2006 Integrated Resource Plan
Public Input Meeting

June 7, 2006
Agenda

• Demand-Side Management: Class I & III Resource Assessment Update
• Procurement Update: Demand-Side Management
• Procurement Update: Supply-Side Resources
• IRP Resource Alternatives
• IRP Transmission Analysis Approach
• Portfolio Analysis Scenarios and Risk Analysis
• Resource Adequacy/Capacity Planning Margin
• Next Steps
Demand-Side Management:
Class I & III Resource Assessment Update

Hossein Haeri
Lauren Miller Gage
Quantec, LLC, Portland, OR
Assessment Scope and Objectives

1. Develop Proxy Supply Curves:
   – Resources:
     • Class I (fully dispatchable)
     • Class III (non-dispatchable)
   – Customer Class Coverage:
     • Residential, Commercial, Industrial, (Agricultural) Irrigation

   – Resource Valuation Basis (Reliability, Economic Dispatch)
   – Valuation Methodology
   – Key Value Factors
   • Interviews with utilities
Assessment of Valuation Methods

Possible Key Value Factors:

• The Customer:
  – Financial: direct and indirect
  – Derived services: information, equipment performance, diagnostics, web access, etc.

• Utility:
  – Resource planning: avoided capacity, reserve margin, avoided or deferred grid expansion, reduced grid losses
  – Reliability: emergency control, flexibility in shaping the response, risk management, impact on power suppliers, and resource “equivalency”
  – Costs: implementation costs, revenue impacts, timing, location, data acquisition, verification
  – Other: generation heat rate, line loss?

• Environmental Externalities:
  – Criteria emissions and Green House Gasses
Proxy Supply-Curve Development Methodology

- System Load
- Sector/Segment Loads
- End-Use Loads
- Technical Potential
- Achievable Potential
- Proxy Supply Curves
- Demand Response Strategy
- Class & End-Use Applicability
- Event (Load) Participation
- Sector/Segment Load Shapes
- End-Use Load Shapes
- Current Utility Practices
- Program Participation
- Resource Costs
# Primary Data Sources

<table>
<thead>
<tr>
<th>Data Element</th>
<th>Source - Various Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Total Sales by Customer Class</td>
<td>• PacifiCorp – 2005 Table A</td>
</tr>
<tr>
<td>• Commercial Segmentation</td>
<td>• 2005 Commercial Survey (by participants)</td>
</tr>
<tr>
<td>• Hourly System Load Profiles</td>
<td>• PacifiCorp, 2005</td>
</tr>
<tr>
<td>• End-Use Shares and Load Shapes</td>
<td>• EIA, Commercial Buildings Energy Consumption Survey (CBECS)</td>
</tr>
<tr>
<td></td>
<td>• EIA, Residential Energy Consumption Survey (RECS)</td>
</tr>
<tr>
<td></td>
<td>• Northwest Power Planning Council</td>
</tr>
<tr>
<td></td>
<td>• PacifiCorp</td>
</tr>
<tr>
<td></td>
<td>• PGE</td>
</tr>
<tr>
<td></td>
<td>• Quantec Load Shape Library</td>
</tr>
<tr>
<td>• Existing PacifiCorp Demand Programs</td>
<td>• PacifiCorp studies, various years</td>
</tr>
<tr>
<td>• Demand Response Impact Estimates</td>
<td>• PacifiCorp, California Energy Commission, Peak Load Management Alliance (PLMA), Edison Electric Institute (EEI), Lawrence Berkeley National Laboratories (LBNL), Various RTO and Utility Reports, Best Practices Study</td>
</tr>
<tr>
<td>• Demand Response Program Costs</td>
<td>• PacifiCorp, Other Utilities, Regional Transmission Organizations.</td>
</tr>
<tr>
<td>• Technical Impacts</td>
<td>• Utility Programs/Studies</td>
</tr>
</tbody>
</table>
Secondary Data Sources

• ~ 150 Research Publications:
• Program Information
• ~ 31 Utilities, Regional Transmission Organizations
• ~ 60 Programs:
  – Direct Load Control – 11 programs
  – Interruptible/Curtailment Contract – 14 programs
  – Demand Buyback – 11 programs
  – Real-Time Pricing – 8 programs
  – Time-of-Use – 8 programs
  – Critical Peak Pricing – 8 programs
PacifiCorp System Load Duration Curve (2005)
Typical Daily (Week-Day) System Load Profiles

Summer

Winter
End-Use Contributions to System Load- Summer
End-Use Contributions to System Load - Winter
Demand-Response Resources Considered

- **Class I (Firm) DSM Resource**
  1. Fully dispatchable programs, 10 minute or less response, up to 87 hours annually (e.g. direct curtailment of air conditioning, space heating, water heating loads)
  2. Fully dispatchable programs, over 10 minute response, up to 87 hours annually (e.g. commercial energy management system co-ordinations)
  3. Scheduled firm up to 170 hours annually (e.g. irrigation load curtailment)
  4. Scheduled firm at 360 or more hours annually (e.g. energy storage)

- **Class III (Non-Firm) DSM Resources**
  1. Curtailment Contracts (Interruptible Prices)
  2. Demand buy-back commercial and industrial energy bid program (hour ahead, day ahead, week ahead – near term), such as PacifiCorp’s Energy Exchange
  3. Residential and commercial challenge programs (seasonal offers with longer lead times and fixed pricing) – programs such as Customer Energy Challenge
  4. Critical peak pricing programs
Typical Demand Response Classification Scheme

Demand Response

- Reliability Objectives
  - Price-Based (Curtailment Contracts)
  - Incentive-Based (Fully Dispatchable, Scheduled Firm)

- Economic Objectives
  - Price-Based (Critical Peak Pricing)
  - Incentive-Based (Demand Buyback)
Typical Proxy Programs Considered

• Class I
  – Fully Dispatchable - Winter
    • Space and water heating direct load control
  – Fully Dispatchable – Summer
    • Air Conditioning and water heating direct load control
  – Fully Dispatchable - Large C&I
    • Energy management system co-ordinations
  – Scheduled Firm – Irrigation
    • Irrigation load curtailment, scheduled
  – Scheduled Firm – Thermal Energy Storage
    • Small thermal energy storage

• Class III
  – Curtailment Contracts (Interruptible Pricing)
  – Critical Peak Pricing
    • Similar to Time of Use, with super peak pricing signals
  – Demand Buyback
    • Bidding programs such as Energy Exchange
Resource Potential Definitions

• **Technical Potential**: Assumes that all “applicable” loads are available for curtailment regardless of costs or market barriers. Basis for assessment:
  - Customer class/segment/end-use applicability
  - Customer load eligibility
  - Expected end-use load reduction impacts

• **Achievable Potential**: That portion of technical potential that is likely to be available, subject to customers’ ability and willingness to participate in load reduction based on unique business priorities, operating requirements, and economic (price) considerations. Basis for assessment:
  - *Program* participation
  - *Event* participation
  - Price elasticity of load response
Basis for Calculation of Costs

- Fixed Program Development Costs
  - Program Development
  - Hardware
  - Software (Infrastructure)
  - Marketing

- Variable (On-Going) Implementation Costs
  - Incentives
  - Communications
  - Program Administration
  - Marketing
  - Data acquisition
  - Evaluation
Next Steps

• Develop Potential Estimates
• Review
• Additional Analysis
  – Role of Uncertainty in Customer Response
    • Price Elasticity of Response
      – Program Participation
      – Event Participation
  – Resource Interaction Effects
    • Intra-Class Interactions
    • Inter-Class Interactions
• Define Resource Acquisition Ramping Options
• Prepare Proxy Supply Curves and Planning Model Inputs
• Complete Resource Valuation Study – Scheduled for June
Procurement Update: Demand-Side Management

Jeff Bumgarner
Demand-Side Management Procurement Status

- New Demand-Side Proposals and/or Concepts:
  - Class 1
    - Thermal energy storage – commercial cooling loads
    - Expansion of our Cool Keeper program beyond 90 MW
    - Air conditioner load control network in the west
    - Expansion of irrigation load control in the east
    - Coordination of commercial and industrial responsive loads east and west
  - Class 2
    - Home Energy Savers Incentive program – filed in Idaho in April
      - Utah, Washington, California and Wyoming interest
    - Expanded our commercial and industrial market characterization study to incorporate proposal aimed at identification of alternative approaches to improve penetration of energy efficiency in new construction projects
    - 80 PLUS®, national program geared towards increasing the penetration of energy efficient power supplies in personal computers and network servers
    - Commercial kitchen pre-rinse spray valve direct install program
    - Assessment, implementation and monitoring of compressed air systems
    - Several existing program lift and awareness/training proposals

- Proposal Review Status
  - Continuing to evaluate proposals; next step is to apply valuation criteria that assigns system benefits
  - Intend to incorporate Quantec’s survey of electric utility valuation methodologies and best-practices into the bid evaluation process
Procurement Update: Supply-Side Resources

Stacey Kusters
Requests for Proposals

Request for Proposal - 2003 B Renewables

- Amendment issued March 24, 2006 for up to 400 MW prior to December 31, 2007
  - Proposals were due April 12
  - Evaluation completed April 17
  - Target negotiations complete June 2006
- Results on the 2003B RFP, as amended consist of a mix of proposals
  - Power Purchase Agreements
  - Build Own Transfers
  - Sites Sales
- Shortlist currently consists of multiple projects with adequate opportunity to meet the 400 MW target

Request for Proposal – 2012 Resources

- Pre-Draft RFP Presentation to Bidders June 1, 2006
- Pre-Draft RFP Presentation to Stakeholders June 2, 2006
- PacifiCorp files Draft RFP July 11, 2006
- PacifiCorp issues RFP Target for 90 days after the Draft
IRP Resource Alternatives

Jim Lacey
Use of the Electric Power Research Institute’s Technical Assessment Guide

- PacifiCorp recently purchased a license to access technology reference data from the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG) database.
- The TAG database is considered the default source for developing the supply-side resource alternatives used in the 2006 IRP.
- The purpose of using TAG data is to rely on consistently-derived cost estimates from a well-respected outside source.
- Values are adjusted as necessary using information from PacifiCorp or other sources that reflects corporate or location-specific considerations (a common practice among TAG data customers).
  - TAG capital costs for certain technologies were adjusted to be more in line with PacifiCorp’s recent cost studies and project experience.
    - WorleyParsons IGCC Update
    - Jim Bridger 5 Feasibility Study
    - Previous Hunter 4 Studies
    - Intermountain Power Unit 3 Participation
    - Actual Recent and Current Projects (Gadsby Peakers, Currant Creek, Lake Side)
  - TAG emission estimates were adjusted based on permitting expectations in PacifiCorp’s service territory.
Integrated Gasification Combined Cycle

- Two Utah IGCC options included:
  - Each option includes sulfur removal and Selective Catalytic Reduction (SCR) equipment consistent with high levels of NO\textsubscript{x} removal
  - Each option assumes carbon ready provisions in the form of high performance Acid Gas Removal and space allocations for future water gas shift reactors and CO\textsubscript{2} compression. No additional capacity included in the gasifier or Air Separation Unit for future CO\textsubscript{2} capture
  - One Utah option has a spare gasifier for increased unit availability (\~90%). The other Utah option does not have a spare gasifier and the gasifier availability is assumed to be \~10% less. Natural gas is available for backup at a 16% reduced plant capacity. The Wyoming option includes the spare gasifier
- Option included for an IGCC plant on the West Side (capacity represents partial ownership)
- Option will be included for an IGCC plant with carbon capture and sequestration – intended for scenario analysis only
### Supply Side Table Options

<table>
<thead>
<tr>
<th>Technology</th>
<th>Average Capacity in Megawatts</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Coal</strong></td>
<td></td>
</tr>
<tr>
<td>Utah Super-critical Pulverized Coal</td>
<td>575</td>
</tr>
<tr>
<td>Utah Integrated Gasification Combined Cycle (Minimum Carbon Prep./Level II Controls)</td>
<td>508</td>
</tr>
<tr>
<td>Utah Integrated Gasification Combined Cycle (Minimum Carbon Prep./Level II Controls - no spare gasifier)</td>
<td>508</td>
</tr>
<tr>
<td>Utah Integrated Gasification Combined Cycle (Full Carbon Prep and Sequestration)</td>
<td>508</td>
</tr>
<tr>
<td>Wyoming Super-critical Pulverized Coal</td>
<td>750</td>
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<tr>
<td>Wyoming Integrated Gasification Combined Cycle (Minimum Carbon Prep./Level II Controls)</td>
<td>497</td>
</tr>
<tr>
<td>West Side Integrated Gasification Combined Cycle, PacifiCorp Share (Minimum Carbon Prep./Level II Controls)</td>
<td>200</td>
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<tr>
<td><strong>Natural Gas (4500 feet elevation)</strong></td>
<td></td>
</tr>
<tr>
<td>Microturbine</td>
<td>0.03</td>
</tr>
<tr>
<td>Fuel Cell - Small</td>
<td>0.25</td>
</tr>
<tr>
<td>Fuel Cell - Large</td>
<td>25</td>
</tr>
<tr>
<td>Single Cycle Combustion Turbine - Aeroderivative</td>
<td>79</td>
</tr>
<tr>
<td>Intercooled Aeroderivative Single Cycle Combustion Turbine</td>
<td>78</td>
</tr>
<tr>
<td>Internal Combustion Engines</td>
<td>153</td>
</tr>
<tr>
<td>Single Cycle Combustion Turbine (Two Frame &quot;F&quot;)</td>
<td>302</td>
</tr>
<tr>
<td>Combined Cycle Combustion Turbine (Wet &quot;F&quot; 1x1)</td>
<td>222</td>
</tr>
<tr>
<td>Combined Cycle Combustion Turbine Duct Firing (Wet &quot;F&quot; 1x1)</td>
<td>50</td>
</tr>
<tr>
<td>Combined Cycle Combustion Turbine (Wet &quot;F&quot; 2x1)</td>
<td>448</td>
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<tr>
<td>Combined Cycle Combustion Turbine Duct Firing (Wet &quot;F&quot; 2x1)</td>
<td>100</td>
</tr>
<tr>
<td>Combined Cycle Combustion Turbine (Wet &quot;G&quot; 1x1)</td>
<td>297</td>
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<tr>
<td>Combined Cycle Combustion Turbine Duct Firing (Wet &quot;G&quot; 1x1)</td>
<td>60</td>
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<tr>
<td><strong>Renewables and Other</strong></td>
<td></td>
</tr>
<tr>
<td>Wind (34% CF)</td>
<td>50</td>
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<tr>
<td>East Side Geothermal</td>
<td>35</td>
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<tr>
<td>Battery Storage</td>
<td>20</td>
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<tr>
<td>Pumped Storage</td>
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</tr>
<tr>
<td>Compressed Air Energy Storage</td>
<td>350</td>
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<tr>
<td>Solar</td>
<td>200</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td>TBD</td>
</tr>
<tr>
<td>Customer Standby Generators</td>
<td>TBD</td>
</tr>
</tbody>
</table>

- Nuclear will not be included as an option in the 2006 Integrated Resource Plan
Capital Costs

- Capital costs are, in general, higher than the previous IRP
  - Increases in material costs
  - Developing shortage in experienced contractors (especially specialized craft labor) and engineering support
- Capital costs will be represented by a range of values due to expected increase in construction cost volatility
- Coal-fired options have increased more than gas-fired options have increased
- Costs represent all-in costs and include:
  - EPC type contracting including all guarantees and contractual securities typical in such contracts
  - All Owners Costs including financing
  - Total nominal in-service costs are de-escalated and stated in 2006 dollars
O&M Costs – East Side

• In general, O&M estimates have increased from the previous IRP
• O&M for coal options have increased more than O&M for the natural gas-fired options
• Previously assumed O&M benefits from locating additional pulverized coal units at existing sites is reduced in new estimates due to:
  – Application of advanced technology (i.e. Supercritical Boilers and/or IGCC)
  – Siting issues at most probable locations (i.e. separate operations)
IRP Transmission Analysis Approach

Ken Dragoon
IRP Transmission Approach

• Potential transmission additions identified
  – MidAmerican Energy Holding Company Commitments
  – IRP Wind Additions
  – Others?

• Capacity Expansion Model (CEM) will determine which options are economic

• Path C Upgrade has been added to the fixed topology
  – Addressed in 2004 IRP Update; not an option for CEM to select
IRP Topology
Capacity Expansion Model Transmission Options

CEM options:

1. Walla to Mid-C (250 MW)
2. Bridger to Ben Lomond (750-1,500 MW)
   • 750 MW Bridger to Ben Lomond (Bridger 5)
   • 750 MW Bridger to Ben Lomond (Bridger 6)
3. Mona to Utah North (750 MW)
   • Hunter or IPP
4. Additional Path C Upgrade (300 MW)
   • Southeast Idaho wind
5. Miners to Ben Lomond (600 MW)
6. Southwest Wyoming wind to Utah North (600 MW)
7. Montana Yellowtail to Bridger (200 MW)
   • South Central Montana wind
IRP Topology with Transmission Options

2006 IRP Topology with transmission options

1. Walla, Walla to Mid-C (260 MW)
2. Bridgerty to Ben Lomond (750-1300 MW)
3. Moneta to Utah North (730 MW)
4. Additional Path C Upgrade (300 MW)
5. Miners to Ben Lomond (260 MW)
6. Wyoming wind to Utah North (800 MW)
7. Yellowtail to Bridger (260 MW)
Portfolio Analysis Scenarios and Risk Analysis

Pete Warnken
Role of Portfolio Analysis Scenarios in the 2006 Integrated Resource Plan

- Portfolio analysis scenarios are intended to investigate portfolio characteristics—resource types, amounts, and timing—given key planning uncertainties
- Along with stochastic simulation, they support the risk assessment strategy employed for resource portfolio evaluation
- Portfolio analysis scenarios will be used to:
  - determine the low-cost portfolios under a range of alternative futures
  - determine the resources, or resource combinations, that consistently yield robust portfolios—those that perform well given a broad range of future conditions
  - evaluate the impact of various resource strategies on portfolio cost (e.g., diversified versus coal-, gas-, or wind-dominated portfolios)
  - assess impacts to a portfolio due to a change in
    - a single input variable
    - a single resource type
Scenario Types

• **Alternative Futures**
  – Composed of different risk conditions that reflect a future state different from current expectations
  – Consists of a sample of potential futures that adequately captures the range of portfolio cost uncertainty, and should be of most interest to customers
  – Designed exclusively for deterministic portfolio optimization analysis using PacifiCorp’s Capacity Expansion Module (CEM)

• **Sensitivity Analysis**
  – Composed of different model inputs for a single variable or resource to determine the influence on portfolio costs and risks. Used for:
    • Threshold analysis (i.e., the risk condition level needed to change resource selection)
    • Testing alternative technology configurations
    • Testing alternative resource strategies and planning criteria
    • Addressing specific regulatory analysis requirements best handled using this scenario type
  – Designed for both deterministic portfolio optimization analysis and detailed stochastic analysis using PacifiCorp’s Planning and Risk (PaR) modeling system
Portfolio Variables

• Key risk variables include:
  – Carbon dioxide costs
  – Wholesale natural gas prices
  – Wholesale electricity prices
  – Retail load growth
  – Resource adequacy level (annual capacity planning margin)

• Additional risk variables include:
  – Start of carbon dioxide regulations
  – Renewable Portfolio Standard scope
  – Coal prices
  – Capital cost for Integrated Gasification Combined Cycle plants
  – Capital cost for wind projects
  – Demand-Side Management program market penetration level
  – Renewable resource Production Tax Credit availability
  – Existence of a regional transmission project (to determine commodity price and market access impacts)
Portfolio Development and Analysis Process

Resource Screening (Capacity Expansion Module)
- Alternative Futures Scenarios
- Conduct portfolio optimization runs
- Determine resource candidates
- Build portfolios for further analysis
- Resource Profiles*

Detailed Stochastic Analysis (Planning and Risk Module)
- Sensitivity Analysis Scenarios
- Conduct portfolio optimization runs
- Conduct base case stochastic simulations
- Conduct Sensitivity Analysis stochastic simulations

Preferred Portfolio Selection
- Sensitivity Analysis Scenarios
- Non-modeling considerations
- Final Candidate Portfolios
- Select the Preferred Portfolio

* Resource profiles consist of various comparative metrics and descriptive attributes; for example, frequency of appearance in portfolios generated according to Alternative Futures scenarios, frequency of appearance with other resource types, per-megawatt cost rankings, etc.
Alternative Futures Scenarios for Portfolio Optimization Analysis

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Description</th>
<th>CO2 Adder Level</th>
<th>CO2 Start Date</th>
<th>RPS Scope</th>
<th>Load Growth</th>
<th>Gas Price</th>
<th>Coal Price</th>
<th>Electric Price</th>
<th>Capacity Planning Margin Level</th>
<th>IGCC Capital Cost</th>
<th>Wind Capital Cost</th>
<th>DSM Market Penetration Level</th>
<th>Renewables PTC Availability</th>
<th>Regional Trans. Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Government institutes carbon dioxide (CO2) regulations by 2010 (base case adder with inflation-rate escalation), and a Renewable Portfolio Standard is enacted in Washington.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>2</td>
<td>No new regulatory requirements. Load growth and fuel prices are realized at currently forecasted levels.</td>
<td>None</td>
<td>N/A</td>
<td>CA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>3</td>
<td>Government institutes high-cost CO2 regulations, combined with higher-than-expected natural gas and electricity prices, provide a boost to coal-based resources.</td>
<td>None</td>
<td>N/A</td>
<td>CA</td>
<td>Base</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>15%</td>
<td>Base</td>
<td>High</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
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<tr>
<td>4</td>
<td>Government institutes high-cost CO2 regulations, but leaves technology choice up to the market. For example, the renewables Production Tax Credit (PTC) is eliminated and no new clean coal subsidies are provided beyond those currently provided for in the Energy Policy Act of 2005 (EPACT05). The economy is significantly impacted, driving load growth lower than expected. Gas demand, gas prices, and wholesale electricity prices increase due to the planning shift from coal to gas resources. Gas plants are viewed as the transition resource to other alternatives in the long term. Lower coal prices and slightly lower CO2 emissions relative to conventional coal plants give IGCC opportunities a modest boost.</td>
<td>High</td>
<td>2010</td>
<td>CA,WA</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>5</td>
<td>Government institutes high-cost CO2 regulations. Liquefied Natural Gas (LNG) infrastructure development and aggressive gas resource development suppresses gas prices below current expectations. Load growth is higher than projected due to a strong economy and a stable retail electricity price outlook. Coal prices are depressed as interest in conventional coal and IGCC wanes. Price pressure for wind turbines drops, lowering capital costs for wind projects.</td>
<td>High</td>
<td>2010</td>
<td>CA,WA</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>15%</td>
<td>Low</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>6</td>
<td>Government institutes high-cost CO2 regulations. The economy is impacted, lowering load growth. Clean coal incentives and Renewable Portfolio Standards applicable to entire PacifiCorp service territory improve the outlook for Integrated Gasification Combined Cycle (IGCC) and renewables development. Wind turbine manufacturers ramp up turbine production, thereby mitigating price increases. Upward pressure on electricity prices occurs. Load growth continues as expected.</td>
<td>High</td>
<td>2010</td>
<td>All States</td>
<td>Base</td>
<td>High</td>
<td>Base</td>
<td>High</td>
<td>15%</td>
<td>Low</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>7</td>
<td>Government institutes CO2 regulations, and fuel market conditions conspire to raise fuel prices beyond current forecasts. Capital costs for IGCC are higher than expected. Upward pressure on wind costs is mitigated by an aggressive ramp up of turbine production. The economy absorbs the higher energy prices without a significant impact to load growth.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>15%</td>
<td>High</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>8</td>
<td>Government institutes CO2 regulations, but favorable fuel market conditions lower fuel prices relative to current forecasts.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>9</td>
<td>This is a “bookend” scenario meant to show what an optimal portfolio looks like with greater-than-expected resource requirements, CO2 regulatory costs, commodity prices, and capital costs.</td>
<td>High</td>
<td>2010</td>
<td>CA,WA</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>15%</td>
<td>High</td>
<td>Base</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>10</td>
<td>This is a “bookend” scenario meant to show what an optimal portfolio looks like with lower-than-expected resource requirements, commodity prices, and capital costs. Base case CO2 regulatory costs are assumed.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
<td>15%</td>
<td>Low</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>
# Resource Type Risk Profile for Alternative Futures Scenarios

- Table at right shows how each of the main resource types—coal, natural gas, and wind—are stressed in the Alternative Futures scenarios
- Categorization as “higher” or “lower” risk is relative to the base case variable levels

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Description</th>
<th>Resource Types Stressed</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Government institutes carbon dioxide (CO2) regulations by 2010 (base case adder with inflation-rate escalation), and a Renewable Portfolio Standard is enacted in Washington.</td>
<td>Coal: Lower Risk, Gas: Lower Risk, Wind: Lower Risk</td>
</tr>
<tr>
<td>2</td>
<td>No new regulatory requirements. Load growth and fuel prices are realized at currently forecasted levels.</td>
<td>Lower Risk</td>
</tr>
<tr>
<td>3</td>
<td>No CO2 regulatory requirements, combined with higher-than-expected natural gas and electricity prices, provide a boost to coal-based resources.</td>
<td>Lower Risk, Higher Risk</td>
</tr>
<tr>
<td>4</td>
<td>Government institutes high-cost CO2 regulations, but leaves technology choice up to the market. For example, the renewables Production Tax Credit (PTC) is eliminated and no new clean coal subsidies are provided beyond those currently provided for in the Energy Policy Act of 2005 (EPACT05). The economy is significantly impacted, driving load growth lower than expected. Gas demand, gas prices, and wholesale electricity prices increase due to the planning shift from coal to gas resources. Gas plants are viewed as the transition resource to other alternatives in the long term. Lower coal prices and slightly lower CO2 emissions relative to conventional coal plants give IGCC opportunities a modest boost.</td>
<td>Higher Risk, Higher Risk, Higher Risk</td>
</tr>
<tr>
<td>5</td>
<td>Government institutes high-cost CO2 regulations. Liquefied Natural Gas (LNG) infrastructure development and aggressive gas resource development suppresses gas prices below current expectations. Load growth is higher than projected due to a strong economy and a stable retail electricity price outlook. Coal prices are depressed as interest in conventional coal and IGCC wanes. Price pressure for wind turbines drops, lowering capital costs for wind projects.</td>
<td>Higher Risk, Lower Risk, Lower Risk</td>
</tr>
<tr>
<td>6</td>
<td>Government institutes high-cost CO2 regulations. The economy is impacted, lowering load growth. Clean coal incentives and Renewable Portfolio Standards applicable to entire PacifiCorp service territory improve the outlook for Integrated Gasification Combined Cycle (IGCC) and renewables development. Wind turbine manufacturers ramp up turbine production, thereby mitigating price increases. Upward pressure on electricity prices occurs. Load growth continues as expected.</td>
<td>Higher Risk, Higher Risk, Lower Risk</td>
</tr>
<tr>
<td>7</td>
<td>Government institutes CO2 regulations, and fuel market conditions conspire to raise fuel prices beyond current forecasts. Capital costs for IGCC are higher than expected. Upward pressure on wind costs is mitigated by an aggressive ramp up of turbine production. The economy absorbs the higher energy prices without a significant impact to load growth.</td>
<td>Higher Risk, Higher Risk</td>
</tr>
<tr>
<td>8</td>
<td>Government institutes CO2 regulations, but favorable fuel market conditions lower fuel prices relative to current forecasts.</td>
<td>Lower Risk, Lower Risk</td>
</tr>
<tr>
<td>9</td>
<td>This is a &quot;bookend&quot; scenario meant to show what an optimal portfolio looks like with greater-than-expected resource requirements, CO2 regulatory costs, commodity prices, and capital costs.</td>
<td>Higher Risk, Higher Risk, Higher Risk</td>
</tr>
<tr>
<td>10</td>
<td>This is a &quot;bookend&quot; scenario meant to show what an optimal portfolio looks like with lower-than-expected resource requirements, commodity prices, and capital costs. Base case CO2 regulatory costs are assumed.</td>
<td>Lower Risk, Lower Risk, Lower Risk</td>
</tr>
</tbody>
</table>
Sensitivity Analysis Scenarios for Portfolio Optimization Analysis

- Alternative capacity Planning Margin levels
- Variability in the timing and level of a carbon dioxide cost adder
- Alternative Integrated Gasification Combined Cycle technology configurations
- Impact of a regional transmission project, such as the proposed Frontier Project
- Alternative approach for determining the peak system obligation
- Impact of alternative market potentials for demand-side management programs

### Portfolio Risk Variables

<table>
<thead>
<tr>
<th>Scenario Description</th>
<th>CO2 Adder Level</th>
<th>CO2 Start Date</th>
<th>RPS Scope</th>
<th>Load Growth</th>
<th>Gas Price</th>
<th>Coal Price</th>
<th>Elect. Price</th>
<th>Capacity Planning Margin Level</th>
<th>IGCC Capital Cost</th>
<th>Wind Capital Cost</th>
<th>DSM Market Penetration Level</th>
<th>Renewables PTC Availability</th>
<th>Regional Trans. Project</th>
<th>Resource or Load Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Using Alternative Futures Scenario 1 as the basis, PacifiCorp decides to plan to a lower capacity planning margin of 12%.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 12%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>Using Alternative Futures Scenario 1 as the basis, PacifiCorp decides to plan to a higher capacity planning margin of 18%.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 18%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>Using Alternative Futures Scenario 1 as the basis, assume that a CO2 adder is implemented in 2016.</td>
<td>Base</td>
<td>2016</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>Using Alternative Futures Scenario 1 as the basis, assume that the Frontier Line project is built. The new transmission impacts market prices in the Western Electricity Coordinating Council and provides transfer capability to move power to PacifiCorp’s Utah loads.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>Yes</td>
<td>N/A</td>
</tr>
<tr>
<td>Using Alternative Futures Scenario 1 as the basis, test CO2 adder value increments needed to change the optimal resource mix. Also test $0/ton, $10/ton, $25/ton, and $40/ton to meet Oregon Public Utility Commission sensitivity analysis requirement. Calculate $/ton CO2 cost.</td>
<td>Variable</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>Yes</td>
<td>N/A</td>
</tr>
<tr>
<td>Replace a Preferred Portfolio baseload resource with a IGCC/carbon sequestration resource to determine Present Value of Revenue Requirements (PVRR) impact.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15% High</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain to select IGCC with carbon sequestration</td>
</tr>
<tr>
<td>Replace Preferred Portfolio baseload resource with IGCC/carbon sequestration resource to determine PVRR impact.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain to select IGCC with/without spare gasifier</td>
</tr>
<tr>
<td>Develop a load &amp; resource balance assuming that PacifiCorp plans to the super-peak hourly load average, and run the CEM with the adjusted loads.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain peak load to super-peak hourly average</td>
</tr>
<tr>
<td>Model high/low maximum market potential levels using Quantec probabilistic-based estimates</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base 15% High/Low</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Sensitivity Analysis Scenarios for Detailed Simulation Analysis

- Risk analysis associated with Front Office Transactions
- Analysis of Combined Heat & Power (CHP) and customer-owned standby generators
- Evaluation of demand-response programs
- Stochastic risk analysis of various capacity planning margin levels
- Evaluation of building to early long position

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Name</th>
<th>Scenario Description</th>
<th>CO2 Adder Level</th>
<th>CO2 Start Date</th>
<th>RPS Scope</th>
<th>Load Growth</th>
<th>Gas Price</th>
<th>Coal Price</th>
<th>Elect. Price</th>
<th>Capacity Planning Margin Level</th>
<th>IGCC Capital Cost</th>
<th>Wind Capital Cost</th>
<th>Renewables PTC Availability</th>
<th>Regional Trans. Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Front Office Transactions risk assessment</td>
<td>Develop a portfolio that includes Front Office Transactions from 2012 and beyond, if not derived from the results of CEM optimization runs, and conduct a stochastic analysis.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>2</td>
<td>CHP/standby generator analysis (OPUC portfolio analysis requirement)</td>
<td>Stochastic analysis of Preferred Portfolio Combined Heat &amp; Power/standby generator capacity substitution; include &quot;high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas.&quot;</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>3</td>
<td>Class 3 DSM impact on unserved energy (OPUC portfolio analysis requirement)</td>
<td>Stochastic analysis to determine the amount of Class 3 DSM required to eliminate Energy Not Served (ENS).</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>4</td>
<td>Resource adequacy risk analysis</td>
<td>Conduct stochastic simulations for portfolios resulting from Sensitivity Analysis Scenarios 1 and 2 (Portfolio Optimization Analysis).</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>12%,15%,18%</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>5</td>
<td>Build to early long position</td>
<td>Using stochastic simulation, test the cost impact of building to an early long position rather than adding resources on a staggered basis. Assume that the annual Planning Margin level is relaxed beginning in 2012.</td>
<td>Base</td>
<td>2010</td>
<td>CA,WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>
Resource Adequacy/Capacity Planning Margin

Ken Dragoon
Resource Adequacy Methodology

- Begin with 15% planning reserve margin (PRM).
  - Run bulk of scenarios to a 15% planning reserve margin
- Test Alternative Planning Reserve Margins
  - Run Scenario 1 using 12% and 18% Planning reserve margins
- Analyze the three resulting Scenario 1 portfolios (12%, 15%, and 18%) in the stochastic Planning and Risk model.
  - Expected PVRR, Energy Not Served, extreme PVRR, etc.
Next Steps

Pete Warnken
Next Steps

IRP Meeting schedule for remainder of 2006
• September 13 or 14 – Presentation of modeling results
• October 17th – Currently scheduled

PacifiCorp
Integrated Resource Planning
825 NE Multnomah, Suite 600
Portland, Oregon 97232
Phone: (503) 813-5245
Email: IRP@PacifiCorp.com
## Scenario Description

**CO2 Adder**

**Level**

**CO2 Start Date**

**RPS Scope**

**Load Growth**

**Gas Price**

**Coal Price**

**Electric Price**

**Capacity Planning Margin Level**

**IGCC Capital Cost**

**Wind Capital Cost**

**DSM Market Penetration Level**

**Renewables PTC Availability**

**Regional Trans. Project**

### Scenario 1
- **Description:** Government institutes carbon dioxide (CO2) regulations by 2010 (base case adder with inflation-rate escalation), and a Renewable Portfolio Standard is enacted in Washington.
- **CO2 Adder Level:** Base
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** Base
- **Gas Price:** Base
- **Coal Price:** Base
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** Yes
- **Regional Trans. Project:** No

### Scenario 2
- **Description:** No new regulatory requirements. Load growth and fuel prices are realized at currently forecasted levels.
- **CO2 Adder Level:** None
- **CO2 Start Date:** N/A
- **RPS Scope:** CA
- **Load Growth:** Base
- **Gas Price:** Base
- **Coal Price:** Base
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** Yes
- **Regional Trans. Project:** No

### Scenario 3
- **Description:** No CO2 regulatory requirements, combined with higher-than-expected natural gas and electricity prices, provide a boost to coal-based resources.
- **CO2 Adder Level:** None
- **CO2 Start Date:** N/A
- **RPS Scope:** CA
- **Load Growth:** Base
- **Gas Price:** High
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 4
- **Description:** Government institutes high-cost CO2 regulations, but leaves technology choice up to the market. For example, the renewables Production Tax Credit (PTC) is eliminated and no new clean coal subsidies are provided beyond those currently provided for in the Energy Policy Act of 2005 (EPACT05). The economy is significantly impacted, driving load growth lower than expected. Gas demand, gas prices, and wholesale electricity prices increase due to the planning shift from coal to gas resources. Gas plants are viewed as the transition resource to other alternatives in the long term. Lower coal prices and slightly lower CO2 emissions relative to conventional coal plants give IGCC opportunities a modest boost.
- **CO2 Adder Level:** High
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** Low
- **Gas Price:** High
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 5
- **Description:** Government institutes high-cost CO2 regulations. Liquefied Natural Gas (LNG) infrastructure development and aggressive gas resource development suppresses gas prices below current expectations. Load growth is higher than projected due to a strong economy and a stable retail electricity price outlook. Coal prices are depressed as interest in conventional coal and IGCC wanes. Price pressure for wind turbines drops, lowering capital costs for wind projects.
- **CO2 Adder Level:** High
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** High
- **Gas Price:** Low
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Low
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** Yes
- **Regional Trans. Project:** No

### Scenario 6
- **Description:** Government institutes high-cost CO2 regulations. The economy is impacted, lowering load growth. Clean coal incentives and Renewable Portfolio Standards applicable to entire Pacificorp service territory improve the outlook for Integrated Gasification Combined Cycle (IGCC) and renewables development. Wind turbine manufacturers ramp up turbine production, thereby mitigating price increases. Upward pressure on electricity prices occurs. Load growth continues as expected.
- **CO2 Adder Level:** High
- **CO2 Start Date:** 2010
- **RPS Scope:** All States
- **Load Growth:** High
- **Gas Price:** Low
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Low
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Yes
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 7
- **Description:** Government institutes CO2 regulations, and fuel market conditions conspire to raise fuel prices beyond current forecasts. Capital costs for IGCC are higher than expected. Upward pressure on wind costs is mitigated by an aggressive ramp up of turbine production. The economy absorbs the higher energy prices without a significant impact to load growth.
- **CO2 Adder Level:** Base
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** High
- **Gas Price:** High
- **Coal Price:** High
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** High
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Yes
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 8
- **Description:** Government institutes CO2 regulations, but favorable fuel market conditions lower fuel prices relative to current forecasts.
- **CO2 Adder Level:** Base
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** Low
- **Gas Price:** Low
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Base
- **IGCC Capital Cost:** Base
- **Wind Capital Cost:** Base
- **DSM Market Penetration Level:** Yes
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 9
- **Description:** This is a "bookend" scenario meant to show what an optimal portfolio looks like with greater-than-expected resource requirements, CO2 regulatory costs, commodity prices, and capital costs.
- **CO2 Adder Level:** High
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** High
- **Gas Price:** High
- **Coal Price:** High
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** High
- **IGCC Capital Cost:** High
- **Wind Capital Cost:** High
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** No
- **Regional Trans. Project:** No

### Scenario 10
- **Description:** This is a "bookend" scenario meant to show what an optimal portfolio looks like with lower-than-expected resource requirements, commodity prices, and capital costs.
- **CO2 Adder Level:** Base
- **CO2 Start Date:** 2010
- **RPS Scope:** CA, WA
- **Load Growth:** Low
- **Gas Price:** Low
- **Coal Price:** Low
- **Electric Price:** 15%
- **Capacity Planning Margin Level:** Low
- **IGCC Capital Cost:** Low
- **Wind Capital Cost:** Low
- **DSM Market Penetration Level:** Base
- **Renewables PTC Availability:** Yes
- **Regional Trans. Project:** No
## Capacity Expansion Model - Scenarios

*Resource Type Risk Profile for Alternative Futures Scenarios*

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Description</th>
<th>Coal</th>
<th>Gas</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Government institutes carbon dioxide (CO2) regulations by 2010 (base case adder with inflation-rate escalation), and a Renewable Portfolio Standard is enacted in Washington.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>No new regulatory requirements. Load growth and fuel prices are realized at currently forecasted levels.</td>
<td></td>
<td></td>
<td>Lower Risk</td>
</tr>
<tr>
<td>3</td>
<td>No CO2 regulatory requirements, combined with higher-than-expected natural gas and electricity prices, provide a boost to coal-based resources.</td>
<td>Lower Risk</td>
<td>Higher Risk</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Government institutes high-cost CO2 regulations, but leaves technology choice up to the market. For example, the renewables Production Tax Credit (PTC) is eliminated and no new clean coal subsidies are provided beyond those currently provided for in the Energy Policy Act of 2005 (EPACT05). The economy is significantly impacted, driving load growth lower than expected. Gas demand, gas prices, and wholesale electricity prices increase due to the planning shift from coal to gas resources. Gas plants are viewed as the transition resource to other alternatives in the long term. Lower coal prices and slightly lower CO2 emissions relative to conventional coal plants give IGCC opportunities a modest boost.</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
</tr>
<tr>
<td>5</td>
<td>Government institutes high-cost CO2 regulations. Liquefied Natural Gas (LNG) infrastructure development and aggressive gas resource development suppresses gas prices below current expectations. Load growth is higher than projected due to a strong economy and a stable retail electricity price outlook. Coal prices are depressed as interest in conventional coal and IGCC wanes. Price pressure for wind turbines drops, lowering capital costs for wind projects.</td>
<td>Higher Risk</td>
<td>Lower Risk</td>
<td>Lower Risk</td>
</tr>
<tr>
<td>6</td>
<td>Government institutes high-cost CO2 regulations. The economy is impacted, lowering load growth. Clean coal incentives and Renewable Portfolio Standards applicable to entire PacifiCorp service territory improve the outlook for Integrated Gasification Combined Cycle (IGCC) and renewables development. Wind turbine manufacturers ramp up turbine production, thereby mitigating price increases. Upward pressure on electricity prices occurs. Load growth continues as expected.</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
<td>Lower Risk</td>
</tr>
<tr>
<td>7</td>
<td>Government institutes CO2 regulations, and fuel market conditions conspire to raise fuel prices beyond current forecasts. Capital costs for IGCC are higher than expected. Upward pressure on wind costs is mitigated by an aggressive ramp up of turbine production. The economy absorbs the higher energy prices without a significant impact to load growth.</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Government institutes CO2 regulations, but favorable fuel market conditions lower fuel prices relative to current forecasts.</td>
<td></td>
<td>Lower Risk</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>This is a &quot;bookend&quot; scenario meant to show what an optimal portfolio looks like with greater-than-expected resource requirements, CO2 regulatory costs, commodity prices, and capital costs.</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
<td>Higher Risk</td>
</tr>
<tr>
<td>10</td>
<td>This is a &quot;bookend&quot; scenario meant to show what an optimal portfolio looks like with lower-than-expected resource requirements, commodity prices, and capital costs. Base case CO2 regulatory costs are assumed.</td>
<td>Lower Risk</td>
<td>Lower Risk</td>
<td>Lower Risk</td>
</tr>
</tbody>
</table>
# Capacity Expansion Model
## Sensitivity Analysis Scenarios for Portfolio Optimization Analysis

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Description</th>
<th>CO2 Adder Level</th>
<th>CO2 Start Date</th>
<th>RPS Scope</th>
<th>Load Growth</th>
<th>Gas Price</th>
<th>Coal Price</th>
<th>Elect. Price</th>
<th>Capacity Planning Margin Level</th>
<th>IGCC Capital Cost</th>
<th>Wind Capital Cost</th>
<th>DSM Market Penetration Level</th>
<th>Renewables PTC Availability</th>
<th>Regional Trans. Project</th>
<th>Resource or Load Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Using Alternative Futures Scenario 1 as the basis, PacifiCorp decides to plan to a lower capacity planning margin of 12%.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>12%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>2</td>
<td>Using Alternative Futures Scenario 1 as the basis, PacifiCorp decides to plan to a higher capacity planning margin of 18%.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>18%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>3</td>
<td>Using Alternative Futures Scenario 1 as the basis, assume that a CO2 adder is implemented in 2016</td>
<td>Base</td>
<td>2016</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>4</td>
<td>Using Alternative Futures Scenario 1 as the basis, assume that the Frontier Line project is built. The new transmission impacts market prices in the Western Electricity Coordinating Council and provides transfer capability to move power to PacifiCorp's Utah loads.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>Yes</td>
<td>N/A</td>
</tr>
<tr>
<td>5</td>
<td>Using Alternative Futures Scenario 1 as the basis, test CO2 adder value increments needed to change the optimal resource mix. Also test $0/ton, $10/ton, $25/ton, and $40/ton to meet Oregon Public Utility Commission sensitivity analysis requirement. Calculate $/ton CO2 cost.</td>
<td>Variable</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>N/A</td>
</tr>
<tr>
<td>6</td>
<td>Replace a Preferred Portfolio baseload resource with a IGCC/carbon sequestration resource to determine Present Value of Revenue Requirements (PVRR) impact.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>High</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain to select IGCC with carbon sequestration</td>
</tr>
<tr>
<td>7</td>
<td>Replace Preferred Portfolio baseload resource with IGCC/carbon sequestration resource to determine PVRR impact.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain to select IGCC with/without spare gasifier</td>
</tr>
<tr>
<td>8</td>
<td>Develop a load &amp; resource balance assuming that PacifiCorp plans to the super-peak hourly load average, and run the CEM with the adjusted loads.</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td>Constrain peak load to super-peak hourly average</td>
</tr>
<tr>
<td>9</td>
<td>Model high/low maximum market potential levels using Quanetic probabilistic-based estimates</td>
<td>Base</td>
<td>2010</td>
<td>CA, WA</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>High/Low</td>
<td>No</td>
<td>N/A</td>
</tr>
</tbody>
</table>
### Planning and Risk Model - Scenarios

<table>
<thead>
<tr>
<th>#</th>
<th>Scenario Name</th>
<th>Scenario Description</th>
<th>CO2 Adder Level</th>
<th>CO2 Start Date</th>
<th>RPS Scope</th>
<th>Load Growth</th>
<th>Gas Price</th>
<th>Coal Price</th>
<th>Elect. Price</th>
<th>Capacity Planning Margin Level</th>
<th>IGCC Capital Cost</th>
<th>Wind Capital Cost</th>
<th>Renewables PTC Availability</th>
<th>Regional Trans. Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Front Office Transactions risk assessment</td>
<td>Develop a portfolio that includes Front Office Transactions from 2012 and beyond, if not derived from the results of CEM optimization runs, and conduct a stochastic analysis.</td>
<td>Base</td>
<td>2010</td>
<td>CA,W</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>2</td>
<td>CHP/standby generator analysis (OPUC portfolio analysis requirement)</td>
<td>Stochastic analysis of Preferred Portfolio Combined Heat &amp; Power/standby generator capacity substitution; include &quot;high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas.&quot;</td>
<td>Base</td>
<td>2010</td>
<td>CA,W</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>3</td>
<td>Class 3 DSM impact on unserved energy (OPUC portfolio analysis requirement)</td>
<td>Stochastic analysis to determine the amount of Class 3 DSM required to eliminate Energy Not Served (ENS).</td>
<td>Base</td>
<td>2010</td>
<td>CA,W</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>15%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>4</td>
<td>Resource adequacy risk analysis</td>
<td>Conduct stochastic simulations for portfolios resulting from Sensitivity Analysis Scenarios 1 and 2 (Portfolio Optimization Analysis).</td>
<td>Base</td>
<td>2010</td>
<td>CA,W</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>12%,15%,18%</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>5</td>
<td>Build to early long position</td>
<td>Using stochastic simulation, test the cost impact of building to an early long position rather than adding resources on a staggered basis. Assume that the annual Planning Margin level is relaxed beginning in 2012.</td>
<td>Base</td>
<td>2010</td>
<td>CA,W</td>
<td>Base</td>
<td>Base</td>
<td>Base</td>
<td>Relax annual Planning Margin values beginning in 2012</td>
<td>Base</td>
<td>Base</td>
<td>Yes</td>
<td>No</td>
<td></td>
</tr>
</tbody>
</table>