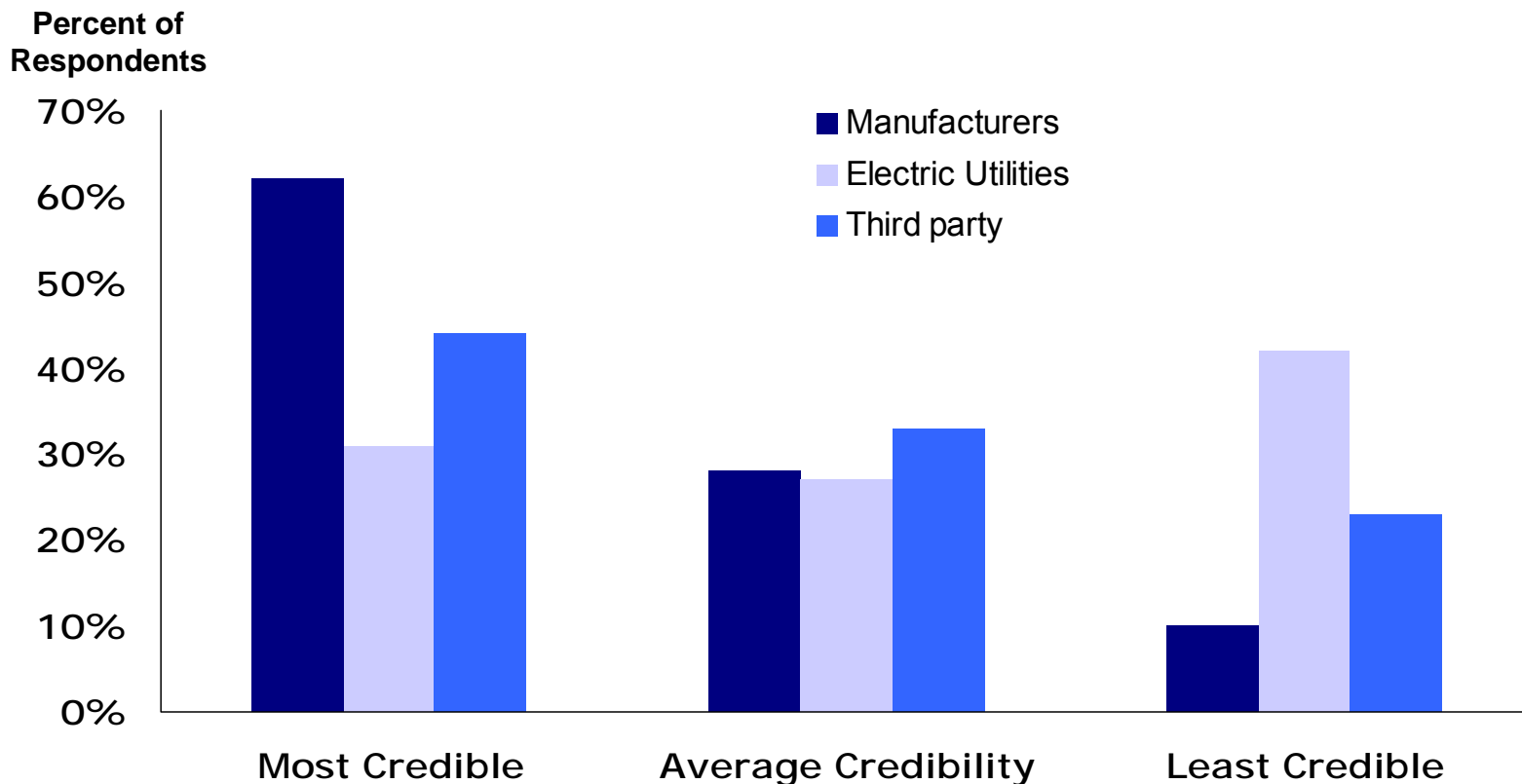
- » Both private businesses and public institutions appear to have seemingly ad hoc decision making processes when it comes to DE:
 - Both types of organizations are accustomed to making capital expenditures and typically have processes in place for approving such purchases
 - Since DE impacts a wide range of stakeholders within an organization, the usual process may be expanded to include others- thereby extending the approval process time even longer
- » In addition, many publicly owned institutions have additional hurdles to cross:
 - Government organizations usually require a sign-off at least from the administrative head of the organization
 - A public vote from an elected government body, such as a city or county council, may also be required

DE providers and role of the electric utility

- » North American energy users believe that manufacturers and third-party developers are more credible equipment suppliers and DE service providers than electric utilities

Credibility of DE Equipment Providers

- » When SLC users were asked to rate the credibility of DE equipment providers, manufacturers were rated the most credible, and utilities as the least credible



Next Steps for DE in the 2004 IRP

- » Update DE Resource Addition assumptions
- » Allow DE Selection (with limits) in Automated Resource Addition Logic



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Resource Addition Logic

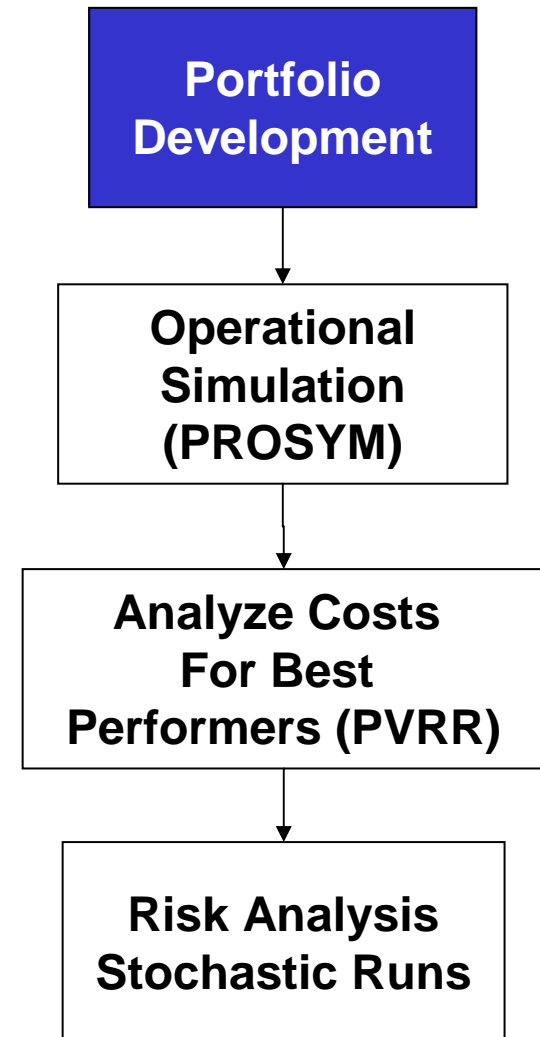
Stan Williams

Agenda – Resource Addition Logic

- » Review 2002 / 2003 IRP Modeling Approach
- » History of Resource Addition Logic
- » General Description
- » Objective Function & Constraints
- » Timeline
- » Summary

The IRP Analytical Approach

- » 1. Portfolio Development
 - Add new resources to incumbent portfolio to develop candidate portfolios
 - » 2. Operational Simulation (PROSYM)
 - Deterministic, hourly cost simulations
 - Hourly cost schedule for each portfolio
 - » 3. Analyze Costs
 - Narrow list to the best PVRR's
 - » 4. Stochastic Risk Analysis
 - Simulate each portfolio under a large number of possible futures
 - Sensitivities to assumptions about the future
 - Reveal the cost variability of each portfolio
- Result: Best portfolio(s) from perspectives of cost and risk



History of Resource Addition Logic

- » In the previous IRP process, there was significant interest in the use of a tool to facilitate resource additions to the incumbent portfolio
- » We therefore looked at various vendors for such a tool and, as we indicated last summer, we selected Henwood Energy Services
- » So we are now working with Henwood to develop the resource addition logic to use for the current IRP

General Description

- » A mixed integer programming (MIP) model that schedules new resource additions and existing resource retirements to minimize total costs over the planning horizon
- » Simplified Granularity:
 - Computational demands of a detailed model
- » Two-bubble Topology:
 - Compare to fifteen-bubble topology discussed earlier
 - Model East and West separately with energy transfers between them
- » Time periods will be monthly:
 - Split by hour type (Peak, Off-peak, etc.)
- » Linear programming models have two basic features:
 - Objective function
 - Set of linear constraints

Objective function

- » Minimize the present value of the total system cost over the planning horizon
- » Includes three categories of costs:
 - Capital costs for new resources
 - Fixed O&M costs for existing and new resources
 - Variable operating costs for existing and new resources

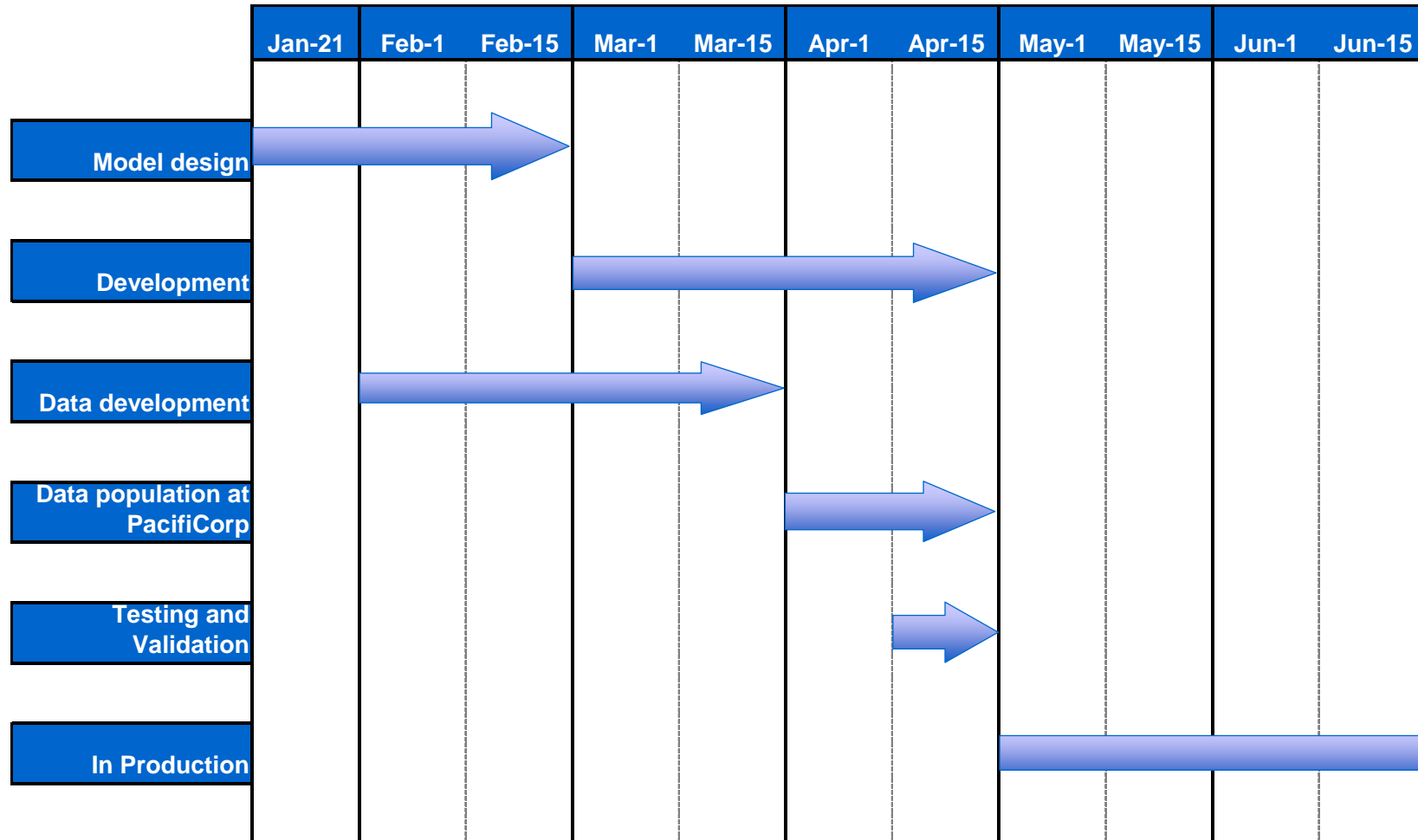
Major Constraints

- » Energy balance constraints
- » Resource operation state constraints
- » Resource building constraints
 - A new resource can't be used until built
 - Define time periods when resources can be built and brought on line
- » System capacity reserve constraints
- » Hydro energy constraints by time period
- » Fuel consumption constraints by time period
- » Emission limits constraints by time period

Comments

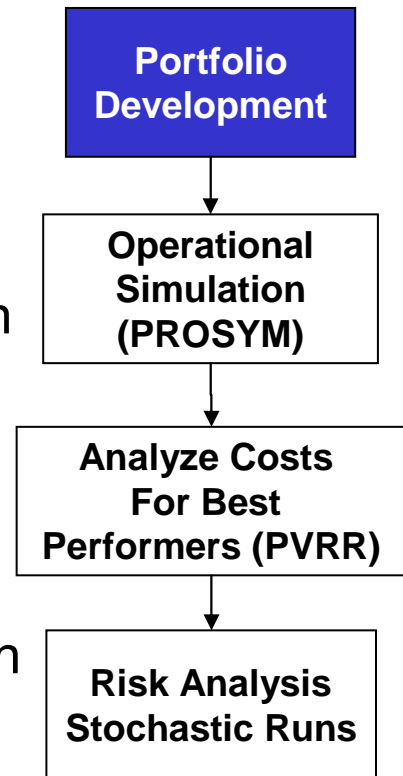
- » Not a magic box!
 - Additional analyses will be necessary to develop portfolios that are truly optimal
- » Moderately Detailed Model
 - High level focus as compared to the detailed focus of PROSYM (transmission and resource location)
- » Screening Tool
 - Used to develop portfolios to be analyzed in production cost model (PROSYM)

Resource Addition Model - Time Line



Summary

- » The Resource Addition Logic will be used in step 1 of the IRP analytical process, Portfolio Development. It will replace previously used heuristic methods for resource additions
- » It will be used to construct portfolios which will then be put through detailed simulations to determine the hourly least-cost, least-risk portfolio(s)
- » It will use a simplified two-bubble topology, with monthly time periods
- » It will consider many more candidate portfolios than was possible using the heuristic methods
- » It will improve upon methods previously used to compute true least-cost portfolios
- » The Resource Addition Logic will be production-ready by May 1, 2004





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Next Steps

Melissa Seymour

Next Steps

- » Load Forecasting Technical Workshop – January 30
- » Public Input Meeting Schedule:
 - March 16
 - May 6
 - June 24
- » Possible Topics at Next Meeting (March 16):
 - Wind Study
 - Market Depth and Liquidity
 - Progress on the Planning Margin Study
 - Environmental Assumptions

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