This Integrated Resource Plan (IRP) is based upon the best available information at the time the IRP is filed. The Action Plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information.

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# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Executive Summary</strong></td>
<td>1</td>
</tr>
<tr>
<td>Summary</td>
<td>1</td>
</tr>
<tr>
<td>The Changing Context For Resource Planning</td>
<td>3</td>
</tr>
<tr>
<td>Current Position</td>
<td>3</td>
</tr>
<tr>
<td>Risk And Uncertainty</td>
<td>4</td>
</tr>
<tr>
<td>Stochastic Risks</td>
<td>5</td>
</tr>
<tr>
<td>Scenario Risks</td>
<td>5</td>
</tr>
<tr>
<td>Paradigm Risks</td>
<td>6</td>
</tr>
<tr>
<td>Analytical Approach</td>
<td>6</td>
</tr>
<tr>
<td>Resource Alternatives</td>
<td>8</td>
</tr>
<tr>
<td>Portfolios</td>
<td>8</td>
</tr>
<tr>
<td>Common Features of Portfolios</td>
<td>8</td>
</tr>
<tr>
<td>Thermal Portfolios</td>
<td>9</td>
</tr>
<tr>
<td>Alternative Technology Portfolios</td>
<td>9</td>
</tr>
<tr>
<td>Transmission Portfolios</td>
<td>9</td>
</tr>
<tr>
<td>Results And Conclusions</td>
<td>10</td>
</tr>
<tr>
<td>Action Plan</td>
<td>11</td>
</tr>
<tr>
<td>Planning Under Uncertainty</td>
<td>13</td>
</tr>
<tr>
<td>Planning was Least Cost and Deterministic</td>
<td>13</td>
</tr>
<tr>
<td>Planning Must Recognize Risks and Markets</td>
<td>13</td>
</tr>
<tr>
<td>Growing Prominence Of The Energy Marketplace</td>
<td>14</td>
</tr>
<tr>
<td>Federal Regulation Directs Movement to Market</td>
<td>14</td>
</tr>
<tr>
<td>Merchant Generators and Power Marketers</td>
<td>14</td>
</tr>
<tr>
<td>New Risks for Traditional Utilities</td>
<td>15</td>
</tr>
<tr>
<td>Recent Experience In The Western Energy Marketplace</td>
<td>15</td>
</tr>
<tr>
<td>The Electricity Supply Crisis</td>
<td>15</td>
</tr>
<tr>
<td>The Natural Gas Shortage</td>
<td>16</td>
</tr>
<tr>
<td>Meltdown of the California Market</td>
<td>16</td>
</tr>
<tr>
<td>Further Blow to PacifiCorp</td>
<td>16</td>
</tr>
<tr>
<td>End of the Crisis</td>
<td>16</td>
</tr>
<tr>
<td>Boom and Bust</td>
<td>17</td>
</tr>
<tr>
<td>Retrenchment in Merchant Power</td>
<td>18</td>
</tr>
<tr>
<td>Natural Gas Supply Issues</td>
<td>18</td>
</tr>
<tr>
<td>Price Response in Natural Gas</td>
<td>18</td>
</tr>
<tr>
<td>Declining Productivity</td>
<td>19</td>
</tr>
<tr>
<td>Future Emission Compliance Issues</td>
<td>19</td>
</tr>
<tr>
<td>Implications Of Market Development And Fundamental Trends</td>
<td>20</td>
</tr>
<tr>
<td>The New IRP Imperatives</td>
<td>21</td>
</tr>
<tr>
<td>Conclusion</td>
<td>22</td>
</tr>
<tr>
<td><strong>2. Current Position</strong></td>
<td>23</td>
</tr>
<tr>
<td>Overview</td>
<td>23</td>
</tr>
<tr>
<td>Service Territory</td>
<td>23</td>
</tr>
<tr>
<td>PacifiCorp Retail Load</td>
<td>24</td>
</tr>
<tr>
<td>Wholesale Load</td>
<td>25</td>
</tr>
<tr>
<td>Resources</td>
<td>25</td>
</tr>
<tr>
<td>Demand Side Management (DSM) Programs</td>
<td>25</td>
</tr>
<tr>
<td>Supply Side Resources</td>
<td>27</td>
</tr>
<tr>
<td>Hydro</td>
<td>27</td>
</tr>
<tr>
<td>Thermal</td>
<td>27</td>
</tr>
<tr>
<td>Wind</td>
<td>27</td>
</tr>
<tr>
<td>Fuel</td>
<td>29</td>
</tr>
<tr>
<td>Wholesale Sales And Purchased Electricity</td>
<td>29</td>
</tr>
<tr>
<td>Section</td>
<td>Page</td>
</tr>
<tr>
<td>------------------------------------------------------------------------</td>
<td>------</td>
</tr>
<tr>
<td>Balancing and Hedging Strategy</td>
<td>29</td>
</tr>
<tr>
<td>Wholesale Sales and Purchases</td>
<td>30</td>
</tr>
<tr>
<td>Transmission</td>
<td>31</td>
</tr>
<tr>
<td>Pacificorp Position -The Gap</td>
<td>32</td>
</tr>
<tr>
<td>Pacificorp West</td>
<td>35</td>
</tr>
<tr>
<td>Pacificorp East</td>
<td>35</td>
</tr>
<tr>
<td>Conclusion</td>
<td>35</td>
</tr>
<tr>
<td><strong>3. Risks And Uncertainties</strong></td>
<td>37</td>
</tr>
<tr>
<td>Introduction</td>
<td>37</td>
</tr>
<tr>
<td>Classification Of Risk</td>
<td>37</td>
</tr>
<tr>
<td>Stochastic Risks</td>
<td>38</td>
</tr>
<tr>
<td>Scenario Risks</td>
<td>38</td>
</tr>
<tr>
<td>Paradigm Risks</td>
<td>40</td>
</tr>
<tr>
<td>Discussion Of Specific Risks</td>
<td>41</td>
</tr>
<tr>
<td>RTO and SMD</td>
<td>41</td>
</tr>
<tr>
<td>Potential Impact</td>
<td>42</td>
</tr>
<tr>
<td>Treatment in the IRP Models</td>
<td>42</td>
</tr>
<tr>
<td>Comprehensive Air Strategy</td>
<td>42</td>
</tr>
<tr>
<td>New Source Review (NSR)</td>
<td>43</td>
</tr>
<tr>
<td>Climate Change</td>
<td>43</td>
</tr>
<tr>
<td>Multi-pollutant Legislation</td>
<td>44</td>
</tr>
<tr>
<td>Mercury Maximum Achievable Control Technology (MACT)</td>
<td>44</td>
</tr>
<tr>
<td>Approach</td>
<td>45</td>
</tr>
<tr>
<td>Potential Impact</td>
<td>45</td>
</tr>
<tr>
<td>Pacificorp Approach to Air Quality Standards</td>
<td>45</td>
</tr>
<tr>
<td>Treatment in the Model</td>
<td>45</td>
</tr>
<tr>
<td>Hydro Generation-Relicensing</td>
<td>46</td>
</tr>
<tr>
<td>Potential Impact</td>
<td>46</td>
</tr>
<tr>
<td>Pacificorp’s Approach to Hydrogeneration Relicensing</td>
<td>47</td>
</tr>
<tr>
<td>Treatment in the IRP Model</td>
<td>47</td>
</tr>
<tr>
<td>Renewable Portfolio Standard (RPS)</td>
<td>47</td>
</tr>
<tr>
<td>Potential Impact</td>
<td>48</td>
</tr>
<tr>
<td>Treatment in the IRP Model</td>
<td>48</td>
</tr>
<tr>
<td>Multi-State Process (MSP)</td>
<td>49</td>
</tr>
<tr>
<td>Pacificorp’s Approach to MSP</td>
<td>49</td>
</tr>
<tr>
<td>Treatment In The IRP Model</td>
<td>49</td>
</tr>
<tr>
<td>Oregon Electricity Restructuring (SB1149)</td>
<td>49</td>
</tr>
<tr>
<td>Pacificorp’s Approach to SB 1149</td>
<td>50</td>
</tr>
<tr>
<td>Treatment In The IRP Model</td>
<td>50</td>
</tr>
<tr>
<td>Risk Assessment</td>
<td>50</td>
</tr>
<tr>
<td>Relative Importance Of Risk Categories</td>
<td>51</td>
</tr>
<tr>
<td>Customer And Shareholder Risks</td>
<td>52</td>
</tr>
<tr>
<td>Customers vs. Shareholder Risks</td>
<td>53</td>
</tr>
<tr>
<td>Shareholder Risks</td>
<td>53</td>
</tr>
<tr>
<td>Customer Risks</td>
<td>54</td>
</tr>
<tr>
<td>Customer Risk Tradeoff</td>
<td>54</td>
</tr>
<tr>
<td>Electric Price Risk</td>
<td>55</td>
</tr>
<tr>
<td>Load Risk</td>
<td>55</td>
</tr>
<tr>
<td>Fuel Risk</td>
<td>55</td>
</tr>
<tr>
<td>Plan Cost Effectiveness</td>
<td>56</td>
</tr>
<tr>
<td>Conclusion</td>
<td>56</td>
</tr>
<tr>
<td><strong>4. Analytical Approach Used In IRP</strong></td>
<td>59</td>
</tr>
<tr>
<td>Overview</td>
<td>59</td>
</tr>
<tr>
<td>Steps In Analysis</td>
<td>59</td>
</tr>
<tr>
<td>Portfolio Development</td>
<td>60</td>
</tr>
</tbody>
</table>
Operational Simulation: 62
Cost Analysis: 63
Screening: 63
Risk Analysis and Stress Testing: 63
Optimization: 64
Portfolio Screening Curve: 64
Theories and Themes: 64
Operational Signals: 65
Cost and Risk Analysis: 65
Industry Expertise: 65
Convergence: 65
Conclusion: 66

5. Resource Alternatives: 67

Overview: 67
Demand Side Resources: 67
Classes of DSM: 68
Class 1: 68
Class 2: 68
Class 3: 68
Class 4: 69
Future Programs: 69
Residential: 69
Nonresidential: 69
Supply Side Resources: 70
Candidate Supply Side Resources Used in the IRP Analysis: 70
Utah Coal Options: 70
Wyoming Coal: 71
Combined Heat and Power (CHP or cogeneration): 71
Geothermal: 71
Fuel Cells: 71
Market Purchases/Contracts: 72
Natural Gas: 74
Wind: 75
Supply Side Resources Not Used in the IRP Analysis: 76
Transmission: 76

6. Portfolios: 79

Overview: 79
Common Factors & Metrics: 79
DSM: 79
Wind Resource Additions: 80
Short-Term Purchases: 80
Reserve Peakers: 80
Portfolio Development: 80
Base Load: 80
Peaking: 81
Shaped Products: 81
Transmission: 81
Portfolio Categories: 81
Portfolio Category: Thermal: 81
Gas/Coal: 81
Coal/Gas: 82
All Natural Gas: 82
PacifiCorp Build: 82
Benefits, Uncertainties and Issues: 82
Portfolio Category: Alternative Technology: 82
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appendix D – Portfolio Summary Tables</td>
<td>233</td>
</tr>
<tr>
<td>Appendix E – Analysis Results</td>
<td>277</td>
</tr>
<tr>
<td>Appendix F – Portfolio Load And Resource Balances</td>
<td>299</td>
</tr>
<tr>
<td>Appendix G – Demand-Side Management</td>
<td>303</td>
</tr>
<tr>
<td>Classes Of DSM</td>
<td>303</td>
</tr>
<tr>
<td>Class 1 - Fully Dispatchable Resources</td>
<td>303</td>
</tr>
<tr>
<td>Class 2 - Non Dispatchable; Growth Neutral</td>
<td>303</td>
</tr>
<tr>
<td>Class 3 - Non Dispatchable; Buydown</td>
<td>303</td>
</tr>
<tr>
<td>Class 4 - Non-Dispatchable; Conservation Education</td>
<td>304</td>
</tr>
<tr>
<td>Modeling DSM</td>
<td>304</td>
</tr>
<tr>
<td>Class 1 DSM – Direct Load Control</td>
<td>304</td>
</tr>
<tr>
<td>Class 2 DSM – Conservation Measures</td>
<td>305</td>
</tr>
<tr>
<td>Additional Planning Decrement</td>
<td>309</td>
</tr>
<tr>
<td>Class 3 DSM - Curtailment</td>
<td>309</td>
</tr>
<tr>
<td>DSM Summary</td>
<td>310</td>
</tr>
<tr>
<td>Decrement Procedure To Determine DSM Decrement Values</td>
<td>310</td>
</tr>
<tr>
<td>Decrement Procedure</td>
<td>311</td>
</tr>
<tr>
<td>Results</td>
<td>313</td>
</tr>
<tr>
<td>Portfolio Assignment</td>
<td>313</td>
</tr>
<tr>
<td>New Portfolio Design</td>
<td>314</td>
</tr>
<tr>
<td>D150-10</td>
<td>314</td>
</tr>
<tr>
<td>D300-20</td>
<td>315</td>
</tr>
<tr>
<td>D150-40</td>
<td>315</td>
</tr>
<tr>
<td>D300-60</td>
<td>316</td>
</tr>
<tr>
<td>D150-1, D300-1</td>
<td>317</td>
</tr>
<tr>
<td>Decrement Case Comparison</td>
<td>317</td>
</tr>
<tr>
<td>Transmission and Distribution Deferral Benefits</td>
<td>317</td>
</tr>
<tr>
<td>Appendix H – Risk Assessment Methodology</td>
<td>319</td>
</tr>
<tr>
<td>Introduction</td>
<td>319</td>
</tr>
</tbody>
</table>
Appendix K – Retail Load Forecasting ........................................................................................................... 359
  Introduction - Methodology ........................................................................................................................... 359
  Near Term Methods ....................................................................................................................................... 359
    Residential, Commercial, Public Street and Highway Lighting, and Irrigation Customers...................... 359
    Industrial Sales and Other Sales to Public Authorities ............................................................................. 360
  Long Term Methods ...................................................................................................................................... 360
    Economic and Demographic Sector ............................................................................................................. 361
    Residential Sector ..................................................................................................................................... 361
    Commercial Sector .................................................................................................................................. 362
    Industrial Sector .................................................................................................................................... 362
    Other Sales ............................................................................................................................................. 363
    Merging of the Near Term and Long Term Forecasts .............................................................................. 363
    Allocating Sales Forecasts by Month ......................................................................................................... 363
    System Load Forecasts ............................................................................................................................... 363
    System Peak Forecasts ............................................................................................................................... 364
    Hourly Load Forecasts ............................................................................................................................... 364
    Summary of System Load Forecast ............................................................................................................ 364

Appendix L – Renewables/Wind Integration ................................................................................................... 365
  Background .................................................................................................................................................... 365
  Imbalance Costs .......................................................................................................................................... 366
  Incremental Operating Reserve Requirements ............................................................................................. 367
  Total Wind Resource Costs .......................................................................................................................... 370
  Summary ...................................................................................................................................................... 371

Appendix M – Glossary ..................................................................................................................................... 373

Appendix N – Standards And Guidelines ..................................................................................................... 385
  Pacificorp Compliance With IRP Standards And Guidelines ....................................................................... 385
  Background .................................................................................................................................................. 385
  General Compliance .................................................................................................................................. 385
    Idaho ....................................................................................................................................................... 386
    Oregon .................................................................................................................................................... 386
    Utah ......................................................................................................................................................... 387
    Washington ............................................................................................................................................. 389
    Wyoming ................................................................................................................................................ 389

The IRP Customer Impact Calculation: ........................................................................................................ 348
Scorecards ...................................................................................................................................................... 348
  Portfolio Scorecard ..................................................................................................................................... 348
  Stress Scorecards ..................................................................................................................................... 348
Critical Assumptions ...................................................................................................................................... 349
  Market Access Assumptions ......................................................................................................................... 349
    Transmission .......................................................................................................................................... 349
    Liquidity .................................................................................................................................................. 349
  RPS Assumption ........................................................................................................................................ 350
  DSM Assumption .................................................................................................................................... 350
  5% Build Requirement ................................................................................................................................. 350
  Additional Critical Assumptions ................................................................................................................. 351
  Integrated Resource Plan Capital Revenue Requirement Methodology .................................................... 351
    Introduction ........................................................................................................................................... 351
    Nominal Capital Revenue Requirement ................................................................................................... 351
    Nominal Revenue Requirements Inadequate for Comparison ................................................................ 352
    Real Levelized Revenue Requirement .................................................................................................... 354
    Comparison to Market Purchases ............................................................................................................ 356
    Real Levelized Revenue Requirements Calculation ................................................................................ 356
    Summary and Conclusion ......................................................................................................................... 356

Appendix L – Renewables/Wind Integration ................................................................................................. 365
Scorecards ...................................................................................................................................................... 348
  Portfolio Scorecard ..................................................................................................................................... 348
  Stress Scorecards ..................................................................................................................................... 348
Critical Assumptions ...................................................................................................................................... 349
  Market Access Assumptions ......................................................................................................................... 349
    Transmission .......................................................................................................................................... 349
    Liquidity .................................................................................................................................................. 349
  RPS Assumption ........................................................................................................................................ 350
  DSM Assumption .................................................................................................................................... 350
  5% Build Requirement ................................................................................................................................. 350
  Additional Critical Assumptions ................................................................................................................. 351
  Integrated Resource Plan Capital Revenue Requirement Methodology .................................................... 351
    Introduction ........................................................................................................................................... 351
    Nominal Capital Revenue Requirement ................................................................................................... 351
    Nominal Revenue Requirements Inadequate for Comparison ................................................................ 352
    Real Levelized Revenue Requirement .................................................................................................... 354
    Comparison to Market Purchases ............................................................................................................ 356
    Real Levelized Revenue Requirements Calculation ................................................................................ 356
    Summary and Conclusion ......................................................................................................................... 356

Appendix K – Retail Load Forecasting ........................................................................................................... 359
  Introduction - Methodology ........................................................................................................................... 359
  Near Term Methods ....................................................................................................................................... 359
    Residential, Commercial, Public Street and Highway Lighting, and Irrigation Customers...................... 359
    Industrial Sales and Other Sales to Public Authorities ............................................................................. 360
  Long Term Methods ...................................................................................................................................... 360
    Economic and Demographic Sector ............................................................................................................. 361
    Residential Sector ..................................................................................................................................... 361
    Commercial Sector .................................................................................................................................. 362
    Industrial Sector .................................................................................................................................... 362
    Other Sales ............................................................................................................................................. 363
    Merging of the Near Term and Long Term Forecasts .............................................................................. 363
    Allocating Sales Forecasts by Month ......................................................................................................... 363
    System Load Forecasts ............................................................................................................................... 363
    System Peak Forecasts ............................................................................................................................... 364
    Hourly Load Forecasts ............................................................................................................................... 364
    Summary of System Load Forecast ............................................................................................................ 364

Appendix L – Renewables/Wind Integration ................................................................................................... 365
  Background .................................................................................................................................................... 365
  Imbalance Costs .......................................................................................................................................... 366
  Incremental Operating Reserve Requirements ............................................................................................. 367
  Total Wind Resource Costs .......................................................................................................................... 370
  Summary ...................................................................................................................................................... 371

Appendix M – Glossary ..................................................................................................................................... 373

Appendix N – Standards And Guidelines ..................................................................................................... 385
  Pacificorp Compliance With IRP Standards And Guidelines ....................................................................... 385
  Background .................................................................................................................................................. 385
  General Compliance .................................................................................................................................. 385
    Idaho ....................................................................................................................................................... 386
    Oregon .................................................................................................................................................... 386
    Utah ......................................................................................................................................................... 387
    Washington ............................................................................................................................................. 389
    Wyoming ................................................................................................................................................ 389

- ix -
Appendix O – Response To Comments ........................................................................................................ 393
Comments On The Draft Report And Pacificorp’s Response ........................................................................ 393
Optimality and Finality ................................................................................................................................. 393
Action Plan Specificity ................................................................................................................................... 394
Action Plan Must Follow Analytics ............................................................................................................. 394
Procurement and RFPs ................................................................................................................................... 395
Multi-State Process ......................................................................................................................................... 395
System-wide Planning .................................................................................................................................... 396
Renewable Resources .................................................................................................................................... 396
Geothermal Resources .................................................................................................................................... 397
DSM Resources .............................................................................................................................................. 397
Supply-Side Resources ................................................................................................................................. 399
Solar Resources .............................................................................................................................................. 399
Coal .................................................................................................................................................................. 399
Airshed Issues ............................................................................................................................................... 401
Climate Change ............................................................................................................................................ 402
Transmission .................................................................................................................................................. 402
Risk Analysis ................................................................................................................................................ 403
Planning Margin ............................................................................................................................................ 404
Spot Purchases .............................................................................................................................................. 404
Load Transfers .............................................................................................................................................. 405
Load Forecasts .............................................................................................................................................. 405
Rate Impacts ................................................................................................................................................ 405
IRP Standards and Guidelines ...................................................................................................................... 406
Parties Who Provided Written Comments .................................................................................................. 406
Appendix P – Performance On Rampp-6 Action Plan .................................................................................. 409
Overview ....................................................................................................................................................... 409
DSM Goals From RAMPP-6 ............................................................................................................................ 409
New Generation ............................................................................................................................................ 411
IRP Organization .......................................................................................................................................... 411
Summer Tiered Rates .................................................................................................................................... 411
INDEX OF TABLES
Table 2.1 Approved DSM Programs .......................................................... 25
Table 2.2 DSM Programs Operating During 2002 ........................................ 26
Table 2.3 Existing Generation Facilities ...................................................... 28
Table 2.4 PacifiCorp Coal Reserves ............................................................ 29
Table 2.5 PacifiCorp Mid-Columbia Hydro Contracts ................................. 31
Table 5.1 Energy Trust of Oregon Projected DSM Achievements (MWa) ........ 68
Table 5.2 The planned build up of RPS over the period 2005 to 2013 .......... 75
Table 6.1 Alternative Technology I Portfolio Comparison for Build Pattern .... 83
Table 6.2 Alternative Technology II Portfolio Comparison for Build Pattern .... 83
Table 6.3 RPS Replacement in Diversified Portfolios .................................... 86
Table 6.4 Diversified I Portfolio Comparison ............................................... 87
Table 6.5 Diversified II Portfolio Comparison ............................................. 87
Table 6.6 Diversified III Portfolio Comparison ............................................. 88
Table 6.7 Diversified IV Portfolio Comparison ............................................. 88
Table 6.8 Renewable Portfolio Comparison ................................................ 89
Table 7.1 Hybrid Portfolio Scorecard ......................................................... 94
Table 7.2 Variable Cost Elements .............................................................. 96
Table 7.3 East – West Cost Breakdown ...................................................... 103
Table 7.4 Natural Gas Capacity Comparison ............................................. 105
Table 7.5 Coefficient of Variation ............................................................. 108
Table 7.6 Real Levelized versus Nominal PV versus Constant .................. 115
Table 7.7 IRP Annual Increase Calculation Example ................................. 117
Table 7.8 Summary of IRP Stress Test ..................................................... 120
Table 7.9 Diversified I Stress to Renewable Uncertainties ......................... 128
Table 7.10 Application of 15% Wind Capacity to Planning Margin ............. 131
Table 7.11 Resource Timing ................................................................. 134
Table 7.12 Loss of Load Comparison ........................................................ 136
Table 7.13 Decrement Results Summary (nominal $/MWh) For Class 2 DSM Programs ..................................................... 137
Table 7.14 Nominal Market Prices ............................................................ 137
Table 7.15 Decrement Results Summary (nominal $000) For Class 1 DSM Programs ............................................................ 138
Table 8.1 Diversified Portfolio I Resource Addition Summary ..................... 144
Table 8.2 Planned DSM Over the Period 2004 to 2013 .............................. 146
Table 8.3 The planned Wind build up in Diversified Portfolio I .................. 146
Table 9.1 IRP Action Plan Findings of Need ............................................. 153
Table 9.2 Action Plan Implementation Actions for Diversified Portfolio I ...... 154
Table C.1 Contracts Modeled in IRP .......................................................... 182
Table C.2 Long Term Wholesale Purchase Contracts ................................ 184
Table C.3 Long-Term Wholesale Sales Contracts ...................................... 185
Table C.4 DSM All-State Summary .......................................................... 186
Table C.5 Idaho DSM Projects ............................................................... 187
Table C.6 Washington DSM Projects ....................................................... 189
Table C.7 Wyoming DSM Projects .......................................................... 191
Table C.8 Utah DSM Projects ................................................................. 192
Table C.9 California DSM Projects .......................................................... 194
Table C.10 SO2 Emission Costs .............................................................. 195
Table C.11 NOx Emission Costs .............................................................. 196
Table C.12 Annual Average Natural Gas Prices ........................................ 198
Table C.13 Annual Average Coal Prices for each of the PacifiCorp owned plants 199
Table C.14 Thermal Plant Heat Rates ....................................................... 200
Table C.15 Hydrogeneration Plant Life ...................................................... 204
Table C.16 Hydrogeneration Relicensing Impacts on Generation ................. 205
Table C.17 Calculation of the Federal Renewable Portfolio Standard (RPS) Model .......................................................... 207
Table C.18 Potential Supply Side Resources ............................................. 209
Table C.19 Potential Supply Side Resources ............................................. 213
INDEX OF FIGURES

Figure 1.1 Electricity Price Volatility ................................................................. 17
Figure 1.2 Natural Gas Price Volatility ............................................................. 17
Figure 2.1 PacifiCorp Service Area ................................................................. 24
Figure 2.2 PacifiCorp System Capacity ............................................................. 33
Figure 2.3 PacifiCorp West Gap Analysis ......................................................... 34
Figure 2.4 PacifiCorp East Gap Analysis .......................................................... 34
Figure 3.1 Risk Diagram .................................................................................. 38
Figure 3.2 Stochastic and Scenario Risk Illustration ....................................... 40
Figure 3.3 Probability Density ......................................................................... 52
Figure 4.1 Analysis Process ............................................................................ 60
Figure 4.2 Sample Resource Deployment Curve .............................................. 61
Figure 5.1 IRP Price Forecast – Monthly Flat, Average Prices ......................... 72
Figure 5.2 Utah Main Transmission Triangle .................................................. 77
Figure 7.1 Portfolio PVRR Comparison............................................................ 92
Figure 7.2 Real Levelized Fixed Costs ............................................................. 95
Figure 7.3 Inc. Net Variable Power Costs ......................................................... 95
Figure 7.4 Spot Market Sales - West ................................................................. 98
Figure 7.5 Spot Market Sales - East ................................................................. 99
Figure 7.6 Spot Market Purchases - West ......................................................... 100
Figure 7.7 Spot Market Purchases - East ........................................................ 100
Figure 7.8 95th Percentile .............................................................................. 104
Figure 7.9 5th Percentile ............................................................................... 105
Figure 7.10 95th – 5th Percentile .................................................................. 107
Figure 7.11 Mean of Tail .............................................................................. 108
Figure 7.12 PVRR vs. 95th Percentile ............................................................. 110
Figure 7.13 PVRR vs. 95th – 5th Percentile .................................................... 111
Figure 7.14 Div I High Loads and Natural gas ................................................. 112
Figure 7.15 Div IV High Loads and Natural Gas ............................................ 112
Figure 7.16 Div I Low Loads and Natural Gas ............................................... 112
Figure 7.17 Div IV Low Loads and Natural Gas ............................................ 112
Figure 7.18 IRP Annual Increase as a Percent of CY 2001 Retail Rates ............ 118
Figure 7.19 PVRR vs. Carbon Allowance Cost Scenarios ......................... 123
Figure 7.20 CO2 Emissions vs. Carbon Allowance Cost Scenarios ............... 124
Figure 7.21 PVRR With and Without Wind ................................................... 125
Figure 7.22 Diversified I Wind Stresses ......................................................... 129
Figure 7.23 Combined Carbon and Wind Stress .......................................... 130
Figure 7.24 Planning Margin Comparison ..................................................... 140
Figure 7.25 Differences Between Planning Margins By Category .................. 141
Figure 8.1 IRP Capacity Requirement Breakdown – Rounded to the Nearest 100 MWs .............................................. 145
Figure 9.1 Decision Process chart for Portfolio Resource Analysis ................ 158
Figure 9.2 Decision Process Chart for Wind (Renewables) Generation Development .................................................. 159
Figure 9.3 Decision Process Chart for Base Load Technology Choice .......... 159
Figure A.1 Retail Restructuring ..................................................................... 167
Figure A.2 Transmission System Interconnections for the United States and Canada .................................................. 169
Figure A.3 Major Transmission lines in WECC ............................................. 170
Figure A.4 WECC Existing and New Generation versus Demand ................. 171
Figure A.5 Major Gas pipelines and Supply Basins ...................................... 172
Figure B.1 Annual Average Natural Gas Prices .......................................... 199
Figure C.2 IRP Transmission Topology .......................................................... 224
Figure G.1 Class 2 DSM Program Resource Stack (1) .................................. 306
Figure G.2 Class 2 DSM Program Resource Stack (2) .................................. 306
Figure G.3 Class 2 DSM Levelized Costs - Actual DSM Program Resource Stack .................................................. 307
Figure G.4 DSM Class 2 Hourly Load Decrement ........................................ 309
Figure J.1 IRP Development Process ............................................................. 339
2002 INTEGRATED RESOURCE PLAN
EXECUTIVE SUMMARY

SUMMARY

The purpose of PacifiCorp’s Integrated Resource Plan (IRP) is to provide a framework for the prudent future actions required ensuring PacifiCorp continues to provide reliable and least cost electric service to its customers. The IRP was developed with considerable public involvement from customer interest groups, regulatory staff, regulators and other stakeholders. PacifiCorp is filing this IRP with its State regulatory agencies and requesting that they acknowledge and support its conclusions, including the proposed Action Plan.

This IRP is developed against the backdrop of continuing market, regulatory and structural changes in the electric industry. These changes highlight the importance of understanding the risks and uncertainties inherent in resource planning. This IRP uses a robust and objective analytical framework to simulate the integration of new resource alternatives with PacifiCorp’s existing generation and transmission assets, and to compare their economic and operational performance. The methodology also accounts for the uncertain future by testing resource alternatives against measurable future risks and possible Paradigm shifts in the industry.

The IRP reveals that PacifiCorp has substantial new resource needs. Looking forward, PacifiCorp expects its obligations to provide electricity to its customers will continue to grow, while at the same time its existing resources will diminish significantly. Load growth, load shape growth, asset retirement and contract expirations cause the gap between demand and supply to grow over time. Measures need to be taken to close the gap, and a number of diverse actions are proposed. Not taking prompt and focused action to close this gap would expose PacifiCorp and its customers to unacceptable levels of cost, reliability and market risk.

Other key findings in the IRP include:

- The strongest resource strategy relies on a diverse portfolio of options, including strong components of renewables and demand side management, but also natural gas- and coal-fired generating resources. A resource procurement process to pursue this diversified approach is described in the Action Plan.
- Possible Paradigm shifts in the electric industry driven by Federal regulatory requirements are significant uncertainties for PacifiCorp and its customers to manage in the next several years. These issues include (potentially favorable) changes in transmission operations, as well as the potential increased costs associated with PacifiCorp’s existing resource assets, including complying with air emission standards and relicensing hydroelectric facilities.
- Renewable resources are a good fit for PacifiCorp within the context of a diversified portfolio. The IRP proposes procuring renewable resources (primarily wind, and possibly geothermal) at a level shown to be cost effective, given the assumptions used to evaluate the resource. The amount of renewables is also a level that would meet or exceed renewable portfolio standards that have been proposed in Federal and State legislation.
Demand-side management (DSM) will continue to be an important and cost-effective program for PacifiCorp. A significant increase in programmatic measures is proposed, including a load control program to help mitigate growing capacity requirements.

In addition to renewable resources and DSM, the study concludes that additional resources from thermal generation will also be required. The least cost option is a combination of three natural gas-fired units and one coal unit to meet both growing energy and capacity requirements.

The least cost portfolio includes a coal baseload thermal unit in the East. Coal-fired generation may be particularly advantageous when procuring resources in the Rocky Mountains because coal is an abundant indigenous resource there. However, the long-term impacts of atmospheric emissions are casting doubt on the viability of coal-fired generation. The IRP least cost portfolio is dependent upon the impact of a number of these Paradigm risks, including air emission standards and possible global warming measures. PacifiCorp believes it has adequately addressed these risks, based on our current understanding of them, and coal plants remain a low-cost option. The IRP Action Plan includes further work to develop and test the viability of a coal baseload thermal unit, including an ongoing assessment of the risks.

This IRP proposes a significant procurement of new resources. The strategy outlined in this IRP includes the addition of about 4,000 MW of new capacity over the first ten years of the 20-year IRP. The least-cost, risk-adjusted approach proposed is a diverse portfolio of resources, including renewables, DSM, and thermal baseload and peaking units. These additions include the following portfolio additions during the planning period:

- 1,400 MW of renewable resources
- 450 MWa of DSM and 90 MW of direct load control
- 2,100 MW of baseload capacity
- 1,200 MW of peaking capacity
- 700 MW shaped resource contracts

The Action Plan details findings of resource need and specific implementation actions. The Plan also outlines step-by-step decision processes by which proposed resources will be continually evaluated and procured. Going forward, PacifiCorp will implement the Action Plan, while also maintaining the flexibility to adjust to future changes and opportunities. The Action Plan will also be revisited and refreshed no less frequently than annually.

For analytic purposes, the IRP assumes new resources are developed and owned by PacifiCorp. However, no decision has been made to invest in specific resources. The decision to own, build and invest in a new resource versus contracting with a third party will be made as part of the procurement process for each new resource addition, and on a case-by-case basis. A Multi-State Process (MSP) will provide clarity on the regulatory treatment of investment decisions and the degree of cost recovery risk held by PacifiCorp. The MSP is expected to issue findings in the spring, 2003. The MSP outcome will influence the activities and operations of PacifiCorp, and may impact Action Plan implementation.
A significant procurement program and potential investment is required to maintain reliable electric service. It is critically important that State regulators support this IRP and issue their acknowledgement of the Action Plan. This support coupled with a useful and durable MSP outcome is vital to PacifiCorp being able to resolve issues around recovery lag and achieving allowed rates of return, and continue to provide low cost, reliable service to its customers.

THE CHANGING CONTEXT FOR RESOURCE PLANNING

The electricity industry continues to evolve due to regulatory changes and market forces. The volatility and uncertainty in the industry has increased in a number of areas. Through overt public policy and an emerging industry structure, the wholesale competitive marketplace has evolved. Market price uncertainty remains a concern, as was highlighted by the dramatic volatility in West-wide electricity prices during the 2000-2001 period. Federal regulatory changes are likely to be significant, particularly with regard to how transmission will be controlled and operated in the future. Nation-wide, natural gas-fired generation has emerged as the industry’s thermal resource of choice, and this growth in the reliance on natural gas increases supply and price uncertainty. Throughout this evolution PacifiCorp’s obligation to serve remains inviolate.

These ongoing changes in the structure and regulation of the industry require changes in the approach to resource planning. Given the potential for commodity markets (both natural gas and electric) to exhibit rapid price swings, or volatility, alternative resource plans must be evaluated in terms of their exposure to this volatility, in addition to their long-run average costs. Furthermore, unpredictability in the future costs of new supply alternatives arising from fuel cost (primarily natural gas price) and emissions cost uncertainties must be recognized. Finally, the rapidly evolving structure of markets and their attendant risks demand a more timely and responsive process for keeping IRPs current. This IRP represents PacifiCorp’s efforts to adapt its resource planning to these requirements. The IRP provides analysis leading to a comprehensive portfolio and strategy for supply acquisitions, transmission investments and demand-side management that balance low cost with risk to result in the long-run least cost solution.

CURRENT POSITION

PacifiCorp serves approximately 1.5 million retail customers in service territories comprising about 135,000 square miles in portions of six Western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The service territory has diverse regional economies ranging from rural, agricultural, and mining areas to urban, manufacturing, and government service centers.

PacifiCorp forecasts load on its system to grow by 2.2% in the East and 2.0% in the West per year, on average. Given uncertainties of economic growth and other factors, this growth in PacifiCorp’s load could vary between 1.4% and 3.4%. At the same time, the resources available to PacifiCorp to serve this demand will diminish over time as supply contracts expire, hydroelectric generation facilities are subjected to relicensing conditions and thermal plants
comply with more stringent emissions requirements. This creates an imbalance that is referred to as the *gap*. This gap between loads and existing resources will grow through time.

The load forecast and the existing PacifiCorp resources define the shortfall in supplies. The figure below is an illustration of PacifiCorp’s peak system requirement with a 15% planning margin compared to the capacity of the existing resources as they are expected to exist in the future. Use of this assumption does not presume 15% is the ideal level for reliability purposes. More or less planning margin could be warranted. Rather, the assumption is consistent with the ranges discussed under the FERC Standard Market Design (SMD) proposal, and reinforced by the public input process.

**PacifiCorp System Capacity**

While the exact size of this gap is uncertain, PacifiCorp expects it will require an additional 4,000 MW of new resources (DSM, generation, and supply contracts) through 2013. Understanding the size and timing of the gap, as well as the seasonal and hourly shape of existing loads and resources, is a fundamental driver with this IRP. It drives the overall need for new resources, the appropriate balance between baseload and peaking requirements, the transmission needs and demand side management decisions.

**RISK AND UNCERTAINTY**

Clearly, resource planning must consider many future risks and uncertainties. While the need for planning under uncertainties has been clear for some time, general techniques for effectively
incorporating risk analysis into utility resource plans have been more elusive. PacifiCorp has adopted a new methodology to evaluate how alternative resource options perform against the risks and uncertainties in three categories: Stochastic, Scenario and Paradigm risks. The figure below provides an illustrative example of these risks (the acronyms are defined below).

![Risk Diagram]

**Stochastic Risks**
Many risks facing PacifiCorp are quantifiable business risks and are referred to as Stochastic risks. The expected variability in Stochastic risk parameters, such as in electricity price, for example, can be derived from historical experience and simulated. The resource planning analysis assumes that these stochastic risks are driven by uncertainty in the following parameters (risk factors):

- Retail load forecasts
- Natural gas prices
- Spot market electricity prices
- Hydroelectric generation
- Thermal unit availability

**Scenario Risks**
Other risks that are evaluated quantitatively in this IRP are scenario-driven, such as the introduction of high carbon taxes. The probability of high carbon taxes cannot be determined based upon historical experience, so a scenario is created without applying a probability. In the case of changing Scenario risks, the time evolution of the Present Value of the Revenue Requirement (PVRR) takes a distinctly different path, rather than fluctuating around an expected
value. The measure of Scenario risk is the difference between the expected PVRR generated by applying different scenarios.

Scenario risks addressed include:

- Charges for prospective CO2 emissions
- Effect of relicensing outcomes on future hydroelectric generation cost and availability
- The market value of Green Tags, as influenced by the possible passage of Federal and State renewable portfolio standards
- Limits to the availability and liquidity of spot market purchases, as an alternative to procuring resources
- Potential for ongoing renewable production tax credits

**Paradigm Risks**

Significant structural changes to the electricity business model associated with a large shift in market structure or regulatory requirements are treated as Paradigm risks in the IRP. The key Paradigm risks considered within this IRP include:

- Structural changes in operation and control of transmission promulgated by the Federal Energy Regulatory Commission (FERC) rules including potential formation of a regional transmission organization (RTO) and the SMD proposal
- Federal legislation that could establish a Renewable Portfolio Standard (RPS)
- The outcome of the pending multi-State discussions (MSP) addressing PacifiCorp’s method of regulation and cost recovery

Since the details of such changes are not presently specified, Paradigm risks do not lend themselves to quantitative analysis. Structural changes to fundamentals generally defy reasonable approaches at numerical representation. While not explicitly modeled, Paradigm risks cannot be ignored. Accordingly, Paradigm risks are addressed qualitatively. In some instances, assumptions are explicitly modeled to impute additional flexibility. Despite these efforts, Paradigm risks, as they arise, ultimately require a well reasoned response arrived at in conjunction between PacifiCorp, its regulators and the public. The flexibility to respond to changes in the Paradigm environment is an element of the Action Plan.

**ANALYTICAL APPROACH**

This IRP uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp’s existing generation and transmission assets. The model includes hourly data granularity and consideration of market trading hubs, and transmission paths and constraints, to provide a detailed examination of the economic and operational performance of resource alternatives.

The starting point for the analysis is the determination of the gap between growing loads and existing resources, discussed above. From this starting point, the analysis involves a number of distinct steps:
Executive Summary

- **Portfolio Development**: The first step is the formulation of resource portfolios. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios were chosen to span a complete range of likely resource strategies.

- **Operational Simulation**: Next, the operation of each portfolio is simulated. The simulation develops a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.

- **Cost Analysis**: Each portfolio’s system operating costs are combined with the corresponding capital costs, yielding the PVRR, the main cost metric.

- **Screening**: Performance measures (PVRR and others) are used to screen the portfolios. Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.

- **Risk Analysis & Stress Testing**: The risk analysis simulates the performance of a portfolio under a large number of possible futures. The risk analysis also allows conclusions to be drawn regarding each portfolio’s sensitivities to assumptions about the future and assessments to be made regarding the variability in a portfolio’s cost.

- **Portfolio Refinement**: Based on these results, iterative improvements to the best performing portfolios are made, defining hybrid portfolios that are tested against each other to identify the least cost, risk-adjusted portfolio.

Four key assumptions were particularly important to the analytical approach:

- Where possible, the analytical approach presumed new resources were actual specific assets. This allowed precise modeling of different site, technology and transmission costs. In practice, as seen in the Action Plan, new development will be rigorously compared to alternative purchase options and “then-appropriate” asset definitions that include current technology, specific siting and tailored asset capacity. Such a program assures new resources are ultimately obtained from the least cost provider.

- The analysis conservatively assumed no renewal of long term contracts. The modeling approach assumed future resources are obtained at market prices and that the costs of long-term contracts converge on such prices. From an economic and modeling standpoint further distinctions are unnecessary.

- Since PacifiCorp has a well-defined obligation to serve load, only firm transmission was included to ensure that it was always available to provide service. This is another conservative assumption matching PacifiCorp’s load serving obligations.

- All portfolios were built to closely match load growth, plus a 15% planning margin. While the model assumed system sales occur for balancing purposes, new resources were not added for merchant purposes.

Modeling was performed on a system basis. Although the transfers between the East and West systems were measured and reported, State specific impacts were not assessed. It is expected that these issues will be addressed in detail following the conclusion of the MSP discussions.
RESOURCE ALTERNATIVES

There are a large number of demand side and supply side options that could be used in filling the gap between PacifiCorp’s known resources and prospective load obligations. The IRP focuses on the candidate options that are considered realistic, feasible alternatives for balancing resource supply with electricity demand. Key resources that may be economical and could feasibly be procured by PacifiCorp to meet customer needs include:

- Demand side management programs
- Transmission alternatives
- New generation investment or purchase based on energy sources such as:
  - Wind
  - Coal
  - Geothermal
  - Combined heat and power (i.e., cogeneration)
  - Fuel cells
  - Natural gas (peaking and combined cycle units)
- Repowering or expanding existing PacifiCorp resources
- Market purchases and shaped products
- Transmission

Other resource technologies exist, but were not considered feasible for meeting PacifiCorp’s resource needs. These include nuclear resources, tidal action resources, micro-turbines, and others that are either not commercially available or have not yet proven to be cost effective. However, three options that are currently not being included in IRP portfolio analysis due to cost, but are being monitored closely for future use, include “clean” coal technology (IGCC), pumped storage and solar resource options.

PORTFOLIOS

To explore a broad range of possible resource mixes, portfolios were initially developed in three different categories: thermal, alternative technology and transmission. The different categories were compared to learn operational differences based on resource type under varying assumptions. Based on this analysis, several hybrid portfolios were developed by taking the best of all portfolios and combining them to achieve the least-cost solution.

Common Features of Portfolios

Several resource additions are common to all portfolios and contribute substantially to future resource requirements. All portfolios share base DSM investments, beginning in 2004 and steadily increasing their contributions. The portfolios also all include a base level of renewables resources. Initially, these were wind additions based on the level required in the proposed Federal RPS. However, in the final portfolios, the analytical approach to renewables was refined, and renewables were included based solely on the economic merits. All portfolios also include purchases to meet capacity and energy needs for the 2004-2006 period (the period in which long-term procurement options are limited).
Thermal Portfolios
The portfolios in the thermal category contain a mix of coal and natural gas additions. There were four subcategories of thermal portfolios: Diversified Gas/Coal, Diversified Coal/Gas, All Gas, and PacifiCorp Build. Each subcategory contains individual portfolios that were used to test the timing and size of resource additions.

The thermal options have good prospects for siting and licensing generation, since PacifiCorp currently controls existing thermal generation sites with room for expansion. Another benefit to the thermal portfolios is that PacifiCorp can make use of existing transmission corridors. Finally, PacifiCorp currently has experience with building, owning and operating thermal facilities. Key uncertainties associated with thermal portfolios are the impact of future environmental legislation, future natural gas price volatility, and regulatory cost recovery.

Alternative Technology Portfolios
The purpose of the Alternative Technology portfolios was to continue to test the strategy that replaced thermal plants with a more aggressive resource program focused on conservation and alternative technologies. This was accomplished by adding additional wind plants, over and above the anticipated Federal RPS, as well as geothermal plants, fuel cells, combined heat and power (CCHP) and additional DSM. Natural gas-fired plants (CCCTs and Peakers) were used to fill the energy balance and build the portfolio to the required 15% planning margin.

Alternative technology portfolios perform particularly well in reducing emissions and providing diversification in PacifiCorp’s overall resource portfolio, which helps mitigate fuel price risks. There are significant uncertainties with an aggressive renewables portfolio. The uncertainties identified include:

- Fuel cells are not a proven technology that has been widely dispersed in the utility industry.
- The size and timing of the resource addition requirement that is daunting particularly with respect to amounts of required capital component and suitable sites.
- Quality and location of potential wind sites, and associated transmission which have not been identified.
- Integration costs associated with the wind plants need additional study, including regulating margin uncertainty, balancing charges for natural gas supply, and changes in integration costs as a function of amount of wind capacity installed.
- Assumptions surrounding the Green Tags and Production Tax Credits, which also represent uncertainty.
- Specific incremental DSM programs have not been identified or modeled in these portfolios.

Transmission Portfolios
Portfolios in this category increase system transmission capability to markets and between PacifiCorp control areas and load centers. There are two subcategories of transmission portfolios: East-West Transmission and Transmission to Asset Markets. For East-West transmission, a DC line was constructed from the Wasatch front to Malin, Oregon to allow better flexibility to transfer electricity from the East and West control areas. For Transmission to Asset
Executive Summary

Markets, transmission access to markets is increased with assets built by other parties, and concentrates on building lines to southern Nevada.

Constructing a DC line that connects the East and West control areas potentially allowed for greater system flexibility and greater utilization of existing resources, and could reduce the necessary planning margin. Increased transmission access to markets would allow PacifiCorp access to markets, and reduce the capital requirement necessary to construct new plants. Major uncertainties associated with the transmission portfolios included the impact of RTO West as well as siting and permitting difficulties. Transmission should be looked at on a WECC-wide basis in order to capture further potential system wide benefits.

Hybrid Portfolios
After the initial portfolios were developed, analyzed and screened, hybrid portfolios were structured using the best characteristics of the results. Five hybrid portfolios were created – Renewable, Diversified I, Diversified II, Diversified III and Diversified IV. The Renewable portfolio was created by removing the fuel cells, CHP, and DSM from the Alternative Technology II portfolio, and adding a CCCT at Mona in 2009. The diversified portfolios were developed using the top four thermal portfolios in each sub-category (Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build), and with the gradual, profiled wind used in the Renewable and Alternative Technology II portfolios.

RESULTS AND CONCLUSIONS

The portfolios were studied and compared for their operating and economic performance, in combination with PacifiCorp’s current resources and the operational features and constraints of the electric system. This analysis yielded a large body of results. The operational results were further tested for their robustness to risks and stress tested against potential outcomes of important Scenario and Paradigm risks. The portfolios were also compared from a customer impact perspective. This analysis helped to identify the context and meaning of the portfolio studies and how they compared to each other. Through this extensive and iterative process, the least cost portfolio was identified and confirmed to perform well against risks and uncertainties.

The conclusion reached through this analysis is that Diversified Portfolio I is the least-cost, least-risk portfolio to fill PacifiCorp’s long-term resource needs. In support of this conclusion are a number of findings.

- Diversified Portfolio I produces the lowest PVRR and lowest risk profile of the portfolios studied.
- In relative terms, the portfolios are close in PVRR. The five hybrid portfolios ranged from 0.2% to 3.6% above the PVRR of Diversified I. Given the time period of the study and the large number of inputs considered, these differences could arguably be described as statistically insignificant.
- Portfolios with higher fixed costs tend to yield even greater reductions in variable cost requirements. The Diversified I portfolio has the greatest real levelized fixed cost and the least incremental net variable cost of the top portfolios.
Executive Summary

• Exposure to natural gas prices appears to be a leading contributor to the risk differences in the portfolios. The Diversified I portfolio featuring the addition of a coal plant with the earliest installation schedule has the least natural gas exposure.

• The evolution of Paradigm and Scenario risk factors could change resource decisions and warrants a plan with flexibility.

The actions related to procuring the resources identified in Diversified Portfolio I are the basis for the Action Plan.

ACTION PLAN

The Action Plan aims to ensure PacifiCorp will continue meeting its obligation to serve customers at a low cost with manageable and reasonable risk. At the same time, the Plan remains adaptable to changing course, as uncertainties evolve or are resolved, or if a Paradigm shift occurs. An element of the Action Plan is to preserve PacifiCorp’s optionality and flexibility in the future.

The Action Plan is based upon the best information available at the time the IRP is filed. It will be implemented as described, but is subject to change, as new information becomes available or as circumstances change. It is PacifiCorp’s intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. The Action Plan will also be revised as a consequence of subsequent IRPs.

Included in the Action Plan are:

• A detailed plan, including specific Findings of Need and Implementation Actions
• The Decision Processes for implementing the Action Plan
• The Procurement Program for implementing the Action Plan
• An update on PacifiCorp’s Current Procurement and Hedging Strategy
• Description of how PacifiCorp Resource Planning and Business Planning are aligned
• Discussion on the Action Plan’s consistency with the Oregon’s restructuring legislation (SB-1149)

Key elements in the Action Plan to implement Diversified Portfolio I include:

• Demand Side Management (DSM) – 450 MWa to reduce overall system demand and peak requirements
• Renewables – 1,400 MW of primarily wind resources but also potential geothermal resources
• Baseload Resources – 2,100 MW to cover load growth, plant retirement and contract expiration across the PacifiCorp system. This includes three units in the East (one fueled with coal and two with natural gas) and one natural gas unit in the West. However, PPA’s could replace the need for building assets as a result of the Decision Processes and Procurement Program for implementing the Plan
Executive Summary

- Peaking Resources – 1,200 MW in natural gas-fired units to address the pronounced system peak
- Transmission – upgrades and additions to further optimize the use of the network, provide greater access to market, and support the addition of new generating assets
- Shaped Products and Power Purchase Agreements – 700 MW to resolve immediate energy requirements prior to physical assets being built and to support optimization of the portfolio.

In implementing the Plan, all resource options will be rigorously compared to alternative purchase options either from the market or from other existing potential electricity suppliers. The Action Plan includes Decision Processes and a Procurement Program to assure new supplies ultimately are obtained from the least cost source. The proposed Procurement Program will also ensure consistency with anticipated ratemaking requirements, including industry restructuring implementation in Oregon.

PacifiCorp is seeking acknowledgement of the Action Plan by regulatory Commissions in five States. How these Commissions will treat a favorable acknowledgement of an IRP Action Plan in subsequent rate cases may vary. To accommodate potential differences in treatment of an acknowledgement, the detailed Action Plan provides both specific findings regarding the need for resources, and details the implementation actions to address the findings of need. The Findings of Need and Implementation Actions are consistent with each other and support the implementation of the Diversified Portfolio I.

This IRP provides the rationale for PacifiCorp’s resource procurement going forward. The Action Plan contemplates a potential substantial financial commitment from PacifiCorp. Sustainable cost recovery of investment is an outstanding risk that must be addressed prior to such investments being made. MSP is currently addressing this issue and is expected to issue findings in spring, 2003. The outcome of the MSP discussion will strongly influence PacifiCorp’s ability to implement this IRP Action Plan.

It is critically important that State regulatory commissions efficiently acknowledge and support this IRP, including the Action Plan. This support coupled with a useful and durable MSP outcome will enable PacifiCorp to resolve issues such as recovery lag and achieving allowed rates of return. PacifiCorp’s current and potential shareholders as well as the financial community must and will take into account the governmental and public response to the IRP when making capital allocation and investment decisions. Among other things, these decisions will depend on investors’ anticipation of successful, timely and economic recovery of this investment. A successful MSP outcome along with a Regulatory acknowledgement of this IRP, are both critical in ensuring PacifiCorp can continue to provide reliable and least-cost electric service to its customers.
1. MARKETPLACE & FUNDAMENTALS: THE CHANGING CONTEXT OF INTEGRATED RESOURCE PLANNING

The overriding objective of integrated resource planning, to develop a firm plan for the lowest cost resources for a utility and its customers, is sensible and enduring, but the practice of planning must be adaptive to changing circumstances. This chapter provides an overview of emerging trends and recent developments in PacifiCorp’s situation and in the Company’s evolving business environment that leads to the conclusion that lowest cost must be balanced with lowest risk to produce the most economic solution.

PLANNING UNDER UNCERTAINTY

The competitive marketplace in the electric power industry has grown in importance and introduced new opportunities and risks to PacifiCorp’s future supply portfolio. Future natural gas price uncertainty, in light of this fuel’s prominence in new electricity plants, contributes to a more complex and uncertain future, as does the potential for additional limits or penalties on emissions from generators. These trends and uncertainties expose PacifiCorp and its customers to new and significant risks that must be recognized in the preparation of the integrated resource plan. Although these risks cannot be eliminated, the IRP can help manage them by:

- Recommending new resource portfolios
- Guiding PacifiCorp to an appropriate margin of resources over demand
- Providing flexibility to respond to market changes

Planning was Least Cost and Deterministic

At its inception and through much of its history, conventional utility resource planning concerned itself primarily with choices among alternative supply-side resources and demand-side measures. Those choices were typically compared according to their cost implications, emphasizing lowest system cost under a limited set of future growth assumptions. The environmental impacts of choices were also quantified, principally as mass of air emissions and sometimes through imputed externality costs or emission “adders”. Typically, utilities developed non-integrated resource plans as if the utilities were isolated entities. In such analyses, utilities were assumed to build generation and implement demand-side measures to meet all of their future needs, while wholesale energy markets were largely relegated to the calculation of short-run balancing “off-system” sales and purchases, a component of electricity costs.

Planning Must Recognize Risks and Markets

This least-cost and deterministic planning was entirely consistent with most utilities’ operating and development practices and reflected the state of the industry through its history. This after-the-fact treatment of the wholesale marketplace in resource planning is increasingly untenable for several reasons.

First, through overt public policy and emerging industry structure, the competitive marketplace has emerged as a primary source of new supply for utilities.
Second, the current state of policy and market structure still leaves substantial uncertainties in the marketplace. The 2000-2001 experience in western electricity markets amply demonstrated issues of supply reliability and extreme price volatility in the marketplace.

Third, gas-fired generation has emerged as the resource of choice for the U.S. electricity industry. The reliance on natural gas has grown to such an extent that the adequacy of supply and volatility in price for gas is the major contributor to supply adequacy and price volatility for electricity. Equally, the growth in electricity generation’s demand for natural gas adds to price uncertainty and volatility for gas markets.

The sections below examine these marketplace issues and experiences. (For a more extensive discussion of the history of electricity industry regulation and the emerging structure of the industry, see Appendix A.)

GROWING PROMINENCE OF THE ENERGY MARKETPLACE

The electricity industry market environment changed greatly in the last several years. Evolving federal policy and many state regulatory initiatives are encouraging competitive markets and a growing independent supply sector. Many states are also experimenting with or instituting retail competition.

Federal Regulation Directs Movement to Market

Over the last 10 years, the Federal Energy Regulatory Commission (FERC) has been the primary locus of federal policy developments for the electricity industry. The Energy Policy Act of 1992 set federal policy direction to encourage robust competition in wholesale electricity markets. Following its introduction of service unbundling and competitive forces to natural gas pipeline regulation, the FERC turned its attention to transmission with its Order 888 implementing open access. FERC’s Order 2000 moved further in the direction of orienting transmission to serving a competitive electricity market by encouraging regional transmission organizations (RTOs). Most recently, with its July 2002 notice of proposed rulemaking on a standard market design (SMD), the FERC underscored its intentions to develop a competitive wholesale market and to clarify the rules under which markets should operate. With these regulatory initiatives, federal policy has encouraged new players to participate in wholesale electricity markets. At the same time the FERC has concluded that, where effective competitive markets operate, wholesale prices can be set by market forces rather than by traditional cost of service regulation. Similarly, since 1992 and FERC Order 636, prices for natural gas commodity and bulk natural gas transmission have been deregulated.

Merchant Generators and Power Marketers

In parallel to these policy and regulatory developments, a new electricity industry segment has evolved and grown to supply traditional utilities or load-serving entities. These non-utility

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suppliers include cogenerators, small electricity producers, independent electricity producers, merchant generators and power marketers. Power marketers and merchant generators, in particular, have gained prominence in recent years. Power marketers, who buy and sell electricity as independent intermediaries, grew their U.S. sales from 27 million MWh in 1995 to 2,700 million MWh in 1999. Merchant generators grew into the role of acquiring, developing and owning power plants and marketing their output, often on a speculative basis.

Growth of the merchant sector of the electricity industry and increasing public policy emphasis on a competitive supply sector throughout the 1990s led a number of states to question whether traditional utilities should continue to build or acquire new resources to meet their customers’ needs. Some have suggested that, instead, utilities should procure new resources from a competitive wholesale market. This philosophy is supported by experience in other restructured industries where competitive markets encourage both innovation in services and lower long-run costs. In this spirit, some states encouraged or required utilities to rely on the marketplace, even going so far, as in the case of California, requiring incumbent utilities to divest generating assets. In Oregon, the adoption of restructuring legislation and rules requires the revenue requirement from any new generating resources to be based on market prices rather than the traditional rate-basing of costs.

**New Risks for Traditional Utilities**

Load-serving-entities including PacifiCorp are now subject to new risks. What if independent electricity producers do not build enough supply? For years, utilities in the Pacific Northwest (PNW) planned their new resource needs around the concept that there should be enough resource to cover loads even under periods of extreme drought. New merchants may not develop resources to this level. If not, what happens if a drought then occurs? It is also possible that independent electricity producers will, at times, over-supply the market driving wholesale electricity prices below levels that recover investment costs. What if PacifiCorp develops new resources, only to find their costs higher than purchases from a temporarily depressed market? Will recovery of these “above market costs” be assured?

The potential for competitive supply markets to deliver innovation and lower costs is still being tested. However, given the fluid and evolving nature of wholesale markets, they potentially increase the risk of market price uncertainty and volatility. Recent experience in western wholesale markets underscores this risk.

**RECENT EXPERIENCE IN THE WESTERN ENERGY MARKETPLACE**

**The Electricity Supply Crisis**

The reality of new risks in the competitive marketplace became painfully clear in the WECC electricity crisis of 2000 and 2001. In the prior decade, little new generation had been installed in the region, in relation to demand growth. A severe shortage of supply became apparent in May 2000. Later in the year, a rare severe Westwide drought significantly reduced WECC hydrogeneration resources. With prices set by the market rather than by regulation based on cost of supply, wholesale electricity prices rose to unprecedented levels, perhaps in part due to alleged market manipulation. To compensate for the hydrogeneration energy shortage,
inefficient gas-fired generation (normally not expected to run) was operated often around the
clock. This occurred at the same time that natural gas markets were experiencing their own
strains.

The Natural Gas Shortage
Natural gas prices nationwide rose dramatically in 2000, reaching record levels in early 2001
before receding in the summer. This extraordinary run-up was caused by several factors.
Relatively stagnant gas production for several preceding years was masked by a series of mild
winter heating seasons. This imbalance was brought to a head by healthy gas demand growth in
2000. The imbalance led to low levels of gas storage entering into the 2001 heating season.
Storage resources quickly became strained by exceptionally cold weather in November and
December. The time lag between higher gas prices and the increased drilling and production
meant very high prices would endure through and beyond the heating season. Supplies and
prices were strained even further during this time by pipeline constraints into and within
California.

The skyrocketing prices for natural gas plus limited hydro generation forced up spot electricity
prices in all western markets. In addition, many of the inefficient gas-fired generation resources
did not have sufficient emissions credits to cover their operation. Further increasing the price of
spot electricity, the shortage of credits caused the price for any available credits to skyrocket.

Meltdown of the California Market
California’s market structure also took its toll on electricity markets entering 2001. Since retail
prices for the two largest utilities in the state (Southern California Edison and Pacific Gas and
Electric) were capped while their supply costs were skyrocketing, a severe cash drain occurred.
Competitive suppliers demanded price premiums to compensate for increased credit risk. In
addition, the utilities withheld payments to some of their suppliers under direct electricity supply
contracts (such as Qualifying Facilities (QF)) to preserve cash. In the face of extraordinary
natural gas prices and no income, many QFs shut down generation, exacerbating the resource
shortfall.

Further Blow to PacifiCorp
For PacifiCorp, the impact of these events was compounded by an unusual extended forced
outage of its 430 MW Hunter 1 unit beginning on November 24, 2000 in PacifiCorp’s eastern
control area. This outage left PacifiCorp in a position of having to purchase electricity from the
market to make up for the lost generation at just the time that market prices were at their highest.
Moreover, PacifiCorp’s eastern control area has limited access to major market points in the
western system due to transmission constraints to the south and west. This left PacifiCorp
exposed to markets that were potentially higher cost and more volatile than prevalent elsewhere
in the west due to an absence of depth and liquidity.

End of the Crisis
Electricity prices began to drop rapidly from their unprecedented highs in June 2001. The
dominant factor was a series of orders aimed at mitigating the potential for market power and
reining in runaway prices issued by the FERC, especially the Price Cap order of June 19, 2001.
Market fundamentals after June 19th, combined with a decline in the demand for electricity kept 2001 spot prices low as the cap held down forward prices. Demand declined significantly in 2001 compared to the previous year, due to the economic slowdown, substantial conservation efforts by utilities and their customers, the reaction to higher prices in consumption decisions, and a fortuitously mild summer. Similar factors also helped ease natural gas demand while gas production rebounded, combining to bring gas prices down dramatically. New generation resources coming on line in the western system also helped restore reserve margins. As a result of all of these factors, by the middle of summer 2001, prices had retreated to levels 10% or less of what had been expected only months earlier. The extreme natural gas and electricity price volatilities over this period are illustrated in Figures 1.1 and 1.2.

**Figure 1.1 Electricity Price Volatility**

Electricity Prices from 2000-2001

**Figure 1.2 Natural Gas Price Volatility**

Spot Natural Gas Prices from 2000 to 2001

**Boom and Bust**

Another aspect of uncertainty and volatility in electricity markets is portended by recent history in the WECC. The potential has emerged for a boom and bust cycle in electricity markets due to the cyclic addition of new generation. Between 1990 and 2000, less than 10,000 MW of new generating capacity was added to the WECC system. In contrast, more than 15,000 MW have been added in the 2000-2002 period, and an additional 16,000 MW of capacity are under construction in the WECC. Moreover, almost 95% of this new capacity is gas-fired. This wave of capacity additions is rapidly shifting WECC markets from a very tight (low reserve margin) to an over-supplied (high reserve margin) condition, probably for a number of years.

Two major consequences of this wave of new generation in the WECC are likely. First, electricity prices are expected to be depressed during the impending period of over-supply. Depressed prices discourage new construction and potentially set up another cycle of under- and over-supply. Second, gas-fired generation will now be the marginal resource and set spot market price in most peak hours. This ties WECC electricity prices inextricably to natural gas prices and their attendant uncertainty and volatility.
Retrenchment in Merchant Power
Another recent electricity market trend has arisen from the events described above. That trend is the remarkable retrenchment of the merchant electricity sector in the wake of the construction boom and wholesale electricity price volatility. As a result of an overhang of debt, credit problems, and other financial duress, a number of large energy merchants have reduced or eliminated their energy trading activities. Others have been forced to scale back their generation project developments, suspend construction, or dispose of assets. Lenders and rating agencies have recently questioned the entire merchant generation business model. This will reduce the depth and liquidity of energy commodity markets in the near term. In the long term it could impede the ability of existing merchant generators to provide additional generating capacity just as it impedes the entrance of new merchant generators. This decline of merchant generators underscores the need for capacity commitments from traditional utilities, either through longer-term forward contracts or their own resource development, and less exposure to volatile, short-term commodity markets to meet customers’ needs.

NATURAL GAS SUPPLY ISSUES
North America is supplied by a large and diverse set of natural gas producers operating in a number of geographically dispersed producing regions tied together by an extensive pipeline network. As electricity generation increasingly relies on natural gas as a fuel, two issues deserve attention. First, declines in production from mature producing regions are forcing producers to turn to frontier regions for new supplies. This raises the prospect of an upward trend in natural gas costs. Second, the supply-and-demand dynamics of natural gas portend continued volatility in gas prices, especially when little spare production capacity is evident on the horizon.

Currently, mature producing areas (onshore and shallow water Gulf of Mexico and the mid-continent including the Permian Basin) account for about two-thirds of U.S. domestic gas production. Experience of the last five years demonstrates two factors that suggest growth in productive capacity from these areas should not be expected. First, drilling rig productivity (first year production per operating rig) is declining significantly. Second, the loss in annual deliverability from older wells is accelerating. Production in the Western Canadian sedimentary basin is beginning to exhibit these same tendencies.

Dynamics within the natural gas industry may cause the number of drilling rigs, production, investment, and prices to become more volatile. The dynamics that increase the likelihood of volatile behavior include the responsiveness of supply and demand to changes in gas prices and the declining productivity of new wells.

Price Response in Natural Gas
In the short run, natural gas supply is fairly inelastic – in other words, the quantity supplied does not respond quickly to price changes. However, short-run demand is more responsive to changes in price and weather. The supply and demand dynamics and the ensuing abundance or scarcity

of production can lead to extreme fluctuations in short-run prices. Natural gas supply and demand has historically been more elastic in the long run. Therefore, large price fluctuations will eventually result in significant changes in consumption, producer cash flows and investment, and drilling activity. Typically, the delay between the onset of a price increase and the consequent increase in natural gas production is six to eighteen months. The average lag between a price decrease and the corresponding drop in production is seven months.

**Declining Productivity**
Declining production from new natural gas wells is an additional factor that impacts long-run price volatility. Between 1990 and 1999, the amount of time that passed before a well produced half its life time volume declined by 40%. Declining productivity and the consequent increase in drilling costs will leave investment and production more responsive to price changes. Incorporating random events into this potentially volatile market makes extreme fluctuations in price, investment and production more likely.

One firm, prominent in the analysis of natural gas markets, concludes the following from these trends:

*On the supply side, the North American gas industry essentially can move in two directions. One would be to accelerate efforts to bring capital-intensive frontier gas resources into the market. Another would be to push forward the rapid expansion of liquefied natural gas (LNG). In either case, we envision a period when the North American gas industry will be hard-pressed to adjust domestic supply in a timely response to volatile shifts of demand. The past year’s gas price spikes to $10 and below $2/MMBtu were no fluke, but instead they reflected this emerging supply/demand conflict.*

**FUTURE EMISSION COMPLIANCE ISSUES**

Over the next decade, PacifiCorp faces a changing environment with regard to electricity plant emission regulations. The exact nature of these changes remains uncertain. Within the current federal political environment there exists a contentious debate over establishing a new energy policy and consequently, revising the Clean Air Act (CAA) to reduce overall emissions. Currently, the debate focuses on emission standards and compliance measures for sulfur dioxide (SO₂), nitrogen oxides (NOₓ), mercury (Hg), and carbon dioxide (CO₂). Several proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level. A variety of existing and proposed requirements including multi-pollutant legislation, EPA’s Regional Haze Rule, the Western Regional Air Partnership effort, and the Kyoto Protocol or alternative greenhouse gas emissions restrictions will further shape PacifiCorp’s emission requirements over the coming decade.

Currently, PacifiCorp’s generation units must comply with the Clean Air Act Amendments (CAAA) of 1990, which established standards for SO₂ and NOₓ, and addressed a variety of toxic gasses. The CAAA also addressed PM₁₀ (particulate matter smaller than 10 microns in size), but

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the standards have since been revised to include PM$_{2.5}$. Should standards under the current CAAA remain as is, future compliance costs would be relatively easy to estimate.

However, new federal proposals point to future changes. Specifically, proposed federal multi-pollutant legislation outlines changes in emission standards and compliance for SO$_2$ and NO$_x$, and establishes new definitive standards for mercury. The compliance costs associated with these future scenarios will largely depend on the levels of required reductions, the allowed compliance mechanisms, and the compliance time frame.

The Bush Administration’s *Clear Skies Act (CSA)* is the less stringent of the legislative proposals, with a cap-and-trade system for SO$_2$, NO$_x$, and mercury and changes to new-source-review (NSR). CSA standards to reduce emissions would be established in two phases, starting in 2010 and 2018.

*Senate Bill S. 556 (Clean Power Act)*, introduced by Senator Jeffords (I-VT), is the more stringent proposed legislation, with lower annual emission caps for SO$_2$ and mercury than CSA, and an emission cap for CO$_2$. All caps would apply starting in 2008. CPA also utilizes a cap and trade system for all emissions except mercury.

*The Clean Air Planning Act of 2002* introduced by Senators Carper (D-DE), Lincoln Chafee (R-RI), John Breaux (D-LA), and Max Baucus (D-MT) sets emission caps for SO$_2$, NO$_x$, Hg and CO$_2$ that are more moderate than the Jeffords’s proposal and more stringent than the President’s CSA.

**IMPLICATIONS OF MARKET DEVELOPMENT AND FUNDAMENTAL TRENDS**

PacifiCorp and its customers are exposed to commodity markets that are likely to exhibit continued uncertainty and volatility. The uncertainty of future environmental costs and constraints also weigh heavily on future supply costs. Although the risks from exposure to these uncertainties cannot be eliminated entirely, prudent choice of new resources and the appropriate margin of resources in relation to demand can help to manage these risks.

One conclusion from the 2000-2001 market turmoil is that there is a clear asymmetry to market risks. On the high side, prices can increase rapidly under market shortage conditions, with limits set only by the perceived damage costs of shortages or by backstop caps set by regulation. Utilities with insufficient resources (those that are physically short electricity, in the parlance of commodity traders) are exposed to the risks of these spikes.

On the low price side, when markets have an overabundance of supply, wholesale market prices can fall not only below long-run replacement costs, but even below the short-run marginal cost of generation. Under these conditions, utilities or energy merchants who have excess of resources (have a long position) are exposed to the risk of not recovering their fixed costs in the market.

While significant, the low-side risk of a long position pales in comparison to the risk of a chronically short physical position. In general, neither an extremely long nor short position is
desirable. A balanced position with sufficient planning margin so as to avoid physical short exposure to markets is prudent. While there is no silver bullet, as a prudently-run utility, PacifiCorp can manage the risk of commodity market exposure, in large measure, by planning and acting to maintain an adequate reserve margin. This broad conclusion is consistent with the FERC’s Standard Market Design (SMD) proposal, which suggests that utilities be required to own or contract forward for resources sufficient to maintain an adequate planning reserve margin.

The exposure to fuel prices (for coal and natural gas) and environmental cost risks is no less complex. New gas-fired generation can help to mitigate future emission cost uncertainties, but exposes the supply portfolio to gas price volatility. New coal-fired generation avoids the fuel price volatility of gas but further exposes the supply portfolio to emission cost risks. Both demand-side management and renewable resources can avoid emission and fuel price exposures, but it is not clear how much of PacifiCorp’s future resource requirements can be met from these sources.

There are no simple answers to these aspects of PacifiCorp’s complex business environment. At the same time, these trends and uncertainties do provide clear direction to PacifiCorp’s integrated resource planning.

THE NEW IRP IMPERATIVES

Changes in the structure and regulation of the electricity industry require changes in the approach PacifiCorp takes to integrated resource planning. Given the potential for commodity markets (both gas and electric) to exhibit rapid price swings (volatility), alternative resource plans must be evaluated in terms of their exposure to price volatility, in addition to their long-run average costs. Furthermore, unpredictability in the future costs of new supply alternatives arising from gas price and emissions cost uncertainties must be recognized. Finally, the rapidly evolving structure of markets and their attendant risks demand a more timely and responsive process for keeping resource plans current. This plan represents PacifiCorp’s efforts to adapt IRP to these new requirements.

Fortunately, the emerging electricity industry structure presents opportunities as well as risks. Over time, a deep and liquid market for electricity and transmission increases the opportunity to acquire resources with differing terms, structures, and points of delivery. Moreover, new products will be offered by market participants to hedge or manage risks.

These risks and opportunities place new demands on PacifiCorp’s IRP methods and processes. The analytical approach behind this IRP moves towards addressing those demands. Improvements incorporated into this IRP include a simulation approach that allows the performance of resource portfolio alternatives to be compared over a number of possible future conditions. This methodology provides an examination of both the expected future costs and the risks of future outcomes. It also allows an examination of the tradeoff between cost and risk inherent in resource planning choices. This is in contrast to PacifiCorp’s recent IRPs, in which a point-estimate optimization method was used to develop plans tuned to a few specific future
cases. This IRP also emphasizes portfolios of resources, since a diverse portfolio is a well-known means of managing risks.

**CONCLUSION**

As described in this chapter, the competitive energy market presents PacifiCorp with the prospect of continued price volatility and risk, and significant uncertainty affecting future resources. Although the risks from exposure to these uncertainties cannot be eliminated, the IRP will help to identify and manage these risks through the choice of new resources and by guiding PacifiCorp to an appropriate margin of resources over demand. This Integrated Resource Plan provides analysis leading to a comprehensive portfolio and strategy for PacifiCorp supply acquisition that balances low cost with risk.
2. CURRENT POSITION

OVERVIEW

The regulated PacifiCorp is divided into (1) the transmission company and (2) the generation, wholesale and distribution company. Functionally, the PacifiCorp integrated system is made up of three functional service components or sectors: generation, transmission, and distribution. The generation sector is the production arm of the business. The transmission sector can be thought of as the interstate highway system of the business; the large high voltage lines that deliver electricity from electricity plants to local areas. The distribution sector can be thought of as the local delivery system; the relatively low voltage electricity lines that bring electricity to homes and businesses, constituting loads.

PacifiCorp forecasts load on its system to grow by 2.2% in East and 2.0% in West per year, on average over the next 20 years. Given uncertainties of economic growth and other factors, this growth in PacifiCorp’s load could vary between 1.4% and 3.4% over the forecast period (see Appendix C for more details.) In contrast, PacifiCorp’s resources available to serve demand will likely diminish over time as plants retire, certain contracts expire, hydro facilities are subjected to relicensing conditions and thermal plants comply with more stringent emissions requirements. This creates an imbalance that is referred to herein as the “Gap”. This Gap between loads and existing resources grows through time. The Gap is expected to be large and strategically important.

While the exact size of this Gap is uncertain, PacifiCorp expects it will require approximately 4,000 MW of new resources (see Chapter 5 for an overview of new resources alternatives) through 2013. Understanding the size and timing of the Gap, as well as the seasonal and hourly shape of existing loads and resources, will help PacifiCorp choose the best new resources to fill this need. Similarly, an understanding of the transmission limitations linking the East and West control areas, and the resource needs facing the two control areas will help the company understand how the Gap grows and its relative shape in both areas.

Service Territory

PacifiCorp serves approximately 1.5 million retail customers in service territories aggregating about 135,000 square miles in portions of six Western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The service area’s diverse regional economies range from rural, agricultural, and mining areas to urban, manufacturing, and government service centers. No one segment of the economy dominates, which helps mitigate exposure to economic swings.

In the Eastern portion of the service area, Wyoming and Eastern Utah, the main industrial activities are mining: extracting coal, oil, natural gas, uranium, and oil shale. In the Western part of the service territory, mainly consisting of Oregon and southeastern Washington, the economy generally revolves around agriculture and manufacturing, with pulp and paper, lumber and wood products, food processing, high technology, and primary metals being the largest industrial sectors.
The geographical distribution of PacifiCorp’s retail electric customers is Utah, 650,445; Oregon, 496,226; Wyoming, 120,676; Washington, 118,363; Idaho, 55,813; and California, 41,891.

**Figure 2.1 PacifiCorp Service Area**

**PacifiCorp Retail Load**

In fiscal year 2002, PacifiCorp sold 47,527 Gigawatt-hours (GWh) of electricity to retail consumers in its service territory. This included 19,611 GWh of sales to industrial loads, 13,810 GWh of sales to commercial loads, and 13,395 GWh of sales to residential loads. As a result of the geographically diverse area of operations, PacifiCorp's service territory has historically experienced complementary seasonal load patterns. In the Western portion, customer demand peaks in the winter months due to heating requirements. In the Eastern portion, customer demand peaks in the summer when irrigation and cooling systems are heavily used.

At the current time, no single retail customer accounts for more than 1.4% of PacifiCorp’s retail utility revenues and the 20 largest retail customers account for 13.8% of total retail electric revenues.
Wholesale Load
In fiscal year 2002, PacifiCorp sold 24,438 GWh of electricity to wholesale customers in the WECC. These sales included:

- Requirement sales
- Long term firm sales (greater than five year)
- Short term firm sales
- Long term unit contingent sales
- Non-firm sales

PacifiCorp has not included any new wholesale electricity sales in its load forecast. The regulated arm of PacifiCorp does not intend to build or acquire electricity supplies for the purpose of making new wholesale electricity sales. However, in the day-to-day operation of its electricity supplies against its retail load, PacifiCorp will make sales into (and purchases from) the broader WECC wholesale market as economics dictate.

RESOURCES

Demand Side Management (DSM) Programs
PacifiCorp has been operating DSM programs for many years. Following is a summary of these DSM program accomplishments for the last 10 years.

Previous PacifiCorp IRP (RAMPP - Resource & Market Planning Program) annual DSM system MWa goals acknowledged by the utility commissions have been regularly exceeded.

Table 2.1 Approved DSM Programs

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Goal MWa</th>
<th>Actual MWa</th>
<th>Actual Costs ($ MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1992</td>
<td>8.50</td>
<td>8.57</td>
<td>NA</td>
</tr>
<tr>
<td>1993</td>
<td>12.92</td>
<td>15.04</td>
<td>32.7</td>
</tr>
<tr>
<td>1994</td>
<td>15.29</td>
<td>20.79</td>
<td>34.3</td>
</tr>
<tr>
<td>1995</td>
<td>29.90</td>
<td>30.59</td>
<td>29.9</td>
</tr>
<tr>
<td>1996</td>
<td>23.09</td>
<td>24.11</td>
<td>16.5</td>
</tr>
<tr>
<td>1997</td>
<td>15.44</td>
<td>17.33</td>
<td>6.5</td>
</tr>
<tr>
<td>1999</td>
<td>9.00</td>
<td>12.19</td>
<td>7.2</td>
</tr>
<tr>
<td>2000</td>
<td>9.00</td>
<td>14.03</td>
<td>7.9</td>
</tr>
<tr>
<td>2001</td>
<td>16.51</td>
<td>16.67</td>
<td>21.9</td>
</tr>
</tbody>
</table>
Table 2.2 DSM Programs Operating During 2002

<table>
<thead>
<tr>
<th>DSM Program Name</th>
<th>Description</th>
<th>Availability (* programs under evaluation)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy FinAnswer (Schedule 125, enhanced with incentives)</td>
<td>Engineering &amp; incentive package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial, and irrigation.</td>
<td>OR, WA, UT</td>
</tr>
<tr>
<td>Lighting Retrofit Incentive (Schedule 116)</td>
<td>Incentives for energy-efficient lighting retrofit projects in commercial and industrial facilities greater than 20,000 sq. ft.</td>
<td>OR, WA, UT</td>
</tr>
<tr>
<td>Small Retrofit Incentive (Schedule 115)</td>
<td>Incentives for energy-efficient retrofit projects in commercial and industrial facilities less than 20,000 sq. ft.</td>
<td>OR, WA, UT</td>
</tr>
<tr>
<td>Energy FinAnswer (engineering and loan program; schedules vary by state)</td>
<td>Engineering &amp; financing package for improved energy efficiency in new construction and retrofit projects. Commercial, industrial and irrigation.</td>
<td>WY, ID, CA</td>
</tr>
<tr>
<td>Appliance Recycling Program</td>
<td>An incentive program designed to remove inefficient refrigerators from the market.</td>
<td>ID*, UT*, WA*</td>
</tr>
<tr>
<td>Compact Fluorescent Light Bulb Program</td>
<td>Two free CFLs are offered to residential customers through direct mail offer. Provides immediate savings benefits and encourages CFL use.</td>
<td>ID*, WY*</td>
</tr>
<tr>
<td>Enhanced Audit and Weatherization Program</td>
<td>Residential In-home audit with customer choice of low interest loan or 25% rebate to assist in funding of cost effective recommended measures. Instant savings measures were added to legislatively mandated audit in mid-2000 in order to “enhance” the offer, improving cost effectiveness of program, providing for instant savings and increasing participation.</td>
<td>OR</td>
</tr>
<tr>
<td>Utah Residential and Small Commercial A/C Load Control Program</td>
<td>Turn-key load control network financed, built, operated and owned by a third party vendor through a pay-for-performance contract.</td>
<td>UT*</td>
</tr>
<tr>
<td>Low-Income Weatherization Program</td>
<td>The Company partners with community action agencies to provide no cost residential weatherization services to income qualifying households.</td>
<td>CA, ID, WA</td>
</tr>
<tr>
<td>Do-It-Yourself Home Audit</td>
<td>A residential fuel blind do-it-yourself home energy audit. Customers fill out the form and send it in, company generates a report of cost-effective recommendations and mails to customer.</td>
<td>CA, ID, OR, UT, WA, WY</td>
</tr>
<tr>
<td>Do-It-Yourself Web based audit</td>
<td>Residential and small commercial web based energy audit. Fill in the audit information and program provides an energy analysis of your home or business. Fuel blind audit.</td>
<td>Pilot in WA and possibly UT.</td>
</tr>
<tr>
<td>BPA Conservation and Renewable Discount Program</td>
<td>Credits received against our BPA electricity purchases for incremental energy efficiency and renewable investments. Strategy will be created on how best to leverage these dollars to best benefit the company and the communities we serve. About $2M annually through 2006.</td>
<td>OR*, WA*, ID*</td>
</tr>
<tr>
<td>Energy Efficiency Education – Bright Ideas Booklet</td>
<td>Published booklet featuring residential energy use and efficiency information that is mailed to customers upon request. Available in English and Spanish.</td>
<td>CA, ID, OR, UT, WA, WY</td>
</tr>
<tr>
<td>Low Income Energy Education Services</td>
<td>Provide qualifying customers energy education and do-it-yourself instruction on how to reduce energy costs and minimal direct install assistance to qualifying senior citizens.</td>
<td>OR – Portland Area only</td>
</tr>
<tr>
<td>Efficient Air Conditioning Program</td>
<td>Provide customer incentives for improving the efficiency of air conditioning equipment and/or maintaining or converting air conditioning equipment to evaporative cooling technologies.</td>
<td>UT*, WA*</td>
</tr>
<tr>
<td>Energy Education to Schools</td>
<td>Provide classroom instruction to grade school and intermediate students on energy education.</td>
<td>WA, Lower Yakima Valley Schools</td>
</tr>
<tr>
<td>Low Income Conservation</td>
<td>Energy education and conservation measure installation services to a minimum of 550 households annually over a 3 year period (beginning FY 2001). Estimated savings per home 1,636 KwH.</td>
<td>UT</td>
</tr>
<tr>
<td>Northwest Energy Efficiency Alliance (NEEA)</td>
<td>A series of conservation programs sponsored by utilities in the region designed to support market transformation of energy efficient products and services in OR, WA, ID. Programs include manufacturer rebates on compact fluorescent bulbs to building operator training courses</td>
<td>WA, ID</td>
</tr>
</tbody>
</table>
### DSM Program Name

<table>
<thead>
<tr>
<th><strong>DSM Program Name</strong></th>
<th><strong>Description</strong></th>
<th><strong>Availability</strong> (* programs under evaluation)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial Retro Commissioning</td>
<td>Pilot program designed to work with customers to re-commission the operation of their commercial buildings consistent with the building was designed to operate.</td>
<td>UT*</td>
</tr>
</tbody>
</table>

### Supply Side Resources

PacifiCorp owns or has interests in generating plants with an aggregate plant net capability of 7,920 MW. With its present generating facilities, under average water conditions, approximately 6% of PacifiCorp’s energy requirements for 2003 would be supplied by its hydroelectric plants, 66% by its thermal plants, and the balance of 28% would be obtained under long-term purchase contracts, exchange and other purchase arrangements.

### Hydro

PacifiCorp’s hydroelectric portfolio consists of 53 generating plants, with a capacity of 1,119 MW. Ninety-seven percent of the installed capacity is regulated by FERC through 20 individual licenses. These projects account for about 13% of PacifiCorp’s total generating capacity and provide operational benefits such as peaking capacity, generation, spinning reserves and voltage control.

Nearly all of PacifiCorp’s hydroelectric projects are in some stage of relicensing under the Federal Power Act (FPA). The relicensing process is a public regulatory process that involves controversial resource issues. In granting the new licenses, FERC is expected to impose conditions designed to address the impact of the projects on fish and other environmental concerns. In addition, under the FPA and other laws, the state and federal agencies and tribes have mandatory conditioning authorities that give them significant influence and control in the relicensing process. It is difficult to determine the economic impact of these mandates, but capital expenditures and operating costs are expected to increase in future periods while electricity losses may result due to environmental and fish concerns. As a result of these issues, for example, PacifiCorp has analyzed the costs and benefits of relicensing the Condit Dam and has agreed to remove the Condit Dam at a cost of approximately $17 million.

### Thermal

PacifiCorp also owns or has interests in 18 thermal-electric generating plants with an aggregate nameplate rating of 7,289 MW and plant net capability of 6,769 MW.

During 2001 and 2002, PacifiCorp leased gas turbine peaking generators with 95 MW capacity to provide electric generation to meet load requirements in Utah. The Company has replaced these leased gas turbine peakers at its Gadsby Plant, in Salt Lake City, Utah, with 120 MW (three 40 MW units) Company-owned gas-fired turbines. The turbines went online in late summer 2002, and are included in the thermal-electric generating plant totals listed above.

### Wind

PacifiCorp jointly owns one wind electricity generating plant at Foote Creek, Wyoming with a plant net capability of 33 MW. In addition, PacifiCorp has signed a 20-year agreement to purchase the entire output of the Rock River I wind electricity project located in Arlington, Wyoming, which has a net capacity of 50 MW. This project continues PacifiCorp’s commitment
to develop additional megawatts generated by renewable resources. Table 2.3 summarizes PacifiCorp’s existing generating facilities.

Table 2.3 Existing Generation Facilities

<table>
<thead>
<tr>
<th>HYDROELECTRIC PLANTS</th>
<th>Location</th>
<th>Energy Source</th>
<th>Installation Dates</th>
<th>Nameplate Rating (MW)</th>
<th>Plant Net Capability (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Swift</td>
<td>Cougar, WA</td>
<td>Lewis River</td>
<td>1958</td>
<td>240.0</td>
<td>263.6</td>
</tr>
<tr>
<td>Merwin</td>
<td>Ariel, WA</td>
<td>Lewis River</td>
<td>1932-1958</td>
<td>135.0</td>
<td>144.0</td>
</tr>
<tr>
<td>Yale</td>
<td>Amboy, WA</td>
<td>Lewis River</td>
<td>1953</td>
<td>134.0</td>
<td>134.0</td>
</tr>
<tr>
<td>Five North Umpqua Plants</td>
<td>Toketee Falls, OR</td>
<td>N. Umpqua</td>
<td>1949-1956</td>
<td>133.5</td>
<td>137.5</td>
</tr>
<tr>
<td>John C. Boyle</td>
<td>Keno, OR</td>
<td>Klamath River</td>
<td>1958</td>
<td>80.0</td>
<td>84.0</td>
</tr>
<tr>
<td>Copco Nos. 1 and 2 Plants</td>
<td>Hornbrook, CA</td>
<td>Klamath River</td>
<td>1918-1925</td>
<td>47.0</td>
<td>54.5</td>
</tr>
<tr>
<td>Clearwater Nos. 1 and 2</td>
<td>Toketee Falls, OR</td>
<td>Clearwater</td>
<td>1953</td>
<td>41.0</td>
<td>41.0</td>
</tr>
<tr>
<td>Grace</td>
<td>Grace, ID</td>
<td>River</td>
<td>1914-1923</td>
<td>33.0</td>
<td>33.0</td>
</tr>
<tr>
<td>Prospect No. 2</td>
<td>Prospect, OR</td>
<td>Bear River</td>
<td>1928</td>
<td>32.0</td>
<td>36.0</td>
</tr>
<tr>
<td>Cutler</td>
<td>Collington, UT</td>
<td>Rogue River</td>
<td>1927</td>
<td>30.0</td>
<td>29.1</td>
</tr>
<tr>
<td>Oneida</td>
<td>Preston, ID</td>
<td>Bear River</td>
<td>1915-1920</td>
<td>30.0</td>
<td>28.0</td>
</tr>
<tr>
<td>Iron Gate</td>
<td>Hornbrook, CA</td>
<td>Bear River</td>
<td>1962</td>
<td>18.0</td>
<td>19.5</td>
</tr>
<tr>
<td>Soda</td>
<td>Soda Springs, ID</td>
<td>Klamath River</td>
<td>1924</td>
<td>14.0</td>
<td>14.0</td>
</tr>
<tr>
<td>Fish Creek</td>
<td>Toketee Falls, OR</td>
<td>Bear River</td>
<td>1952</td>
<td>11.0</td>
<td>12.0</td>
</tr>
<tr>
<td>33 Minor Hydroelectric Plants</td>
<td>Various</td>
<td>Fish Creek</td>
<td>1896-1990</td>
<td>89.3*</td>
<td>89.1*</td>
</tr>
</tbody>
</table>

SUBTOTAL (53 HYDROELECTRIC PLANTS) | 1,067.8 | 1,119.3 |

<table>
<thead>
<tr>
<th>THERMAL ELECTRIC PLANTS</th>
<th>Location</th>
<th>Energy Source</th>
<th>Installation Dates</th>
<th>Nameplate Rating (MW)</th>
<th>Plant Net Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jim Bridger</td>
<td>Rock Springs, WY</td>
<td>Coal-Fired</td>
<td>1974-1979</td>
<td>1,541.1*</td>
<td>1,413.4*</td>
</tr>
<tr>
<td>Huntington</td>
<td>Huntington, UT</td>
<td>Coal-Fired</td>
<td>1974-1977</td>
<td>996.0</td>
<td>895.0</td>
</tr>
<tr>
<td>Dave Johnston</td>
<td>Glenrock, WY</td>
<td>Coal-Fired</td>
<td>1959-1972</td>
<td>816.8</td>
<td>762.0</td>
</tr>
<tr>
<td>Naughton</td>
<td>Kemmerer, WY</td>
<td>Coal-Fired</td>
<td>1963-1971</td>
<td>707.2</td>
<td>700.0</td>
</tr>
<tr>
<td>Hunter 1 and 2</td>
<td>Castle Dale, UT</td>
<td>Coal-Fired</td>
<td>1978-1980</td>
<td>727.9*</td>
<td>662.5*</td>
</tr>
<tr>
<td>Hunter 3</td>
<td>Castle Dale, UT</td>
<td>Coal-Fired</td>
<td>1983</td>
<td>495.6</td>
<td>460.0</td>
</tr>
<tr>
<td>Cholla Unit 4</td>
<td>Joseph City, AZ</td>
<td>Coal-Fired</td>
<td>1981</td>
<td>414.0*</td>
<td>380.0*</td>
</tr>
<tr>
<td>Wyodak</td>
<td>Gillette, WY</td>
<td>Coal-Fired</td>
<td>1978</td>
<td>289.7*</td>
<td>268.0*</td>
</tr>
<tr>
<td>Carbon</td>
<td>Castle Gate, UT</td>
<td>Coal-Fired</td>
<td>1954-1957</td>
<td>188.6</td>
<td>175.0</td>
</tr>
<tr>
<td>Craig 1 and 2</td>
<td>Craig, CO</td>
<td>Coal-Fired</td>
<td>1979-1980</td>
<td>172.1*</td>
<td>165.0*</td>
</tr>
<tr>
<td>Colstrip 3 and 4</td>
<td>Colstrip, MT</td>
<td>Coal-Fired</td>
<td>1984-1986</td>
<td>155.6*</td>
<td>144.0*</td>
</tr>
<tr>
<td>Hayden 1 and 2</td>
<td>Hayden, CO</td>
<td>Coal-Fired</td>
<td>1965-1976</td>
<td>81.3*</td>
<td>78.0*</td>
</tr>
<tr>
<td>Blundell</td>
<td>Milford, UT</td>
<td>Geothermal</td>
<td>1984</td>
<td>26.1</td>
<td>23.0</td>
</tr>
<tr>
<td>Gadsby</td>
<td>Salt Lake City, UT</td>
<td>Gas-Fired</td>
<td>1951-1955</td>
<td>251.6</td>
<td>235.0</td>
</tr>
<tr>
<td>Gadsby Peakers</td>
<td>Salt Lake City, UT</td>
<td>Gas-Fired</td>
<td>2002</td>
<td>120.0</td>
<td>120.0</td>
</tr>
<tr>
<td>Little Mountain</td>
<td>Ogden, UT</td>
<td>Gas-Fired</td>
<td>1971</td>
<td>16.0</td>
<td>236.0*</td>
</tr>
<tr>
<td>Hermiston</td>
<td>Hermiston, OR</td>
<td>Gas-Fired</td>
<td>1996</td>
<td>237.0*</td>
<td>52.0</td>
</tr>
<tr>
<td>James River</td>
<td>Camas, WA</td>
<td>Black Liquor</td>
<td>1996</td>
<td>52.2</td>
<td></td>
</tr>
</tbody>
</table>

Subtotal (18 Thermal Electric Plants) | 7,288.8 | 6,768.9 |

<table>
<thead>
<tr>
<th>OTHER PLANTS</th>
<th>Location</th>
<th>Energy Source</th>
<th>Installation Dates</th>
<th>Nameplate Rating (MW)</th>
<th>Plant Net Capability (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foote Creek</td>
<td>Arlington, WY</td>
<td>Wind Turbines</td>
<td>1998</td>
<td>32.6*</td>
<td>32.6*</td>
</tr>
</tbody>
</table>

Subtotal (1 Other Plant) | 32.6 | 32.6 |
Fuel
As of March 31, 2002, PacifiCorp had 218 million tons of recoverable coal reserves that are mined by PacifiCorp or its affiliates. All coal reserves are dedicated to nearby generating plants operated by PacifiCorp. During 2002, these mines supplied approximately 32.5% of PacifiCorp’s total coal requirements, compared to approximately 50% in 2001. The decline is due to the 2001 closure of the Trail Mountain Mine, which was no longer economically viable. Coal is also acquired through long-term and short-term contracts. It is deemed favorable to have a mix of purchased and mined coal supplies. Table 2.4 describes PacifiCorp’s recoverable coal reserves as of March 31, 2001.

Table 2.4 PacifiCorp Coal Reserves

<table>
<thead>
<tr>
<th>Location</th>
<th>Plant Served</th>
<th>Recoverable Tons (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Craig, Colorado</td>
<td>Craig</td>
<td>50⁴</td>
</tr>
<tr>
<td>Emery County, Utah</td>
<td>Huntington and Hunter</td>
<td>68⁵</td>
</tr>
<tr>
<td>Rock Springs, Wyoming</td>
<td>Jim Bridger</td>
<td>100⁶</td>
</tr>
</tbody>
</table>

The Company supplies its generation plants with the natural gas needed for operations through long-term and short-term contracts.

WHOLESALE SALES AND PURCHASED ELECTRICITY

PacifiCorp wholesale purchases and sales complement its retail business, form a critical part of its balancing and hedging strategy, and enhance the efficient use of its generating capacity.

Balancing and Hedging Strategy
PacifiCorp’s primary business is to serve its retail customers. The Company's business is exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. The Company enters into derivative instruments, including electricity, natural gas and coal forward, option and swap contracts, and weather contracts to manage its exposure to commodity price risk and ensure supply and thereby attempts to minimize variability in net power costs for customers. The Company has policies and procedures to manage risks inherent in these activities and a Risk Management Committee to monitor compliance with the Company's risk management policies and procedures.

The Risk Management Committee has limited the types of commodity instruments the Company may utilize to those relating to electricity, natural gas and coal commodities, and those

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⁴ These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis in which PacifiCorp has an ownership interest of approximately 21.4%.
⁵ These coal reserves are leased by subsidiaries of PacifiCorp and are in underground mines.
⁶ These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc., a subsidiary of PacifiCorp, and a subsidiary of Idaho Power Company. Pacific Minerals, Inc. has a two-thirds interest in the joint venture.
instruments are used for hedging price fluctuations associated with the management of resources. The Company’s hedging is done solely to help balance retail and wholesale load. Short-term commodity instruments are occasionally held by the Company for trading purposes.

**Wholesale Sales and Purchases**

Long-term electricity purchases supplied 11.8% of PacifiCorp's total energy requirements in 2002. Short-term and spot market electricity purchases supplied 20.5% of PacifiCorp's total energy requirements in 2002.

Historically, during the winter, PacifiCorp has been able to purchase electricity from utilities in the Southwestern United States, principally for its own peak requirements. The Company's transmission system connects with market hubs in the Pacific Northwest having access to low-cost hydroelectric generation and also with market hubs in California and the Southwestern United States with access to higher-cost, fossil-fuel generation. The transmission system is available for common use consistent with open access regulatory requirements. If PacifiCorp is in a surplus electricity position, PacifiCorp is able to sell excess electricity into the wholesale market.

In addition to its base of thermal and hydroelectric generation assets, PacifiCorp utilizes a mix of long-term, short-term and spot market purchases to meet its load obligations, wholesale obligations and its balancing requirements. Many of PacifiCorp's purchased electricity contracts have fixed-price components, providing protection against price volatility.

PacifiCorp currently purchases 925 MW of firm capacity annually from BPA pursuant to a long-term agreement. This purchase helps PacifiCorp to balance its thermal generation to loads by taking delivery during on-peak hours and make the required return of energy during off-peak hours. The purchase amount declines to 750 MW in July 2003 and again to 575 MW in July 2004 through August 2011.

Under the requirements of the Public Utility Regulatory Policies Act of 1978, PacifiCorp purchases the output of qualifying facilities constructed and operated by entities that are not public utilities. During 2002, PacifiCorp purchased an average of 104 MW from qualifying facilities, compared to an average of 109 MW in 2001.

PacifiCorp also has commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. For 2002, such purchases approximated 1.9% of energy requirements.

Under the hydroelectric purchases described above, PacifiCorp contracts for electricity from four dams located on the middle Columbia River. These four dams are currently licensed by FERC to three public utility districts (PUD) located in central Washington. Chelan County PUD has the FERC license for Rocky Reach Dam, Douglas County PUD has the license for Wells Dam, and Grant County PUD has the license for Priest Rapids and Wanapaum Dams. PacifiCorp’s
contracts with these PUDs generally terminate at the same time as the current FERC license expires.

In December 2001, PacifiCorp reached an agreement with Grant County PUD to renegotiate the Wanapum and Priest Rapids contracts after the current contracts expire. The terms and conditions of the new contracts will vary from terms and conditions currently in place.

Table 2.5 shows PacifiCorp’s share of long-term arrangements with public utility districts as of March 31, 2002

Table 2.5 PacifiCorp Mid-Columbia Hydro Contracts

<table>
<thead>
<tr>
<th>Generating Facility</th>
<th>Year Contract Expires</th>
<th>Capacity Winter (MW)</th>
<th>Percentage of Output (%)</th>
<th>Annual Costs7(a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wanapum</td>
<td>2009</td>
<td>155</td>
<td>18.7</td>
<td>7.0</td>
</tr>
<tr>
<td>Priest Rapids</td>
<td>2005</td>
<td>110</td>
<td>13.9</td>
<td>4.0</td>
</tr>
<tr>
<td>Rocky Reach</td>
<td>2011</td>
<td>64</td>
<td>5.3</td>
<td>3.1</td>
</tr>
<tr>
<td>Wells</td>
<td>2018</td>
<td>60</td>
<td>6.9</td>
<td>2.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>389</strong></td>
<td></td>
<td><strong>$16.1</strong></td>
</tr>
</tbody>
</table>

In September 2001 PacifiCorp, through an independent third party, issued a Request for Proposals for electric supply that can be delivered into PacifiCorp's Utah Power electric service territory. This process resulted in a lease with PacifiCorp Power Marketing (PPM, PacifiCorp’s unregulated wholesale power marketing affiliate) for new peaking resources in the Utah Power service territory and several contracts for peak electricity to be delivered into that territory. The costs associated with the leasing of a 200 MW natural gas-fired electricity plant from PPM (located in West Valley, UT) is subject to regulatory acceptance. The plant became operational in the summer of 2002, and is currently operating at its full capacity.

See Appendix C, Tables C.1, C.2, and C.3 for a complete listing of long-term purchase, sales and exchange contracts.

**TRANSMISSION**

PacifiCorp’s transmission system is interconnected with more than 80 generating plants and 15 adjacent control areas at 124 interconnection points. PacifiCorp’s transmission asset ownership has resulted in PacifiCorp’s significant involvement in recent transmission industry changes. PacifiCorp has had an open access transmission tariff on file at the Federal Energy Regulatory Commission (FERC) since 1989. The PacifiCorp transmission business operates independently and markets its transmission services using an Open Access Same-time Information System (OASIS).

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7 Annual costs in millions of dollars. Includes debt service of $6.3 million. The Company's minimum debt service obligation at March 31, 2002 was $9.0 million, $9.0 million, $8.0 million, $10.0 million and $10.0 million for the years 2003 through 2007, respectively.
PacifiCorp operates two separate control areas, the West and the East. The Bridger Plant in Wyoming (with associated transmission through Idaho) is a dedicated Western resource. PacifiCorp has contractual rights to transfer up to 1,600 MW of electricity from the Bridger plant on Idaho Power Company’s transmission lines to PacifiCorp transmission at the Midpoint substation in Idaho. These rights are unidirectional with the exception of 100 MW bi-directional allocated to reserves (RTSA). Other transmission that permits benefits from regional diversity includes PacifiCorp’s share of the AMPS line. Outside of these ownership rights and firm contracts, PacifiCorp has to pay for transmission wheeling and congestion costs to fully optimize use of its resources between East and West.

In the West, PacifiCorp territory is integrated with the BPA network. PacifiCorp uses network firm rights on the BPA transmission to cover its service territory and connect to markets. In the East, however, the PacifiCorp transmission system in Wyoming and Colorado is sufficient, though in Utah it is becoming congested.

Congestion refers to transmission paths that are constrained, imposing limited power transactions because of insufficient capacity. Congestion can be relieved by increasing generation, reinforcing transmission or by reducing load. The following are examples of congested paths that were encountered in the IRP planning:

- Constraints on the west of Bridger transmission system resulted in increased PVRR due to greater transmission integration costs, hence making the Wyoming coal option less attractive than Hunter #4
- The rating of WECC Path C, i.e., the lines between Utah and Idaho, limits transfer capability into the Utah bubble
- West of the Cascade South congestion increases the integration cost for wind developments from an area considered to be one with the highest wind potential in the Northwest

PacifiCorp’s firm transmission rights must be analyzed with caution. At times, the sum of imports “available” according to stated contract rights do not equal the transfers physically available to the system. Such inequalities occur because transmission paths and system subsets operate in an interrelated manner. For example, transmission in and around Utah is particularly prone to inadvertent (or loop) flow. Inadvertent flows cause the simultaneous import capability into Utah to be significantly lower than the non-simultaneous limit. In other words, reaching the transfer limit on one path may concurrently diminish the transfer limits on other paths.

**PACIFICORP POSITION - THE GAP**

The difference between the load forecast and the existing PacifiCorp resources define the shortfall in supplies. Figure 2.2 provides an illustration of the peak system requirement with a 15% planning margin and the capacity of PacifiCorp’s existing resources as they are expected to exist in the future.

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8 The Amps line is a 230 kV transmission line linking eastern Idaho with western Montana.
The annual peak system requirement can be defined as the hour of the year when the loads plus long-term firm sales minus long-term firm purchases results in the largest requirement on our system. The planning margin (15%) is the target reserve level assumed to provide sufficient future resources to cover forced outages, provide operating reserves and regulatory margin, and allow for demand growth uncertainty.

As mentioned earlier in this chapter, PacifiCorp operates in two control areas – West and East. These two control areas have very different resource and transmission issues, which results in a different balance in loads and resources for each side of the system.

Figures 2.3 and 2.4 represent the average net position for each month from April 2003 to March 2011, for both PacifiCorp West and East, respectively. Hourly net operating margins are included in the calculations of net position, and the values are shown after East-West transfers. The net position is shown for the Heavy Load Hour (HLH) and Light Load Hour (LLH) periods (see glossary for definition of HLH and LLH).
Figure 2.3 PacifiCorp West Gap Analysis

Figure 2.4 PacifiCorp East Gap Analysis
**PacifiCorp West**

The gap in PacifiCorp West is the result of a financial and an energy problem. The financial problem is caused by contract expirations and the uncertainty surrounding renegotiating these contracts at a favorable price. A significant impact of these expirations is felt as early as 2007 when a few large contracts such as Clark County and Transalta expire (see Appendix C for complete list of existing contracts). While the resources associated with these contracts remain, there is uncertainty around renegotiating the contract, and an inherent impact on new resource choices.

The energy problem in the West results from uncertainty around the energy that a hydro unit produces. While there is adequate hydro capacity, the energy can vary seasonally and with changing weather. Furthermore, hydroelectric generation makes up a very large percentage of the PacifiCorp portfolio of generation in the West. Therefore, when hydroelectric generation is particularly deficient, there is limited PacifiCorp-owned thermal capacity to provide sufficient output to serve energy needs.

**PacifiCorp East**

PacifiCorp East has a transmission problem and a need for additional capacity. These needs are interrelated. The East requires more physical resources to fulfill the obligation to serve load. Transmission constraints limit imports from out of area. This results in either a need to build or buy additional generation capacity to fulfill the load obligation, or to build or upgrade the transmission system to relieve congestion and allow additional generation to be brought into the East.

However, as one can see from Figure 2.4, the Gap occurs only in the heavy load hours, which results in a load-shaping problem in the East. Particularly in the Wasatch front, where the peak is growing faster than the load, a need is demonstrated for more flexible or peaking resources.

**CONCLUSION**

PacifiCorp has a complex service territory served by a large and diverse portfolio of resources. Linked by an enormous transmission network, the service territory covers broad and distant areas of the WECC. PacifiCorp’s generation portfolio contains a wide array of coal and natural gas fired units as well as a large collection of flexible hydroelectric resources. Also, many contractual arrangements complement these resources. However, the combination alone is insufficient to meet the growing load obligation. To serve the gap, PacifiCorp’s body of assets is supplemented by a large and complicated array of electricity purchase arrangements. The gap, as defined earlier, is net of long-term contracts and supplemented by short-term contracts.

The gap between load and resources is perhaps the most distinctive and important feature of PacifiCorp’s current position. Similarly, resolving the gap economically and reliably plays the central role in PacifiCorp’s planning process.
3. RISKS AND UNCERTAINTIES

INTRODUCTION

Electric utilities operate in an increasingly uncertain and volatile environment. The Western energy market conditions of 2000-2001 described in Chapter 1 graphically illustrate this. These recent events underscore the importance of risk management.

Clearly, every planning process should consider risk – that is, the possibility of different outcomes due to uncertainty about the future. However, general techniques for effectively incorporating risk analysis into utility resource plans have been more elusive. This Chapter discusses risk in general and describes the techniques PacifiCorp employed to incorporate risk analysis into its resource plan.

CLASSIFICATION OF RISK

Not all risks are assessed in the same way. For example, the Palo Verde electricity price realized next summer will most likely vary from expectations today (i.e., the forward price or a fundamental price forecast). This uncertainty and the associated impact can be quantified by applying stochastic modeling techniques described in Appendix H. However, if radical change is introduced in the way the electric utilities do business, e.g. Standard Market Design (or SMD), the model itself needs to be modified to account for the structural changes. Since the details of such radical changes are largely unknown, it is not possible at this time to quantify the related impact with mathematical modeling techniques.

Accordingly, the risks faced by PacifiCorp can be sorted into three general categories: Stochastic, Scenario and Paradigm risks. Scenario and Paradigm Risks constitute categories of what is frequently referred to as formal uncertainty. Figure 3.1 illustrates the categories of risk PacifiCorp faces.
Stochastic Risks
Stochastic risks are quantifiable risks. These parameters can be numerically represented and a known statistical process can be used to represent their variability.

Risks associated with business as usual variability typically falls within this category. PacifiCorp’s analysis assumes that the Stochastic risk is driven by uncertainty in the following parameters (risk factors):

- Retail Loads (Northwest, Wyoming, Utah, Idaho)
- Spot Market Natural Gas Price (Mid Columbia, and two Utah nodes)
- Spot Market Electricity Price (Mid C, COB, PV)
- Hydrogeneration (PacifiCorp West, PacifiCorp East)
- Thermal Unit Availability

Explained by a known statistical process, Stochastic risks naturally lend themselves to simulation. As such, their variability is captured in the IRP’s modeling and reported in Chapter 7. Refer to Appendix H for detailed information about the risk parameters above.

Scenario Risks
Scenario risks are also parameter driven. However the parameter variability cannot be reasonably represented by a known statistical process. This risk category is intended to embrace abrupt changes in the risk factors, such as introduction of high carbon allowance costs. The probability of high carbon allowance costs cannot be determined with a reasonable degree of
accuracy. Therefore, a scenario of this occurrence is created without applying a probability to it. With assumed values (as opposed to simulated values) portfolios can be tested for their sensitivity to a specific Scenario risk.

Examples of Scenario risks addressed in the model are listed below. For a complete list of assumptions regarding these and other risk parameters, refer to Appendix C.

- Charges for prospective CO\textsubscript{2} emissions can be assigned. For example charges in the model are assumed to equal $8/ton above the year 2000 cap. Stress cases also modeled the impact of varying this allowance rate ($2/ton, $25/ton and $40/ton).
- Hydrogeneration relicensing efforts could affect future hydrogeneration capacity and energy levels. Adjusting expected energy output and stressing the capacity availability could assess the impact of this risk.
- The market value of Green Tags is influenced by the unknown probability of the passage of Federal and/or State renewable portfolio standards. However, Green Tags can be assumed to have an explicit value. For example a $5/MWh value was assigned for green tags.
- Renewable production tax credits are easily represented as a measurable economic subsidy to green generation because the value of the credit is provided by all tax payers. The probability of their extension is unknown. Therefore, modeling the parameter requires applying assumed values for the credit.

In the case of changing Scenario risks, the time evolution of Present Value Revenue Requirement (PVRR) takes a distinctly different path, rather than fluctuating around an expected value. The measure of Scenario risk is the difference between the expected PVRRs generated by applying different scenarios. The Figure 3.2, below, illustrates the different impacts of Stochastic and Scenario risks on a hypothetical series of annual revenue requirements.

Stochastic risks by definition vary randomly given a specific set of core assumptions for the Scenario Risks. We see the solid line jaggedly moving through time demonstrating a random (stochastic) series of outcomes.

Initially, the dashed and solid lines follow a similar path. However, the line shifts with the introduction of a change in a Scenario risk. For example, assume carbon allowance costs fall to $2/ton from $40/ton. The dashed line illustrates the shift (or shock) associated with a change in this Scenario risk assumption. The Scenario risk parameter is manually modified in order to observe the impact on the model. This is a form of stress testing.
Paradigm Risks
Paradigm risks cannot be reasonably represented by a number. Accordingly, the variability of Paradigm risks cannot be represented by a known statistical process. Paradigm risks are typically associated with large shifts in market structure or business practices, such as introduction of RTO West and SMD. Such innovations involve radical changes in the business model. Since the details of such changes are not presently specified, Paradigm risks do not easily lend themselves to quantitative analysis. The radical changes to fundamentals generally defy reasonable approaches to numerical representation until they are more fully specified.

While not explicitly modeled, Paradigm risks cannot be ignored. Accordingly, Paradigm risks are typically addressed outside of the model and cannot be summarized by a simple series of metrics. The assessment of Paradigm risks is usually qualitative rather than quantitative. Attempts, described below, are made to create a plan with the flexibility to respond to changes in Paradigm risks. In some instances, assumptions are explicitly modeled to impute additional flexibility. Despite these efforts, Paradigm risks, as they arise, will ultimately require a well reasoned response developed in conjunction with PacifiCorp, its regulators and the public.
DISCUSSION OF SPECIFIC RISKS

A large number of critically important Scenario and Paradigm risks currently fill the market. Each has the ability to dramatically affect PacifiCorp’s operation. These risks merit additional discussion and include:

- Regional Transmission Organization and FERC’s proposed Standard Market Design (RTO and SMD)
- Comprehensive Air Strategy
- Hydrogeneration Relicensing
- Renewable Portfolio Standard
- Multi-State Process
- Oregon Electric Restructuring (SB1149)

The information below provides background information on each risk. It also describes how the resolution of the risks could affect PacifiCorp and how the risks are analyzed within this IRP.

**RTO and SMD**

PacifiCorp, in conjunction with nine other utilities, is seeking to form a Regional Transmission Organization (“RTO West”), in response to FERC Order 2000. The 10 members (“filing utilities”) of RTO West would be:

- Avista Corporation
- British Columbia Hydro Power Authority
- Bonneville Power Administration
- Idaho Power Company
- NorthWestern Energy LLC
- Nevada Power Company
- PacifiCorp
- Portland General Electric Company
- Puget Sound Energy, Inc
- Sierra Pacific Power Company

Creation of RTO West is subject to regulatory approvals from the FERC. Some of the states served by the filing utilities may also assert jurisdiction over certain matters relating to the formation of RTO West. RTO West, when fully implemented, will operate transmission facilities needed for bulk power transfers and control the majority of the 60,000 miles of transmission lines owned by the entities.

On July 31, 2002, the FERC issued its Notice of Proposed Rulemaking ("NOPR"), proposing a new Standard Market Design (SMD) for wholesale electricity markets and requesting comments from market participants. Comments are due in mid-November or mid-January, depending on the subject.

On September 18, 2002, the FERC Commissioners voted that, with some modification and further development of certain details, and the RTO West proposal not only satisfies the 12 characteristics and functions of Order 2000, but also provides a basic framework for standard market design for the West.
Going forward, the focus of the RTO project will be on completing the RTO West design details, influencing the final SMD Western market design framework. The filing utilities also plan to submit a proposed RTO West tariff in early 2003. In addition, the filing utilities have entered into a Memorandum of Understanding with the other two potential Western RTOs, namely WestConnect and California Independent Grid Operator and will work on inter-regional issues through that forum.

**Potential Impact**

Resource adequacy has been addressed in both the RTO West Order and the SMD NOPR. Within the SMD NOPR, FERC proposes that all Load Serving Entities must meet a minimum capacity reserve planning margin (12%) or face potential penalties. The required reserve margin could be set higher by a Regional State Advisory Committee, proposed by the SMD NOPR to advise the independent transmission provider. In contrast, the RTO West Order is more flexible in that it encourages the filers to consider reliability based development of a resource adequacy plan.

If a generation adequacy standard is imposed on PacifiCorp, either through the SMD requirement or as a consequence of a future standard adopted by the RTO West, the impact on PacifiCorp’s IRP process could be both direct and indirect. Directly, PacifiCorp could be required to make generation additions or enter into firm contracts to meet a minimum Planning Reserve Margin. If the Planning Reserve Margin were set too high, PacifiCorp and its customers would incur unnecessarily high costs without reliability or risk reducing benefits. Since the same requirement would impact all other load serving entities in the WECC, it could be expected to impact the supply-demand balance throughout the WECC. This would indirectly affect PacifiCorp’s system through its impacts on market prices throughout the WECC. The impact could be seen through a smoothing of boom-bust cycles of generation additions and market prices, an intended impact of the SMD. This impact could result in chronically low market prices and could potentially impact overall depth and liquidity of electricity markets.

**Treatment in the IRP Models**

The ultimate reserve requirements of SMD are unknown. Planning Margin discussions range from 12% to 18%. A 15% Planning Reserve Margin was assumed as a reasonable proxy for final SMD requirements. A 10% Planning Margin requirement was also analyzed as a stress to test the risk of a divergence from this assumption. Forecasts of future market prices were developed assuming that future resources would be added to the WECC to maintain a 16% reserve margin, on average.

RTO could impact the economics by which transmission rights are procured and energy flows. The risk of this change was addressed with a conservative bias. Accordingly, only firm transmission rights were modeled.

**Comprehensive Air Strategy**

PacifiCorp's coal-fired plants must comply with numerous, complex environmental air quality laws and regulations, some of which are the subject of industry-wide enforcement initiatives. In addition, new emissions requirements are expected to emerge over the next several years that will impose even more stringent pollution control requirements. PacifiCorp is the single biggest coal-fired power producer in the Western energy market. Therefore, existing and expected future
emissions regulations create significant uncertainty for the future operations and investment requirements of PacifiCorp.

Air emissions are regulated under both federal and state law. The Environmental Protection Agency (EPA) oversees federal laws although most states, including Utah and Wyoming, have authority to administer the federal laws within their borders subject to EPA's oversight. At times, federal and state laws can overlap or seemingly be in conflict.

The primary pollutants of concern for coal-fired plants include: sulfur dioxide (SO\textsubscript{2}), nitrous oxide (NO\textsubscript{x}), particulate matter (PM), carbon dioxide (CO\textsubscript{2}) and mercury (Hg). The environmental impact of these pollutants differs in the western and eastern part of the United States, with SO\textsubscript{2} being the biggest concern in the west and NO\textsubscript{x} the largest concern in the east. The Administration's Clear Skies proposal recognizes that the West faces different air quality issues than other parts of the country and would set emission caps to account for these differences.

Coal-fired plants in general face future regulatory uncertainty due to a number of regulatory tools used by both government and private citizen groups to require further emission reductions. These methods include: (1) the New Source Review (NSR) enforcement initiative (see explanation below); (2) NSR rule changes; (3) visibility requirements; (4) ongoing compliance issues; (5) emerging new emission requirements, including new legislation; and (6) changing federal, state and public attitudes, including an increase in lawsuits by citizen groups to achieve emissions reductions. The most pressing of these is the NSR enforcement initiative which involves an attempt by the U.S. Environmental Protection Agency (EPA) to force emission reductions from coal fired powerplants through enforcement activities. These enforcement activities have included Notices of Violations (NOVs), civil complaints and similar actions against eight utilities and one federal agency in the eastern US along with the investigation of countless other coal plants across the country, including four PacifiCorp plants.

**New Source Review (NSR)**
The NSR program in general requires utility owners or operators to undertake NSR review and obtain a new permit if they propose to build new generating units or modify existing plants in a way that increases emissions of regulated pollutants. EPA’s current interpretation of these rules has created substantial legal controversy and has resulted in EPA launching the NSR enforcement initiative.

**Climate Change**
Some compliance costs – like those associated with pollution control equipment for SO\textsubscript{2} and NO\textsubscript{x} – can more easily be predicted based on current and expected rules. However, other compliance costs are far less easily predicted or quantified. Most notable among these uncertain costs are costs associated with compliance with future climate change requirements regulating emissions of greenhouse gases. Determining the impact of potential carbon regulations poses a challenge due to the tremendous amount of uncertainty surrounding such a policy. This uncertainty includes the stringency of potential future regulations; the timing of these regulations; and the way in which they will be implemented – including the flexibility to trade emission allowances across sectors and countries.
Climate change policies are developing as a complex mix of requirements debated on both the international stage and through domestic policy developments.

**Multi-pollutant Legislation**

Several national proposals to amend the Clean Air Act to limit air pollution emissions from the electric power industry are being discussed at the national level. The three most prominent are:

- President Bush’s Clear Skies Act/Global Climate Change Initiatives,
- Clean Power Act (S. 556) introduced by Senator Jeffords (I-Vt.), and
- The Clean Air Planning Act of 2002 (S.) introduced by Senators Carper (D-DE), Lincoln Chafee (R-RI), John Breaux (D-LA), and Max Baucus (D-MT).

The Administration's Clear Skies Act (H.R. 5266 and S.B. 2815), which was introduced by Reps. Barton (R-TX), Tauzin (R-LA) and Sen. Robert Smith (R-NH), requires reductions for SO₂, NOx and Hg. Implemented through a tradeable allowance program, the emissions caps would be imposed in two phases: 2008 and 2019. The Administration proposal recognizes that the east faces different air quality issues than other parts of the country and will set emission caps to account for these differences. The second Bush Administration proposal (for which no legislation has been introduced) initiates a new voluntary greenhouse gas reduction program. The plan focuses on improving the carbon efficiency of the economy, reducing current emissions of 183 metric tons per million dollars of GDP to 151 metric tons per million dollars of GDP by 2012. The Administration's proposal relies on various voluntary programs and incentives to encourage reductions in greenhouse gases from diverse sources, including CO₂ from electric generation.

The Carper bill would regulate SO₂, NOx, mercury and CO₂ emissions from the electric generating sector: (1) the SO₂ mandate would reduce emissions via three phases to 2.25 million tons in 2015; (2) the 2-phase NOx program culminates with a 2012 cap of 1.7 million tons; (3) the mercury cap would be in two phases: 2008 and 2012; (4) the two-phase CO₂ program would cap emissions at 2005 levels in 2008 and 2001 levels in 2012.

The Jeffords bill (S. B. 556), the most stringent of the bills, requires power plants to reduce sulfur dioxide and nitrogen oxide emissions by 75 percent, mercury emissions by 90 percent and carbon dioxide to 1990 levels, all by 2008.

**Mercury Maximum Achievable Control Technology (MACT)**

Mercury (Hg) controls are also being considered separately from multipollutant legislation under the Maximum Achievable Control Technology (MACT) standards under the CAA (Clean Air Act). In December 2000, EPA determined that Hg emissions must be regulated. EPA is under a court-approved consent decree to propose a rule establishing MACT standards for Hg for coal-fired power plants by December 2003 and to finalize that rule by December 2004. Power plant operators must comply with the rule by December 2007.

Mercury control options are highly dependent on the chemical form and concentration of mercury in the coal and the fuel’s chlorine content. These parameters may be tied to the type of coal used. Western bituminous coals have characteristics that are closer to sub-bituminous coals.
than to eastern bituminous coals. Sub-bituminous and western bituminous are generally harder to control than eastern bituminous coal.

Further analysis of existing data and the collection of new data would potentially lead to a better understanding of the relationship between Hg emissions and an array of likely contributing factors including the chemical and physical characteristics of the coal, boiler technologies, control technologies, and stack parameters.

Approach
The company believes that improved environmental quality can be achieved by taking leadership positions in these arenas, but it must work with utility rate commissions to achieve alignment between environmental policies and allowable expenses.

Potential Impact
The cost of meeting present, pending and future SO2, NOx and Hg regulations will be substantial, with related after-tax OMAG and capital expenditures through 2025 ranging between $500 million (NPV) and $1.7 billion (NPV). The $500 million represents a scenario in which SO2 scrubbers and low-oxides of nitrogen burners (low-NOx burners) are installed on PacifiCorp-operated units. The $1.7 billion represents full controls (SO2 scrubbers, Selective Catalytic Reduction controls for NOx, and baghouses with activated carbon injection for mercury)

Costs associated with potential future CO2 requirements are not included in the above scenarios.

PacifiCorp Approach to Air Quality Standards
PacifiCorp is advocating a comprehensive approach to meeting various air quality standards. The plan would yield significant air quality improvements, a safe, reliable and cost effective energy supply, meet the company’s commitment under the WRAP sulfur dioxide emission reduction curve, and integrate necessary improvements in air quality equipment with other efficiency and equipment replacement schedules at the coal facilities. The approach would give PacifiCorp the ability to integrate air quality concerns and expenditures into the overall Integrated Resource Plan (IRP) with improved certainty.

Treatment in the Model
• PacifiCorp’s comprehensive approach to addressing air issues was not explicitly assigned a cost. Costs associated with this approach are common to all portfolios. It assumes existing plants run for their expected lives with assumptions for emissions reductions resulting from installation of new control technologies.
• PacifiCorp included CO2 emission “adders” for the purposes of stress testing. The base case assumption is for a CO2 tax of $8/tarin charged for each ton above year 2000 level emissions and credited if below the cap beginning in fiscal year 2009. Additional stresses were done
with $2, $25, and $40/ton scenarios representing various possible policy outcomes with varying implementation dates and cap levels.

- SO₂ and NOₓ emission restrictions impact portfolio cost by assessing a $/ton charge for emissions above their cap or paying credit below the cap. Representative charges, based on PIRA estimates, are modeled.

**Hydro Generation-Relicensing**

Like the CAI, the issues involved in relicensing hydrogeneration facilities are complex. They involve numerous federal environmental laws and regulations.

PacifiCorp’s hydrogeneration portfolio is 1,100 MW, generated at 54 facilities with 20 individual Federal Energy Regulatory Commission (FERC) licenses in six states. Hydrogeneration facilities account for about ten percent of PacifiCorp’s overall generation portfolio and provide a critical resource to meet peak demands. The current hydrogeneration relicensing schedule with FERC extends to 2013.

FERC hydrogeneration relicensing is a very complex regulatory environment and is an extremely political and public process involving complicated and controversial public policy issues. Litigation is prevalent. There is only one alternative to relicensing, that being decommissioning. Both choices are expensive.

Under the Federal Power Act that governs the FERC process, fish and wildlife, cultural, recreational, land-use and aesthetics all are considered equal to energy production when considering relicensing. Since the responsible agencies place mandatory conditions in the license, FERC is not in a position to balance the requests between different agencies. For example, on a single-project relicensing, issuance of a water quality certification (referred to as a “401 certification” due to its placement in the Clean Water Act) is completed by the following agencies:

- Washington State Department of Ecology,
- National Marine Fisheries Services,
- U.S. Fish and Wildlife Agency (which prescribes fishway conditions),
- U.S. Forest Service
- Indian Nations (which prescribe measures if the project includes reservation lands).

These different requirements may not align. In addition, more federal, state and local regulations may apply. These include provisions of the Clean Water Act, Northwest Forest Plan, consultation under the Endangered Species Act, and state and federal fish recovery plans.

**Potential Impact**

Relicensing hydrogeneration facilities is costly. To date, relicensing has resulted in $75m of accumulated costs that are anticipated to be added to the rate base when the generating facilities receive a new operating license. An additional $60 million is expected to be spent over the next 10 years for this process. Costs related to the requirements of relicensing are expected to total $1.5 billion to $2.2 billion over the next 30 to 35 years. About 90 percent of the cost relates to the three largest projects Lewis River, Klamath River and North Umpqua, and nearly half of these costs are attributed to lost generation.
PacifiCorp’s Approach to Hydrogeneration Relicensing
PacifiCorp is managing this process by attempting negotiated settlements as part of the relicensing process. PacifiCorp believes this proactive approach is the best way to achieve environmental improvement while managing costs. PacifiCorp is prepared to consider project decommissioning if that appears to offer the lowest-cost alternative for our customers. Finding ways to engage a larger public interest voice in these licensing projects would be helpful. Reforming the Federal Power Act to allow mitigation alternatives to agency mandates also is a priority.

Treatment in the IRP Model
- The model assumes a loss of energy due to operational changes and increased bypass flows in the base case for all portfolios. Future impacts are highly speculative at this time due to ongoing negotiations.
- The costs of relicensing projects are not included in the model analysis since they are common to all portfolios.
- Relicensing involves the risk (however remote) of a loss of capacity. Accordingly, a stress case was run to test the impact of losing just over 200 MW of hydrogenation capacity, or 20% of our hydrogenation portfolio.

Renewable Portfolio Standard (RPS)
The RPS examined in many of the modeling runs was based upon the version passed by the U.S. Senate in S. 517, which was the Senate’s version of the federal Energy Bill in the 2001-2002 session. With the mid-term elections, it appears unlikely that the energy legislation adopting a federal RPS will be passed in the 2003 – 2004 session. The bill was the product of substantial negotiation and may indicate the form of a future federal RPS in the long-term. While discussion may stall on Capitol Hill, 13 states have passed a RPS, including Texas, California and Nevada. Other states, such as Utah and Washington, are contemplating an RPS in their 2003 legislative sessions.

The Senate version requires 1% of investor-owned utilities’ electricity to come from non-hydrogeneration renewables, with the requirement rising by adding 0.6% each year to reach 10% in 2020.

The annual targets are lowered by rewarding retail electricity suppliers for existing hydrogenation and renewables generation. Both existing hydrogenation and renewables count towards reducing the load to which the percentage is applied. Existing renewables further count as a portion of the actual electricity generated to meet the standard. In addition, there is a 1.5 cent/kWh price cap on the premium cost above non-renewable electricity. These provisions will lower the explicit numerical targets of the bill—one recent study finds that the standard results in renewables representing just 6.5% of electricity supplied in 2020.

Based on PacifiCorp’s estimates, which include the Senate’s treatment of existing renewables and hydrogenation, but do not include the 1.5 cent/kWh price cap, the current federal RPS proposal would result in PacifiCorp building or buying 20 new MWa of renewables by 2005. The target rises every year thereafter to 229 MWa by 2010 and 829 MWa by 2020.
Potential Impact
Early modeling runs featuring the RPS considered early adoption of renewables for numerous strategic and economic reasons.

With the renewables totals in the portfolio, PacifiCorp could be well positioned for future federal RPS. The Senate proposal provided full credit for existing renewables. Such legislation in the future would provide full regulatory risk reduction benefits to the renewables component of the portfolio.

Implementation of a renewables procurement strategy before broader sectoral demand “runs” on renewables technology such as wind would avoid high price spikes for equipment and services associated with demand-supply imbalances, particularly on hardware such as wind turbines. Further, current pursuit of the best renewable resources, such as sites with good wind patterns and proximity to transmission, allows PacifiCorp to take advantage of the cheapest opportunities to develop renewables for customers.

While reliance on current thermal generation and future thermal investments are highly likely scenarios, sole reliance on gas and coal exposes PacifiCorp to the risks they embody, with no other fuel option. Pursuing renewables for resource diversity assumes that, without revolutionary technology change, new hydrogeneration and nuclear generation are extremely unlikely in the near- to medium-term due to cost, including siting challenges and safeguards required by current regulations. Further, existing hydrogeneration is increasingly constrained by state and federal regulations.

A mix of renewable resources diversifies supply options in the generation portfolio. Geothermal is a baseload resource that complements existing thermal baseload. Solar offers a resource whose availability coincides with periods of high demand in the summer and therefore offers valuable electricity. Wind electricity is intermittent but its technological maturity provides high energy value with modularity benefits as discussed below.

Portfolio diversity benefits are further enhanced by renewables’ fuel-free qualities. The value is related to natural gas prices. As gas price volatility persists, renewables look more attractive as a risk mitigation tool.

Treatment in the IRP Model
• The IRP initially included the federal renewable portfolio standard (RPS) in all modeling runs. Accordingly, 10% of system retail load (adjusted as per detailed discussion from Appendix C, Table C.17) is met by renewable electricity resources by 2020.
• The RPS was initially modeled as a flat contract with delivery to load, system integration, and shaping costs included in the $/MWh rate.
• Subsequent portfolio iterations, with the exception of Renewable, converted the flat, fixed price RPS contract with one referred to as profiled wind. The profiled wind contract is a resource modeled with a production shape reasonably representative of the resource’s expected physical output, e.g. without any associated firming or shaping provided by a third party.
Multi-State Process (MSP)
In April 2002, PacifiCorp and interested parties from across PacifiCorp’s service area initiated the MSP to design a mutually acceptable solution or solutions to the states’ and the company’s problems arising from the current approach to operating PacifiCorp as a multi-state utility. The parties entered into an MSP to develop and review possible solutions to those challenges. The MSP builds on feedback PacifiCorp received on a Structural Realignment Proposal it filed with state regulatory commissions in December 2000.

PacifiCorp’s Approach to MSP
PacifiCorp is committed to designing a solution that will be mutually acceptable, durable and feasible in a multi-state environment. Through the MSP, the participants are working on a number of issues, including providing states the ability to independently implement their own energy policy objectives, establishing entitlement to the benefits of PacifiCorp’s existing assets and related costs, and determining a durable allocation method for future resources. As part of the process, parties submitted potential solutions and those solutions, along with modeling that supports them, are being carefully reviewed for their ability to:

• Preserve system reliability, efficiency and safety
• Balance risks and rewards among customers and shareholders
• Be able to respond to emerging issues

Discussions are scheduled through December 2002. Once parties arrive at a solution, PacifiCorp will seek regulatory approval from each state.

Treatment In The IRP Model
Clearly, changes resulting from MSP fall into the paradigm category of risks. The risks of the MSP are among the most difficult to quantify. While a recognizable risk, MSP represents distinct and separate process. The IRP process seeks to develop a least cost plan for serving PacifiCorp’s customers. MSP moves beyond the context of IRP by addressing the allocation of costs among the states. Accordingly, no model adjustments or scenarios include assumptions specifically related to MSP.

Oregon Electricity Restructuring (SB1149)
During 1999, the Oregon legislature enacted electric industry restructuring, including a competition requirement for industrial and large commercial customers of both PacifiCorp and Portland General Electric Company. Under the legislation, referred to as SB1149, PacifiCorp is also required to unbundle rates for generation, transmission, distribution and other retail services, and to offer residential customers a cost-of-service rate option and a portfolio of rate options that include new renewable energy resources and market-based generation. Finally, SB1149 authorizes the OPUC to make decisions on certain matters, in particular the method for valuation of stranded costs/benefits if customers elect market access.

Implementation of SB 1149 began March 1, 2002, when PacifiCorp provided all customers with a cost-of-service rate option for an indefinite period and allowed industrial and large commercial customers a choice of energy provider. As a result of adopting SB 1149, 16 customers elected an
alternate choice to cost-based standard offer tariffs. Only one large PacifiCorp customer elected market access in the choice window that closed in December of 2002.

**PacifiCorp’s Approach to SB 1149**

Implementation of SB 1149 affects both the MSP and IRP processes. PacifiCorp continues to participate in the on-going PUC proceedings to establish the rules and procedures related to SB 1149. SB 1149 requires that

"Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company;"

Suggested revisions and interpretations of this rule generated much discussion and little agreement between parties in the recent OPUC rulemaking such that the Commission determined that further review of the issues surrounding the rule should occur in an investigation docket. PacifiCorp's current multi-jurisdictional regulatory rules do not allow the Company to make state specific resource decisions. This issue is being addressed in the MSP. As such, it is not clear at this time how the SB1149 rules can be met without either a change to the multi-state regulatory processes or a change in the SB1149 rules themselves.

In addition when parties opt out from service by PacifiCorp they must pay a stranded cost/benefit charge. One proposal discussed in the recent rulemaking was that customers should have a one-time chance to opt out with no stranded cost/benefit charge. Discussions with parties on this proposal are continuing. A durable solution coming from the MSP regarding rights and responsibilities for the Company's supply resources, which are currently shared across states, will be necessary to address the prospect of freed-up resources associated with SB1149 implementation.

**Treatment In The IRP Model**

A stress case was developed to determine the possible impact to the system if several industrial and large commercial customers chose another energy provider under SB1149. The major assumption for this stress was that 400 MW of flat load would leave our service territory in Oregon in July 2003. Study details and the associated findings are available in the Stress Testing section of Chapter 7.

**RISK ASSESSMENT**

Because of the fundamental differences between the risk categories, results of the risk analysis can not be combined into a single number. Instead, PacifiCorp has chosen a hybrid approach, which begins with Stochastic and Scenario risks being evaluated and reported as separate metrics. Therefore, several risk measures characterize each portfolio. It is likely that no single portfolio will rank highest in all risk categories. As a consequence, the methodology will not necessarily result in identifying a single optimal portfolio. However, the methodology does result in weeding out obviously bad portfolios and motivates a more focused discussion over competing portfolios that have different risk merits. The risk metrics are part of a mosaic approach used to ultimately choose the portfolio characteristics to be pursued by the IRP.
RELATIVE IMPORTANCE OF RISK CATEGORIES

Prudence requires developing a framework that will embrace all flavors of risk. However, the merit of each risk category changes as time goes by. In the past, risk associated with the electric utility business was dominated by quantifiable but difficult to probabilistically represent Scenario risks. During the periods of transition such as the one the industry is going through today, the most serious of concerns often fall in the domain of Paradigm risks. When electricity markets reach maturity, the Stochastic risks will likely prevail.

The significance of Stochastic risks should not be underestimated. It may seem that deviations of random (stochastic) variables, added on top of each other, ‘wash-out’. However, statistics tells us that this is only the case when such variables are perfectly, negatively correlated. Because of this, the “jaws of uncertainty” in PVRR broaden with time. Alternatively stated, outcomes become increasingly uncertain as time progresses.

This effect is exacerbated by the non-linear dependence of PVRR on risk factors. The dependence causes the distribution of possible outcomes to be skewed. Understanding the nature of this skew is important. On a year-to-year basis, skewed distributions imply the occurrence of many, slightly smaller than expected PVRRs. More importantly, they also imply that less frequent, dramatically high PVRRs can be expected. The graph in Figure 3.3 illustrates the impact of a skewed distribution vs. a symmetrical distribution.
The results of the risk analysis presented in Appendix I show only seemingly moderate differences among the portfolios. In fact, the differences are hundreds of millions of dollars in size, but seem moderate since the resource additions considered by any of the portfolios are moderate compared to the size of the existing PacifiCorp system. Therefore, the differences between the portfolio risk profiles are camouflaged by the size inertia of the system. This, however, will not always be the case as electricity demand grows and the old electricity plants get decommissioned.

CUSTOMER AND SHAREHOLDER RISKS

Assessing and categorizing risk is an important component of the IRP analysis. Such assessments attain greater meaning when the holders of the risk are identified. Identification is valuable analytically. It is also an important element of the IRP standards and guidelines. For example, the Utah IRP standards and guidelines include the following requirement:

Identify which risks will be borne by ratepayers and which will borne by shareholders.

Based upon recent discussion with Utah commission staff, the first question stems from two issues.

1. Is PacifiCorp’s participation in the market or in resource development for the benefit of customers only, or also for the potential benefit of shareholders? If benefits accrue to both customers and shareholders, a clear understanding of risk allocation is critical.
2. If PacifiCorp mitigates regulatory risks through the IRP (such as risks associated with normalized costs), are costs borne by ratepayers to reduce shareholder risk?

**Customers vs. Shareholder Risks**
Under the regulatory compact, PacifiCorp provides cost-based electric service to retail customers. The IRP addresses the resource actions required to meet this obligation. The IRP exclusively focuses on resource actions required to meet PacifiCorp’s obligation to serve retail customers. The IRP does not contemplate resource additions or market activities directly benefiting shareholders or parties other than retail customers in existing jurisdictions served by PacifiCorp.

To the extent PacifiCorp shareholders implement the IRP by prudently investing capital to provide low-cost, reliable service, shareholders have the opportunity to earn a fair, regulated rate of return, subject to ratemaking in the regulatory process. Thus, the sole shareholder benefit opportunity from the IRP is the opportunity to earn the allowed rate of return on any investments resulting from the plan. Consequently, risks borne by shareholders associated with implementing the IRP can be categorized as regulatory risks, as discussed below.

**Shareholder Risks**
Under perfect regulation, if PacifiCorp makes prudent investments, the investments as well as associated and reasonable expenses would be allowed fully into rates on the plant in-service date, without any lags or adjustments. However, the system is not perfect in this sense and regulatory risks are borne by shareholders. These risks include:

- **Lag** - delayed recovery of the investment measured relative to incidence of investment
- **Allocation Gap** - overlapping regulatory authorities or conflicting regulatory rules that do not allow all prudently incurred investments into rates.
- **Normalization** - certain costs which are normalized in ratemaking are actually incurred at higher than expected levels, during a period in which rates are not adjusted
- **Disallowances** - investment costs and associated expenses are disallowed because they are deemed to have not been prudently incurred at reasonable levels.

Two of the above regulatory risks borne by shareholders are examined in the IRP: (1) the Allocation Gap risk and (2) normalization risk for certain costs for a period of at least some duration in ratemaking.

Allocation Gap risk is a Paradigm Risk. It is faced by both PacifiCorp’s shareholders and customers. This risk is being addressed through the MSP process and a solution is critical for resource plan implementation.

Normalization is used in ratemaking. Certain costs are normalized over the period in which rates are set. Such costs include, but may not be limited to:

- Forecast power prices,
- Fuel costs,
- Forecast load,
- Hydroelectric availability and
• Thermal outage rates,

If abnormal (and potentially non-recurring) events occur in a cost that is normalized, the risk (potentially a cost or benefit) is borne by shareholders. Extraordinary events in these areas may or may not be expected to continue to be borne by shareholders. However, changes in the trend of expectations may over time be shifted to customers by adjusting the normalized value in the succeeding rounds of ratemaking proceedings.9

The Stochastic Risks quantified in the IRP translate into normalization risks in ratemaking. Consequently, over time, the risk is shared between shareholders and customers. This sharing can be understood in terms of two time frames. Over a multi-year time frame, the ratemaking process will respond to the volatility of portfolio operating costs by either increasing rates if operating costs rise or decreasing rates when operating costs decline. In this time frame, these risks are borne by customers. In a shorter, between-rate-cases time frame, normalized rates do not respond to operating cost variations and such risk is borne by shareholders.

Minimization of Stochastic Risk was not a key driver in the IRP portfolio approach. Among the best performing portfolios, the exposure to Stochastic Risks, described in Chapter 7, is indeed very similar. The Paradigm Risks and the CO2 Scenario Risks received particular consideration in the risk evaluation and contributed more to the conclusion to pursue a diversified portfolio approach.

**Customer Risks**

Customers face all of the risks evaluated in the IRP, including the Stochastic, Scenario and Paradigm Risks. As noted above, shareholders share some of the risks, notably normalization of Stochastic Risks and certain Paradigm Risks, including MSP. Customer risk associated with failure to solve MSP problems takes the form of inability of PacifiCorp to deliver the optimal portfolio option due to cost recovery problems or to be able to do so only at a higher cost (either capital expenditures, fuel costs or other variable costs). The customer perspective on these risks should be the driving criteria in determining the best resource strategy to pursue on behalf of these customers. PacifiCorp believes the IRP Action Plan, detailed in Chapter 9, strikes the best, prudent balance between cost and risk on behalf of its customers.

**Customer Risk Tradeoff**

A fundamental risk tradeoff borne by customers is the tradeoff between serving resource needs through generating assets versus serving the needs through market purchases. Resourcing through generating assets assumes assets are owned by PacifiCorp. Resourcing through market purchases assumes resources are secured through long-term firm or unit-contingent power purchase agreements (PPAs) with the purchase costs determined by cost formula.

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9 There may also be an asymmetry to normalization risks borne by shareholders because, under regulatory treatment, the magnitude of net power cost upward excursions are virtually unlimited while the magnitude of downward excursions is limited by the high probability that low prices will remain positive.
For the purpose of highlighting this trade-off, consider this comparison of two strategies for resource planning: a Short Assets (relying on market purchases to meet load obligations) and a Long Assets (Building Assets or the above described firm or unit contingent PPAs tied to specific assets).

The risks and benefits of these two strategies can be summarized in the following categories: Electric Prices, Loads and Fuels

**Electric Price Risk**
The Short Assets strategy includes volatility around market price as a risk. Lower power prices would be a benefit to customers, while higher power prices would be a disadvantage to customers. Such a strategy brings greater rate fluctuation. Normalized prices used in rate cases would fluctuate annually with higher than normal or lower than normal prices. Another risk to customers is supplier risk, including both credit risk and performance risk.

A benefit of a Long Assets strategy is the price stability associated with non-reliance on market purchases. It is a form of insurance against price volatility, but as with most insurance, it comes with the cost, or premium, which is the embedded cost of the assets. There is also a risk to the Long Assets strategy if the normalized market price falls below the embedded cost of the new resource. Here the customer pays more than what market could provide under a Short Assets strategy. Another risk to customers is operations risk.

**Load Risk**
The Short Assets strategy is beneficial when loads unexpectedly decline or when expected load growth fails to materialize. In such instances the cost of embedded resources do not need to be spread across a smaller number of customers. Conversely, if load increases more than anticipated, PacifiCorp would be even shorter. PacifiCorp would have to rely more heavily on market purchases, which may result in higher net power costs. Higher net power costs translate to higher rates through electric price risk discussed above. However, surplus energy may have to be sold (which could be good if prices are high or bad if prices are low).

One of the benefits of a Long Assets strategy is that if load increases, there are more assets to cover load growth and less reliance on the market. The risk, however, is that with lower-than-expected load, there is less need for already-newly-built assets, and the embedded cost of the new resources will have to be redistributed across a smaller number of customers thus resulting in higher prices. Of course planned, but unbuilt resource acquisitions can be cancelled if load is lost.

**Fuel Risk**
As was discussed above, fuel risks are normalized in ratemaking. Therefore, customers and shareholders share this risk. The element of fuel risk borne by customers varies with resource strategy, as follows:

Short Assets – To the extent reliance is on Short Assets, there is not a direct Fuel price risk. However the risk is present. It resides in the market prices paid for power. Customer performance risk still exists (as a fuel risk dependency) since the customer bears the fuel risk.
Long Assets – The type of new asset would have an impact on the fuel price volatility, which impacts customer rates.

- Wind – no fuel and, thus, no market price volatility. Therefore, customers face no variable fuel price risk. However, availability of wind could be a variable affecting rates.
- Coal – relatively stable fuel prices. Therefore, customer rates would marginally be affected by changes in fuel price.
- Natural gas – inherent price volatility. Portfolios heavy in gas carry greater fuel price risk, which could either benefit or disadvantage customer rates.

**Plan Cost Effectiveness**

The Utah IRP standards and guidelines also call for an evaluation of cost-effective resource options from the perspective of both PacifiCorp and the different ratepayer classes. Understanding risk apportionment is one important element in the evaluation. Another is assessing the relative cost-effectiveness of the resource plan from the perspective of the utility and the different customer classes.

All customer classes share the same fundamental interest in electric service, i.e., it needs to be low cost and reliable. In general, customers face the same risks associated with selecting a resource plan strategy. It is equally presumed that the relative cost-effectiveness of the resource options is the same across customer classes. This presumption deserves one important caveat. Some customers (e.g., large industrial customers) may tolerate a lower reliability and favor a lower cost (or riskier) approach to power supply. This issue is addressed in ratemaking and with interruptible tariffs, and is not addressed as a resource planning issue. The IRP is based upon providing system-wide firm service with a reliable, low-cost system.

The customers will receive all the benefit of a successfully implemented IRP by receiving low-cost, stable cost, reliable, and well risk-managed power supply. Other than the opportunity to earn a fair rate of return on shareholder investments, subject to regulatory risk as discussed above, PacifiCorp’s shareholders are neutral to the IRP decisions. The choice of resource strategy should be driven by customer interests and should seek the best available balance between cost and risk in meeting power supply needs. Lower risk options tend to impose higher fixed cost “insurance premiums” while higher risk options tend to impose lower “insurance premiums”. The IRP risk analysis is primarily focused on striking the right balance to service this customer interest.

**CONCLUSION**

PacifiCorp faces a wide variety of risks. These risks are inherently linked to the development of the Integrated Resource Plan. Given their distinct nature, different categories of risk receive different treatment within the plan.

Stochastic Risks, with an expected distribution of random outcomes are addressed directly by an analytical approach employing a Monte Carlo simulation. Scenario Risks do not have a
predictable behavior but can still be reasonably represented by parameters in an analytical model. Paradigm Risks do not naturally fit a mathematically driven model and are treated separately. Planning requires thoroughly understanding the Paradigm risks, cogently monitoring their development and structuring the plan to maintain the flexibility necessary to respond to them.

Risk modeling efforts capture and emulate Stochastic risks while representing and testing reasonable ranges for Scenario risks. The results are then interpreted in light of relevant Paradigm risks. By addressing each of these categories of risk, the IRP modeling efforts provide the framework for sound decision making. The next chapter describes this modeling framework.
4. ANALYTICAL APPROACH USED IN IRP

OVERVIEW

The main analytical objective in IRP is to compare the cost (measured as PVRR) and performance (risk or variability of PVRR) of various resource plans. This Chapter highlights the analytical framework used for the IRP. It also describes the methodology for finding the portfolio(s) performing best under a range of possible futures. The information drawn from this analysis, summarized in Chapter 7, will help identify near term actions consistent with the best-performing portfolios.

STEPS IN ANALYSIS

The analysis involves a number of distinct steps.

- **Portfolio Development:** The first step is the formulation of resource portfolios and the selection of modeling assumptions. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios were chosen to span a complete range of likely resource strategies. Detailed assumptions are listed in Appendix C.

- **Operational Simulation:** Next, the operation of each portfolio is simulated. The simulation develops a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.

- **Cost Analysis:** Each portfolio’s system operating costs are then combined with the corresponding capital costs, yielding the PVRR, the main cost metric.

- **Screening:** The PVRR and other measures of a portfolio’s performance allow a screening or winnowing of portfolios, while highlighting those with the most promising performance (lower costs). Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.

- **Risk Analysis & Stress Testing:** The risk analysis simulates the performance of a portfolio under a large number of possible futures. The risk analysis also allows conclusions to be drawn regarding each portfolio’s sensitivities to assumptions about the future and assessments to be made regarding the variability of a portfolio’s cost (see Chapter 3).

The following sections provide a brief summary of each of these analytical steps. More details on the models and methods used in this analysis are provided in Appendix J. Figure 4.1 provides a high level diagrammatic representation of the IRP development process.
**Figure 4.1 Analysis Process**

Portfolio Development
Constructing portfolios was a process of assembling system and market assumptions, estimating PacifiCorp’s short position and choosing which portfolio resources are added each year to serve it. The first two boxes illustrated in Figure 4.1 represent this step.

Determining the short position began with the base demand growth forecast and the profile of energy needs. The profile combined with existing resources illustrated PacifiCorp’s expected short position.

The resources described in Chapter 5 served as the set of building blocks from which each portfolio was constructed. The expected costs of each base-load, intermediate and peaking resource were used to create screening curves, guiding the selection of each building block. Helping fit the most economical resource to the shape and duration of the existing short position, the screening curve served as a simple but highly effective tool to minimize portfolio costs.
As illustrated in the figure above, the selection of building blocks depended upon the size and duration of the short position. Large, long duration short positions were filled with base load resources (coal and/or CCCT gas), since resource screening curves show these are the lowest cost resources when required to operate at high capacity factors. Smaller short positions were filled with intermediate gas resources. Finally, the remaining short position was filled with peakers. This process was repeated every year until the portfolio was completed.

Building a portfolio was not merely a process of randomly adding resources. Guidelines were established to bound portfolio development. For example, resources were added to limit expected spot purchases to 5% or less of each year’s hours. Furthermore, a required planning reserve margin was used to determine any additional capacity resource requirements. A 15% planning reserve margin was used as primary criterion. An alternative of 10% was also tested. Appendix J summarizes the decision process leading to the 5% and 15% limitations.

During the public process surrounding the development of this IRP, significant discussion around “automatic resource addition logic” occurred. PacifiCorp recognizes the potential merit of automatic resource addition logic. The lessons learned from this portfolio building exercise may allow PacifiCorp to include such logic in the next iteration of this IRP. Clearly such logic is complex and for it to be a value adding exercise, much more than construction of a resource addition stack dependent on dispatch cost is required. PacifiCorp is committed to exploring the addition of this logic in the next IRP.

As a result of the resource addition guidelines, each portfolio of new contracts and generation covered much of the anticipated short position. Market purchases satisfy any remaining short position. These guidelines served to constrain PacifiCorp’s exposure to volatile wholesale electricity markets.
While each portfolio differed, groups of portfolios tended to share common characteristics. The following categories evolved:

- PacifiCorp Build
- Transmission
- Diversified Generation
- Renewable
- All-Gas

Details regarding the portfolios and categories are available in Chapter 6. A detailed, step-by-step description of the portfolio development process can be found in Appendix K.

**Operational Simulation**

With candidate portfolios assembled, PacifiCorp simulated the combined hourly operation of its system and the additions. For this purpose, PacifiCorp employed PROSYM, a detailed hourly operations simulation model. PROSYM provides a very precise analysis of resource interactions and the resulting operating costs. Accordingly, the PROSYM box in Figure 4.1 represents this step. Details regarding the PROSYM model can be found in Appendix I.

Before providing output, the model first consumes enormous amounts of data. This kind of resource modeling requires very detailed information including:

- Transmission constraints
- Market price forecasts
- Market price variability
- Resource operating characteristics, and
- The hourly shape of demand

Assumptions for these inputs are important. Changes in each can make a large difference. Market price forecasts begin with PIRA Energy’s long range forecast of natural gas prices. PacifiCorp’s fundamental WECC market model, MIDAS, uses the gas forecast to generate forward electricity prices. Details of the MIDAS model assumptions and methods are described in Appendix I. Assumptions regarding transmission as well as existing and proposed resources are listed in Appendix C and Chapter 5, respectively.

The above inputs are processed and the resulting operating costs are determined. PROSYM also provides a rich array of other details. These include:

- Unit capacity factors
- Transmission loading
- Planning margin
- Market purchases / sales
- Emissions
Combined with operating costs, these factors provide valuable information as to how successfully a portfolio meets its intended purposes. Scorecards, detailed in Appendix E, consolidate and summarize the cost output of PROSYM.

**Cost Analysis**
Operating costs represent only part of a portfolio’s cost profile. An accounting for capital costs must also be made. Capital costs are a function of the kinds of resources in each portfolio and the timing of their addition.

A simple discounted cash flow model combines the capital and operating costs and calculates the PVRR of each portfolio. Real levelized capital was used in the revenue requirement calculation to allow reasonable life cycle cost comparison. (See Appendix K for more details on levelized vs. nominal capital costs.)

**Screening**
With the completion of the previous steps, we obtain a detailed representation of each portfolio. A series of summaries, called scorecards, are assembled for comparative purposes. The scorecards provide comparisons of each portfolio’s

- PVRR,
- Capital Costs,
- Emissions,
- Market Purchases
- Market Sales
- Unit Capacity Factors, and
- Transfers

Using the portfolio scorecards, PacifiCorp narrowed the list of candidate portfolios for stress testing, risk performance measurement and other general analysis. Selected portfolios had superior PVRRs and preferred operating characteristics. Portfolios meeting the 15% and the 10% reserve margin standard were selected, so as to analyze the effect of this significant planning choice.

**Risk Analysis and Stress Testing**
The narrowed list of portfolios was analyzed to assess their risk characteristics. Many of the characteristics necessary to simulate operations and calculate net electricity cost are uncertain. PacifiCorp analyzed the effect of varying these Stochastic Risks using the MarketSym model.

MarketSym develops a large number of scenarios using a statistically valid sampling of the risk parameters. Parameters are randomly varied based on our understanding of the correlation among them as well as their expected values and variability through time. 100 such scenarios were used to test the performance of the portfolios and provide a detailed picture of portfolio performance over a wide range of environments.
Like PROSYM, MarketSym used a detailed hourly dispatch simulation. Unlike PROSYM, the model varied the input risk parameters. Also, to obtain required computational speed, the model employed a simplified transmission representation.

In addition to modeling stochastic risks to observe portfolio performance, several Scenario Risk parameters were modified for the purpose of stress testing the portfolios. Such testing provided performance information over a range of assumed circumstances and allowed the modeling of the impact of parameters without inherently definable, randomly moving characteristics.

A detailed description of each of the risks and the manner it was addressed is available in Chapter 3.

**OPTIMIZATION**

The IRP’s analytical process was, in part, an exercise in portfolio least cost optimization. The convergence of different portfolio PVRRs and rapidly decreasing cost improvements associated with recent modifications, presented later in Chapter 7, are clear signs that portfolios are approaching, if they haven’t already attained, optimality. While the results of the optimization process are apparent, the presence of the optimization process may not be obvious. The information below summarizes some of the procedures, rules and heuristics employed in this process.

**Portfolio Screening Curve**

Discussed earlier in this chapter, portfolios were constructed to fit PacifiCorp’s short position. Individual resources were selected according to a screening curve such that segments of the short position were matched with the most cost effective resources to serve them. Figure 4.2 illustrates the approach.

The screening curve was a powerful first step in the optimization process. The curve served to remove obviously impractical resource solutions from consideration and dramatically reduced the number of model runs needed for the analysis.

**Theories and Themes**

Pursuant to the screening curve, various resource theories and themes were tested. Chapter 6 summarizes the major areas of research which include:

- The effect of altering the order of gas and coal plant installation
- The impact of using coal vs. gas for base load resources
- The value of replacing base load gas resources with multiple, highly flexible peakers
- The effect of altering the timing of base load installation
- The value derived from purchasing contracts vs. resource development.
- The benefit of adding and removing renewable resources.
- The value of greatly expanding East-West transmission links
Portfolios within these themes were modified and improved through an iterative process, serving to identify and eliminate less desirable characteristics. Accordingly, numerous portfolios were generated and tested. For the sake of time and space Chapter 7 and Appendix E list and describe 22 of the major portfolios tested. Detailed discussions are limited to the top four Diversified as well as the Renewable portfolios.

**Operational Signals**
The model simulated portfolio operations and summarized the results. The operating results provided insight into each portfolio’s dispatch profile. They also signaled the presence of inefficient operation. In light of such signals, portfolios were iteratively modified and re-run to produce lower cost configurations.

The following items provide examples of some signals:
- Low capacity utilization factors signaled surplus capacity and suggested the elimination or postponement of resource additions.
- High market purchases signaled a potential under-build of resources.
- High emissions costs signaled sensitivity to Scenario Risks like CO2 taxes and suggested modifications and stress tests.

**Cost and Risk Analysis**
Successful portfolios presented superior cost and risk results. As different portfolio configurations were exhausted, themes with consistently inferior results were eliminated from further consideration. For example the Peakers portfolios (replacing gas base-load with peaking units) as well as the Transmission portfolio strategies consistently diverged from the PVRRs of the top portfolios.

**Industry Expertise**
Perhaps the most important element of the optimization process is the industry and operating experience employed in the development and testing of the portfolios. The modeling process drew upon the experience of individuals inside PacifiCorp. It also drew upon a wealth of intellectual capital outside PacifiCorp through consultants and the public process. Such experience helped identify and overcome operating constraints and capture system benefits in the simulations. It also helped identify portfolio flaws as well as intuit promising areas of research.

**Convergence**
The clearest sign of the success of an optimization process is convergence. Convergence within the IRP is revealed into two ways.

1. Recent, successive iterations provide decreasing, if any, additional cost benefits. Such a progression would be expected as portfolio configurations approach or achieve optimality.

2. The cost and risk differences between top portfolios collapses. As representatives of different, surviving portfolio categories individually approach an optimum, it is expected that the cost and risk differences between the different portfolios collapse.
CONCLUSION

PacifiCorp performed a thoughtful and comprehensive analysis. The analysis began by constructing various portfolios of new resources and then simulating their performance within a model of PacifiCorp’s system and operating environment. From this analysis, PacifiCorp obtained detailed information regarding each portfolio’s costs, performance and risk characteristics. The output was used by PacifiCorp to draw conclusions about strategies with the best cost and risk profiles and naturally leads to the development of a plan of action.
5. RESOURCE ALTERNATIVES

OVERVIEW

There are a large number of demand side and supply side options that could be used in filling the gap between PacifiCorp’s known resources and prospective load obligations. Prior PacifiCorp resource plans have discussed many of these options. This Integrated Resource Plan will focus on the candidate options that are known and are considered as realistic, feasible alternatives for balancing resource supply with electricity demand. Key resources that may be economical and could feasibly be developed by PacifiCorp to meet its needs include:

- Demand side management programs
- New generation investment or purchase based on energy sources such as:
  - Wind
  - Coal
  - Geothermal
  - Combined heat and power
  - Fuel cells
  - Natural gas (peaking and combined cycle units)
- Repowering or expanding existing PacifiCorp resources
- Market purchases
- Shaped products
- Transmission

DEMAND SIDE RESOURCES

A number of influences can cause customers to use electricity more efficiently or to use electricity at non-peak periods. Pricing structures and education can encourage customers to use electricity wisely in their homes and businesses. For the purpose of this IRP, the candidate DSM programs are limited to specific programs that provide financial support to encourage activity that will result in long-term reduced consumption or short-term curtailment.

There are three general sources of DSM resources evaluated in this plan:
- Programs that are currently running or programs in which detailed evaluations have been completed. This analysis resulted in programs that have identified value in $/MWh. This “resource stack” of DSM programs is listed in Appendix G, Table G.2.
- Future, as yet unidentified, DSM opportunities that were determined through stress analysis to the final IRP portfolio using a “decrement approach.” This analysis is described in detail in Appendix G.
- DSM which the Energy Trust of Oregon (ETO) currently has plans to achieve. Table 5.1 provides an overview of the ETO targets.
Table 5.1 Energy Trust of Oregon Projected DSM Achievements (MWa)

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In Oregon, SB 1149 requires that investor-owned electric companies collect from all retail customers a public purpose charge equal to 3% percent of revenues collected from customers. Funds raised through this channel will be spent on energy conservation, new market transformation efforts, above-market costs of new renewable resources, and low-income weatherization. The Energy Trust of Oregon (ETO) was set up to determine the manner in which public purpose funds will be spent. The ETO currently does not have programs up and operating at a level to achieve the goals listed above. The base Oregon load forecast in this plan does account for past DSM activity continuing forward. Over the last 4 years, PacifiCorp’s DSM activities in Oregon have resulted in more than 6 MWa per year of DSM.

**Classes of DSM**

DSM programs vary in their dispatchability, firmness of results, term of load reduction benefit and persistence over time. For purposes of this IRP and for communication clarity when discussing DSM, these programs are being divided into four general classes:

**Class 1**

Fully dispatchable resources: Load reduction only occurs when actively controlled by PacifiCorp. Once the customers agree to participate in a Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within agreed limits and parameters. This type of DSM could affect business economic output.

Examples include residential and commercial central air conditioner load control, irrigation load control, electric water heater load control, interruptible tariffs (facilitated by an under-frequency relay or other utility control system).

**Class 2**

Non dispatchable, growth neutral: Energy and capacity savings that have been achieved through a technological improvement in appliances, equipment or structures. Savings will endure for the life of the installed system. This type of DSM does not negatively affect business economic output.

Examples include programs that add an incentive to customers to replace existing (or to upgrade new construction) customer-owned equipment to more efficient lighting, motors, air conditioning systems, etc. Program examples include the Energy FinAnswer, more energy efficient vending machines (Vendmiser) and the Compact Fluorescent Bulb Giveaway.

**Class 3**

Non dispatchable; buydown: Short duration (hour by hour) energy and capacity savings that are achieved through actions taken by customers voluntarily, based on a financial incentive provided by the Company with hour by hour load reduction results measured on an individual customer...
basis. This type of DSM could negatively affect business economic output. Load reduction endures only for the duration, in hours, of the incentive offering. Permanent facility and equipment changes or improvements are not made. There is no persistence in the load reductions.

Examples include the Energy Exchange program, curtailable tariffs, or real-time pricing.

**Class 4**

Non-dispatchable, conservation education: Energy and capacity reductions achieved through behavioral changes. Specific program results cannot be relied upon for planning purposes. Long-term, persistent changes will be seen in historical load growth pattern changes over time.

Examples include Power Forward, 20/20 Customer Challenge, public education and awareness programs that promote energy-reducing methods such as conservative thermostat settings, turning off appliances when not in use, and inverted block and time-of-use pricing structures.

**Future Programs**

In addition to existing DSM programs listed in Chapter 2 that will be considered for expansion, new programs under consideration include:

**Residential**

Class 1
- Central electric air conditioner load control (residential and small commercial)
- Irrigation load control

Class 2
- Comprehensive residential cooling efficiency. Promote use of fans, evaporative cooling, and high-efficiency air conditioning above federal standards.
- Appliance recycling - Early replacement of old refrigerators and elimination of second refrigerators.
- Energy Star appliance promotion - promote Energy Star appliances which includes incentives for efficient clothes washers that save energy and water.
- “Best practice” AC servicing program to provide targeted tune-up of cooling systems.

**Nonresidential**

Class 1
- Central electric air conditioner load control
- Irrigation load control

Class 2
- Retrofit Building Commissioning - a process for “tuning up” systems in buildings and getting them to work properly, thereby improving the energy performance and comfort in existing buildings.
- Expansion of Energy FinAnswer program.
Class 3

- New commercial and industrial interruptible, curtailable tariffs and real-time pricing.

In addition to these specific potential programs, we are modeling further decrements to the load forecast in the IRP model to determine the value of additional load reductions at various load factors. Further program designs will be considered and the model re-run with these actual program load decrements. Further description of this decrement approach is contained in Appendix G.

SUPPLY SIDE RESOURCES

For the purpose of modeling portfolios, PacifiCorp has identified a list of prospective resources for balancing resource supply with electricity demand based on options uniquely available to PacifiCorp. Table C.18 in Appendix C lists these resources and their specific operating characteristics.

Candidate Supply Side Resources Used in the IRP Analysis

Utah Coal Options

The addition of a fourth unit (Hunter 4) at the existing Hunter Plant in central Utah was selected to represent a state of the art pulverized-coal plant option for the IRP. Hunter 4 would use the latest available emission control technology for SO₂, NOₓ, and particulate. This unit would remove more than 97% of the SO₂ produced and would incorporate Selective Catalytic Reduction (SCR) to control NOₓ emissions to less than 0.08 lb. NOₓ/mmBtu. The Hunter site is presently viewed as an excellent company owned location for an additional unit because the existing units already there would lend supporting infrastructure (substation and transmission included) and manpower to its operation. It is also close to sufficient coal resources to fuel the unit.

The Utah Greenfield PC represents a new coal plant at a completely new generation site in the Utah area. Costs for the greenfield facility are based upon a two unit plant (to achieve economies of scale) using the Hunter 4 design. These costs are higher than those of Hunter 4 simply because of the inability to use common facilities, as compared to the common facilities already existing at the Hunter Plant.

IGCC is a clean coal technology that utilizes a coal gasification process to produce clean fuel gas that can then be used to fuel a combined cycle gas turbine. This technology can achieve slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant. However, IGCC is only now beginning to reach full commercialization. There are a half a dozen or so commercial plants in the world to date and most of these are fueled by petroleum residuals. Capacity factors for these plants typically have been less than 80%. Nevertheless, work is being done to improve their operation on both coal and petroleum residuals and progress in this area is expected. Capital and operating costs are now higher than those of traditional coal-fired plants, but these could come down as larger economies of scale are reached. IGCC production costs in the Utah and Wyoming areas will be further disadvantaged compared to lower elevation areas because of elevation de-rating of the gas turbines. Most of the Utah and Wyoming coal sites are
at relatively high elevations. PacifiCorp will continue to follow this technology for future additions as the technology becomes more established and the cost decreases.

**Wyoming Coal**

Because Wyoming has large quantities of low cost coal, new conventional coal plants there are a definite possibility. A fifth unit at the Jim Bridger Plant represents the first 500 MW plant shown for Wyoming. Additional units would be built near the Powder River Basin coal area. Capital costs for all of these units were derived from the design and cost for Hunter 4, a plant of similar size. However until transmission constraints in Wyoming are removed, it will be economically difficult to justify building a new coal plant there.

**Combined Heat and Power (CHP or cogeneration)**

Utah CHP was developed to represent a cogeneration opportunity along the Wasatch Front. The “Cogen-CT” CHP represents a combustion turbine generating steam for industrial purposes. A large CT is modeled. This option is dependent on the proper host and is considered a low probability considering the industrial base in Utah. The “Non CT” case is intended to be a boiler or waste heat application that could apply a topping steam turbine at relatively low cost. No specific candidate cogeneration sites are currently identified.

**Geothermal**

Renewable energy could be added to the resource portfolio with the addition of more geothermal capacity at the Blundell Plant. The 50 MW block of electricity shown represents the cost of adding bottoming cycle to the current Blundell Plant and then adding an additional flash and bottoming cycle system. This is a very realistic option currently under review by PacifiCorp. Total capacity of the Blundell Plant with the addition of the Blundell Upgrade would be about 75 MW.

Two other geothermal sites are considered for modeling purposes. These are known sites with some development work completed and known potential plant capacity evaluated. One is a 50 MW site near the current Blundell plant in Utah. The second is a 50 MW Newberry volcano site in central Oregon, near the city of Bend. Other sites will also be considered, as information becomes available.

**Fuel Cells**

Fuel cell technology continues to improve and become more cost effective. A fuel cell is an electricity-generating device, fueled by natural gas, that utilizes the reaction between hydrogen and oxygen with the only by product being water. Attractive fuel cell characteristics include:

- High energy conversion efficiency
- Modular design
- Very low chemical and acoustical pollution
- Fuel flexibility
- Cogeneration capability
- Rapid load response.

Disadvantages include high capital costs and technological uncertainty.
Market Purchases/Contracts
Market Representation Assumptions
The process of developing portfolios must also contemplate supplemental access to the spot market. PacifiCorp considered several methods for representing market purchases and sales. Initial studies included few limitations on spot market transactions. This raised concerns regarding the extent to which spot markets could reasonably be depended upon to meet short duration peak deficits and to follow load during light load and shoulder hours. Exempt from such considerations, the studies tended to undervalue load-following and peaking resources.

To better represent market limitations, the availability of market purchases was constrained. The limitations are described in more detail below:

- Three markets are represented in the model (Palo Verde, Mid Columbia, and COB)
- Purchases and sales were limited at each (250 MW each at Mid Columbia and COB, and 500 MW at Palo Verde).
- Transmission congestion issues and limited firm transmission rights in the East require a transmission cost associated with reaching the Palo Verde market.
- Purchases and sales into these stations have no ramp rate, minimum up time, minimum down time, or startup cost restrictions.

The markets are meant to represent the flexibility of hourly transactions that routinely take place on the system to help balance loads and resources. Figure 5.1 provides a graphical depiction of the price forecast used in the modeling.

Figure 5.1 IRP Price Forecast – Monthly Flat, Average Prices

![Price Forecast Graph]
Asset-Based, Long Term Power Purchase Agreements (PPA’s)
All market purchases used in building portfolios are modeled as PPA’s that are tied to physical assets. These purchases are from energy merchants and other industrials offering surplus electricity that they have available. Contracts are modeled such as would be used in real life and are modeled to perform accordingly. Most contracts have fixed prices and are used in the heavy demand hours; the price of several contracts tie to indices and so will dispatch based on least cost as compared to their associated markets.

A review of WECC-wide load as compared to WECC-wide resources suggests there will be an over-supply of generation available in the next five years. The over supply will largely be as a result of more than 16,500 MW of new generation currently under construction (plus approximately 15,500 MW new generation between January 2000 and August 2002). However, due to transmission constraints, additional transmission capacity would have to be built to reach the load centers.

Shaped-Products
Several short term Power Purchase Agreements (PPAs) from energy merchants and others are available to PacifiCorp today and availability of these products is expected to continue in the future. While not all these shaped products are explicitly modeled in the portfolios, they will be used in the future to meet load requirements if the cost/risk balance at the time is appropriate for the customers and PacifiCorp.

The following is a list of energy or shaped-products that PacifiCorp would consider purchasing from credit-worthy market participants if they exist:

- **Call Option with fixed premium** – The option buyer has the right but not the obligation to buy energy and capacity at specific rates at a defined strike price. The buyer would exercise this right when market prices exceed the strike price. This option provides price protection from high prices.
- **Put Option with fixed premium** – The option buyer has the right but not the obligation to put, or sell, energy and capacity at specific rates at a defined strike price. The buyer exercises this right when market prices are below the strike price. This option provides price protection from low prices.
- **Swap** – A swap is an exchange of cash flows between a swap seller and the swap buyer. The swap seller owns capacity and energy at a fixed price and has exposure if market prices move lower (a coal plant for example). The swap buyer needs energy and capacity and purchases this requirement each day and has exposure if prices move higher (a marketer without generation). The swap seller hedges his position by selling a notional (financial) quantity of energy and capacity to the buyer at a fixed price. The swap allows the seller to hedge his fixed price risk and allows the buyer to hedge his index or daily price risk.
- **Tolling Option with fixed premium** - The option buyer has the right but not the obligation to call, or buy, energy and capacity at specific rates at a defined heat rate multiplied by a gas price index (energy price). The buyer would exercise this right when market price for electricity exceeds this energy price. This option provides protection from high prices and might be used instead of a call option with a fixed strike price.
• **Straight Block Purchases (e.g. 6 x 16, 7 x 24)** – Buyer has the obligation to take and pay for energy and capacity at specific rates at a fixed price. The buyer needs energy and capacity and purchases this requirement each day and has exposure if prices move. The buyer reduces his floating price exposure and receives energy and capacity at a fixed price. The seller reduces his index price exposure and sells energy and capacity at a fixed price.

**Natural Gas**

**Natural Gas East Side**

Several options exist in the Utah area for new natural gas-fired electricity plants all based on using gas turbines. Gas turbines in the Utah area are assumed to be located at an elevation of 4,500 feet and would experience a de-rating of 15% from ISO values due to this elevation. Additionally, the ratings used are based on a 90°F summer type condition since Utah is a summer peaking application.

Simple-cycle Combustion Turbines (SCCTs) are modeled. These machines are true peakers and are represented by aero (aeroderivative) machines such as the LM6000 design from GE recently installed at West Valley and Gadsby. These machines have high efficiency and can start within 10 minutes to qualify as spinning reserves.

The Frame machine represents another type of SCCT. These heavy-duty industrial combustion turbines are generally larger, lower in first cost, less efficient, and have longer start times than the aero machines. A Siemens-Westinghouse 501D5A machine was used to represent this option. The Brownfield SCCT Frame Mona option represents this type of machine located away from the Wasatch Front to allow installation without maximum NOx control. Not installing SCR for NOx on this type of machine will save considerable capital cost but would most likely involve operating restrictions in the form of reduced allowed operating hours. Limited hours of operation may be acceptable if the machine is installed mainly for super-peak type capacity.

Combined-Cycle Combustion Turbines (CCCT) are also modeled. On the Utah side, an addition to the Gadsby Plant is shown as either a single 1x1 machine or a CCCT in a 2x1 configuration. Emission controls are assumed to be Best Available Control Technology (BACT). A 2x1 configuration (two gas turbines and one steam turbine) is the best representation for a base-loaded CCCT with a capacity factor greater than 70%. For more intermediate duty (capacity factors between 30% and 70%) the 1x1 configuration will be a better application. The 1x1 design will be easier to start and stop on a frequent basis and will have a quicker starting time profile. The O&M costs for the 1x1 options reflect the additional starts associated with intermediate operation.

Combined cycle equipment is also modeled with the option of adding duct firing for additional peak capacity. This option may or may not be available with all CCCT suppliers but has been included to reflect the capability of the GE machines used. Duct firing will require additional investment in gas burners and the steam turbine system. It is expected that environmental constraints may limit the capacity factor of installed duct firing to an equivalent of 15% capacity factor.
Natural Gas West Side
Similar natural gas options are available on the West Side as were identified on the East Side of the PacifiCorp system. Simple cycle and combined cycle gas turbine representative installations on the West Side of the system have been adjusted for an elevation near the Hermiston Plant. The equipment ratings are based on an elevation of 1500 feet, which results in a 5% derating from ISO conditions. The 90-degree Fahrenheit rating has been maintained.

Wind
Wind generation has been represented in the IRP model for east and west control areas in two ways. Initially, wind resources were modeled at the proposed Federal RPS level as a flat 7x24 product purchased at $50/MWh in 2002 dollars, escalating at inflation in all the IRP Portfolios. This rate includes obtaining any tax benefits in the negotiated price from the developer as well as an assumption regarding integration costs, capital, O&M, and transmission. Estimates are included in Appendix L. Table 5.2 provides an overview of the planned build up of the RPS.

Table 5.2 The planned build up of RPS over the period 2005 to 2013

<table>
<thead>
<tr>
<th>Year</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>% of Resources</td>
<td>1.0</td>
<td>1.6</td>
<td>2.2</td>
<td>2.8</td>
<td>3.4</td>
<td>4.0</td>
<td>4.6</td>
<td>5.2</td>
<td>5.8</td>
</tr>
<tr>
<td>Cumulative MW (Capacity)</td>
<td>60</td>
<td>186</td>
<td>318</td>
<td>414</td>
<td>546</td>
<td>687</td>
<td>834</td>
<td>981</td>
<td>1,146</td>
</tr>
</tbody>
</table>

All of the final portfolios contain wind resources that were modeled with representative wind electricity production shapes according to site location. The hourly wind sites were created on simulated historical hourly generation data from Stateline and actual historical data from Foote Creek. These two data streams were modified by lagging by one hour and moving data ahead one hour to create four new data ranges for the model. The two Stateline streams were added together and then sized to the maximum capacity of the Yakima and Bend sites in the West with a capacity factor of 32%. The two new Foote Creek sites were combined and prorated up to the maximum capacity of the Evanston and Tooele sites in the East control area with a 36% capacity factor. A single year of hourly generation was repeated over the 20-year life of the study. Further information is still required on the actual quality and location of sites.

The cost of installed wind capacity is based on the latest Northwest Power Planning Council (NWPPC) estimates of $1000/kW. Total $/MWh costs are sensitive to expected capacity factor, which are modeled as described above, and include fixed O&M, transmission, system integration costs, the production tax credit, and green tag value. Further detail on system integration and pricing can be found in Appendix L.

For modeling purposes PacifiCorp assumes it can take advantage of Federal wind energy tax credits, a wind energy production tax credit applied to energy delivered, when the company builds and owns new wind generation projects and produces electricity. Whether PacifiCorp can or cannot take full advantage of these production tax credits in any given year depends upon the company's tax situation in that year. PacifiCorp from time to time may be subject to the alternative minimum tax which would limit its ability to fully use tax credits. The wind energy tax credit can be carried forward; however, this results in less value from the tax credit because
PacifiCorp loses the time value due to the delay in cash flow from the tax credit. The economics of a wind facility is adversely impacted if the credit is not allowed in the year of production.

**Supply Side Resources Not Used in the IRP Analysis**

Certain resources listed in Table C.18 in Appendix C are not currently considered feasible for meeting PacifiCorp’s resource needs. These include nuclear resources, tidal action resources, microturbines, and others that are either not commercially available or are clearly not cost effective based on earlier IRP analysis.

Two options that are currently not being included in IRP portfolio analysis due to cost, but are being monitored closely for future use, include pumped storage and solar.

The pumped storage option was not cost effective based on the known location. The pumped storage option represented in Table C.18 was a potential project near Las Vegas. This 400 MW project would take off-peak coal-fired generation and use the energy to pump water into a reservoir. Water from the reservoir would then be released to spin the pumps as a generator to provide peaking electricity. The 400 MW capacity could be used about four hours during a day under this operating scenario.

The solar options in Table C.18 are represented by a solar thermal plant similar to Solar II that was demonstrated in the California desert in from 1996 to 1999 with PacifiCorp’s participation. Molten salt is used as a heat reservoir to get a capacity factor of better than 63% and to avoid equipment down time during cloudy days.

Photovoltaic projects are not listed due to the extreme cost of this technology for large electrical production needs.

**TRANSMISSION**

Several upgrades and additions to the Transmission network are necessary to further optimize the use of the network, provide greater access to market or support the addition of new assets. As mentioned in Chapter 2, the main area of congestion on the system is Utah, therefore the focus of this section will be on explaining the current situation in Utah and how the portfolios were built to relieve transmission congestion issues.

The simultaneous import capability into the Utah Bubble is significantly lower than the sum of the individual non-simultaneous path limits, as it is not possible to reach each path limit at the same time due to loop flow. In other words the one-path limit is reached while there is remaining capacity on other paths that cannot be realized. The Mona entry is excluded from the simultaneous import limit total, as it ties into the center of the Utah Bubble.

Load growth further saturates the existing transmission system. Additional transmission facilities were needed north of Mona in all portfolios to bring power into the Wasatch Front. These additions consist of a new Static Var Compensator (SVC) at the Wasatch Front load center for voltage support, and new breaker additions at Mona and Spanish Fork substations to “loop in” existing 345 kV lines for increased transfer capability from Mona to the Wasatch Front load.
center. These additions by Fiscal Year 2005 increase the Mona to the Wasatch Front interface capability by 500 MW increasing the available capacity north of Mona to 1,000 MW.

The southern entries into Utah consist of three lines: Four Corners to Pinto to Huntington 345 kV, Harry Allen to Red Butte to Sigurd 345 kV, and Glen Canyon to Sigurd 230 kV. These lines span southern Utah to the north, connecting to the main Utah grid at Sigurd and Hunter/Huntington. These two network nodes interconnect to the main Utah grid, forming a triangle with Camp Williams and Spanish Fork the entrance points into the Wasatch Front. The three legs of the triangle are:

1. Two 345 kV lines from Hunter/Huntington to Sigurd
2. Two 345 kV lines from Sigurd to Camp Williams and one from Huntington to Camp Williams, connecting through Mona; making Mona a natural trading hub. Two 345 kV lines from Hunter/ Huntington to Spanish Fork to Camp Williams; the triangle depiction is as shown in Figure 5.2.

Figure 5.2 Utah Main Transmission Triangle

![Figure 5.2 Utah Main Transmission Triangle](image)

The close proximity of Mona to the Wasatch Front makes it a practical site for building, optimizing the capital requirement for transmission integration. This is the logic for targeting Mona in the IRP for an additional 1,000 MW of resources. Hence, reinforcement to the triangle was nominated to integrate the incremental addition. The Nevada market, via Harry Allen to Red Butte is then pursued beyond the 1,000 MW capability at Mona.

Transmission facilities were also added south of Mona when additional resources were delivered from points south (i.e. Hunter, Nevada). Such resources also require additional reinforcement to the triangle when these southern resources plus Mona resources were in excess of 1,000 MW.

In addition to these upgrades and additions, transmission options were considered for opening up and building greater flexibility into the system. Two DC transmission lines of 1,000 MW and 2,000 MW DC transmission lines were considered, which would increase the bi-directional line capacity between the East and West control areas.
6. PORTFOLIOS

OVERVIEW

This describes the portfolios that were evaluated based on the methodology described in Appendix J. Each portfolio contains realistic, feasible demand side and supply side alternatives for balancing resource supply with electricity demand. Timing and size of these alternatives are compared between portfolios.

While the majority of the individual portfolios were developed based on the methodology that required a 15% planning margin, a stress case was tested on some of the portfolios using a 10% planning margin. These portfolios were developed to compare the financial, operational, risk, and customer impacts of a 10% versus a 15% planning margin. These portfolios can be identified by the ‘-10%’ after the portfolio name. The results of this stress will be discussed in Chapter 7.

A detailed description of each portfolio is located in Appendix D. The tables in Appendix D contain portfolio names, resource types, size and timing of installation, and total megawatts installed. Transmission installations and estimated costs required for each portfolio, along with capital costs of resources are also provided. The Appendix should be consulted for details on the resource mix and addition dates for each portfolio.

The Chapter will begin by discussing some of the factors and metrics common to all the portfolios that were developed. There will then be an overview of some of the observations and conclusions that can be drawn from the portfolio development process. An overview of the first iteration of portfolios based on portfolio category will be provided, along with the benefits, issues and uncertainties associated with each portfolio category. And finally, a discussion on how the portfolios were further refined (“hybrid portfolios”) by taking the best of all portfolios and combining them to achieve the least-cost solution.

COMMON FACTORS & METRICS

Several resource additions are common to all portfolios and contribute substantially to future resource requirements. All portfolios required substantial resource additions to meet base demand growth of 2.2% East and 2.0% West per year, on average, to replace resources that are lost through attrition of the existing base of resources and to cover the 15% planning margin. Total system resource additions of approximately 4,000 MW are required in the next ten years. Additions are required in both East and West control areas.

DSM

All portfolios share base DSM investments, beginning in 2004 and steadily increase their contributions to 146 MWa by 2013 of Class 2 DSM and 91 MW of Class 1 DSM. This base DSM resource is included whether the system is built to 10% or 15% reserve margin. Additional DSM resources are evaluated as stresses to the final portfolio using the decrement analysis technique which is described in Appendix G.
Wind Resource Additions
The portfolios that were developed in the beginning of the analysis contained common wind resource additions based on the levels required in the proposed Federal Renewable Portfolio Standard (RPS). The wind additions began in 2006 and grew to about 1,150 MW by 2013, and were modeled as a $50/MWh flat contract. A flat contract provides equal delivery of energy in every hour of the day.

In the final portfolios, the $50/MWh flat contract was replaced with “profiled wind”, i.e. wind whose profile follows an anticipated, more realistic production shape. Under profiled wind, energy deliveries are anticipated to differ in each hour of the day. This profiled wind has been included based solely on its economic merits.

Short-Term Purchases
All portfolios require short-term purchases to meet capacity and energy needs for the 2004-2006 period. These purchases will be secured from the marketplace. Capacity purchases of 225 MW for summer super-peak hours are indicated for PacifiCorp’s eastern control area. In the western control area, purchases of 500 MWa of off-peak energy are required. The timing of this need appears to coincide with a likely temporary over-supply situation in western electricity markets. These near-term purchases are required whether a 10% or 15% reserve margin is adopted.

Reserve Peakers
If a 15% reserve margin is adopted, an additional 430 MW of reserve peaking generation are required in 2006. In general, 200 MW are needed in the eastern control area and 230 MW in the western control area. By 2007-2008, additional capacity resources are needed to meet reserve capacity needs of either the 10% or 15% reserve margin requirements.

PORTFOLIO DEVELOPMENT

The portfolio development process discussed in Chapter 4 and Appendix J provided a number of useful insights. Many observations and conclusions could be drawn at the portfolio development stage of modeling. Model runs and subsequent analysis further clarified these initial observations and conclusions. They are as follows:

Base Load
The East and the West systems require additional base load resources in the future. Existing plant retirements, load growth, and long-term purchase contract expirations all contribute to this need and are common to all portfolios. The net position duration curves for the system show large gaps for greater than 60% of all hours by 2008. All portfolios fill this need for base load resources with combined cycle units and/or coal fired resources.
**Peaking**
Every portfolio required at least 1,000 MW of peaking resources to meet the needs of additional capacity for the planning margin. Peakers are lower cost capacity options, which provide the necessary operational flexibility to manage system reliability requirements. The gap in the West can be described as a base load profile, though the addition of peaking units provides the reserves necessary to meet the planning margin.

**Shaped Products**
Shaped products and electricity purchase agreements (PPAs) help resolve some of the immediate requirements for on-peak energy in the East and the off-peak gap in the West prior to actual physical assets being built. It is expected that any build option will be compared to the equivalent available shaped product or PPA at the time the decision to proceed with the build option has to be made. It is anticipated that the majority of shaped products and PPAs will be closely linked to physical assets to ensure the capacity is available. Shaped products will also be procured to hedge and reduce the risk exposure to variations in thermal, hydro and wind performance.

**Transmission**
Every portfolio involves some investment in transmission upgrades. Without transmission improvements, the growing needs of the East will not be met. Only a limited number of resources can be added directly into the Wasatch Front due to airshed restrictions. Increased transmission capability is needed to meet growing loads.

**PORTFOLIO CATEGORIES**
To explore a broad range of possible resource mixes, portfolios were first developed in three different portfolio categories: thermal, alternative technology and transmission. The different portfolio categories can be compared to learn operational differences based on resource type under varying assumptions. The following section discusses each category in more detail.

**Portfolio Category: Thermal**
Portfolios in the thermal category contain a mix of coal and natural gas additions. There are four subcategories of thermal portfolios: Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build. Each subcategory contains individual portfolios that are used to test the timing and size of resource additions. Below are brief descriptions of the each subcategory, and a listing of all portfolios that were developed in each subcategory:

**Gas/Coal**
This subcategory includes wide ranging portfolios with one or more natural gas plant additions in the early years and a coal fired plant in Utah or Wyoming in later years. In this and other portfolios peaking units are added as required to bring capacity up to required margin levels.

Portfolios contained within this subcategory include Gas/Coal I, Gas/Coal I – 10%, Gas/Coal II, Gas/Coal III, Wyoming Coal, and Peakers.
Coal/Gas
This subcategory also includes wide ranging portfolios however timing of the Coal and Natural Gas base load units are switched. These cases install a Utah area coal plant addition in the early years and combined cycle natural gas plants in later years. Portfolios contained within this subcategory include Coal/Gas I, Coal/Gas II, Coal/Gas III, and Coal/Gas III – 10%.

All Natural Gas
The all natural gas portfolios are similar to the Gas/Coal and Coal/Gas portfolios listed above, except a base load coal plant is replaced with a combined cycle natural gas plant. Therefore, in this subcategory, the primary fuel in all new thermal resources is natural gas.

Portfolios contained within this subcategory include All Gas I, All Gas II, and All Gas II – 10%.

PacifiCorp Build
This subcategory places additional emphasis on construction. The contracts present in other portfolios are replaced with PacifiCorp constructed assets. These portfolios can be compared to those with contracts to determine the difference in costs to build as well as the level of risk associated with building.

Portfolios contained within this subcategory include PacifiCorp Build I, PacifiCorp Build II, and PacifiCorp Build II – 10%

Benefits, Uncertainties and Issues
There are benefits, uncertainties, and issues associated with portfolios in the thermal category. One benefit is the good prospects for siting and licensing generation, since PacifiCorp currently owns or controls existing thermal generation sites with room for expansion. Another benefit to the thermal portfolios is that PacifiCorp can make use of existing transmission corridors. Finally, PacifiCorp currently has experience with building, owning and operating thermal facilities.

One uncertainty associated with thermal portfolios, and more specifically those thermal portfolios that contain coal additions, is the impact of future environmental legislation. The thermal portfolios with a large amount of combined-cycle or peaking plants are also faced with the uncertainty surrounding future natural gas price volatility.

Portfolio Category: Alternative Technology
The purpose of the Alternative Technology portfolios was to build portfolios that ultimately reduced the number of thermal plants in PacifiCorp’s system and replace them with a combination of conservation and alternative technologies. This was accomplished by adding additional wind plants, over and above the wind that was developed in the Thermal Portfolios, in both the East and West control areas, as well as geothermal plants, fuel cells, CHP and additional DSM. The Load control program used in these portfolios is 30MW of new A/C load control program above that contained in all portfolios. Natural gas-fired plants (CCCTs and Peakers) were used to fill the energy balance and build the portfolio to the 15% planning margin.
Portfolios contained within this category include Alternative Technology I and Alternative Technology II. The differences between these two portfolios include the wind and peaker build patterns, as well as the replacement of a 1x1 CCCT in the West with a 2x1 CCCT. Tables 6.1 and 6.2 highlight the differences between the Alternative Technology I and Alternative Technology II portfolios.

### Table 6.1 Alternative Technology I Portfolio Comparison for Build Pattern

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</thead>
<tbody>
<tr>
<td>Wind East</td>
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<td>-</td>
<td>600</td>
<td>-</td>
<td>-</td>
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<td>200</td>
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<td>Peakers West</td>
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<td>-</td>
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### Table 6.2 Alternative Technology II Portfolio Comparison for Build Pattern

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<td>Wind East</td>
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<td>-</td>
<td>-</td>
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<td>-</td>
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<td>200</td>
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<td>200</td>
<td>-</td>
<td>200</td>
<td>-</td>
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</tr>
<tr>
<td>Peakers Mona</td>
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<td>200</td>
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<td>-</td>
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<td>Peakers East</td>
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<tr>
<td>Peakers West</td>
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<td>CCCT KFalls</td>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>510</td>
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</table>

As mentioned above, in all the initial portfolios the wind was modeled as a flat contract based on the Federal RPS. In the Alternative Technology portfolios, the additional wind (above the RPS level) is modeled as a PacifiCorp build option using historical wind plant data from sources near potential plant sites. By modeling the historical data some indication can be given of plant output variability, but this does not necessarily result in a fair representation of all the wind integration costs associated with firming electricity output and dispatching. Appendix L provides additional information regarding the costs associated with wind integration costs.

An important assumption to note in this portfolio is that the additional wind capacity (1,420 MW) added in this portfolio was not used in the calculation of the planning margin, therefore the additional capacity identified for the wind plants was over and above the 15% planning margin in this portfolio. This assumption was based on the fact that hourly wind output is not sufficiently reliable to count towards reserves. This is another conservative assumption. This conservative assumption is tested as a stress case in Chapter 7.

For the first five years of their operation, it is assumed that a Green Tag credit of $5/MWh accrues to PacifiCorp and its customers, as a result of adding the wind and geothermal plants. There is also an assumption that the Production Tax Credit (PTC) will be available at $18/MWh for the first ten years of the wind plant life and the first five years of the geothermal plant’s life. These credits assumed for renewable resources, together with the differential provided by the
assumed carbon tax costs inherent in other portfolios, combine to suggest significant cost savings for the Alternative Technology category that may or may not be realized, as is discussed in Appendix L.

Benefits, Uncertainties and Issues
There are benefits, uncertainties, and issues associated with the Alternative Technology portfolios. One of the most noticeable benefits is the reduction in emissions as a result of adding renewable and natural gas resources. There is also a benefit associated with further diversification of the resources in PacifiCorp’s overall resource portfolio. Diversification mitigates fuel price risks and paradigm risks.

Some of the uncertainties identified in the Alternative Technology portfolios include:

- Fuel Cells are commercially proven technology that has been widely dispersed in the utility industry.
- There is both a high capital requirement and siting uncertainty for either PacifiCorp or a third party to build the level of wind required in these portfolios.
- Quality and location of potential wind sites, and associated transmission have not been fully identified.
- Specific DSM programs have not been identified or modeled for these portfolios.
- Integration costs associated with the wind plants need additional study, including regulating margin uncertainty, balancing charges for natural gas supply, and changes in integration costs as a function of wind capacity installed. Appendix L provides more detail on wind integration costs.
- The market clearing value of Green Tags and the annual availability of the Federal Production Tax Credit associated with the renewable resources are uncertain.

Portfolio Category: Transmission
The purpose of portfolios in this category is to concentrate on increasing system benefits by enhancing transmission capability to liquid and built markets as well as between PacifiCorp control areas and load centers. One of the main assumptions common to each portfolio in this category is that PacifiCorp builds and owns the transmission lines constructed, and does not include any participation or use of the line by third parties. It is assumed that such participation, though not modeled, would reduce costs of these portfolios.

There are two subcategories of thermal portfolios: East-West Transmission and Transmission to Asset Markets. Below are brief descriptions of the each subcategory, and a listing of all portfolios that were developed in each subcategory:

East-West Transmission
In these portfolios, a DC line was constructed from the Wasatch front to Malin, Oregon to allow better flexibility to transfer electricity from the East and West control areas. The new transmission line is a bi-directional, high-voltage DC line that was evaluated at two different sizes (1,000MW and 2,000 MW) to determine the most cost-effective option. Thermal resources are added to both the East and West control areas in each of these portfolios to meet energy requirements, and additional capacity was added to meet a 10% planning margin.
Portfolios contained within this subcategory include Transmission 1,000 MW DC and Transmission 2,000 MW DC.

Transmission to Asset Markets
This portfolio increases transmission access to markets with assets built by other parties. This portfolio assumes that by building and owning transmission, there will be additional opportunities for electricity purchase agreements tied to these assets. This portfolio concentrates on building lines in the eastern control area, specifically to the southern Nevada. As described in Chapter 1, there is currently a wave of new merchant generation construction in the WECC. This is concentrated in the Southwest. Transmission access to these assets in and through southern Nevada represents a significant opportunity to negotiate electricity purchase agreements with third parties that constructed plants in this area.

The only portfolio constructed in this subcategory is called Transmission to Asset Build Market.

Benefits, Uncertainties and Issues
There are benefits, uncertainties, and issues associated with portfolios in the transmission category. One benefit to constructing a DC line that connects the East and West control areas is that it would allow for greater system flexibility and greater utilization of existing resources. This could also result in a reduced planning margin. A benefit to increased transmission access to markets with assets built by other parties, is that it allows PacifiCorp to have access to low cost markets, and would reduce the capital requirement necessary to construct new plants.

The major uncertainty associated with the transmission portfolios is the potential impact of the RTO West. There are still unknowns related to who will pay for the cost and the mechanism in place for recovery of transmission investments. Under RTO West, planning authority for an individual utility is also uncertain. Market design is still under discussion and will affect the economics of both transmission and generation investments. Third party utilization is an important factor in making the construction of new transmission cost-effective, and is still an uncertainty related to RTO West. There is also the issue related to constructing the DC line from the Wasatch Front to Malin, 625 miles of “right of way” would need to be negotiated to construct the line.

HYBRID PORTFOLIOS
After portfolios were developed and analyzed based on the portfolio categories, hybrids of these portfolios were developed using the best characteristics of the results of the existing portfolios. Five hybrid portfolios were created - Renewable, Diversified Portfolio I, Diversified Portfolio II, Diversified Portfolio III, and Diversified Portfolio IV. Below is a summary of how these portfolios were developed:
**Renewable**
This portfolio was developed using the Alternative Technology II portfolio as a starting point. To create the Renewable portfolio, the fuel cells, CHP, and DSM were removed from the Alternative Technology II portfolio, and replaced with a Mona 2x1 in 2009.

**The Diversified Portfolios**
These portfolios were developed using the top four thermal portfolios in each sub-category (Gas/Coal, Coal/Gas, All Gas, and PacifiCorp Build), and replacing the RPS flat $50/MWh contract with the gradual, profiled wind used in the Renewable and Alternative Technology II portfolios. A thermal contract was added to each of these portfolios to replace the lost capacity associated with the $50/MWh flat contract. Table 6.3 summarizes the new gradual, profiled wind used in all three diversified portfolios, as well as the thermal contract added to replace the capacity value given to the $50/MWh flat wind contract.

**Table 6.3 RPS Replacement in Diversified Portfolios**

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<td>-</td>
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<td>-</td>
<td>200</td>
<td>-</td>
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<td>25</td>
<td>25</td>
<td>25</td>
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The three Diversified Portfolios were developed from the following initial portfolios:
- Diversified I was developed from Coal/Gas III
- Diversified II was developed from PacifiCorp Build I
- Diversified III was developed from Gas/Coal I
- Diversified IV was developed from All Gas II

**Hybrid Portfolio Comparison**
The following tables (Tables 6.4, 6.5, 6.6, 6.7 and 6.8) identify key distinctions between the five hybrid portfolios.
### Table 6.4 Diversified I Portfolio Comparison

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<tr>
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<th>2006</th>
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<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>Total MW's</th>
</tr>
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<td></td>
</tr>
<tr>
<td>Thermal contract (installed capacity in MW)</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>175</td>
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<td></td>
</tr>
<tr>
<td>Class 1 DSM (load control - peak MW capability)</td>
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<td>30</td>
<td>31</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Class 2 DSM (MWs added each year)</td>
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<td>11</td>
<td>12</td>
<td>12</td>
<td>12</td>
<td>12</td>
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<td>200</td>
<td>200</td>
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<td>Coal Base Load (Hunter 4)</td>
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</tr>
<tr>
<td>CCCT (Mona)</td>
<td>First new base load is coal in 2008 vs. gas in 2007 for other portfolios.</td>
<td>510</td>
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<td>Peaker East (Mona)</td>
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<td>175</td>
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<td>2</td>
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<td>200</td>
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### Table 6.5 Diversified II Portfolio Comparison

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<th>2012</th>
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<th>Total MW's</th>
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<td>Thermal contract (installed capacity in MW)</td>
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<td>25</td>
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<td>25</td>
<td>25</td>
<td>175</td>
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<tr>
<td>Class 1 DSM (load control - peak MW capability)</td>
<td>30</td>
<td>30</td>
<td>31</td>
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<tr>
<td>Class 2 DSM (MWs added each year)</td>
<td>30</td>
<td>12</td>
<td>11</td>
<td>12</td>
<td>12</td>
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<td>Wind (East - installed capacity in MW)</td>
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<tr>
<td>Coal Base Load (Hunter 4)</td>
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<tr>
<td>CCCT (Mona)</td>
<td>First new base load is coal in 2008 vs. gas in 2007 for other portfolios.</td>
<td>510</td>
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<tr>
<td>Peaker East (Mona)</td>
<td>Hunter and Mona base load units exchange places in this portfolio.</td>
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<tr>
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<td>175</td>
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<td>22</td>
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### Table 6.6 Diversified III Portfolio Comparison

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<th>Total MW's</th>
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<td>Thermal contract</td>
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<tr>
<td>Class 1 DSM (load control - peak MW capability)</td>
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<td>Super Peak Contract</td>
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<td>Coal Base Load (Hunter 4)</td>
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**Notes:**
- Gadsby and Mona additions switch between Diversified II & III
- Smaller K-Falls CCCT replaces Albany CCCT in other portfolios

### Table 6.7 Diversified IV Portfolio Comparison

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**Notes:**
- All new base-load units are gas-fired
### Table 6.8 Renewable Portfolio Comparison

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**SUMMARY**

This Chapter has provided an overview of the different resource portfolios PacifiCorp has analyzed. The focus of Chapter 7 will be on reviewing the results of the portfolio analysis.
7. RESULTS

Previous Chapters described the process of simulating the marketplace and modeling various resource portfolios. This systematic and thorough methodology yielded a large body of results. This chapter discusses those results and analyzes them to identify their context and meaning. The most important of these create the foundation for the Action Plan detailed in Chapter 9.

Discussion of the results falls into four categories.

- Operational Results: This section presents the expected base-case costs of each portfolio. It summarizes the observations of simulated portfolio operations and explains why portfolios performed differently.
- Risk Analysis: The risk analysis summarizes portfolio variability due to the Stochastic Risks discussed in Chapter 3.
- Customer Impacts: The customer impacts section expresses portfolio results from the perspective of customers.
- Stress Testing: This section presents the findings associated with shocking or stressing different Scenario Risks.

OPERATIONAL RESULTS

The modeling process simulated expected portfolio operations. The results culminate in total portfolio costs, measured by Present Value Revenue Requirement (PVRR). The PVRR is a central measure of portfolio performance and a critical driver of resource selection in the Action Plan.

The modeling also captures a number of other important measures. These include cost sub-categories, which roll up into PVRR. Evaluating the cost components identifies relative strengths and weaknesses of different resource configurations. Explaining why different portfolio combinations result in different costs, the model finally provides a number of influential operating characteristics. Complete scorecards, summarizing the metrics for every portfolio, are provided in Appendix E.

PVRR

Determining portfolio Present Value Revenue Requirements was a principal objective of the modeling process. PVRR is the sum of year by year revenue requirements of a portfolio, discounted at an after-tax cost of capital to a common date. PVRR takes into account the time value of money such that different projections of costs of various timing and magnitude can be evaluated on a comparable basis. Therefore, comparing PVRRs helps identify, on an expected present value basis, the least cost portfolio.

---

10 Utah guidelines require PVRR to be expressed in terms of total resource costs. PVRR values provided within this chapter are based on total utility costs. Total resource costs can be derived by adding $81,384,458 to all PVRRs provided herein.
Figure 7.1 illustrates the PVRR for each of the major portfolios evaluated. Early portfolios were developed to test different resource attributes. Subsequent modifications eliminated undesirable characteristics. As portfolios improved, they moved from the right to the left, as seen in Figure 7.1. Such movement demonstrates the success of the optimization process discussed in Chapter 4. The information below summarizes portfolio PVRRs:

**Figure 7.1 Portfolio PVRR Comparison**

<table>
<thead>
<tr>
<th>Portfolio Name</th>
<th>PVRR ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified Portfolio 1</td>
<td>12,559</td>
</tr>
<tr>
<td>Diversified Portfolio 2</td>
<td>12,360</td>
</tr>
<tr>
<td>Diversified Portfolio 3</td>
<td>12,338</td>
</tr>
<tr>
<td>Diversified Portfolio 4</td>
<td>12,313</td>
</tr>
<tr>
<td>Alternative Tech 1</td>
<td>12,360</td>
</tr>
<tr>
<td>Alternative Tech 2</td>
<td>12,650</td>
</tr>
<tr>
<td>Alternative Tech 3</td>
<td>12,850</td>
</tr>
<tr>
<td>Alternative Tech 4</td>
<td>13,050</td>
</tr>
<tr>
<td>Coal Gas I</td>
<td>12,679</td>
</tr>
<tr>
<td>Coal Gas II</td>
<td>12,651</td>
</tr>
<tr>
<td>Coal Gas III</td>
<td>12,850</td>
</tr>
<tr>
<td>Gas Coal I</td>
<td>12,908</td>
</tr>
<tr>
<td>Gas Coal II</td>
<td>12,908</td>
</tr>
<tr>
<td>Gas Coal III</td>
<td>13,166</td>
</tr>
<tr>
<td>Packers</td>
<td>12,759</td>
</tr>
<tr>
<td>Renewable</td>
<td>13,218</td>
</tr>
<tr>
<td>Tariff</td>
<td>13,250</td>
</tr>
<tr>
<td>Transmission Asset Build 1000</td>
<td>13,218</td>
</tr>
<tr>
<td>Transmission 2000</td>
<td>13,218</td>
</tr>
</tbody>
</table>

The top four portfolios, shown on the left of the graph, represent the best PVRRs of the group and the conclusion of the refinement process. The remainder of this chapter focuses on these four. With a large concentration of renewable resources, the results of the Renewable portfolio are also of interest. Therefore, subsequent analysis includes frequent references to this Renewable portfolio.

Key Observations on the top four portfolios include:

- Diversified portfolio I has the lowest PVRR of the portfolios studied.
- In relative terms, Diversified Portfolios I - IV provided similar PVRRs. Among the five hybrid portfolios (Diversified I-IV and Renewable), differences ranged from 0.2% to 3.6% above the Diversified I.
- In absolute terms, Diversified Portfolios II - IV differed from Diversified I by $25m to $82m. Renewable exceeded Diversified I by $454m.
Portfolio Scorecard
For convenient reference, model output is summarized on Portfolio Scorecards. Table 7.1 contains the Scorecard for the Renewable and four Diversified Portfolios. Scorecards include the following measures:

- PVRR and capital costs
- Emissions
- Market sales and purchases
- Existing and new unit capacity factors
- System transfers between East and West

The analysis and related discussion in this section frequently refer to this scorecard. Additional scorecards found in Appendix E summarize the alternative portfolios studied as well as the results of numerous stress tests.
### Table 7.1 Hybrid Portfolio Scorecard

<table>
<thead>
<tr>
<th>VALUE MEASURE</th>
<th>Diversified I</th>
<th>Diversified II</th>
<th>Diversified III</th>
<th>Diversified IV</th>
<th>Renewable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Present Value Rev. Req’t (20 Year $000)</td>
<td>12,313,159</td>
<td>12,337,893</td>
<td>12,360,185</td>
<td>12,395,185</td>
<td>12,767,268</td>
</tr>
<tr>
<td>Percent Greater Than Lowest NPV</td>
<td>0.000%</td>
<td>0.201%</td>
<td>0.382%</td>
<td>0.666%</td>
<td>3.688%</td>
</tr>
<tr>
<td>Incremental Net Variable Power Cost</td>
<td>9,779,027</td>
<td>9,841,314</td>
<td>9,992,809</td>
<td>10,456,417</td>
<td>10,576,052</td>
</tr>
<tr>
<td>Incremental Real Levelized Fixed Cost</td>
<td>2,343,907</td>
<td>2,306,354</td>
<td>2,177,151</td>
<td>1,748,542</td>
<td>2,000,991</td>
</tr>
<tr>
<td>DSM Real Levelized</td>
<td>190,225</td>
<td>190,225</td>
<td>190,225</td>
<td>190,225</td>
<td>190,225</td>
</tr>
<tr>
<td>Capital Cost (2002$-millions)</td>
<td>2,643</td>
<td>2,831</td>
<td>2,644</td>
<td>2,077</td>
<td>2,237</td>
</tr>
<tr>
<td>Emissions (2004-2023 PVRR $000)</td>
<td>21,750</td>
<td>32,826</td>
<td>(7,237)</td>
<td>(122,127)</td>
<td>(138,826)</td>
</tr>
<tr>
<td>CO₂ (thousand tons 2009-2023)</td>
<td>847,919</td>
<td>851,850</td>
<td>841,248</td>
<td>811,477</td>
<td>807,598</td>
</tr>
<tr>
<td>CO₂ (% of cap)</td>
<td>105%</td>
<td>105%</td>
<td>104%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>SO₂ (thousand tons 2009-2023)</td>
<td>652</td>
<td>655</td>
<td>654</td>
<td>645</td>
<td>644</td>
</tr>
<tr>
<td>SO₂ (% of cap)</td>
<td>63%</td>
<td>63%</td>
<td>63%</td>
<td>62%</td>
<td>62%</td>
</tr>
<tr>
<td>NOₓ (thousand tons 2009-2023)</td>
<td>1,046</td>
<td>1,049</td>
<td>1,047</td>
<td>1,036</td>
<td>1,035</td>
</tr>
<tr>
<td>NOₓ (% of cap)</td>
<td>102%</td>
<td>102%</td>
<td>102%</td>
<td>101%</td>
<td>101%</td>
</tr>
<tr>
<td>Hg (thousand tons 2009-2023)</td>
<td>0.0038</td>
<td>0.0036</td>
<td>0.0036</td>
<td>0.0024</td>
<td>0.0024</td>
</tr>
<tr>
<td>Hg (% of cap)</td>
<td>69%</td>
<td>66%</td>
<td>66%</td>
<td>44%</td>
<td>44%</td>
</tr>
<tr>
<td>Market Purchases (10 Year)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PAC East (% of load)</td>
<td>0.1%</td>
<td>0.1%</td>
<td>0.1%</td>
<td>0.1%</td>
<td>0.1%</td>
</tr>
<tr>
<td>PAC East Average MW</td>
<td>10</td>
<td>9</td>
<td>9</td>
<td>11</td>
<td>9</td>
</tr>
<tr>
<td>PAC West (% of load)</td>
<td>1.1%</td>
<td>1.1%</td>
<td>1.1%</td>
<td>1.1%</td>
<td>1.1%</td>
</tr>
<tr>
<td>PAC West Average MW</td>
<td>80</td>
<td>80</td>
<td>83</td>
<td>80</td>
<td>82</td>
</tr>
<tr>
<td>Market Sales</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PAC East (% of owned Generation)</td>
<td>7.1%</td>
<td>6.9%</td>
<td>7.0%</td>
<td>6.7%</td>
<td>6.9%</td>
</tr>
<tr>
<td>PAC East Average MW</td>
<td>323</td>
<td>313</td>
<td>316</td>
<td>300</td>
<td>310</td>
</tr>
<tr>
<td>PAC West (% of owned Generation)</td>
<td>11.0%</td>
<td>10.7%</td>
<td>10.7%</td>
<td>10.8%</td>
<td>10.7%</td>
</tr>
<tr>
<td>PAC West Average MW</td>
<td>304</td>
<td>304</td>
<td>296</td>
<td>304</td>
<td>300</td>
</tr>
<tr>
<td>Unit Capacity Factors (2014)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing Coal East</td>
<td>84.3%</td>
<td>84.6%</td>
<td>84.2%</td>
<td>86.2%</td>
<td>86.5%</td>
</tr>
<tr>
<td>Existing Other East</td>
<td>92.2%</td>
<td>92.2%</td>
<td>92.2%</td>
<td>92.2%</td>
<td>92.2%</td>
</tr>
<tr>
<td>Existing Peaker East</td>
<td>3.3%</td>
<td>3.0%</td>
<td>3.5%</td>
<td>4.2%</td>
<td>3.6%</td>
</tr>
<tr>
<td>IRP CCCT East</td>
<td>47.8%</td>
<td>47.0%</td>
<td>47.5%</td>
<td>63.3%</td>
<td>62.7%</td>
</tr>
<tr>
<td>IRP Coal East</td>
<td>91.0%</td>
<td>91.0%</td>
<td>91.0%</td>
<td>5.5%</td>
<td>5.2%</td>
</tr>
<tr>
<td>IRP Peaker East</td>
<td>4.6%</td>
<td>4.5%</td>
<td>5.0%</td>
<td>10.1%</td>
<td>9.6%</td>
</tr>
<tr>
<td>Existing CCCT West</td>
<td>34.2%</td>
<td>31.5%</td>
<td>35.2%</td>
<td>37.8%</td>
<td>36.9%</td>
</tr>
<tr>
<td>Existing Coal West</td>
<td>86.0%</td>
<td>86.2%</td>
<td>86.1%</td>
<td>86.9%</td>
<td>87.0%</td>
</tr>
<tr>
<td>Existing Other West</td>
<td>90.9%</td>
<td>90.9%</td>
<td>90.9%</td>
<td>90.9%</td>
<td>90.9%</td>
</tr>
<tr>
<td>IRP CCCT West</td>
<td>77.4%</td>
<td>77.2%</td>
<td>78.5%</td>
<td>81.8%</td>
<td>82.2%</td>
</tr>
<tr>
<td>IRP Peaker West</td>
<td>9.0%</td>
<td>11.9%</td>
<td>10.1%</td>
<td>9.6%</td>
<td></td>
</tr>
<tr>
<td>East West Transfers (MWHs)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014 East-West Transfer</td>
<td>1,077,393</td>
<td>1,124,739</td>
<td>1,083,438</td>
<td>766,831</td>
<td>790,797</td>
</tr>
<tr>
<td>Percent Increase/Decrease over 2004</td>
<td>135%</td>
<td>140%</td>
<td>135%</td>
<td>96%</td>
<td>99%</td>
</tr>
<tr>
<td>2004 West-East Transfer</td>
<td>1,901,936</td>
<td>1,899,981</td>
<td>1,901,936</td>
<td>1,899,981</td>
<td>1,902,380</td>
</tr>
<tr>
<td>2014 West-East Transfer</td>
<td>1,303,125</td>
<td>1,332,926</td>
<td>1,253,016</td>
<td>1,588,166</td>
<td>1,554,709</td>
</tr>
<tr>
<td>Percent Increase/Decrease over 2004</td>
<td>88%</td>
<td>70%</td>
<td>68%</td>
<td>84%</td>
<td>82%</td>
</tr>
</tbody>
</table>
Cost Categories
Evaluating the components of PVRR provides insight into portfolio performance. These evaluations help explain the results observed and aids the development of an Action Plan.

Fixed vs. Variable Costs
PVRR is comprised of both fixed and variable cost elements. Operational simulation demonstrates that portfolios with lower PVRRs tended to exchange higher fixed costs in return for lower variable costs.

For example, the high fixed costs of Diversified I can be attributed to the early installation of a coal plant with associated transmission. Realized the earliest, these fixed costs have greater present values than other portfolios. Offsetting the fixed costs, the variable costs savings of the early coal (compared to natural gas) have a substantial present value advantage over the other portfolios. Figures 7.2 and 7.3 illustrate this tradeoff.

In contrast, Diversified IV enjoys lower fixed costs. It substitutes less capital-intensive natural gas-fired base load units for coal. With reduced dependence on high fixed cost resources, the portfolio relies on higher variable cost resources. The greater dependence on high priced natural gas drives up variable costs substantially. A similar tradeoff occurs with the Renewable portfolio. Under this configuration large renewable contracts (reported as variable costs) replace the capital requirements of a base load unit.

Therefore, among the final portfolios, additional fixed cost investments appear to provide a moderate benefit over variable cost investments. This observation was consistent over the final portfolios as well as the other major portfolios discussed earlier.

Figure 7.2 Real Levelized Fixed Costs

Note: The above figures are plotted on a different scale.

Key Observations
- The Diversified I portfolio has the greatest real levelized fixed cost and the least incremental net variable cost of the final portfolios.
- Conversely, Diversified IV has the lowest real levelized fixed costs and second highest net variable electricity costs among the final portfolios.
Variable costs between Diversified I and Diversified IV differ by $677m. Fixed costs differ by $595m.

Elements of Variable Costs

Variable costs, as traditionally defined, consist of many elements, some of which are individually detailed in other categories of the scorecard. The categories include: fuel costs, variable O&M, unit start-up costs, emissions costs or credits, spot market sales and purchases, and variable long term contract costs. Variable cost characteristics differ, depending on the type and timing of resource installations.

Over the 20-year study period, the variable elements of each portfolio compare to each other as shown in Table 7.2.

Table 7.2 Variable Cost Elements

<table>
<thead>
<tr>
<th>Variable Cost Elements ($000)</th>
<th>Diversified I</th>
<th>Diversified II</th>
<th>Diversified III</th>
<th>Diversified IV</th>
<th>Renewable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Fuel Cost</td>
<td>7,874,230</td>
<td>8,325,842</td>
<td>8,009,694</td>
<td>8,426,120</td>
<td>8,479,704</td>
</tr>
<tr>
<td>Total Variable O&amp;M Cost</td>
<td>620,865</td>
<td>651,759</td>
<td>634,924</td>
<td>653,349</td>
<td>651,144</td>
</tr>
<tr>
<td>Total Emissions Cost</td>
<td>21,750</td>
<td>32,826</td>
<td>(7,237)</td>
<td>(122,127)</td>
<td>(138,826)</td>
</tr>
<tr>
<td>Total Start-up Cost</td>
<td>70,443</td>
<td>69,883</td>
<td>69,868</td>
<td>69,825</td>
<td>69,138</td>
</tr>
<tr>
<td>Sales*</td>
<td>(2,747,817)</td>
<td>(2,726,240)</td>
<td>(2,680,971)</td>
<td>(2,609,685)</td>
<td>(2,625,092)</td>
</tr>
<tr>
<td>Purchases*</td>
<td>695,734</td>
<td>684,103</td>
<td>723,567</td>
<td>767,541</td>
<td>753,957</td>
</tr>
<tr>
<td>Renewable Adjustment**</td>
<td>(368,310)</td>
<td>(368,310)</td>
<td>(368,310)</td>
<td>(368,310)</td>
<td>(430,751)</td>
</tr>
<tr>
<td>Total</td>
<td>9,779,027</td>
<td>9,841,314</td>
<td>9,992,809</td>
<td>10,456,417</td>
<td>10,576,052</td>
</tr>
</tbody>
</table>

*Sales and Purchases refer to spot sales and purchases
**Includes PTC, Green Tag, and Integration Costs

<table>
<thead>
<tr>
<th>% Change from Diversified I</th>
<th>Diversified I</th>
<th>Diversified II</th>
<th>Diversified III</th>
<th>Diversified IV</th>
<th>Renewable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Fuel Cost</td>
<td>--</td>
<td>5.7%</td>
<td>1.7%</td>
<td>7.0%</td>
<td>7.7%</td>
</tr>
<tr>
<td>Total Variable O&amp;M Cost</td>
<td>--</td>
<td>5.0%</td>
<td>2.3%</td>
<td>5.2%</td>
<td>4.9%</td>
</tr>
<tr>
<td>Total Emissions Cost</td>
<td>--</td>
<td>50.9%</td>
<td>-133.3%</td>
<td>-661.5%</td>
<td>-738.3%</td>
</tr>
<tr>
<td>Total Start-up Cost</td>
<td>--</td>
<td>-0.8%</td>
<td>-0.8%</td>
<td>-0.9%</td>
<td>-1.9%</td>
</tr>
<tr>
<td>Variable Contract Cost</td>
<td>--</td>
<td>-12.2%</td>
<td>-0.02%</td>
<td>0.8%</td>
<td>5.7%</td>
</tr>
<tr>
<td>Sales*</td>
<td>--</td>
<td>-0.8%</td>
<td>-2.4%</td>
<td>-5.0%</td>
<td>-4.5%</td>
</tr>
<tr>
<td>Purchases*</td>
<td>--</td>
<td>-1.7%</td>
<td>4.0%</td>
<td>10.3%</td>
<td>8.4%</td>
</tr>
<tr>
<td>Renewable Adjustment**</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>--</td>
<td>17.0%</td>
</tr>
</tbody>
</table>

Fuel Costs: Fuel costs make up the greatest portion of variable costs in every portfolio. Diversified I has the lowest fuel cost. With a coal unit serving as the first base-load addition, high-priced natural gas provides a smaller portion of the portfolio’s fuel requirements. The difference in fuel exposure is a key advantage of this portfolio.

Other portfolios incur greater fuel costs and have greater natural gas exposure. Diversified III fuel costs are 1.7% greater. Diversified III similarly adds a coal unit. However, the coal unit does not go on line until 2012. Diversified III in turn leads Diversified II which has much greater fuel expense due to the late introduction of Hunter 4 and replacement of West contracts (consuming no fuel) with built resources (which do).

It is important to note that, despite its name, the Renewable portfolio contains substantial additions of fossil generation. Like Diversified IV, the Renewable portfolio does not include
coal and features the early installation of a base-load natural gas unit. However, Renewable portfolio units operate at higher unit capacity factors than Diversified IV. Accordingly, the Renewable portfolio incurs the greatest fuel expenses.

**Emission Costs:** Emission charges represent a smaller component of total variable costs. Emissions costs are the lowest for the Renewable portfolio. With emissions below assumed caps these ‘costs’ result in credits to system costs. Conversely, Diversified II features the highest emissions costs.

The distinction between Diversified II and III arises from the use of contract purchases. Diversified III assumes a greater level of variable contract purchases ($3.6 billion vs. $3.1 billion). Regionally, the same level of emissions occurs regardless of who generates the energy. However, a difference appears in this cost category because PacifiCorp incurs an expense for emissions associated with its proprietary generation. Such emissions count against PacifiCorp’s cap levels. If another party generates, the emissions would count towards their emissions cap and are captured in forward prices (falling into a different cost category). Independent of contract purchases, portfolios including new coal, installed before 2012, suffer from notably increased CO₂ and Hg emission costs.

Under base case assumptions emissions represented a smaller cost category. As shown in later stress tests, this could change. The outcome of pending environmental legislation will play a major role in determining the optimal fuel and resource mix. Until the legislation is clarified, it remains a substantial risk factor.

**Start-Up Costs:** Start-Up Costs are insignificant to the overall total variable costs for the portfolios but give insight into differences in unit operations between portfolio. Operations in Diversified I require more frequent unit starts to balance the system.

**Variable Contract Costs:** These costs include long-term purchases like contract renewals and PPAs. Variable contract costs represent the second largest category of variable costs. Here, Diversified II stands out. Contract costs fall approximately 12%, since built resources replace the West contracts found in other portfolios.

Diversified I and Diversified III include similar contracts and costs. The Renewable portfolio has variable contract costs 5.0% greater than Diversified I and Diversified III due to a $50/MWh, flat renewable contract not present in the other portfolios. Strongly influencing its PVRR ranking, the fixed price contract is one of the key features of this portfolio.

**Sales & Purchases:** This category includes the PVRR of spot sales and purchases pursuant to the model dispatch logic. Spot market sale revenues increase in the years a large resource is added. At that point, sales rise over portfolios with smaller, more flexible units. For example, Diversified I adds a large coal plant in 2008. In 2008 sales rise significantly.

---

11 Within the IRP, spot Sales and Purchases include all balancing transactions, which occur outside of existing long-term contracts.
Figures 7.4 and 7.5 plot spot market sales for the West and East markets. On the West plot, Diversified III sales are represented by the first line followed by Diversified II and Diversified I. The Diversified IV and Renewable portfolio were not shown, but present similar profiles. All portfolios follow a similar pattern with a plateau at the 250 MW level. Recall from Chapter 5 that market access in the West is restricted to 250 MW at COB and 250 MW at Mid-Columbia. At the plateau, market prices cause one point to run at the maximum capacity while the other remains at 0 MW. During approximately 30-35% of all hours in 2014, market sales reach a maximum capacity of 500 MW. Conversely, for about 12% of all hours, there are no West market sales.

In the East, market sales reach a maximum of 500 MW for 22% of all hours for the Diversified portfolios. As shown in Figure 7.4 all portfolios have no sales for 5% of all hours. Observed in Figure 7.5, market sales plateau in the East for a significant period of time. The plateau occurs at 350 MW. This is the limit to PacifiCorp’s existing firm transmission rights. Additional sales incur substantial, short-term transmission procurement charges. Thus, the model economically restricts additional sales to a more limited period of time. Additional information regarding market access can be found in Chapter 5 and Appendix J.

Figure 7.4 Spot Market Sales - West
Figures 7.6 and 7.7 illustrate spot market purchases for the three portfolios. Market purchases decrease with each addition of capacity.

Of the other Diversified Portfolios, Diversified II adds the most new resources. It also displays the fewest market purchases. The resources of Diversified II operate more flexibly than the contract purchases of I and III. The physical resources better adjust to variable system demands than the flat contracts.

West FY 2014 purchases are greater than the East with 2-5% of all hours purchasing the maximum available, 500 MW. Diversified II and III require the most market purchases. Diversified I requires the least. Between 60-70% of all hours, West spot market purchases decrease to 0 MW. The very low reliance on market purchases in the East is displayed in Figure 7.7 where all portfolios show East market purchases for fewer than 5% of all hours in FY 2014.
Figure 7.6 Spot Market Purchases - West

Figure 7.7 Spot Market Purchases - East

The purchase and sale profiles demonstrated above consistently lead to superior PVRR performance. In an attempt to reduce market sales, portfolios substituting base load elements with peakers were constructed. Peakers provide more operating flexibility at higher marginal costs. The test produced the intended drop in market sales. However, the resulting portfolios relied more heavily on market purchases. One market exposure (high sales) was merely traded for another (high purchases). Furthermore, the purchases combined with higher operating costs caused PVRR to increase.
Other Operational Measures
Cost measures are important means of evaluating portfolio performance. In addition to costs, Capacity Utilization factors and System Transfers help explain the operations of each portfolio.

Capacity Utilization
Capacity utilization factors provide valuable insight into the appropriateness of resource additions. Poor utilization factors may imply unnecessary capacity costs. They also act as an indicator of stranded power. The measure was particularly useful in the portfolio development process where extreme values signaled a need for resource changes. The final portfolios are the products of iterative improvements driven, in part, by this metric. Accordingly, they generally display favorable utilization factors.

The four Diversified portfolios show very similar unit behavior by 2014. Existing fleet performance by resource type in the East remains high in 2014 for all portfolios. Capacity factors for existing West CCCTs decreases between 32% and 38%. New coal units run at a maximum availability of 91%. New CCCT units operate at 47% to 82% capacity factors. New Peaking units perform as expected - around the 5% to 12% capacity factor level. Refer to Appendix J for a discussion of the screening curve used to assign different resources to different load profiles.

With high capacity factors, there are no obvious signs of new units merely displacing existing units or adding risk by creating a long market position. Furthermore, consistent with the strategy of obtaining resources only to serve load, high utilization factors are evidence that generation is not being added for merchant purposes.

System Transfers
With the exception of the Renewable and Diversified IV portfolios, East to West transfers increase by 135-140% between 2004 and 2014. The Renewable portfolio's West to East transfers decrease. West to East transfers decrease by approximately 70% for Diversified Portfolios I-III, and 82 to 84% for the Renewable and Diversified IV Portfolios. This suggests the system becomes more generally balanced over time with the introduction of Diversified Portfolios I, II and III.

Operational Results - General Conclusions
Portfolio comparisons illustrate an exchange between fixed and variable costs. This exchange is intuitive. Higher fixed and capital cost investments tend to result in lower variable cost resources. Such an exchange, though moderate, appeared to positively impact PVRR.

PVRR differences between final portfolios are heavily influenced by differences in variable costs. Diversified I has the lowest variable costs. Low fuel and variable O&M cost advantages slightly outweigh higher contract purchase costs. The early installation of a coal plant in this portfolio moderately increases fixed costs, but, relative to the other portfolios, greatly reduces fuel and operating expenses for the portfolio between years 2008 and 2011. The timing of the base load unit addition (2008 vs. 2007) also appears to benefit costs.
Superior portfolios tend to require substantial market sales. Built to a 15% planning margin over forecast peak load, top portfolios include substantial balancing requirements in non-peak periods. Attempts to restrict market exposure resulted in poorer PVRRs.

While each portfolio configuration affect cost categories differently, tradeoffs between categories occurred and mollified the overall impact. Changing portfolios to reduce a specific cost can be likened to squeezing a balloon. As a balloon (or cost) is squeezed in one area, other areas of the balloon push outwards. For example, the lower fuel costs associated with Diversified III tended to be offset by higher Variable Contract Costs. Similarly, higher fixed cost investments in Diversified I tended to reduce variable cost exposures.

Although portfolios feature differing resources and installation timing, they tended to converge with respect to costs. This is an expected outcome of an iterative portfolio development process. Portfolios were iteratively improved and collectively approached least cost configurations.

**East – West Cost Segmentation**
Portfolio simulations include the physical transmission limitations between control areas. Accordingly, resources generally fall into east and west portfolio sub-categories. Table 7.3 details the costs associated with each sub-category.

**Incremental PVRR**
Portfolio costs tend to follow a 60x40 split between the east and west sub-categories. This is consistent among all of the final portfolios with 60 percent of the costs associated with the East sub-category.

**Net Variable Power Cost**
Discussed above, Net Variable Power Costs are a significant component of PVRR. Among the sub-categories of each portfolio, greater cost parity was observed. The Net Variable Power Costs tending to be equally divided between the two portfolios.

**Capital Costs**
Table 7.3 demonstrates that the East to West ratio is greater with respect to capital costs. Portfolio sub-categories tended to demonstrate a 70x30 split. Combined with more equivalent division of net variable costs, the capital costs contribute to the observed total PVRR 60x40 split.
Table 7.3 East – West Cost Breakdown

<table>
<thead>
<tr>
<th></th>
<th>Values</th>
<th>Percentages</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Renewable</td>
<td>Diversified Portfolio I</td>
</tr>
<tr>
<td>Portfolio Incremental PVRR</td>
<td>12,767,268</td>
<td>12,313,159</td>
</tr>
<tr>
<td>Incremental PVRR ¹</td>
<td>6,416,083</td>
<td>6,383,121</td>
</tr>
<tr>
<td>PAC West</td>
<td>2,675,331</td>
<td>2,660,562</td>
</tr>
<tr>
<td>Net Variable Power Cost</td>
<td>4,224,853</td>
<td>3,848,975</td>
</tr>
<tr>
<td>PAC West</td>
<td>1,942,885</td>
<td>2,048,493</td>
</tr>
<tr>
<td>PAC East</td>
<td>2,281,967</td>
<td>1,990,483</td>
</tr>
<tr>
<td>Real Levelized Fixed Cost</td>
<td>2,601,005</td>
<td>2,345,921</td>
</tr>
<tr>
<td>PAC West</td>
<td>713,423</td>
<td>601,844</td>
</tr>
<tr>
<td>PAC East</td>
<td>1,287,582</td>
<td>1,562,021</td>
</tr>
<tr>
<td>DSM Real Levelized ²</td>
<td>190,225</td>
<td>190,225</td>
</tr>
<tr>
<td>PAC West</td>
<td>19,023</td>
<td>19,023</td>
</tr>
<tr>
<td>PAC East</td>
<td>171,203</td>
<td>171,203</td>
</tr>
<tr>
<td>Capital Costs</td>
<td>2,262</td>
<td>2,643</td>
</tr>
<tr>
<td>PAC West</td>
<td>313</td>
<td>610</td>
</tr>
<tr>
<td>PAC East</td>
<td>1,450</td>
<td>2,034</td>
</tr>
<tr>
<td>Total MW Additions</td>
<td>6,066</td>
<td>5,365</td>
</tr>
</tbody>
</table>

1. Incremental PVRR of New Resources = Net Variable Power Cost + Real Levelized Fixed Cost + DSM Real Levelized
2. No costs for Oregon Trust DSM are used in this calculation

RISK ANALYSIS

Expressing each portfolio in terms of deterministic PVRR conveys just one dimension of portfolio performance. The risk of each portfolio represents another key dimension. This section provides five risk measures for comparison:

- 95th Percentile
- 5th Percentile
- 95th – 5th Percentile
- Coefficient of Variation
- Mean of Tail

Each measure provides a different perspective on the risk profile of the final portfolios. Taken in aggregate, they help establish portfolio rankings.

While it is helpful to evaluate individual portfolio risks, those risk measures alone do not convey the cost effectiveness of investments needed to achieve (or mitigate) them. Therefore, this section also evaluates the tradeoffs between investment and risk.

Risk Measures

The following risk measures define the risk profile of the final portfolios and allow comparisons between them. In addition to defining the measure and showing the model results, this section details the limitations of each.
**95th Percentile**

This measure allows for high-risk case comparisons between portfolios. Ninety-five percent of the simulated PVRR observations occurred below this point. Given the asymmetrical distribution of simulated outcomes, the 95th percentile provides an efficient risk representation.

Decisions based on this metric must be made with some caution. While the 95th percentile helps define the high side of potential PVRR outcomes, it doesn’t provide insight into the overall variability of the portfolio.

**Figure 7.8 95th Percentile**

Diversified I has the lowest 95th percentile. Thus, according to this measure, its future is expected to entail a lower likelihood of high PVRR outcomes. Renewable exceeds the next nearest portfolio by $328m.

High PVRR iterations tend to coincide with high loads and natural gas prices. A greater sensitivity to natural gas price fluctuations makes Diversified IV prone to high PVRR outcomes during these scenarios. The Renewable Portfolio reliance on natural gas combined with an overall higher cost structure appears to be a leading cause for the divergence in costs at the 95th percentile.

Relative to Diversified I, the Diversified IV portfolio relies more heavily on natural gas fired generation. From the standpoint of PVRR, the dependence on natural gas fired generation is exacerbated by an earlier installation time line. New natural gas-fired base load units arrive earlier in the Diversified IV Portfolio than the Diversified I Portfolio. Table 7.4 illustrates the comparative build-up of natural gas generation in Diversified I and Diversified IV.
Table 7.4 Natural Gas Capacity Comparison

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Base Load MW</th>
<th>Peakers MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified IV Installed through 2008</td>
<td>1,080</td>
<td>430</td>
</tr>
<tr>
<td>Installed through 2014</td>
<td>2,040</td>
<td>1,160</td>
</tr>
<tr>
<td>Diversified I Installed through 2008</td>
<td>570</td>
<td>430</td>
</tr>
<tr>
<td>Installed through 2014</td>
<td>1,560</td>
<td>1,160</td>
</tr>
</tbody>
</table>

Furthermore, the Diversified I, II and III portfolios include a coal base load unit installed no later than in 2014. Though the impact in Diversified II and III is somewhat diminished by discounting, this common element tends to cause their 95th percentiles to converge at a point lower than the Renewable and Diversified IV portfolios.

Other than this exception, the final portfolios are tightly clustered. Given the diversity of modeling inputs and time horizon of the study, it could be argued that the 95th percentiles of the portfolios are statistically indistinguishable.

5th Percentile
Five percent of the simulated observations occurred below this point. Since low PVRRs are generally preferred, this measure of risk helps identify a reasonable approximation of best-case expectations. Like the preceding measures, lower values are generally preferred. They illustrate the reasonable extreme of best-case outcomes. This measure is of particular interest when interpreting the previously discussed risk metrics.

Figure 7.9 5th Percentile
Low PVRR cases (like the 5th percentile) tend to feature low load trajectories and moderate to high natural gas prices. The Diversified IV Portfolio demonstrated the most favorable, best-case results under these conditions. With only natural gas-fired base load capacity, the portfolio enjoys lower fixed and capital costs. Under lower loads, Diversified IV also appears to avoid the expense of its higher market purchases originally observed in Table 7.1.

The Renewable portfolio demonstrates the highest results under this metric. Observed in Chapters 3 and 6, the Renewable portfolio features a large, fixed-price, must-take renewable contract. This contract appears to increase costs at the 5th percentile by contributing to a higher overall cost structure.

Moderate natural gas prices converging with lower loads appear to create favorable conditions for market sales for all portfolios. Intuitively, natural gas dependent Diversified IV should benefit the least from such sales. The greater absolute fuel costs of Diversified IV appear to be partially offset as this portfolio benefits from monetizing the correspondingly higher dollar value of the spark spread.

The Diversified I portfolio includes the early installation of a coal plant. With the large capital costs subjected to fewer years of discounting, this portfolio element causes the 5th percentile of Diversified I to drift upwards.

95th – 5th Percentile
This value is another measure of risk. The measure equals the difference between the 5th percentile and the 95th percentile of PVRR. Nine out of ten iterations fell within this range. Thus, it represents a reasonable range of expected outcomes for each portfolio. The larger this range, the greater the risk associated with each portfolio.

The 95th – 5th measure defines the reasonable range of expected outcomes. However, decisions based on it should be made with some caution. Comparisons based upon this risk measure may be confusing among portfolios with significantly different means and/or 5th percentiles.
Figure 7.10 95th – 5th Percentile

Diversified I yielded the best, least risk, results. This advantage arose from its lower 95th percentile ranking and its higher 5th percentile ranking. Thus, expected PVRRs fall within a narrower range. While Diversified I enjoys the least risk position, Diversified II and III closely follow its performance.

Producing a higher risk profile, the Renewable portfolio high 95th percentile overwhelms its correspondingly high 5th percentile. The resource configuration of Diversified IV brings the greatest degree of variation under this measure. A high 95th percentile combines with its low 5th percentile to produce the greatest range of potential outcomes.

**Coefficient of Variation**

The coefficient of variation is an alternative measure of risk. It equals the standard deviation of the 100 risk iterations divided by their mean. Standard deviation alone is a measure of the relative dispersion (and risk) of iterative outcomes. Dividing by the mean tends to reduce confusion caused when comparing distributions with different means.

While valuable for comparisons, this measure doesn’t provide a complete picture of risk within the context of the IRP. Stated as a percentage, the measure doesn’t convey the dollar variability associated with each portfolio. Defining such dollar variability is an important element of customer impact analysis, discussed later in this chapter.
Table 7.5 Coefficient of Variation

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Coefficient of Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified 1</td>
<td>15.962%</td>
</tr>
<tr>
<td>Diversified 2</td>
<td>16.553%</td>
</tr>
<tr>
<td>Diversified 3</td>
<td>16.387%</td>
</tr>
<tr>
<td>Diversified 4</td>
<td>18.194%</td>
</tr>
<tr>
<td>Renewable</td>
<td>16.784%</td>
</tr>
</tbody>
</table>

Consistent with other risk measures, the Diversified I portfolio demonstrates the least risk while the Diversified IV portfolio offers the greatest degree of variability. Also consistent with other measures, the coefficient of variation of the portfolios is tightly grouped.

**Mean of Tail**

The mean of tail is the simple average of the highest 5% of the simulated PVRR observations. Alternatively stated, it is the average of the five worst-case observations. This measure helps explore the tail risks of portfolios and represents the impact of the skewed distributions discussed in Chapter 3.

The metric is useful for comparative purposes, but should be considered with caution. By definition it averages just five values. Furthermore, as a simple-average it can be dramatically influenced by a single extreme observation.

**Figure 7.11 Mean of Tail**

The mean of tail associated with Diversified I further confirms the portfolio’s lowest risk position. Intended to reflect the most extreme of potential outcomes (the worst 5 out of 100), this measure shows Diversified I is prone to a more moderate series of ‘worst-case’ events. This measure was the highest for the Renewable portfolio. It is clear that Renewable portfolio has greater tail risks than the other portfolios.
Like the 95th percentile, the mean of tail observations tended to occur when high natural gas prices intersect with high loads. However, Diversified IV, with the greatest proportion of natural gas fired resources, performs nearly as well as Diversified I. The reason can be found within the iterations comprising the highest five PVRR observations. While the highest five observations tended to occur at the general intersection of high loads and natural gas prices, two of the five iterations occurred when loads neared the 100th percentile while natural gas prices resided near the bottom of the upper quartile. From a total PVRR standpoint, these iterations were tail events. However, the natural gas exposure and the resulting PVRR of Diversified IV were reduced by the more moderate natural gas prices.

**Risk Tradeoff**

The information above provides valuable comparisons between key portfolio metrics. These comparisons are only the first step in evaluating portfolio risk performance. The next step requires evaluating the tradeoff between investment and risk. Evaluating portfolios in this manner provides useful insight. Superior portfolios should demonstrate a superior tradeoff.

This section details the risk tradeoff associated with two measures. First, this section presents the PVRR relative to the 95th percentile. Second, this section presents the PVRR relative to the 95th – 5th percentile.

**PVRR vs. 95th Percentile**

Figure 7.12 demonstrates the tradeoff between the PVRR and risk. Interpreting the results of this graph is a matter of comparing the investment required by each portfolio (PVRR) against the overall risk the portfolio demonstrated in the model. For purposes of this figure, risk is defined as the 95th percentile.

Stakeholders are assumed to universally prefer lower risk portfolios at any specific investment level. Therefore, portfolios approaching the origin of Figure 7.12 generally dominate those more distant. Under this rule of thumb, Diversified I appears to be the dominant portfolio.
Several points are illustrated by Figure 7.12.

First, the Diversified I and Renewable portfolios fall at opposite points. The Renewable portfolio has the largest PVRR of the top portfolios. Interestingly, this portfolio also has the greatest degree of risk. This figure demonstrates that the Renewable portfolio has the least efficient tradeoff between investment and risk.

Second, Diversified III and IV require greater PVRR commitments than Diversified I. Like Renewable, they also feature greater risk than Diversified I. Therefore, Diversified I dominates Diversified III and IV.

Third, Diversified I and II demonstrate a nearly identical risk profiles. However, the expected PVRR of Diversified II is somewhat higher. Given this less efficient tradeoff, it is concluded that Diversified I also dominates Diversified II.

“Dominant,” as used herein, merely conveys that one portfolio, when compared to another, appears to contain a superior collection of resource choices. The word, however, is not intended to connotate the strength or magnitude of that superiority.

**PVRR vs. 95th – 5th Percentile**

The 95th percentile alone does not provide a complete picture of risk. The Figure 7.13 employs a different risk measure, 95th – 5th percentile, in order to evaluate the tradeoff between PVRR and risk. Interpretation of this figure is performed in the same manner as before. Results closer to the origin are generally preferred. As such, Diversified I, again, appears as the dominant portfolio.
Figure 7.13 reinforces earlier observations.

- Diversified I and Renewable reside at opposite points of the graph with Renewable demonstrating the least efficient tradeoff between PVRR and risk.
- Diversified I has lower risk and a lower expected PVRR commitment than Diversified II, III and IV. Accordingly, Diversified I is viewed to dominate the other three.

**Natural Gas Price Sensitivity**

Observed in the analysis, high PVRRs tend to occur at the intersection of high natural gas prices and high loads. This section adds to that discussion by providing additional analysis of the impact of natural gas prices and portfolio costs. Here, natural gas price sensitivity was assessed by load normalizing portfolio performance.

To load normalize portfolio performance divide the revenue requirement (expressed in dollars) by the energy demanded (expressed in MWhs). The resulting costs are expressed on a $/MWh basis. The Customer Impacts section later in this chapter discusses this process further.

Movement in loads dramatically affects PVRR. The impact may mask the influence of other stochastic measures. Normalizing generally isolates the cost impact of other Stochastic risks from load.

While helping provide insight into the impact of other variables, drawbacks exist. For example, the remaining stochastic variables are not individually isolated. Therefore, within iterations the specific impact of unit outages, hydroelectric conditions as well as natural gas and power prices must be inferred.
Figures 7.14 – 7.17 provide the results of this analysis. The graphs portray the performance of Diversified I and IV. These portfolios, respectively, contain the lowest and highest exposure to natural gas. Therefore, illustrating them frames the comparisons of natural gas price exposure.

The x-axis plots the annual average natural gas prices simulated at Mid-Columbia. The y-axis plots load normalized portfolio costs, expressed in dollars per MWh. Figures 7.14 and 7.15 plot the costs observed when simulated loads were high. Conversely, Figures 7.16 and 7.17 plot costs when loads were low.

The analysis shows the natural gas to cost relationship is not constant. Rather the sensitivity to natural gas price appears to depend on the system loads. The observation is intuitive and consistent with the earlier risk results. Natural gas and electricity prices are highly correlated. When loads are low, sales of surplus electricity generate more revenue when natural gas prices (and power prices) are high. The resulting revenues drive down costs. When loads are high, the reverse is true with fewer sales and more purchases producing greater costs.
The top panels represent iterations where loads are high. Here costs tend to increase with natural gas prices. In the bottom panels, higher natural gas prices drive costs down. For these iterations, high fuel prices (and with them, high electricity prices) coincide with low loads.

This general result applies to all IRP portfolios. Because power prices are highly correlated with natural gas prices (power prices can be viewed as a derivative of the natural gas prices), even a resource mix with no natural gas-fired generation would be short or long natural gas, contingent on what happens to system loads.

Generally speaking, portfolios with more natural gas generation should be more sensitive to natural gas price movements when short power, and less sensitive to natural gas price variations when power is surplus. However, because the share of natural gas fired generation in each resource mix tends to be low even in the more natural gas intensive IRP portfolios, this effect appears insignificant. Indeed, it can be seen from Figures 7.16 and 7.17 that the differences in cost sensitivity to natural gas price between the IRP portfolios with the least (Diversified I) and the most (Diversified IV) amount of natural gas fired generation, are very small.

A further conclusion may be inferred from this analysis. A high observation of any one risk parameter, may not be enough to cause a given year to result in high costs. Useful information, therefore, cannot be obtained by simply moving individual variables in isolation. Rather the convergence between events drives PVRR. For example high loads, high natural gas prices, high unit outages and low hydroelectric output converged to drive costs, as observed during the recent past. Hence, high natural gas prices sometimes reduce PVRR (when loads are low) and sometimes increase it (when loads are high).

**East – West Risk**

Some participants in the public process requested a risk analysis divided between east and west portfolio sub-categories. The current IRP model performs the risk analysis on an integrated basis. It does not yet allow for regional cost segmentation. This is an enhancement targeted for the next IRP.

**CUSTOMER IMPACT**

This section characterizes the costs on a per MWh basis. Describing cost per unit of energy better represents the impact on customer rates. It also helps reflect the rate changes, which might be required moving from one year to another. This analysis, while providing an indication of rate direction, does not represent rates fully allocated by state and customer class. Table 7.6 provides additional details and reflects the following:

- PVRR using both a real levelized and a nominal revenue requirement calculation for resource and transmission capital expenditures
- PVRR discounted at both PacifiCorp’s after-tax weighted average cost of capital (7.5%) and the general escalation rate (2.5%)
- A 20-year average $/MWh utilizing the revenue requirements as stated in constant dollars (discounted at the escalation rate)
**Calculation Method**

**Discount Rate**
Each portfolio PVRR is calculated using real levelized revenue requirements for resource and transmission capital. Additionally, the nominal revenue requirements are calculated and presented at the request of those wishing to see a 20-year PVRR calculated using traditional ratemaking methodology. Portfolios are also shown discounted at PacifiCorp’s weighted average cost of capital (WACC) and at the general escalation rate. Additionally, the constant $/MWh results were calculated by taking the PVRR, calculated using a 2.5% discount rate, and dividing it by the 20-year sum of MWh.

**Relative Rank**
Table 7.6 also shows, within each measurement methodology, what percent each portfolio’s PVRR is above the least cost portfolio. The results indicate that the relative ranking among the portfolios do not materially change when applying alternative measurement methodologies.
Table 7.6 Real Levelized versus Nominal PV versus Constant

<table>
<thead>
<tr>
<th>Discount Rate</th>
<th>Present Value Results Discounted at WACC</th>
<th>Constant Dollar Results Discounted at Escalation Rate</th>
<th>Constant Dollar Results 20-Yr Average $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>w/ real levelized 4/1/2003 PVRR</td>
<td>w/ nominal (1) 4/1/2003 PVRR</td>
<td>w/ real levelized 4/1/2003 PVRR</td>
</tr>
<tr>
<td></td>
<td>Discounted at WACC 7.5%</td>
<td>Discounted at Escalation Rate 25%</td>
<td>Discounted at Escalation Rate 25%</td>
</tr>
<tr>
<td>Diversified I</td>
<td>12,313</td>
<td>21,684</td>
<td>$15.26</td>
</tr>
<tr>
<td>Diversified II</td>
<td>12,338</td>
<td>21,716</td>
<td>$15.28</td>
</tr>
<tr>
<td>Diversified III</td>
<td>12,360</td>
<td>21,757</td>
<td>$15.31</td>
</tr>
<tr>
<td>Diversified IV</td>
<td>12,395</td>
<td>21,855</td>
<td>$15.38</td>
</tr>
<tr>
<td>Alternative Technology II</td>
<td>12,599</td>
<td>22,180</td>
<td>$15.74</td>
</tr>
<tr>
<td>Coal/Gas III</td>
<td>12,651</td>
<td>22,300</td>
<td>$15.69</td>
</tr>
<tr>
<td>PacificCorp Build – I</td>
<td>12,679</td>
<td>22,332</td>
<td>$15.71</td>
</tr>
<tr>
<td>Gas/Coal I</td>
<td>12,706</td>
<td>22,396</td>
<td>$15.75</td>
</tr>
<tr>
<td>Gas/Coal II</td>
<td>12,715</td>
<td>22,396</td>
<td>$15.76</td>
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<tr>
<td>Gas/Coal III</td>
<td>12,743</td>
<td>22,435</td>
<td>$15.78</td>
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<tr>
<td>PacificCorp Build II</td>
<td>12,748</td>
<td>22,477</td>
<td>$15.81</td>
</tr>
<tr>
<td>Peakers</td>
<td>12,759</td>
<td>22,489</td>
<td>$15.82</td>
</tr>
<tr>
<td>Renewable</td>
<td>12,767</td>
<td>22,569</td>
<td>$15.88</td>
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<td>12,770</td>
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<td>12,865</td>
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<tr>
<td>Coal/Gas I</td>
<td>12,910</td>
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</tr>
<tr>
<td>Transmission - 1000MW DC</td>
<td>13,018</td>
<td>22,969</td>
<td>$16.15</td>
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<tr>
<td>Transmission - 2000MW DC</td>
<td>13,218</td>
<td>23,357</td>
<td>$16.43</td>
</tr>
<tr>
<td>Transmission - Asset Build Market</td>
<td>13,221</td>
<td>23,420</td>
<td>$16.48</td>
</tr>
<tr>
<td>Gas/Coal I - 10%</td>
<td>12,358</td>
<td>21,836</td>
<td>$15.55</td>
</tr>
<tr>
<td>Gas/Coal II - 10%</td>
<td>12,376</td>
<td>21,814</td>
<td>$15.34</td>
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<tr>
<td>PacificCorp Build II - 10%</td>
<td>12,531</td>
<td>22,129</td>
<td>$15.56</td>
</tr>
<tr>
<td>All Gas II - 10%</td>
<td>12,576</td>
<td>22,220</td>
<td>$15.63</td>
</tr>
</tbody>
</table>

The comparisons in Table 7.6 of present value vs. constant dollar results and capital costs are calculated using real levelized vs. nominal revenue requirements. Results are based on model runs prepared for the final report. Note: (PVRR Results Are In Millions Of Dollars).
Capital Life – End Effects
It should be noted that the results presented using the nominal revenue requirement calculation do not include an adjustment for capital life end-effects. The analysis period is 20 years, and most of the assets’ lives extend well beyond the end of the analysis. This results in the higher-cost revenue requirements incurred in the early years of a capital addition’s economic life to be included in the PVRR while the lower cost revenue requirements of later years are excluded.

Without some type of end-effects adjustment, the capital-intensive portfolio’s PVRR will tend to show a relatively higher nominal revenue requirement. While utilizing nominal revenue requirements is more reflective of future ratemaking impacts during the 20-year analysis period, it does not, by itself, provide proper comparative economics needed to address the relative costs of long-lived assets.

Revenue Requirement Impacts
IRP Footprint
The IRP customer impacts calculation includes only the $/MWh rate impacts associated with the IRP “footprint” as compared to total PacifiCorp historical $/MWh (CY 2001 actual retail $/MWh was used for comparison).

The IRP footprint includes electricity supply system costs for fuel, variable plant O&M, emission allowance impact, start-up costs, market contracts, spot market purchases and sales, production tax credits, green tag benefits, renewable integration costs, and DSM costs. It also includes all of the revenue requirement costs associated with adding incremental investment in new resources and new transmission. However, the IRP footprint does not include certain costs that are deemed common to all IRP portfolios. The excluded costs are existing generation assets’ capital revenue requirement, existing generation assets fixed O&M, future air emissions costs, hydro relicensing costs, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs.

Impact Calculation
The IRP customer impact calculation is as follows: portfolio $/MWh is calculated annually by dividing the total revenue requirement of the IRP footprint by the IRP load projections. Each year is compared with the previous year’s $/MWh to derive the $/MWh increase. This $/MWh increase is then divided by calendar year 2001’s actual retail rate of $48.97/MWh. (The CY 2001 $/MWh was chosen as a benchmark anchor to which all other years are compared. Figure 7.6 provides an example.) This provides an “indicative” percentage increase attributed to the IRP portfolio for that year.

Effect on Rates
Because the IRP excludes costs common to all portfolios, the customer impacts calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of total PacifiCorp revenue requirement impacts. It is only a portion of the total PacifiCorp revenue requirement. Likewise, the IRP impacts are a consolidated PacifiCorp look assuming immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.
### Table 7.7 IRP Annual Increase Calculation Example

**Example Calculation of IRP Annual Increase as a Percent of CY 2001 Retail Rates**

*Using the Diversified Portfolio I*

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>IRP $/MWh Revenue Requirement</td>
<td>$8.78</td>
<td>$9.30</td>
<td>$11.03</td>
<td>$12.18</td>
<td>$13.91</td>
<td>$15.78</td>
<td>$16.28</td>
<td>$17.43</td>
<td>$19.93</td>
<td>$22.15</td>
<td>$22.41</td>
</tr>
<tr>
<td>2</td>
<td>Year on Year Increase $/MWh</td>
<td>$0.51</td>
<td>$1.73</td>
<td>$1.15</td>
<td>$1.73</td>
<td>$1.87</td>
<td>$0.50</td>
<td>$1.14</td>
<td>$2.50</td>
<td>$2.23</td>
<td>$0.26</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Annual increase over CY 2001 Retail Rates</td>
<td>1.1%</td>
<td>3.5%</td>
<td>2.3%</td>
<td>3.5%</td>
<td>3.8%</td>
<td>1.6%</td>
<td>2.3%</td>
<td>5.1%</td>
<td>4.5%</td>
<td>0.5%</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Cumulative Increase over CY 2001 Retail Rates</td>
<td>1.1%</td>
<td>4.6%</td>
<td>6.9%</td>
<td>10.5%</td>
<td>14.3%</td>
<td>15.3%</td>
<td>17.6%</td>
<td>22.8%</td>
<td>27.3%</td>
<td>27.8%</td>
<td></td>
</tr>
</tbody>
</table>

**Explanation of Calculations:**

These calculations assume immediate rate-making treatment, i.e., all operating costs are recovered through rates as incurred and all new capital is included in rate base when placed in service.

The IRP revenue requirement includes only the impacts suggested by IPP, including system costs for fuel, variable O&M, emission allowance impact, start-up cost, market contracts, spot market purchases and sales, DSM cost, and all revenue requirement costs associated with adding incremental investment in new resources and new transmission.

The IRP revenue requirement excludes existing distribution, transmission and general plant capital and operating costs. It also excludes the fixed costs of existing generation assets which are the same in each portfolio.

- **row 1**: Annual revenue requirement for this IPP Portfolio divided by corresponding annual MWh Load.
- **row 2**: Current year $/MWh in row 1 minus prior year $/MWh in row 1.
- **row 3**: Calendar year 2001 retail revenue divided by retail MWhs sold. Used as a "benchmark" to which each annual IRP revenue requirement increase is compared against.
- **row 4**: Row 2 divided by row 3.
- **row 5**: Cumulative sum of row 5. Another method for calculating this is (ending year $/MWh, row 1 minus 2004 $/MWh, row 1) divided by $48.97.

For example, the 2014 cumulative increase of 30.2% is ($23.66/MWh minus $8.88/MWh) divided by $48.97/MWh.
Customer Impacts – General Conclusions
Consistent with the PVRR findings, Diversified portfolio I requires the smallest rate increases, using this methodology. Also, as shown above in Figure 7.18, the impacts associated with the IRP in the early years are similar among all portfolios.

STRESS TESTING

Described in Chapter 3, certain inputs do not naturally lend themselves to randomized variation within the models. Understanding the nature of these variables and their impact on portfolio performance therefore requires deliberate manipulation of their values. Model assumptions selected for this type of stress testing or scenario analysis include:

1) Modifying the assumed value of CO₂ allowance costs
2) Removing wind capacity
3) Modifying wind resource cost assumptions
4) Removing wind capacity and the carbon allowance costs
5) Attributing 15% wind capacity to planning margin
Each stress test was designed to provide insight into Scenario and Paradigm risks. The results of the testing are important. They demonstrate that the path ultimately taken by each risk can significantly alter the risk and cost profile of different portfolios. Collectively, they demonstrate the need for planning flexibility. Such flexibility in the development of portfolios is the most practical means of addressing each risk.

Because the scope and number of stress tests is broad, Table 7.8 summarizes them. Details of each analysis follow.
Table 7.8 Summary of IRP Stress Test

<table>
<thead>
<tr>
<th>Stress Name</th>
<th>Description</th>
<th>Portfolios Tested*</th>
<th>Conclusions</th>
</tr>
</thead>
</table>
| 1) Modifying CO₂ Allowance Costs    | Vary CO₂ cost. Compare assumptions of $0/ton, $2/ton, $25/ton, $40 to base of $8/ton | DP1, DP2, DP3, RP  | • PVRR escalates with increase in CO₂ allowance cost  
• Greater clarity needed prior to fuel selection  
• Renewable and natural gas resources hedge against CO₂ allowance costs  
• Profiled wind additions reduce costs  
• Findings support seeking a greater understanding of renewables as part of the resource stack |
| 2) Removing wind capacity           | Remove wind capacity from the top three portfolios                           | DP1, DP2, DP3      |                                                                                                                                                                                                                                                                                                                                                                                                     |
| 3) Modify wind resource cost        | Vary assumptions for Production Tax Credit (PTC), green tags, transmission, and integration | DP1                | • PTC provides greatest incentive of Renewable development  
• Transmission costs have potential to outweigh financial benefits from new wind  
• Green tag and integration cost assumptions are important but not the most significant factors in the decision making process  
• Continuous refinement of wind cost assumptions is necessary |
| 4) Remove CO₂ allowance cost and wind capacity | Compare assumption of $0/ton CO₂ cost and no wind capacity in portfolios with assumptions of $0/ton CO₂ cost with wind capacity | DP1, DP2, DP3      | • Very slight increase in PVRR  
• Additional renewables hedge against CO₂ allowance costs but offer imperceptible financial benefit without the allowance cost. |
| 5) Attribute wind capacity to planning margin | Count 15% of total wind capacity towards planning margin. | DP1, DP2, DP3      | • PVRR declines by $100m for all portfolios  
• Making up for resource reductions, existing system generation and market purchases increase  
• Further industry analysis required before % contribution can be determined for planning. |
| 6) Install wind earlier             | Move installation of wind one year forward to FY 2005                       | DP1, DP2, DP3      | • Less than 0.2% increase to PVRR. Tradeoff occurs between reduction in operations costs vs. earlier costs of acquiring resource  
• All responses to RFPs will be evaluated on an individual basis. IRP does not set a rigid timeline for wind resources (see Action Plan). |
<table>
<thead>
<tr>
<th></th>
<th>Description</th>
<th>Portfolio(s)</th>
<th>Summary</th>
</tr>
</thead>
</table>
| 7) | Replace Hunter 4 with IGCC                                                  | DP3          | • 1.4% increase to PVRR with reduced emissions  
• Technology advance may improve availability and lower costs |
| 8) | Replace peaking units with CCCTs                                            | DP1          | • <1% increase to PVRR  
• Increase to market sales  
• Reduction in capacity factors of new CCCTs to 12-37%  
• >20% capacity planning margin through 2011 |
| 9) | Vary the timing and order of large East units                              | DP1 and DP3  | • First installation in 2008 superior to 2007  
• DP 1 is least cost, however each variation’s PVRR is within less than 1% |
| 10)| Hydro licensing impacts                                                     | DP1, DP2, DP3 | • Large increase, $608 million to PVRR  
• Hydro is a valuable system resource  
• Detailed plant specific analysis will be completed as relicensing occurs |
| 11)| SB1149 impacts                                                              | DP1, DP2, DP3 | • Large decrease to PVRR, $1.78 billion  
• Significant impact to West planning  
• Additional transmission loss studies required  
• Planned large build in 2007 could be delayed or decreased due to loss of load |
| 12)| DSM Decrement                                                               | D1           | • Provides preliminary guidance in future DSM program design and valuation  
• As load factors increase, breakeven program costs decrease  
• Distribution costs and program feasibility must be evaluated outside this study |
| 13)| Change planning margin assumption                                          | Gas/Coal I, Coal/Gas III, PacifiCorp Build II and All-Gas II | • The effect of the lower margin (in MW added) by 2013 is between 500 and 550 MW.  
• A 10% planning margin requires slightly higher contingency market participation (7,000MWh/yr vs. 1,000 MWh/hr)  
• The decision to build to a 10% or 15% planning margin will be subject to regional policy issues |

*DP = abbreviation for Diversified Portfolio, RP = Renewable Portfolio

1) CO₂ Stresses
The results of the carbon dioxide (CO₂) emissions allowance cost stresses applied to the Diversified I - IV and Renewable portfolios are summarized in Appendix E, Tables E.4 to E.7. CO₂ emissions are not currently regulated, but may be in the future. As a base case assumption,
CO₂ allowance costs were modeled at $8/ton in all portfolios beginning in FY 2009 for each ton emitted above the calendar year 2000 total. Likewise, emissions under the cap received an $8/ton credit. This stress tests the impact to PVRR due to variation of the amount, timing, and cap level of this assumption.

As discussed in Chapter 3, the CO₂ allowance cost is considered to be a Scenario Risk. Accordingly, upper and lower limits are tested manually to determine the impact to each portfolio. The following is the profile of modeled CO₂:

- Base Case $8/ton cap allowance used is CY 2000 actual, beginning in FY 2009
- $0/ton, without a cap
- $2/ton, cap used is CY 2000 actual, beginning in FY 2013
- $25/ton, cap used is CY 1990 actual, beginning in FY 2008
- $40/ton, cap used is CY 1990 actual, beginning in FY 2008

**Observations**

- PVRR escalates with the increase of CO₂ allowance cost rate
- Existing thermal unit operation decreases with the increase of CO₂ allowance cost rate, prompting an increase in market purchases and a decrease in market sales, for both East and West. Given PacifiCorp’s higher than market proportion of coal fired generation, this finding is intuitive.
- East to West transfers decrease and West to East transfers increase as CO₂ allowance cost increases due to reduced operation of new and existing coal and natural gas units and greater reliance on spot markets.
- Total 2009-2023 CO₂ emissions at the $40/ton allowance cost rate are 92% of total emissions in the $0/ton case for each portfolio. These reductions are achieved at a 20-27% increase to overall PVRR (See Figure 7.19).
- CO₂ stresses impact the relative ranking of portfolios, measured by PVRR.

Using the PVRR as a measure, Diversified I placed first at $0, $2, and $8/ton CO₂ allowance cost. Somewhere between $8/ton and $25/ton the merit switches to Diversified IV with Diversified II placing second. The all gas portfolio, Diversified IV, stays in first place thereafter as the CO₂ allowance cost increases.

Benefits are not limited explicitly to CO₂ related costs. Other pollutants follow course with the CO₂ trend, decreasing as the incremental allowance cost increases are applied to CO₂.

Figures 7.19 and 7.20 below graphically illustrates the key observation of this analysis:

- The first three Diversified portfolios remain very close in PVRR for each case.
- Diversified IV, the all gas portfolio, remains in fourth position at the low end of the allowance cost but rises to first position at the higher allowance cost stresses.
- The timing of the coal plant installation (2008 vs. 2012) impacts the results of the PVRR ranking throughout the stress study.
- With a low CO₂ allowance cost penalty and low cap, the portfolio with early coal, Diversified I, ranks first. The portfolio replacing west contracts with built resources,
Diversified II, ranks second followed by Diversified III, which features the late installation of coal and the retention of West contracts.

- As the cap lowers and the allowance cost rate increases, the order of least rank is reversed.

**Figure 7.19 PVRR vs. Carbon Allowance Cost Scenarios**
Figure 7.20 CO₂ Emissions vs. Carbon Allowance Cost Scenarios

CO₂ Stresses - General Conclusions
• Greater clarity on carbon allowance cost issues would be helpful prior to selecting generation plant fuel type
• Renewables should be further analyzed for their potential use as a hedge against environmental pollutants. The addition of wind resources greatly reduces the range of PVRR outcomes of the CO₂ stress study.

2) No Additional Wind Capacity
The goal of this stress is to test the value in adding variable wind generation to the system portfolio. Diversified Portfolios I, II and III each include a gradually ramping, variable wind resource contract. Under this stress test, the wind contract is removed. Model outputs were then compared to the base case results of the top portfolios.

The wind resource was modeled as if it were a contract with a third party but attached to a wind plant with output varying by hour. The output is based upon actual historic generation data from plants located in each control area with representative hourly distribution shapes for the region. The pricing of the contract includes the capital cost of plant installation and transmission plus O&M and system integration. Some of these charges are offset by calculations for the Production Tax Credit and Green Tags based on the same assumptions as described previously in Chapter 6.
By removing the variable wind resource, the following impacts to the top portfolios are observed:

- Portfolio PVRR rises $68 - 75 million due to increase in net variable electricity cost.
- The variable contract cost line-item declines $1.5 billion due to elimination of the long-term wind contract. While substantial, this cost decline was insufficient to overcome the increases in other variable costs.
- Emissions expenses rise $78-85 million with a 17 million ton increase in CO2 output from 2009-2023.
- East market purchases increase slightly; West market purchases increase 10%.
- In the East, existing coal and peaker units run at slightly higher capacity factors. IRP CCCT East capacity factor rises by 15% by 2014.
- West existing resources also ran more often; CCCT capacity factor rises 18%. IRP CCCTs and peakers also ran more, increasing to 85% and 13% from an average of 78% and 10%.

Figure 7.21 illustrates the PVRR differences between portfolios with and without the wind contract.

**Figure 7.21 PVRR With and Without Wind**

No Additional Wind Capacity - General Conclusions

- Adding wind capacity to the portfolios increases variable contract costs but reduces the overall PVRR.
- Wind resources reduce the capacity factors of existing and new units.
With the above improvements come cost uncertainties, listed and analyzed in the next section.

This stress shows the wind as having an overall positive impact to the system costs and reduction to emissions and supports the continued pursuit of greater understanding of integrating renewables as part of the future resource mix.

3) Analysis of Wind Resource Variable Cost Impacts
Modeling shows wind resources reduce portfolio costs and risks. The purpose of this stress section is to identify the impact associated with the unique renewable energy cost assumptions. Many of these assumptions are uncertain and will impact the cost of developing and contracting for wind resources. Therefore, understanding the results in light of the value imputed by key cost assumptions is important. If these assumptions are stressed up or down, the modeling results may vary and change the pricing of the resource. Specifically, key variables are varied to observe the impact on the Diversified I portfolio.

The key variables in the Wind Resources of the Hybrid Portfolios include:
- Production tax credit (PTC)
- Green tag value
- Transmission
- System integration charges
- Carbon allowance costs
- Application of built wind capacity to planning margin

Each of these variables will be defined and quantified as they relate to the Diversified I portfolio.

Production Tax Credit
This tax incentive applies to new wind and geothermal plants with the intent of bringing their costs in line with other thermal resources. In the model, the tax credit applies to wind projects for the first 10 years of operation at $18/MWh. The credit also applies to new geothermal plants but only for the first 5 years of operation. Annual net operating expenses are directly credited at $18/MWh for each MWh produced by wind and geothermal plants for each year the incentive applies. This is an effective simplification for applying the cost. In reality, the benefits of the tax credit do not apply to the bottom line in such a straightforward manner.

The future of this tax credit is unknown. Although it has been extended through 2003, PacifiCorp assumes it will be continually extended. The PTC is assumed in effect for the life of the study, 2023. For the base case wind resources, the production tax credit reduces the 20-year PVRR by $353 million.

Green Tags
Green tags represent the environmental attributes of renewable energy. Such attributes can be traded between parties and therefore have a dollar value. With such value green tags help lower the installation and production costs of renewable power.
Green tags are the result of policy incentives to encourage renewable energy production. Incentives like the Federal Renewable portfolio Standard or similar state requirements are particularly important. At present, there is no federal RPS. Furthermore, with the exception of California, PacifiCorp’s service territory does not fall within a state featuring an RPS. Independent of legislative requirements, utilities in the future could set proprietary renewable targets independent of a RPS.

Regardless of the outcome of the RPS or similar legislation, green tags are expected to be of value.

- **No RPS**: If a Renewable portfolio Standard does not pass, green-specific energy would not be required for PacifiCorp’s proprietary consumption. Thus, all tags would be available for trading.
- **RPS Implemented**: If RPS is implemented, PacifiCorp’s renewable generation allows it to avoid the market costs of procuring tags. Tags for generation above the Standard would be marketable.

While retaining some value independent of a legislative mandate, the amount of that value is uncertain.

In the model, new wind and geothermal plants are assumed to have a green tag value of $5/MWh for the first five years of production. This rate does not change through time, effectively reducing their value by inflation each year. In the hybrid portfolios, the green tags reduce the overall PVRR by $58 million. Table 7.9 shows the impacts to the 20-year PVRR and relative portfolio ranking when the tag value is increased to $9/MWh as well as if there was no material value for tags in the future ($0/MWh).

The key finding of this study is that changing green tag assumptions, alone, is not enough to impact the portfolio rankings. With no value for the green tags, the PVRR for this portfolio increases less than 1%. Diversified I retains its least cost rank compared to the same portfolio without the wind resources. Higher tag values increase the portfolio’s advantage. Therefore, the future value of green tags alone does not appear to impact the overall decision to add wind resources to the portfolios.

**Transmission**

One major uncertainty associated with planning for new wind sites is the location of those plants and the additional transmission requirements to get generation into PacifiCorp’s system. In the model, there are four separate locations for wind plants:

- Central Oregon,
- South central Washington,
- Wyoming, and
- Utah
Estimated transmission costs range from $2/MWh to over $4/MWh. As demand for wind sites grows, those most convenient to transmission may be developed first, leaving those sites requiring transmission upgrade investments with higher $/MWh expenses.

In the base case for the Diversified I Portfolio, transmission ranges from $2-4/MWh. For an estimated low case, transmission costs were assumed to be half that cost and at the high end, transmission was stressed to three times the base value. Table 7.9 and Figure 7.22 show that only by assuming transmission costs are three times the base assumed value will the overall cost of adding wind to the portfolio outweigh any financial benefits.

**System Integration Costs**
The impact on system operations from adding large variable wind capacity into resource portfolios is unknown. PacifiCorp has begun to quantify the costs of integration by breaking it into two elements, system imbalance, and incremental operating reserves. Appendix J contains the detailed methodology and results from this study. In summary, for 1,000 MW of variable wind capacity in either the East or West sides of PacifiCorp’s system, the results of the study estimate integration costs to range from $5-$6/MWh.

In the model, it’s assumed that integration costs will increase with installed capacity according to the methods determined in the study. For the base case results for each hybrid portfolio, integration costs of the wind resources add $42 million to the 20-year PVRR. To stress these assumptions, the low end assumption is that integration costs are negligible to the system and at the high end, integration costs are set at twice the estimated base value. This range results in PVRRs +/-0.5% of the base. Due to this relatively small impact on the Diversified I portfolio, system integration costs alone do not impact the financial decisions to add additional wind to the system.

**Table 7.9 Diversified I Stress to Renewable Uncertainties**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Low</th>
<th>Base</th>
<th>High</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Green Tag Credits ($/MWh)</td>
<td>9</td>
<td>5</td>
<td>0</td>
<td>1st 5 years</td>
</tr>
<tr>
<td>PVRR ($000s)</td>
<td>12,266,974</td>
<td><strong>12,313,159</strong></td>
<td>12,370,888</td>
<td></td>
</tr>
<tr>
<td>Change from base</td>
<td>(46,185)</td>
<td>-</td>
<td>57,729</td>
<td></td>
</tr>
<tr>
<td>Integration costs</td>
<td>1/2x base</td>
<td>base</td>
<td>2x base</td>
<td>Base = $5-$6/MWh</td>
</tr>
<tr>
<td>PVRR ($000s)</td>
<td>12,271,021</td>
<td><strong>12,313,159</strong></td>
<td>12,355,296</td>
<td></td>
</tr>
<tr>
<td>Change from base</td>
<td>(42,138)</td>
<td>-</td>
<td>42,137</td>
<td></td>
</tr>
<tr>
<td>Transmission</td>
<td>1/2x base</td>
<td>base</td>
<td>3x base</td>
<td>Base = $4-$6/MWh</td>
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<tr>
<td>PVRR ($000s)</td>
<td>12,262,554</td>
<td><strong>12,313,159</strong></td>
<td>12,421,585</td>
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<tr>
<td>Change from base</td>
<td>(50,605)</td>
<td>-</td>
<td>108,426</td>
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<tr>
<td>Production Tax Credits ($/MWh)</td>
<td>18</td>
<td>18</td>
<td>0</td>
<td>1st 10 years</td>
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<td>PVRR ($000s)</td>
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<td><strong>12,313,159</strong></td>
<td>12,665,879</td>
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<tr>
<td>Change from base</td>
<td>0</td>
<td>-</td>
<td>352,720</td>
<td></td>
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<td>CO2 Tax ($/ton)</td>
<td>0</td>
<td>8</td>
<td>40</td>
<td>(see CO2 stress)</td>
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<td>PVRR ($000s)</td>
<td>12,081,433</td>
<td><strong>12,313,159</strong></td>
<td>14,630,030</td>
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<tr>
<td>Change from base</td>
<td>(231,726)</td>
<td>-</td>
<td>2,316,871</td>
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</tbody>
</table>
**Figure 7.22 Diversified I Wind Stresses**

4) **CO₂ Allowance Cost**

The future of the carbon allowance cost is a federal environmental policy decision beyond PacifiCorp’s control but it has potential to greatly impact system operations and long-term resource planning. It is clear that the addition of zero emissions resources to the system when there is a CO₂ allowance cost would most likely have a financial and environmental benefit to the company. This stress tests what the result would be if zero emission resources were added without the policy incentive of a large carbon allowance cost.

The variable wind resource and the $8 carbon allowance cost were removed from Diversified Portfolios 1 through 3. The model run results were then compared to the base case results with wind and $0/ton CO₂ allowance costs. The resulting range of PVRRs rose very slightly (0.04% to 0.17%) without the wind. This stress shows that the addition of wind to the portfolio still produces a reduction to PVRR when there is no carbon allowance cost.

This result was surprising but can be explained by the large reduction in net variable (dispatch) costs, which exceed the costs associated with acquiring the wind capacity. Since the carbon allowance cost is set at zero for both cases, the variable cost reduction is mostly due to the lower fuel use and reduced emissions which produce credits for NOx and SO2 emissions below their cap levels. The wind contract displaces new and existing thermal resources and increases market
sales while reducing market purchases. The final substantial cost components, which reduces variable operating costs, are renewable credit adjustments for green tags and the production tax credit. These credits can be classified as offsetting some of the increased variable contract costs associated with acquiring the variable wind resources.

**Figure 7.23 Combined Carbon and Wind Stress**

The probability of any of these CO₂ allowance cost outcomes is unknown. Model results show that renewable resources can displace thermal resources as a hedge against the high allowance cost scenarios and have little benefit under no allowance cost scenarios.

**5) Application of Wind Capacity to Planning Margin**

The portion of wind capacity modeled in the Renewable, Alternative Technology I and II, and Diversified I-IV portfolios does not contribute to the planning margin. This very conservative assumption is based on the variability of generation output expected from a wind site that can be 0 MW when the wind speed is too low or too high for energy production.

This assumption was stressed by restructuring Diversified portfolios I, II, and III to attribute 15% of new installed wind capacity towards the 15% capacity planning margin. As a result of this addition to capacity margin, other new resources were decreased an equivalent amount to maintain the 15% system planning margin. To do so, the flat market contract contained in each
portfolio was decreased by an amount equal to 15% of the new wind capacity as calculated in the following table.

Table 7.10 Application of 15% Wind Capacity to Planning Margin

<table>
<thead>
<tr>
<th>15% Wind Capacity Stress</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified Portfolio 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fiscal Year</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>East Wind Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>200</td>
<td>200</td>
<td>400</td>
<td>400</td>
<td>600</td>
<td>600</td>
<td>720</td>
</tr>
<tr>
<td>West Wind Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>100</td>
<td>100</td>
<td>300</td>
<td>300</td>
<td>500</td>
<td>500</td>
<td>700</td>
<td>700</td>
</tr>
<tr>
<td>Total System Wind Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>100</td>
<td>300</td>
<td>500</td>
<td>700</td>
<td>900</td>
<td>1100</td>
<td>1300</td>
<td>1420</td>
</tr>
<tr>
<td>15% Total Wind Capacity (MW)</td>
<td>0</td>
<td>0</td>
<td>15</td>
<td>45</td>
<td>75</td>
<td>105</td>
<td>135</td>
<td>165</td>
<td>195</td>
<td>213</td>
</tr>
</tbody>
</table>

When compared to the base case for results, the system was impacted as follows:

- PVRR decrease of $103-$107 million
- $34-$36 million increase in emissions costs contributing to the PVRR
- 11% increase in West market purchases, 5% decrease in West market sales
- No change to East market activity
- New and existing CCCTs and peakers in the West run at 3-6% higher capacity factors
- Capacity factors of new East CCCTs increase from 48% to 52%.
- East to West transfers increase by 8-13% in 2014 over the base case results, West to East transfers decrease 5-9% by 2014.

15% Wind Capacity - General Conclusions
This analysis shows there is a benefit of approximately $100 million (1%) to overall system PVRR when a portion of wind capacity contributes to planning margin. Less additional generation is needed in the future to meet the planning margin when some percentage of wind output is included in the load and resource balance. With the reduction in new resources, existing resources run harder but not at inefficient levels for their resource type characteristics.

If the built wind capacity did contribute to the planning margin at its expected capacity factor of 32-36%\(^{12}\), the amount of new capacity installed in the system through 2013 could be reduced by approximately 475 MW. This would reduce the capital investment in the portfolio and lower the overall PVRR. With increased knowledge and comfort of wind operations, PacifiCorp intends to revisit this assumption. Currently, there is not an industry standard for the percentage of wind capacity attributable to planning margins. Further system analysis, including a loss of load probability (LOLP) study, would help to give a reasonable estimate of the impact of wind variability on system operations.

\(^{12}\) Profiled wind is modeled assuming availability of 32-36% consistent with the historical output of known, wind generation resources.
6) Early Installation of Wind Resources, FY 2005
The modeled wind resources in Diversified I – IV, Renewable, and Alternative Technology I and II portfolios begin installation in FY 2006 at 100MW and grow to 1,420 MW by FY 2013. Since these wind resources do not contribute to the planning margin, the decision to start wind production in FY 2006 was based on the assumed build time for new wind sites including siting, permitting, and construction, not the need for additional capacity. It is possible that new wind resources can be added to the system even earlier than April 2005 if some projects are already in some stage of development.

In this stress case, PacifiCorp assumed each of the wind plant installations could be moved forward one year in the new resource plan. This stress was tested on Diversified Portfolios I – III with the following results:

- Less than 0.2% increase to PVRR ($11-$14 million)
- $6-$7 million decrease in emissions costs contributing to the PVRR
- 3% decrease in West market purchases, 6% increase in West market sales
- 4% increase in East market sales
- No change to unit performance or system transfers

Early Wind Installation - General Conclusions
The decrease in operating costs associated with earlier installation does not offset the increase in time value of costs for acquiring the new resources. The difference is practically insignificant and does not rule out the possibility of entering wind resource contracts before FY 2006. All opportunities for new resources will be evaluated on an individual basis. The model is one representation of a schedule for acquiring new wind resources but the true outcome will be based upon what sites are available and how they fit into the greater system plan.

7) Replace Hunter 4 2012 with IGCC
Integrated gasification combined cycle (IGCC) is a clean coal technology that utilizes a coal gasification process to produce clean fuel gas that can then be used to fuel a combined cycle natural gas turbine. Recognized for achieving slightly lower pollutant emission levels and higher efficiencies than a conventional coal-fired plant, PacifiCorp will continue to follow this technology for future additions as the technology becomes more established and the cost decreases.

In this stress case, the FY 2012 575MW Hunter 4 unit from Diversified portfolio III is replaced by a 370MW IGCC unit at the Hunter location plus a 1x1 CCCT at Mona. The IGCC plant has a more efficient heat rate of 8,311 MMBtus compared to 9,483 MMBtus for Hunter 4 but with this improvement to efficiency is a tradeoff of greater fuel cost, VOM, and a higher outage rate.

This stress was run only on Diversified Portfolios III with Hunter 4 in 2012 and produced the following results:

- 1.4% increase to PVRR ($177 million) due to increased operating costs
- $74 million decrease in emissions costs contributing to the PVRR
- No change to market sales or purchases
• 2% increase in East existing coal capacity factors, 9% increase of new East CCCTs
• Slight increase (2%) in West CCCT Capacity factor to compensate for 13% reduction in East to West 2014 transfers

**IGCC vs. Hunter 4 - General Conclusions**
The replacement of traditional coal technology at Hunter 4 for IGCC in 2012 would increase overall system costs based on cost information and unit performance characteristics available today. The cleaner technology produces lower emissions but at a higher cost. PacifiCorp will continue to monitor the development of this technology for cost reductions and operational improvements.

**8) Replace SCCTs with CCCTs**
All the portfolios in this study contain a combination of simple cycle combustion turbines (SCCTs) and combined cycle combustion turbines (CCCTs) which were installed based upon the size and timing of the resource gap, as defined in earlier chapters under portfolio development. SCCTs were mainly added to the portfolios as reserve peakers, providing the capacity to meet the 15% planning margin for the system. Resources were added such that the 15% planning margin was closely met for each year from 2007 through 2013. The peaking units operate between 2-6% capacity factors throughout the first ten years.

The purpose of this stress is to test the impact of gradually adding reserve peakers to the system compared to installing CCCTs up front. Instead of adding small increments of capacity through time in the form of low efficiency reserve peakers, the system resource plan could be redesigned to provide excess (greater than 15%), high efficiency capacity with CCCTs added earlier in the planning process. This methodology results in a heavy up-front build, into which the system demand would grow.

The Diversified portfolio I was first reconstructed by combining the 500MWs of East reserve peakers (200 MW in 2006 and 300MW in 2013) into a FY 2007 CCCT at Mona and replacing the 460MWs of West peakers (230MW 2006 230MW 2012) with a FY 2007 CCCT at Klamath Falls. The following observations were noted when compared to base case results:

• <1% increase to PVRR ($25 million), greater increase to fixed costs than the reduction to variable costs
• $31 million increase in emissions costs contributing to the PVRR
• Increase to market sales and decrease of purchases
• Substantial reductions to CCCT capacity factors, 12% capacity factor in the West, 37% capacity factor in the East.
• 13% reduction in East to West 2014 transfers

**Replace SCCTs - General Conclusions**
Replacing SCCTs with CCCTs in early years results in a capacity planning margin greater than 20% through 2011. Along with this high level of build is an increased reliance on the market for sales of excess generation. The financial tradeoffs of increased capital from early investment is not fully compensated by the increase in market sales and reduced use of less efficient units causing the PVRR to remain slightly higher than the base case. The resulting capacity factors of
the CCCTs in both the East and West decrease substantially such that the performance of existing CCCTs is more characteristic of an SCCT. At this level of capacity planning margin, retaining the peaking type resources for reserves seems beneficial due to the lower reliance on a sale market and more optimum use of new and existing resources.

9) Timing of Large East Units
Common to all top four portfolios are three large base-load type units in the East. These units include the Gadsby Repower, Mona CCCT, and Hunter 4 options. This study determined that the unit timing of Diversified portfolio I with Hunter in 2008, Gadsby in 2009 and then Mona in 2012 yields the least cost. PacifiCorp recognizes that the many Paradigm risks and industry scenarios could greatly impact future resource decisions including installation and fuel type. The purpose of this stress is to quantify the impact to PVRR from shifting the timing and type of these three large resources.

Two portfolios were used for this stress test, Diversified I and Diversified III. Recall that Diversified III installs three major units in years 2007, 2009, and 2012 and Diversified I plans for units in 2008, 2009, and 2012. The following table illustrates the timing variations studied. Scorecard results for these model runs are in Appendix E, Table E.13.

### Table 7.11 Resource Timing

<table>
<thead>
<tr>
<th>Portfolio Name</th>
<th>Case</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2012</th>
<th>PVRR ($billion)</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified I</td>
<td>Base</td>
<td></td>
<td>Hunter 4</td>
<td>Gadsby</td>
<td>Mona</td>
<td>12.313</td>
<td>0.00%</td>
</tr>
<tr>
<td>Variation 1</td>
<td></td>
<td></td>
<td>Gadsby</td>
<td>Hunter 4</td>
<td>Mona</td>
<td>12.325</td>
<td>0.10%</td>
</tr>
<tr>
<td>Variation 2</td>
<td></td>
<td></td>
<td>Gadsby</td>
<td>Mona</td>
<td>Hunter</td>
<td>12.317</td>
<td>0.03%</td>
</tr>
<tr>
<td>Variation 3</td>
<td></td>
<td></td>
<td>Gadsby</td>
<td>Mona</td>
<td>Mona</td>
<td>12.395</td>
<td>0.67%</td>
</tr>
<tr>
<td>Diversified III</td>
<td>Base</td>
<td>Gadsby</td>
<td>Mona</td>
<td>Hunter 4</td>
<td>12.360</td>
<td>0.38%</td>
<td></td>
</tr>
<tr>
<td>Variation 1</td>
<td></td>
<td>Gadsby</td>
<td>Mona</td>
<td>Hunter 4</td>
<td>12.371</td>
<td>0.47%</td>
<td></td>
</tr>
</tbody>
</table>

The following observations were noted when comparing each variation to the corresponding base case results:

- Variations produce a <1% increase to PVRR ($4-$82 million)
- Installing the first unit in 2008 vs. 2007 provides the greatest reduction to PVRR, regardless of fuel type
- Variations with Hunter 4 in later years show greater benefit in emissions reductions.
- Market activity is unchanged
- Unit capacity factors and system transfers by 2014 are unchanged

Timing of Units - General Conclusions
Diversified I contains the least cost resource mix. Alternatives to the timing of large resources negatively impact the 20-year PVRR. However, cost changes ranged by less than 1%. While the Diversified I configuration is superior, the difference could arguably be described as statistically insignificant. Due to the small magnitude in PVRR difference between portfolios, the Action Plan for acquiring resources can remain flexible without sacrificing a statistical advantage.
10) Hydro Licensing Impacts
A large percentage of PacifiCorp’s hydro resources are involved in some stage of the re-licensing process. In this stress case, PacifiCorp assumed approximately 200 MWs (18%) of owned hydro resources are not successfully relicensed. The 200 MW is a combination of run-of-river and peaking resources in the West control area. These resources are removed and replaced by two additional SCCT peaking units totaling 230 MW. This stress models the impact of losing an existing low cost resource and replacing it with resources with similar capabilities.

This stress was run on Diversified portfolios I - III. When compared to the base case for results, the system was impacted as follows:

- PVRR increase of $608 million due to increase in capital and operating expenses
- $20-$22 million increase in emissions costs contributing to the PVRR
- 16% increase in West market purchases, 8% decrease in West market sales
- No change to East market activity or unit performance
- New and existing CCCTs and peakers in the West run harder
- East to West transfers increase by 11-22% in 2014 over the base case results, West to East transfers decrease 5-15% by 2014.

The new, replacement resources required to meet this resource’s profile tend to be more expensive to run relative to market purchases and imports of excess East generation. Therefore, West purchases and East/West transfers increase to cover West load.

Hydro Licensing - General Conclusions
This analysis shows hydro to be a valuable system resource. With the loss of 200 MW of hydro resources, units operate at higher capacity factors and spot market purchases increase in the West. The East assists the West by transferring more and receiving less. Hydro is a flexible low cost resource which meets PacifiCorp’s system needs well.

The IRP assumes all owned hydro plants would be relicensed. Detailed, plant-specific hydro analysis would be required prior to changing this assumption. This will be done as plant relicensing occurs.

11) Loss Of Load – 400 MW In Oregon (SB 1149 Potential Impact)
The major assumption for this stress case is that with restructuring legislation (SB 1149), PacifiCorp may lose some commercial and industrial customers in Oregon. For purposes of stress testing, an assumption was made that approximately 400 MW of flat commercial and industrial load are removed from the West Main transmission area in July 2003.

To reflect this loss, the model was adjusted to remove 400 MW from the load each hour and the mix of resources in the Hybrid portfolios was reduced to reflect a decrease in capacity requirement. Only new resources in the West were removed for this stress case along with their associated transmission costs. Portfolio resource reductions include the following. The 500 MW off-peak contract which is present in every portfolio and expires in 2006 was reduced to 400 MW, the 2007 2x1 West CCCT was reduced to a 1x1 and the 230MW of new peakers in the
West for 2006 were removed. Even with these resource reductions, the portfolios still attain a 15% planning margin requirement.

In addition to adjusting the portfolio resources for loss of load, system transmission capabilities would also have to be reduced. This step will require further analysis with more detailed assumptions for customer load factors and locations. Due to the complexity of these adjustments, this analysis was completed with the loss of load and resource adjustment but will require further analysis for transmission impacts. The results are considered preliminary.

Compared to the base case scorecard results for the Diversified I – III portfolios, system operations are impacted as follows:

- PVRR decrease of $1.78 billion due almost entirely to reduction in variable operating costs. Only $350 million of the reduction is due to capital costs.
- $80-87 million reduction in emissions cost contribution to PVRR
- Purchases in the West decrease 40% and West sales increase 20%
- East new and existing resources operated at slightly lower capacity factors
- West new and existing CCCT capacity factors greatly decreased

The PVRR results for the scorecard comparison do not determine if the loss of load would be beneficial or detrimental to the system. The best method of evaluating the system performance is by looking at the 20-year, weighted average variable power and incremental fixed costs on a $/MWh basis before and after the loss of load. Table 7.12 shows the comparison of before and after $/MWh. In summary, the loss of load resulted in a $1.30/MWh reduction in incremental system costs. These preliminary results do not include the system impacts due to reduction in transmission capabilities.

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Base $/MWh</th>
<th>Stress* $/MWh</th>
<th>Difference $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diversified I</td>
<td>15.26</td>
<td>13.96</td>
<td>1.30</td>
</tr>
<tr>
<td>Diversified II</td>
<td>15.28</td>
<td>13.97</td>
<td>1.31</td>
</tr>
<tr>
<td>Diversified III</td>
<td>15.31</td>
<td>13.99</td>
<td>1.32</td>
</tr>
</tbody>
</table>

*These results do not include impacts to existing transmission

**Loss of Load - General Conclusions**

The loss of a flat block of load in Oregon greatly impacts West operations but does not significantly impact the East, other than providing more transfers into the East system. The overall PVRR is greatly reduced but change to system costs on a $/MWh basis provide a more meaningful summary of impact due to the stress situation. These results show that the loss of load reduces incremental $/MWh costs. This result is preliminary since it does not include an adjustment for impacts to transmission capabilities associated with these customers. The West is still considered slightly overbuilt in this scenario since market sales increase, purchases decrease, and unit capacity factors are reduced. In 2007, when the large long-term purchase contracts expire, it is unlikely there would be a need to build with this magnitude loss of load. More
likely, PacifiCorp would continue to purchase long-term contracts. An option would be to build or buy smaller resources as modeled through this stress.

12) DSM Decrement
Modeling Results
The effect of increasing the amount of DSM was tested. Since DSM reduces load, the effect of increasing DSM is called the DSM decrement. The nominal results of the DSM decrement runs through 2012 are summarized in Tables 7.13 and 7.14.

For each decrement case, the Revenue Requirement of the Diversified portfolio I containing the base load forecast was compared on a year by year basis with the new decrement case Revenue Requirement with the load decrement. Appendix G details how these decrement runs were designed and includes their detailed results.

Table 7.13 compares the break-even incremental $/MWh value of potential Class 2 DSM programs for the first few fiscal years for each decrement. These values were calculated for the entire planning period and can be found in Appendix G.

Table 7.13 Decrement Results Summary (nominal $/MWh) For Class 2 DSM Programs

<table>
<thead>
<tr>
<th>Decrement Case</th>
<th>2004-2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>D150-10</td>
<td></td>
<td>234</td>
<td>188</td>
<td>189</td>
<td>181</td>
</tr>
<tr>
<td>D300-20</td>
<td></td>
<td>93</td>
<td>91</td>
<td>85</td>
<td>57</td>
</tr>
<tr>
<td>D150-40</td>
<td></td>
<td>60</td>
<td>54</td>
<td>53</td>
<td>41</td>
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<tr>
<td>D300-60</td>
<td></td>
<td>50</td>
<td>48</td>
<td>49</td>
<td>51</td>
</tr>
</tbody>
</table>

These nominal decrement value results per MWh can be compared to the nominal market prices per MWh for those same years from Table C.25:

Table 7.14 Nominal Market Prices

<table>
<thead>
<tr>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30.84</td>
<td>32.29</td>
<td>32.68</td>
<td>33.54</td>
<td>37.34</td>
<td>43.15</td>
<td>38.66</td>
<td>41.58</td>
<td>47.69</td>
</tr>
</tbody>
</table>

As load factors increase, the break even program costs decreased.

The 1% load factor decrements model a load control type of Class 1 DSM program. Since the PROSYM model cannot dispatch load decrements, these decrements were selected based on peak load days in one year, and the same days repeated over the duration of the planning period. The nominal decrement value of these decrements is shown in the Table 7.15 over the first few years of the decrement period. Model results for the entire planning period can be found in Appendix G.
Table 7.15 Decrement Results Summary (nominal $000) For Class 1 DSM Programs

<table>
<thead>
<tr>
<th>Decrement Case</th>
<th>2004-2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>D150-1</td>
<td>Decrement begin in FY 2009</td>
<td>9,887</td>
<td>9,605</td>
<td>7,607</td>
<td>8,853</td>
</tr>
<tr>
<td>D300-1</td>
<td></td>
<td>10,197</td>
<td>9,663</td>
<td>8,415</td>
<td>9,777</td>
</tr>
</tbody>
</table>

One 100MW East reserve peaker was removed from 2006 for each of these model runs. These 1% load factor decrement values reflect the break-even nominal value in each year of the capability to curtail loads by 150 MW and 300 MW respectively. PacifiCorp should not pay more than the lessor of these values or a like market instrument for this load interruptability.

**DSM Decrement General Conclusions**

This study provided preliminary guidance in the future design of DSM programs for the system. Focus should be given to lower load factor programs that match peak without excluding opportunities to conduct programs with higher load factors.

Actual program designs, as they build to higher annual DSM levels (above the base 15 MWa/year) for FY2004 and beyond, will be run through the model and the nominal Revenue Requirements will be compared to the base revenue requirements. A bundle of programs achieving an additional 300 MWa over 10 years that can be implemented with a reduction in revenue requirements using this decrement analysis will be cost effective. Distribution benefits, because they are very local and specific to load characteristics in a distribution area, will be considered as individual programs are designed.

This modeling effort can not determine the feasibility of achieving 450 MWa of DSM in the PacifiCorp service territory over the next 10 years. The Action Plan includes an effort to determine the actual, realistic market potential for DSM in the PacifiCorp service territory. Future goals may be adjusted to reflect actual market potential.

**13) Reducing the Planning Margin**

The initial portfolios were built to meet a 15% planning margin. The effects of reducing the planning margin from 15% to 10% were originally tested on the following portfolios: Gas/Coal I, Coal/Gas III, PacifiCorp Build II and All-Gas II. It is expected that the impact of planning margin reductions would be similar on other portfolios including the Renewable and four Diversified Portfolios. Comparisons between portfolios with very similar resource blends built to different planning margins show the impacts to system reliability, costs and risks associated with varying levels of available resources.

PacifiCorp’s needs are met with a slightly different mix of generation when moving from a 15% to a 10% planning margin. The lower margin changes the level of emissions, market purchases and sales, unit capacity factors and East-West energy transfers. The effect of the lower margin in megawatts added by 2013 is between 500 and 550 MW.

The Scorecard for the portfolios with a 10% Planning Margin is included in Appendix E, Table E.3.
PVRR
A lower margin (from 15% to 10%) is shown to consistently reduce the 20-year PVRR by between $100 million and $325 million, or between 0.8% and 2.5%. A major factor in this cost reduction is a reduction in present value levelized fixed costs of between $300 and $375 million (12-17%). This is partially offset by an increase in net electricity costs. In the all-gas portfolios the reserve margin reduction yields $330 million savings in PVRR levelized fixed cost, offset by an increase of $220 million in PVRR of net electricity cost. In contrast the Diversified Gas/Coal I portfolio shows a $375 million reduction in PVRR levelized fixed cost, but only $50 million increase in PVRR of net electricity cost.

Emissions
The level of emissions from PacifiCorp-owned resources will not materially change when moving from a 15% to 10% planning margin. The reduced capacity results in higher peaking unit use and additional market purchases over the 15% case. NOx and SO2 emissions increase only slightly. CO2 and Hg emissions should not change.

Unit Capacity Factors
As mentioned, the major differences in supply under a 10% planning margin come from additional market purchases and increased peaking unit usage. The capacity factors of non-peaking units remain consistent.

Market Sales and Purchases
Market purchases will increase by a moderate amount when implementing a 10% planning margin. The scorecard shows that 10-year average purchases (2004-2013) are expected to increase by less than 10 MWa. A snapshot of any year beyond 2013, after all resources in the IRP have been installed, shows that annual purchases in the East increase by approximately 10%. West purchases increase by closer to 6%.

PacifiCorp’s market sales decrease with the decreased availability of assets from which to sell.

East West Transfers
The effect of a 10% planning margin on East-West transfers will depend upon how the reduction in capacity is implemented. If the 10% planning margin is accomplished via an equal reduction in planned peaking units in both the East and West control areas, West-to-East transfers will increase marginally (typically in the 5% range) in a diversified portfolio versus the 15% planning margin case.

Contingency Market Purchases
PacifiCorp understands that less routine events, such as multiple unit outages, low hydro availability or high load, occur, and has therefore incorporated in its modeling the ability to access the electricity markets on a contingency basis. For modeling purposes, these electricity purchases are available as a resource under unusual operating conditions – used only after owned assets (and regular markets) have been exhausted. However, energy available from this source is limited. The market size approximates 15% of an area’s peak load.
In the portfolio runs with a 15% planning margin, contingency markets were typically relied on for about 1,000 MWh/year (or about 0.002% of total annual system load) – due to randomly occurring multiple forced outages. This is a very low level of contingency market participation.

A 10% planning margin will require slightly higher contingency market participation. The portfolios tested with a reduced planning margin generally purchased about 7,000 MWh/year (or about 0.01% of total annual system load) from the contingency markets.

**Risk and Planning Reserves**

Figure 7.24 graphically demonstrates the effect of changing planning reserve margin requirements. It compares PVRR, 95th and 5th percentile PVRR as well as the mean of the tail for pairs of portfolios that have a 10% and 15% planning margin. The observations for the 15% planning margin are higher for each measure. Given the additional capital costs of building to a higher planning margin, this should not be surprising.

**Figure 7.24 Planning Margin Comparison**

Reserves, if effectively deployed, should reduce risk. Although all measures for 15% portfolios were higher, the additional cost may be acceptable if risk is improved by a greater margin. Figure 7.25 attempts to convey this issue. It illustrates that risk is reduced.
Figure 7.25 demonstrates that additional planning margin reduced risk. Observe the 5% - 95% Spread. This measure begins by taking the difference between the 5th percentile and the 95th percentile for each portfolio. The difference approximates the range of expected outcomes, a reasonable representation of risk. Next the 5% - 95% Spread is determined by subtracting the calculation above for the 10% portfolio from that found for a 15% portfolio. As expected, the 5-95 spread for each 10% portfolio exceeded that of its 15% counterpart. Thus, the risk or range of expected outcomes under 10% planning margin portfolios is greater than that of the 15% planning margin portfolios.

Now observe the relative size of the expected PVRR as plotted on Figure 7.25 and the corresponding 5% - 95% Spread. The difference between the PVRRs of the two portfolios is much greater than the difference between the 5% - 95% Spread measurements. If the additional reserves adequately offset risk, the reduction in risk (represented by the 5% - 95% Spreads) should equal or exceed the expected investment needed to realize it (represented by the PVRR). Therefore, it can be tentatively concluded the dollar investment in the added resources is not accompanied by a commensurate reduction in risk.

The above risk conclusions are tentative for the following reasons.

- This is a 20-year study assessing investments of billions of dollars. While certain observations appear different, it could be reasonably argued that the study is necessarily too
blunt an instrument to confidently distinguish relatively smaller differences among observations.

- While the risk reduction does not appear favorable compared to the investment needed to realize it, the investment is not without merit. The adequacy of an investment-risk tradeoff is somewhat subjective. Different people, different states and different groups have different sensitivities and preferences for risk.

**Reduced Planning Margin Conclusion**
While the appropriateness of the capital - risk tradeoff remains to be resolved, the decision to build to a 10% or 15% planning margin will be subject to regional policy issues like RTO and SMD. Fortunately, the build time required to install additional capacity neatly overlaps the proposed resolution times of these issues. Current developments could be delayed or future acquisitions eliminated to conform the plan to the then current SMD requirement. Clarity on RTO and SMD should be achieved before PacifiCorp can build to a 10%, much less 15%, planning margin.
8. CONCLUSIONS

OVERVIEW

The goal of this Integrated Resource Plan (IRP) is to develop a clear plan and strategy which will help ensure:

- PacifiCorp fulfills its obligations to serve its customers
- PacifiCorp delivers the most economic solutions for both its customers and shareholders
- The risks to the customers and to PacifiCorp are reduced
- A high level of stakeholder concurrence with PacifiCorp’s resource plans and implementation decisions is obtained

The markets in which PacifiCorp operates are continually developing and changing. It is critical that the plan and actions arising from this IRP lead to a solution which allows PacifiCorp the flexibility to adjust to the changing operational environment and at the same time provide as much certainty and stability as possible for PacifiCorp and its customers.

This Chapter summarizes the main conclusions and key findings outlined in the report from which the Action Plan (Chapter 9) is developed.

PORTFOLIO SELECTION

PacifiCorp’s current position (Chapter 2) reveals a substantial need for new resources. This gap analysis also outlined how the two control areas, PacifiCorp West and PacifiCorp East, have different resource and transmission issues. This difference results in a different balance of loads and resources for each side of the system. Resolving the gap economically and reliably was the focus of PacifiCorp’s planning process.

The analysis of the analytical results (Chapter 7) confirm that the Diversified Portfolio I is the least-cost, lower risk portfolio to fill PacifiCorp’s long-term resource needs based on the forecasted customer demand.

Table 8.1 is a summary of the total MW, timing and capital cost associated with specific resources contained in Diversified Portfolio I. A more comprehensive summary of this portfolio can be found in Appendix D.
Figure 8.1 illustrates how the resources in the Diversified Portfolio I fill the capacity requirement for the 2004 to 2014 time period. The Class 1 and Class 2 DSM programs in Diversified Portfolio I have been included as a decrement to the load forecast, which is used in the calculation of the L/R balance. Since PacifiCorp assumed no capacity credit for wind, the wind capacity in the Diversified Portfolio I is not included in this figure.
DEMAND-SIDE MANAGEMENT

There are 450 MWa of cost effective Class 2 DSM and 100 MW of Classes 1 and 3 DSM expected over the first ten years of the plan. An estimated 90 MW of interruptible load control capacity is implemented during fiscal years 2004 to 2006. Additional cost effective DSM will be reviewed and implemented where possible during the period.

Table 8.2 highlights timing and size of the Class 1 and Class 2 DSM programs identified. These programs are included in all of the portfolio runs and are marked with an ‘A’ in the first column of the table. The Class 1, 2 & 3 DSM programs marked with a ‘B’ in the table, were the hypothetical DSM programs tested in the DSM decrement analysis discussed in Chapter 7 and Appendix G. Actual programs need to be identified and designed for PacifiCorp to achieve higher annual DSM levels beyond the programs in the base portfolio runs.
Table 8.2 Planned DSM Over the Period 2004 to 2013.

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A Class 1 DSM (load control – peak MW Capability)</td>
<td>30</td>
<td>60</td>
<td>91</td>
<td>91</td>
<td>91</td>
<td>91</td>
<td>91</td>
<td>91</td>
<td>91</td>
<td>91</td>
</tr>
<tr>
<td>A Class 2 DSM (cumulative MWa)</td>
<td>35</td>
<td>49</td>
<td>62</td>
<td>76</td>
<td>90</td>
<td>104</td>
<td>118</td>
<td>132</td>
<td>144</td>
<td>144</td>
</tr>
<tr>
<td>B Class 1 &amp; 3 (load control and curtailable tariffs – peak MW)</td>
<td>-</td>
<td>-</td>
<td>50</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>B Class 2 DSM</td>
<td>-</td>
<td>-</td>
<td>150</td>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
<td>300</td>
</tr>
</tbody>
</table>

Notes: A – Base DSM in every portfolio, B – DSM associated with decrement analysis

The modeling effort does not determine the feasibility of achieving 450 MWa of DSM in the PacifiCorp territory over the next ten years. The additional planning decrement resource addition of 300 MWa (above the base 144 MWa) was not included in the final portfolio resource plan because specific cost effective programs to fill the 300 MWa decrement have not yet been identified. To evaluate the cost effectiveness of this additional DSM, the value of the reduction in the load forecast (the decrement) needs to have a resource mix that can be changed once the actual decrement containing program designs have been included. A new load/resource balance will also need to be produced, with supply side resource timing changed because of the load decrement (the capacity deferral value of the decrement). The action plan will include steps to assess the feasibility of an additional cost-effective 300 MWa of DSM resource including a market assessment study, design of additional programs and an RFP to find effective programs from the marketplace. Future goals may be adjusted to reflect actual market potential.

RENEWABLES

As mentioned in Chapters 5 and 6, the portfolios that were developed in the beginning of the analysis contained wind resource additions in line with the proposed Federal Renewable Portfolio Standard (RPS). These additions were modeled as electricity purchase flat contracts for 1,146 MW of wind generation planned from 2003 through 2013 and charged at $50/MWh.

In the final portfolios, the $50/MWh flat contract was replaced with “profiled wind”, i.e. wind whose profile follows an anticipated, more realistic production shape. Under profiled wind, energy deliveries are anticipated to differ in each hour of the day. This profiled wind has been included based solely on its economic merits. Table 8.4 provides a breakdown of the wind build pattern in Diversified Portfolio I.

Table 8.4 The planned Wind build up in Diversified Portfolio I

<table>
<thead>
<tr>
<th>Year</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind East</td>
<td>200</td>
<td>200</td>
<td>200</td>
<td>200</td>
<td>200</td>
<td>120</td>
<td>720 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind West</td>
<td>100</td>
<td>200</td>
<td>200</td>
<td>200</td>
<td>200</td>
<td>700 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Solar and geothermal opportunities will also be examined on a case by case basis for economic merit and inclusion in PacifiCorp’s overall resource portfolio.

PEAKING UNITS

Diversified Portfolio I requires up to 1,200 MW of peaking capacity be added over the plan period 2006 to 2013 (the equipment market and economics will dictate the actual technology used). Peaking resources are a necessary component of every portfolio, and serve two purposes. One is to meet the load shape requirements for both the East and West sides of PacifiCorp’s system, and the second is to meet the capacity requirements of the 15% planning margin. Prior to commitment to build these assets, Purchased Power Agreements (PPAs) and shaped product opportunities will be reviewed and compared for economic benefit, risk reduction and long term optionality.

There remains uncertainty surrounding the planning margin requirements outlined in the proposed SMD. PacifiCorp has designed the action plan based on a 15% planning margin. However, it will take a number of years to build to a significant planning margin (even to 10%). This period will allow PacifiCorp time to modify its plans in concurrence with the future requirements of SMD. Further study of an appropriate planning margin for PacifiCorp will continue, and is an element of the Action Plan.

BASE LOAD UNITS

In line with the load growth, plant retirement and contract expiration, an estimated 2,100 MW of base load capacity is required. As with peakers, the need for additional base load capacity was observed in Chapter 7 and found in every portfolio. Three base load units in the East (in service in 2008, 2009 and 2012) and one unit in the West (in service in 2007) will be further researched and pursued. Here the process of sizing and selecting resources consistently identified base load as having desirable least-cost characteristics.

For IRP modeling purposes, and in line with the market depth and liquidity issues discussed in Chapters 1 and 3, it is assumed that they will be physical assets. However, these units could feasibly be replaced with a long term PPA. Prior to commitment to build any of these assets, PPAs or other asset purchase opportunities will be reviewed and compared for economic benefit, risk reduction and long term optionality. This Procurement Program is discussed in the Action Plan.

SHAPED PRODUCTS AND POWER PURCHASE AGREEMENTS

Diversified Portfolio I required approximately 700 MW of shaped products or PPAs throughout the plan period 2004 to 2013. These contracts will fill an immediate short term peaking need in the East, prior to any assets being built and will supplement the building of additional assets in the long term. Shaped products and PPAs also aim to cover off-peak requirements in the West.
The 700 MWs are in addition to any alternative shaped product or PPAs that may be entered into in relation to the Peaking and Base Load requirements mentioned above.

**TRANSMISSION**

Transmission additions are requested to support all the assets detailed in the Diversified Portfolio I. Several upgrades feeding into the Wasatch Front area, specifically the “Wasatch Front Triangle”, should be implemented immediately (see transmission section in Chapters 5). Additional transmission is necessary to support the new resource additions in Diversified Portfolio I.

This analysis will depend on the as yet unknown outcome of the RTO process. Because of RTO, it is possible that there will be greater potential for additional transmission than is currently suggested by the portfolios. While the modeling process demonstrated that under current assumptions large additions of transmission unrelated to new resources are unwarranted, the RTO Paradigm Risk could change that finding. Further study and attention to developments will be required to determine the RTO West impact and influence.

The transmission associated with the development of the renewables portion of the portfolio requires further clarification. The detail of the transmission requirement and the potential impact on the system performance will be defined when the potential sites are determined.

**COAL VERSUS NATURAL GAS**

**Overview**

The portfolio results clearly show PacifiCorp needs to add base-load resources. The least cost portfolio includes a coal based thermal unit in the East. Coal-fired generation may be particularly advantageous when procuring resources in the Rocky Mountains because coal is an abundant indigenous resource there. However, the long-term impacts of atmospheric emissions are casting doubt on the viability of coal-fired generation. The IRP least cost portfolio is dependent upon the impact of a number of these paradigm risks, including air emission standards and possible global warming measures. PacifiCorp believes it has adequately addressed these risks, based on our current understanding of them, and coal plants remain a low-cost option. The IRP Action Plan includes further work to develop and test the viability of a coal base thermal unit, including an ongoing assessment of the risks.

**Coal Cost Advantage**

Among the four diversified portfolios, which were the top four portfolios based on lowest PVRR and least risk, Diversified Portfolio IV excludes coal-fired generation, while Diversified Portfolios I, II, and III all include a 575 MW base-load coal unit in Utah. In relative terms, all of the Diversified Portfolios provided similar PVRRs over the 20-year plan horizon. The differences between these top four portfolios range from 0.2% to 0.7% above Diversified Portfolio I. Given the time period of the study and the large number of inputs considered, these differences could arguably be described as statistically insignificant.
This same relative advantage of new coal holds in the risk results as well. A greater sensitivity to natural gas price fluctuations makes Diversified Portfolio IV prone to high PVRR outcomes during high loads and high natural gas price iterations. Exposure to natural gas appears to be a leading contributor to the risk differences in the portfolios. The Diversified Portfolio I featuring the addition of a coal plant with the earliest installation schedule has the least natural gas exposure.

**Environmental Cost Risk**

Since base-load coal generation produces more CO₂ and other air emissions per megawatt-hour of energy, the effect of increasing the cost of emissions is to reduce the cost advantage of coal. Examining the CO₂ stresses reveals this effect. Using the PVRR as a measure, Diversified Portfolio I placed first at the $0, $2, and $8/ton CO₂ allowance costs. Somewhere between $8/ton and $25/ton the merit switches to Diversified Portfolio IV with Diversified Portfolio II placing second. This analysis provides the general conclusion that as the CO₂ caps lower and the allowance cost rate increases, the portfolio without the coal plant becomes the least-cost portfolio based on PVRR.

Benefits to a portfolio without a coal plant addition is not limited explicitly to CO₂ related costs. Other pollutants follow course with the CO₂ trend, decreasing as the incremental allowance cost increases are applied. Greater clarity on carbon allowance cost issues, as well as cost issues related to all pollutants, would be helpful prior to selecting a fuel type.

**Timing of Coal Addition**

In Chapter 7, a stress was performed (Stress 9 – Timing of Large East Units) to test the timing of the two natural gas plants and the coal plant that was in Diversified Portfolios I, II, and III. This study determined that the unit timing of Diversified Portfolio I with the coal plant (Hunter 4) in 2008, Gadsby in 2009, and then a natural gas plant at Mona in 2012 yields the least cost solution. The differences between the PVRR results of Diversified Portfolio I and changing the timing of these three base load units is less than 1%. Therefore, the differences between the portfolios that adjust the timing of the base load units could arguably be described as statistically insignificant.

**Coal Versus Natural Gas - Conclusions**

Results appear to favor adding a new coal unit, though with some ambiguity, especially with regard to timing. The preferred timing could also be influenced by the resolution over time of uncertainties, some of which contribute to the ambiguity of results. Over the next three to five years, there may be more certainty with regard to future environmental costs, especially costs of CO₂ emissions, better knowledge of the cost and performance of clean coal technologies that could reduce exposure to environmental risks, and a better picture of the level and volatility of future natural gas prices. Finally, more information can be obtained regarding direct compliance costs and potential offset costs of a specific new coal unit. Though only with the undertaking of specific siting and environmental permitting activities.

This is not an either/or choice of coal versus natural gas, however. Even those portfolios that most heavily favor a new coal unit also require new base-load natural gas CCCTs in the same
2007-2009 time frame. Thus, siting and licensing of both new CCCT and base-load coal are warranted and not mutually exclusive. A new base-load coal unit at Hunter 4, the practical alternative considered in the portfolios described above, could be a valuable portfolio addition somewhere in the 2008-2012 time frame, under most future conditions. However, it can be a realistic alternative in this time frame only if siting and environmental permitting activities prove out its merits.
9. ACTION PLAN

This chapter provides details of the IRP Action Plan that PacifiCorp intends to implement following a fully acknowledged IRP. PacifiCorp requests that each State Commission acknowledge and support the IRP, including acknowledgement of the Action Plan, in accordance with Commissions’ requirements for an IRP.

Included in this chapter are:

- The detailed Action Plan, including specific Findings of Need and Implementation Actions
- The Decision Processes for implementation of the Action Plan
- The Procurement Program for implementing the Action Plan
- An update on PacifiCorp’s Current Procurement and Hedging Strategy
- Description of how PacifiCorp Resource Planning and Business Planning are aligned
- Discussion on the Action Plan’s consistency with the Oregon’s restructuring legislation (SB-1149)

THE IRP ACTION PLAN

The Action Plan arising from this IRP is based on the single least cost, low risk portfolio arising from the analysis results discussed in Chapter 7 and the conclusions summarized in Chapter 8. The Action Plan portfolio is the Diversified Portfolio I (DPI). The resource make up of DPI for the period 2004 to 2014 is as follows:

- 1,400 MW Renewables
- 1,200 MW Peakers
- 2,100 MW Base Load
- 450 MWa DSM
- 700 MW Shaped Products

The Action Plan aims to ensure PacifiCorp will continue meeting its obligation to serve its customers at a low cost with manageable and reasonable risk and at the same time remain adaptable to changing course, as uncertainties evolve or are resolved, or if a Paradigm shift occurs. Given the historical variability and future uncertainty, this represents the least-cost IRP solution. An element of the Action Plan is to preserve PacifiCorp’s optionality and flexibility in the future.

The IRP is intended to provide guidance and rationale for PacifiCorp’s resource planning path forward. A successful IRP will result in “acknowledgement” by the states indicating no significant disagreement with, and a degree of support for, the Action Plan. PacifiCorp’s shareholders must and will take into account this IRP and subsequent governmental and public responses when making future capital allocation and investment decisions. Among other things, these decisions will depend on the shareholders anticipation (as communicated by their representative, the Board of Directors) of successful and economic recovery of their investment.
In addition to a strong IRP acknowledgement, a successful (i.e., acceptable to all parties) MSP outcome is critical to the total success of this effort. The Action Plan results in potentially substantial financial commitments from PacifiCorp. Sustainable cost recovery of investment is an outstanding risk that must be addressed prior to such investments being made. The outcome of the MSP process will strongly influence the activities and operations of PacifiCorp, which in turn may impact the implementation of this IRP Action Plan.

This Action Plan is based upon the best information available at the time the IRP is filed. It will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. The Action Plan may also be revised as a consequence of subsequent IRPs.

**DETAILED ACTION PLAN – FINDINGS OF NEED AND IMPLEMENTATION ACTIONS**

The IRP analysis presumes new resources are actual, specific assets. This assumption allows precise modeling of different site, technology and transmission costs. It also creates a realistic framework for a development timeline. In implementing the Plan, however, all resource options will be rigorously compared to alternative purchase options either from the market or from other existing potential electricity suppliers. Additionally, the specifics of any built or purchased asset may be adjusted to optimize based on then current conditions. The potential risks associated with other developers being able to finance independent and merchant power plants will be assessed on a case-by-case basis. The Procurement Program, further discussed below, will assure that new supplies are obtained from the least cost provider. The proposed Procurement Program will enable consistency with Oregon restructuring requirements, as is also discussed below.

PacifiCorp is seeking acknowledgement of the Action Plan by regulatory Commissions in five States. How these Commissions will treat a favorable acknowledgement of an IRP Action Plan in subsequent rate cases may vary. To accommodate potential differences in treatment of an acknowledgement, the detailed Action Plan includes two components. First, Table 9.1 provides specific findings regarding the need for resources. Second, Table 9.2 provides details of the actions arising from this IRP to address the findings of need. The Findings of Need and Implementation Actions are consistent with each other and support the implementation of the Diversified Portfolio I.

Implementation Actions in the first four years of the plan require greater attention and more specificity than those required in the out-years of the plan. Each Implementation Action has

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13 For example, under the Oregon IRP rules, an acknowledged IRP Action Plan is relevant to subsequent ratemaking. When acknowledged, it becomes a working document for use by parties in a rate case or other proceeding. Oregon has suggested the Action Plan be designed to allow Oregon to acknowledge specific findings of fact. See Appendix N for a summary of each State’s planning requirements.
been categorized by resource addition type, and includes a target date for the delivery or completion of the action item.

Table 9.1 IRP Action Plan Findings of Need

<table>
<thead>
<tr>
<th>REFERENCE</th>
<th>FINDINGS OF NEED</th>
<th>IMPLEMENTATION ACTION REFERENCE (See Table 9.2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>PacifiCorp needs to procure approximately 500 MW of base load resource in the West of the system by April 2006.</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>PacifiCorp needs to procure approximately 570 MW of base load resource in the East of the system by April 2007.</td>
<td>2 &amp; 3</td>
</tr>
<tr>
<td>3</td>
<td>PacifiCorp needs to procure approximately 500 MW of base load resource in the East of the system by April 2008.</td>
<td>4</td>
</tr>
<tr>
<td>4</td>
<td>PacifiCorp needs to procure 200 MW of peaking resources for the East side of the system for operation in 2006.</td>
<td>15 &amp;16</td>
</tr>
<tr>
<td>5</td>
<td>PacifiCorp needs to procure 230 MW of peaking resources for the West side of the system for operation in 2006.</td>
<td>15</td>
</tr>
</tbody>
</table>
| 6         | PacifiCorp needs to prepare, issue and implement RFPs for Renewable resources across the system with a build pattern (based on wind capacity) as follows:  
  • 100 MW – 2006 (West)  
  • 200 MW – 2007 (East)  
  • 200 MW – 2008 (West)                                                                                                                                                                                                                                                                                                                         | 17 - 20                                          |
| 7         | PacifiCorp needs to secure shaped products to optimize and fulfill specific shaping needs of the system. Products to be developed are:  
  • The super-peaking needs in the East of the system for 2004/05/06/07  
  • The off-peak needs in the West of the system for 2005/06  
  • Thermal asset based contracts in support of the capacity requirements to achieve 15% planning margin on both the East and West of the system.                                                                                                                                                                                                 | 21                                               |
| 8         | PacifiCorp needs to develop a more comprehensive portfolio of cost effective Demand Side Management resources with the following targets for the period 2003 to 2014:  
  • Class 1 and Class 3 – 190 MW  
  • Class 2 – 450 MWa                                                                                                                                                                                                                                                                                                                           | 5 -14                                            |
<p>| 9         | PacifiCorp needs specific detailed transmission studies to support reference items 1 to 8 above                                                                                                                                                                                                                                                                                                                                                                 | 24 - 27                                          |</p>
<table>
<thead>
<tr>
<th>ADDITION TYPE</th>
<th>IMPLEMENTATION ACTIONS</th>
<th>TARGET DELIVERY DATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Load - 2007</td>
<td>1. Procure a base load unit in the West of the system for operation in 2007. Prepare detailed plans including an economic review and justification for building or buying a base load CCCT in the West of the system for 2007. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract (Sites under consideration in the review will include opportunities at Albany, Klamath Falls and others in the West of the system)</td>
<td>July 2003</td>
</tr>
<tr>
<td>Base Load - 2008</td>
<td>2. Procure a base load unit in the East of the system for operation in 2008. Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system for 2008. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Hunter, Terminal, Mona, West Valley, Gadsby and others in the East of the system)</td>
<td>October 2003</td>
</tr>
<tr>
<td>Base Load - 2008</td>
<td>3. Continue environmental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation by 2008 in line with DPI requirement (see Action Item 2).</td>
<td>July 2003</td>
</tr>
<tr>
<td>Base Load - 2009</td>
<td>4. Procure a base load unit in the East of the system for operation in 2009. Prepare detailed plans including a review and justification for re-powering of the existing Gadsby plant (units 1, 2 and 3) in 2009. The review will include, but will not be limited to: • Alternative existing or partially developed sites</td>
<td>July 2004</td>
</tr>
<tr>
<td>ADDITION TYPE</td>
<td>IMPLEMENTATION ACTIONS</td>
<td>TARGET DELIVERY DATE</td>
</tr>
<tr>
<td>---------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>DSM</td>
<td>5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.</td>
<td>April, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>6. Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.</td>
<td>April, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.</td>
<td>April, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>8. Complete an evaluation of the available, realistic CHP sites and market size within the PacifiCorp territory.</td>
<td>April, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.</td>
<td>Commence July 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>10. Conduct an Economic and Market Potential study of the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp.</td>
<td>August, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>11. Design a “bundle” of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.</td>
<td>July, 2003</td>
</tr>
<tr>
<td>DSM</td>
<td>12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the “bundle” of options in action item 11.</td>
<td>April, 2003</td>
</tr>
<tr>
<td>Peakers - 2006</td>
<td>15. Procure reserve peaker units for the system for operation in 2006. Develop detailed plans and proposals, including the timeline for delivery, for the reserve peakers required for</td>
<td>July 2003</td>
</tr>
<tr>
<td>ADDITION TYPE</td>
<td>IMPLEMENTATION ACTIONS</td>
<td>TARGET DELIVERY DATE</td>
</tr>
<tr>
<td>---------------</td>
<td>------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>Peaking</td>
<td>Review the West Valley peaker plant performance and requirement and negotiate the West Valley Peaker plant terms and conditions in line with the existing lease contract arrangements.</td>
<td>July 2004</td>
</tr>
<tr>
<td>Renewables</td>
<td>Evaluate expansion options for PacifiCorp’s Blundell Geothermal plant and implement expansion if appropriate and cost effective.</td>
<td>January 2003</td>
</tr>
</tbody>
</table>
| Renewables    | Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern:  
• 100 MW – 2006  
• 200 MW – 2008  
• 200 MW – 2010 | Issue March 2003 |
| Renewables    | Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern:  
• 200 MW – 2007  
• 200 MW – 2009  
• 200 MW – 2011 | Issue March 2003 |
| Renewables    | Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DPI (Action Items 18 and 19). | Issue March 2003 |
| Shaped Products | Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill:  
• The super-peaking needs in the East of the system for 2004/05/06/07  
• The off-peak needs in the West of the system for 2004/05/06  
• Thermal asset based contracts in support of the capacity requirements to achieve 15% planning margin on both the East and West of the system.  
• Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system. | Commencing January 2003 |
<p>| Strategy and Policy | Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP’s | September 2003 |
| Strategy and Policy | Agree any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan | December 2003 |</p>
<table>
<thead>
<tr>
<th>ADDITION TYPE</th>
<th>IMPLEMENTATION ACTIONS</th>
<th>TARGET DELIVERY DATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strategy and Policy</td>
<td>24. 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.</td>
<td>December 2003</td>
</tr>
<tr>
<td>Transmission</td>
<td>25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan for DPI. The studies will provide greater detail on transmission costs associated with all the portfolio additions. Particular attention is required to determine the impact of the potential wind capacity additions on the system from a system stability perspective.</td>
<td>July 2003</td>
</tr>
<tr>
<td>Transmission</td>
<td>26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions</td>
<td>July 2003</td>
</tr>
<tr>
<td>Transmission</td>
<td>27. Prepare detailed plans including an economic review and justification to implement the “Wasatch Front Triangle” transmission upgrades.</td>
<td>July 2003</td>
</tr>
<tr>
<td>Transmission</td>
<td>28. Review options for firming up the IRP non-firm transmission requirement.</td>
<td>July 2003</td>
</tr>
</tbody>
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**IRP ACTION PLAN IMPLEMENTATION - DECISION PROCESSES**

Chapter 3, Risks and Uncertainties, highlights the need for PacifiCorp to retain the right to adjust its implementation of the IRP in light of the already known, but not clearly defined, paradigm risk implications. The Commissions’ IRP rules also point to the need to remain flexible to changes going forward. As discussed above, it is PacifiCorp’s intention to revisit and refresh the Action Plan no less frequently than annually. Any refreshed Action Plan will be submitted to the State Commissions for their information. Figures 9.1 to 9.3 provide some insight on the decision processes PacifiCorp will use while implementing the Action Plan. These decision processes will be iterative and occur in conjunction with the Procurement Program discussed below. The alignment of Resource Planning and Business Planning, also discussed herein, will ensure the IRP Action Plan remains current and consistent with ongoing procurement measures.

Figure 9.1 illustrates the process to be followed as the individual resources within DPI are developed and tested in more detail to ensure they are contributing to the low cost, low risk solution in the manner anticipated in the IRP modeling. If there are major changes to the assumptions associated with the portfolio resource selection it is possible that the portfolio may

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14 For example, the Utah Standards and Guidelines call for a plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.
have to be re-designed and the Action Plan reviewed to ensure the desired low cost, low risk option is still being achieved.

**Figure 9.1 Decision Process chart for Portfolio Resource Analysis**

Figure 9.2 addressed the decision process associated with the wind (and other renewables) resources in the Action Plan. The wind build strategy allows time for all parties to develop a greater understanding of the uncertainties associated with wind. The level of wind resource ultimately procured has the potential to become more or less than is reflected in the DPI portfolio. The impact of wind on the portfolio will be tested through the processes illustrated in Figures 9.1 and 9.2.
DPI introduces the procurement of a base load coal plant by 2008 (Action Item 2). There are still uncertainties surrounding this technology choice so further clarification will be undertaken. The decision processes shown in Figures 9.1 and 9.3 will be followed to test the assumptions surrounding the current coal proposal.

**Figure 9.2 Decision Process Chart for Wind (Renewables) Generation Development**

**Figure 9.3 Decision Process Chart for Base Load Technology Choice**
IRP ACTION PLAN IMPLEMENTATION - PROCUREMENT PROGRAM

PacifiCorp intends to implement many elements of the Action Plan with a formal and transparent Procurement Program. The IRP has determined the need for resources with considerable specificity, and identified the desirable Portfolio and timing for procurement. The IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus power purchase contracts. These decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options. These options will be fully developed using a robust procurement process, including, when appropriate, competitive bidding with an effective request for proposal (RFP) process.

DSM programs currently use an outsource model for procurement of results in many of the programs. PacifiCorp intends to continue this practice. In addition, with the substantial increase in results indicated by the 300 MWa planning decrement, procurement of design and implementation of some of this increase in DSM acquisition is anticipated.

The role of RFPs related to a specific resource procurement decision by PacifiCorp will depend upon the size, type, and location of the resource being considered. A comparison of all competing alternatives, including contract purchase options, will be made before PacifiCorp makes a build decision. This comparison will consist of the identification of relevant alternative developers or purchase contract options through a solicitation process, and compared against the appropriate market. In instances where PacifiCorp feels a formal RFP issuance is warranted, due to specific geographic or other market-related conditions, one will be issued.

The evaluation of specific resource alternatives, whether build or contract purchase, will be performed on the same basis and using the same techniques. All evaluations will utilize the best available information known at the time. This means that certain inputs are bound to change during the lead-time associated with any plant construction. As such, the purchase from a plant developer would be subject to a similar level of uncertainty as a PacifiCorp build option, unless the developer imposed a higher level of restriction than PacifiCorp would experience under a build option.

PacifiCorp will perform all evaluations on the same basis and using the same analytical techniques. In general, it is not currently envisioned that evaluations would regularly be done by an independent third party. However, in certain circumstances, such as where an affiliate transaction may be a potential alternative, PacifiCorp may retain an independent consultant to validate that the evaluation is performed on a non-discriminatory basis.

PacifiCorp plans to keep regulators and their staffs apprised of key resource activities, including progress on the Procurement Program. We anticipate providing Procurement Program status reports approximately every six months. The feedback we receive will be taken into account with respect to the particular resource procurement effort. Given the fact that PacifiCorp operates in multiple states, it is not currently envisioned that every state will directly participate in the preparation of a formal RFP issuance.
Due to competitive confidentiality concerns, and potential conflict of interest, it is also not envisioned that third parties would directly participate in the preparation of a formal RFP.

CURRENT PROCUREMENT AND HEDGING STRATEGY

Prior to the implementation of the IRP Action Plan, PacifiCorp will continue with its current procurement and hedging strategy to ensure a low cost, safe and reliable supply for the customer. This effort includes an extension of the September 2001 RFP activities, cost effective demand-side management programs, construction of the Gadsby peakers (now fully operational), temperature contingent hedges, summer procurement 2002-2004, superpeak purchases 2003-2005, and other portfolio optimization opportunities.

The summer season procurement strategy has integrated both financial and physical hedging instruments to strategically manage the physical system, which requires more than purchasing over the counter (OTC) standard on-peak product (6X16). The 6X16 product available from the OTC market is available in blocks, which creates two problems, the need to cover superpeak demand and the requirement to sell surplus shoulder hour power, potentially at a loss, back to the market. The overall objective is to minimize PacifiCorp's risk and deliver the most economic solutions for both the customers and PacifiCorp.

To date, the September 2001 RFP and subsequent extension has resulted in the following major transactions:

- 200 MW of daily call options June - September 2002-2004,
- 15-year lease with early termination rights on 200 MW at West Valley,
- June - September 2002 Temperature Hedges
- 200 MW of superpeak power 2003 - 2005
- An RFP for a May – September 2003 Quanto Temperature Hedge has been issued.

The IRP will be the road map to address resource requirements beyond 2005. Products similar to those detailed above will continue to be developed in line with the IRP Action Plan as they are critical for shaping, optimizing and minimizing the costs and risks associated with the efficient operation of the network.

ALIGNMENT OF RESOURCE PLANNING AND BUSINESS PLANNING

PacifiCorp has made significant improvements to its resource planning organization and methods. These measures have strengthened the alignment of PacifiCorp’s business planning, regulatory requirements, resource planning, resource procurement and system operations. A Resource Planning function was created and organized in the Commercial and Trading department to ensure integration with PacifiCorp’s resource procurement, trading and risk management functions. New models were developed to ensure the IRP uses a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp’s existing generation and transmission assets, to compare their economic and operational performance. The methodology also accounts for the uncertain future by testing resource alternatives against
measurable future risks and possible paradigm shifts in the industry. The modeling and methodology will continue to be developed to address the paradigm shifts as they unfold.

CONSISTENCY WITH OREGON RESTRUCTURING

The Oregon Restructuring legislation (SB-1149) states that electric companies must include new generating resources in revenue requirement at market prices, and not at cost.\(^{15}\) The Oregon PUC has not resolved how this provision would be implemented or if it should be modified, and recently decided to open an investigation into the matter.\(^{16}\) As noted elsewhere in the report, the IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus power purchase contracts. These decisions will be made subsequently, on a case-by-case basis, as part of the Procurement Program. Thus, the IRP Action Plan is consistent with SB1149 and does not address the ratemaking treatment of new resources. Subsequent procurement of any generating resources will be made consistent with anticipated ratemaking requirements, including SB1149 as implemented by the Oregon PUC.

\(^{15}\) OAR 860-038-0080(1)(b).

\(^{16}\) OPUC Order No. 02-702 at 3.