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Western Wind and Solar Integration Study

February 2008 — February 2010

R. Piwko, K. Clark, L. Freeman, G. Jordan, N. Miller
GE Energy
Schenectady, New York

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Table of Contents

List of Figures v

List of Tables xv

Executive Summary 1

1 Introduction 3

1.1 References 4

2 Objectives and Technical Approach 5

2.1 Project Objectives 5

2.2 Major Tasks 5

2.3 Wind Data Development 6

2.4 Solar Data Development 10

2.5 Load Data 10

2.6 Overview of Study Scenarios 11

2.7 Analytical Methods 14

2.8 References 15

3 Study Scenarios 17

3.1 Development of In Area Scenario 17

3.1.1 Objectives of the Site Selection Process 17

3.1.2 Available Wind and Solar Sites 18

3.1.3 Wind and Solar Site Selection 19

3.1.4 Transmission Zones and Areas 22

3.2 Development of Mega Project Scenario 25

3.3 Development of Local Priority Scenario 28

4 Statistical Analysis: Seasonal Monthly, Daily Trends 31

4.1 Monthly Energy from Wind and Solar 32

4.1.1 Year-to-Year Comparison 33

4.1.2 Scenario Comparison 35

4.1.3 State-by-State Comparison 36

4.2 Yearly Duration Trends 39

4.2.1 Wind Duration 39

4.2.2 Solar Duration 43
4.2.3 Net Load Duration 44
4.3 Wind, Load and Solar Coincident Relationships 49
4.3.1 Average Daily Profiles 49
4.3.2 Weekly Time Series 52
4.3.3 Selected Periods 56
4.4 Observations and Conclusions 58
5 Statistical Analysis: Hourly Variability and Day-Ahead Predictability 61
5.1 Seasonal Trends in Variability 62
5.2 Variability by Hour-of-Day 64
5.3 Variability by Time-of-Year 69
5.4 Analysis of Extreme Deltas 72
5.5 Area-to-Area Variability 75
5.6 Forecast Error Analysis 80
5.7 Observations and Conclusions 82
6 Operational Analysis 83
6.1 Assumptions 83
6.1.1 Scenario Naming Conventions 84
6.2 Annual Operational Impacts 85
6.2.1 Impact of Renewable Forecasts 92
6.2.2 Spinning Reserve 98
6.2.3 Annual Profile Sensitivities 104
6.3 Weekly Operational Analysis 106
6.4 Additional Operational Sensitivities 115
6.4.1 Variations in Renewable Unit Siting 115
6.4.2 Hydro Operation 121
6.4.3 Coal and Gas Pricing Sensitivity 130
6.4.4 Coal Plant Operation 134
6.4.5 Balancing Area Consolidation 140
6.4.6 Transmission Expansion Sensitivity 141
6.4.7 Generation Expansion Sensitivity 142

6.5 Operational Analysis Observations and Conclusions 144
7 Sub-hourly Operational Analysis.....145
7.1 Statistical Analysis 145
7.2 Quasi-Steady State (QSS) Analysis 150
7.2.1 Overview of Algorithm 150
7.2.2 Input Data.....152
7.2.3 Boundary Conditions.....153
7.2.4 Study Periods 154
7.2.5 April 15, 2006 Example 156
7.2.6 October 26, 2006 Example 170
7.2.7 Mitigation 184
7.2.8 Summary 185
7.3 Variability Impacts on Reserves.....186
7.3.1 Load and Net Load Variability.....187
7.3.2 Relationship to Existing Reserve Rules 191
7.3.3 Net Load Variability Relationship to Load and Wind Levels.....193
7.3.4 Reserve Time Frames and Other Reserve Drivers 204
7.4 Reserve Performance 206
7.4.1 Hourly Reserves at Dispatch 206
7.4.2 Intrahour Performance 214
7.5 Concepts for Simple Reserve Rules 220
7.5.1 Load and Wind Level Based Rules 220
7.5.2 3+5 Rule.....220
7.5.3 General Load + Wind Rules 228
7.5.4 Conditional Load + Wind Rules 232
7.5.5 Load only Rules 237
7.5.6 Summary and Trends for Simplified Reserve Rules 243
7.5.7 Other Concepts for Rules 247
7.5.8 Demand Participation in Reserves.....249
7.5.9 Energy Storage Contribution to Reserves 249
7.6 Conclusions on Subhourly Reserves 249

8 Impact of Energy Storage and PHEV 253
8.1 Base Pumped Storage Operation 253
8.2 Pumped Storage Optimization 255
8.3 CSP Operation Optimization 258
8.4 Plug-in Hybrid Electric Vehicles, PHEV 263
8.5 Storage and PHEV Observations 265
9 Reliability Analysis 267
9.1 Introduction 267
9.1.1 Location, Location, Location 268
9.2 Capacity Value 268
9.2.1 Timing is Everything 270
9.2.2 Hourly and Unserved Energy Measures 272
9.3 Capacity Value Variation by Scenario 273
9.4 Capacity Value Variation by Shape Year 275
9.5 Comparison to Other Measures 278
9.6 Yet Another Calculation Method 279
9.7 Capacity Value Observations 282
10 Key Findings 283
Appendix A. Tables of Wind + Solar MW by State; Siting Algorithm PPT 287
Appendix B. Statistics Results 289
Appendix C. Statistics Results 291
Appendix D. MAPS Flow-Duration 293
Appendix E. 10-min Statistics 295
Appendix F. Quasi Steady State Plots 297
Appendix G. Reserves 299

List of Figures

Figure 1.1 Geographic Footprint of WestConnect Utilities. 4
Figure 2.1 Flowchart of WWSIS Project Tasks....6
Figure 2.2 Statistical analysis showing data seam at hour 16 of every third day....7
Figure 2.3 Annual wind energy forecast error by area. 8
Figure 2.4 Monthly wind forecast error in WECC....8
Figure 2.5 Example Result from Wind Dataset Validation Analysis 9
Figure 3.1 All available wind sites in WECC (each grey dot represents 30MW) 18
Figure 3.2 All available solar sites in WECC (each grey dot represents 100 MW)....19
Figure 3.3 Wind sites for In Area Scenario with 30% wind energy and 5% solar energy. 21
Figure 3.4 Solar sites for In Area Scenario with 30% wind energy and 5% solar energy. 21
Figure 3.5 Map of Transmission Zones and Areas 23
Figure 3.6 WECC Transmission Paths and Ratings. 25
Figure 3.7 Map of Mega Project Scenario with Transmission Additions 27
Figure 3.8 Map of Local Priority Scenario with Transmission Additions 29
Figure 4.1 Graphical Representation of Statistical Study Permutations and Most Often Used Path 32
Figure 4.2 Total In-Footprint Monthly Energy from Wind and Solar for 2004 – 2006 (30% In Area Scenario) 34
Figure 4.3 Total In-Footprint Monthly Energy from Wind and Solar for 2004 – 2006 (30% In Area Scenario) 34
Figure 4.4 2006 Total In-Footprint Monthly Energy from Wind and Solar for all Scenarios (30% Penetration)....36
Figure 4.5 2006 Percent In-Footprint Monthly Energy from Wind and Solar for all Scenarios (30% Penetration) 36
Figure 4.6 2006 Arizona Total and Percent Monthly Energy from Wind and Solar (30% LP Scenario) 37
Figure 4.7 2006 Wyoming Total and Percent Monthly Energy from Wind and Solar (30% LP Scenario) 37
Figure 4.8 2006 Study Footprint Wind Duration Plots for all Three Scenarios (30% Penetration)39
Figure 4.9 2006 Study Footprint Wind Duration Plots Normalized as % of Nameplate Wind.....40
Figure 4.10 2006 Study Footprint Wind Duration Plots for all Three Penetration Levels (LP Scenario) 41
Figure 4.11 2006 Study Footprint Wind Duration Plots Normalized as % of Nameplate Wind...41
Figure 4.12 2006 In-Footprint Area Wind Duration Plots for the 30% LP Scenario....42
Figure 4.13 2006 In-Footprint Area Wind Duration Plots Normalized as % of Nameplate Wind42
Figure 4.14 2006 Study Footprint CSP Duration and Penetration for the 30% LP Scenario 43
Figure 4.15 2006 Study Footprint PV Duration and Penetration for the 30% LP Scenario 44
Figure 4.16 Study Footprint 2006 Net Load Duration for the In-Area Scenario....45
Figure 4.17 Study Footprint 2006 Net Load Duration for all Scenarios (30% Penetration) 46
Figure 4.18 Arizona 2006 Net Load Duration for the IA Scenario....47
Figure 4.19 New Mexico 2006 Net Load Duration for the LP Scenario 48

Figure 4.20 Wyoming 2006 Net Load Duration for the MP Scenario....48
Figure 4.21 2006 Study Footprint Load, Wind and Solar Average Daily Profiles By Seasonal Month for the 30% Local Priority Scenario 50
Figure 4.22 Arizona Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario 51
Figure 4.23 Nevada Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario 51
Figure 4.24 Wyoming Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario....51
Figure 4.25 Study Footprint Total Load, Wind and Solar for a Week in July 2006 30% LP Scenario 52
Figure 4.26 Study Footprint Total Load, Net Load for a Week in July 2006 30% LP Scenario 52
Figure 4.27 Study Footprint Net Load for a Week in July 2006 for 10%, 20% and 30% LP Scenario53
Figure 4.28 Study Footprint Total Load, Wind and Solar for a Week in April 2006 30% LP Scenario 54
Figure 4.29 Study Footprint Total Load, Net Load for a Week in April 2006 30% LP Scenario....54
Figure 4.30 Study Footprint Net Load for a Week in April 2006 for 10%, 20% and 30% LP Scenario 55
Figure 4.31 Study Footprint Net Load for November 14th, 2006, 30% LP Scenario....56
Figure 4.32 Arizona Net Load for November 14th, 2006, 30% LP Scenario 56
Figure 4.33 Study Footprint Net Load for June 6th, 2006, 30% LP Scenario....57
Figure 4.34 Colorado-East Footprint Net Load for June 6th, 2006, 30% LP Scenario....57
Figure 4.35 Study Footprint Total Load, Net Load for April 2006, 30% LP Scenario 58
Figure 5.1 Relationship Between Standard Deviation and Area Under the Standard Normal Curve 61
Figure 5.2 2006 Study Footprint Wind Deltas vs. Load Deltas by Season for 30% LP Scenario ...62
Figure 5.3 2006 Study Footprint Wind Deltas vs. Load Deltas by Scenario for 30% Penetration .63
Figure 5.4 Study Footprint Average Daily Profile of Deltas Over Year 2006, 10% LP Scenario ...64
Figure 5.5 Study Footprint Average Daily Profile of Deltas Over Year 2006, 20% LP Scenario ...65
Figure 5.6 Study Footprint Average Daily Profile of Deltas Over Year 2006, 30% LP Scenario ...65
Figure 5.7 Study Footprint Average Daily Profile of Deltas Over April 2006, 30% LP Scenario ..66
Figure 5.8 Average Daily Profile of Load and Net Load Deltas Over 2006 for Selected Areas, 30% LP Scenario 67
Figure 5.9 Study Footprint and Wyoming Net Load for January 8th, 2006, 30% LP Scenario 68
Figure 5.10 Timing of Extreme Load-Alone Positive Deltas in Study Footprint for 2006....69
Figure 5.11 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 10% LP Scenario 70
Figure 5.12 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 20% LP Scenario 70
Figure 5.13 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 30% LP Scenario 70
Figure 5.14 Timing of Extreme Net Load Negative Deltas in Study Footprint for 2006 LP Scenario 71

Figure 5.15 2006 Study Footprint Distribution of Net Load Deltas for LP Scenario) 72
Figure 5.16 Study Footprint Distribution of Extreme Hourly Net Load Deltas 2006 Local Priority Scenario 74
Figure 5.17 Percent Increase in Net Load Delta Sigma in all Areas for In-Area Scenario.....75
Figure 5.18 Percent Increase in Net Load Negative and Positive Deltas in all Areas for In-Area Scenario 77
Figure 5.19 2006 Duration of Extreme Hourly Net Load Deltas in all Areas for 30% Wind LP Scenario 79
Figure 5.20 Distribution of Footprint Day-Ahead Wind Forecast Errors for 2006 10%, 20%, 30% LP Scenario.....80
Figure 5.21 Study Footprint Next Day Wind Forecast Errors vs. Forecast, 30% LP Scenario 81
Figure 6.1 Annual spot price duration curve, perfect forecast, In-Area scenarios.....85
Figure 6.2 Annual spot price duration curve, S-o-A forecast, In-Area scenarios.....86
Figure 6.3 Generation by type - WECC – 2006 87
Figure 6.4 Generation by type - study area - 2006 87
Figure 6.5 Operating cost savings ($B) - WECC – 2006.....88
Figure 6.6 Operating cost savings per MWh of renewable energy, WECC – 2006 88
Figure 6.7 Incremental savings per incremental renewable energy ($/MWh). WECC – 2006.....89
Figure 6.8 Average hourly exports from study footprint. 89
Figure 6.9 Impact of renewables in neighboring areas 90
Figure 6.10 Coal plant statistics, Local Priority scenario 91
Figure 6.11 Combined Cycle plant statistics, Local Priority scenario 91
Figure 6.12 Wyoming to Colorado interface flows.....92
Figure 6.13 WECC operating cost impact of forecasts ($M).....93
Figure 6.14 Operating cost impact of forecast ($/MWh) 93
Figure 6.15 Impact of Forecast on Spilled and Unserved Energy.....94
Figure 6.16 WECC operating cost impact of no forecasts ($M) 94
Figure 6.17 WECC operating cost impact of no forecasts ($/MWh).....95
Figure 6.18 WECC impact of no forecast on spilled and unserved energy.....95
Figure 6.19 Total generation, study area – 2006 96
Figure 6.20 Generator revenue, study area – 2006.....96
Figure 6.21 Incremental value of renewable energy based on spot price revenue, Study area 97
Figure 6.22 Incremental value of renewable energy based on spot price revenue, WECC 97
Figure 6.23 Total emission reductions, WECC - 2006.....98
Figure 6.24 Total emission reductions per MWh of renewable generation, WECC – 2006 98
Figure 6.25 Adjusted wind forecast error, I30R scenario.....99
Figure 6.26 Spilled and unserved energy when discounting forecast 100
Figure 6.27 Distribution of unserved energy versus discounting of wind forecasts 100
Figure 6.28 Hours of interruption versus MW of demand response participation 101
Figure 6.29 Annual spot price duration curve - I30R scenario - impact of discounting forecast 101
Figure 6.30 Total WECC operating costs as a function of discounting the wind forecast ($M)..102
Figure 6.31 Reduced unserved energy with increased reserves committed for wind generation102

Figure 6.32 Cost of reducing unserved energy by increasing reserve commitment for renewables. 103
Figure 6.33 Cost of increasing committed spinning reserve per MWh of wind generation ($/MWh) 103
Figure 6.34 Generation by type, WECC, by scenario and shape year....104
Figure 6.35 Variation in renewable generation by weather year for 30% scenario....104
Figure 6.36 Incremental savings per incremental renewable energy, WECC....105
Figure 6.37 Total generation, study area, for different annual shapes....105
Figure 6.38 Emission reductions, study area, for different annual shapes....106
Figure 6.39 Week of April 10th - Hourly load, renewables and exports for 10% scenario 106
Figure 6.40 Study area dispatch - week of April 10th - no renewables....107
Figure 6.41 Study area dispatch - week of April 10th – 10% R scenario....108
Figure 6.42 Study area - week of April 10th – load and renewables by penetration 108
Figure 6.43 Study area - week of April 10th - net load by penetration 109
Figure 6.44 Study area - week of April 10th - net loads plus exports by penetration....109
Figure 6.45 Study area dispatch - week of April 10th – 20% R scenario....110
Figure 6.46 Study area dispatch - week of April 10th – 30% R scenario....110
Figure 6.47 Change in operation - Week of April 10th 111
Figure 6.48 Study area - week of July 10th - renewables by penetration....111
Figure 6.49 Study area - week of April 10th - net load by penetration 112
Figure 6.50 Study area - week of April 10th - net load plus exports by penetration 112
Figure 6.51 Study area dispatch - week of July 10th – no wind 113
Figure 6.52 Study area dispatch - week of July 10th – 10% R scenario 113
Figure 6.53 Study area dispatch - week of July 10th – 20% R scenario 114
Figure 6.54 Study area dispatch - week of July 10th – 30% R scenario 114
Figure 6.55 Change in operation - week of July 10th....115
Figure 6.56 Generation by type, study area, multiple scenarios....116
Figure 6.57 Annual spot price duration curve - S-o-A Forecast, In-Area scenario 116
Figure 6.58 Annual spot price duration curve - S-o-A Forecast, Local Priority scenario 117
Figure 6.59Annual spot price duration curve - S-o-A Forecast, Mega-Project scenario....117
Figure 6.60 Annual spot price duration curve, perfect forecast, 30% scenarios 118
Figure 6.61 Annual spot price duration curve, S-o-A forecast, 30% scenarios 118
Figure 6.62 Total generation, study area, multiple scenarios....119
Figure 6.63 Operating cost savings per MWh of renewable energy, WECC 119
Figure 6.64 Incremental savings per incremental renewable energy, WECC....120
Figure 6.65 Incremental savings per incremental renewable energy, WECC, In-Area scenario.120
Figure 6.66 Incremental savings per incremental renewable energy, WECC, Local Priority scenario....121
Figure 6.67 Incremental savings per incremental renewable energy, WECC, Mega-Project scenario....121
Figure 6.68 Hydro operation - week of April 10th 122
Figure 6.69 Hydro operation - week of July 10th....122
Figure 6.70 Annual hydro generation duration curve, WECC 123

Figure 6.71 Annual hydro hourly delta duration curve, WECC 123
Figure 6.72 Spot price impact of hydro operation 124
Figure 6.73 Operating cost increase for dispatching hydro on load alone versus net load, WECC124
Figure 6.74 Glen Canyon capacity versus elevation 125
Figure 6.75 Historical elevation of Lake Powell 125
Figure 6.76 Net monthly generation at Glen Canyon 126
Figure 6.77 MAPS daily simulation of Glen Canyon with no wind 126
Figure 6.78 MAPS monthly simulation of Glen Canyon with no wind 127
Figure 6.79 Historical maximum operation of Glen Canyon 127
Figure 6.80 Historical maximum and average operation of Glen Canyon 128
Figure 6.81 Impact of flat hydro operation on WECC operating costs 129
Figure 6.82 Incremental operating cost impact of flat hydro operation 129
Figure 6.83 Spot price impact of flat hydro operation 130
Figure 6.84 Spot price impact of flat hydro operation by penetration 130
Figure 6.85 Historical Henry Hub natural gas prices 131
Figure 6.86 Coal vs. Combined cycle cost comparison 131
Figure 6.87 Generation by type with gas price reductions, WECC 132
Figure 6.88 Emissions with gas price reductions, WECC 132
Figure 6.89 Emission reductions with gas price reductions 133
Figure 6.90 Impact of gas price reductions on operations savings, I30 scenario 133
Figure 6.91 Typical minimum operating ratings of coal units as a percent of capacity 134
Figure 6.92 Number of cycles below operating levels – 100 MW coal unit 135
Figure 6.93 Number of cycles below operating levels – 350 MW coal unit 135
Figure 6.94 Number of cycles below operating levels – 500 MW coal unit 136
Figure 6.95 Cycles per month below 80% or 90% of rating for 500 MW coal unit at 30% penetration 136
Figure 6.96 Operation of 500 MW coal unit week of April 10th at 30% penetration 137
Figure 6.97 Spilled energy as a function of coal minimum operating points 137
Figure 6.98 Unserved energy as a function of coal minimum operating points 138
Figure 6.99 Average system spot price vs. coal minimums 138
Figure 6.100 WECC operating costs vs. coal minimums 139
Figure 6.101 Increased WECC operating costs over coal at 40% minimum rating 139
Figure 6.102 Impact of coal minimums on WECC emissions 140
Figure 6.103 Spot price impact of balancing area consolidation, 10% penetration. 141
Figure 6.104 Spilled and unserved energy w/o transmission expansion 142
Figure 6.105 Savings reductions with no transmission expansion 142
Figure 6.106 Emission impact of reduced capacity additions 143
Figure 6.107 Operating cost impact of reduced capacity additions 143
Figure 7.1 Wind Deltas vs. Load Deltas by Season for Study Area (2006, 30%, LP Scenario) 147
Figure 7.2 Timing of Maximum Daily 10-Min Positive Deltas for Study Area (2006, LP Scenario)148
Figure 7.3 Timing of Maximum Daily 10-Min Negative Deltas for Study Area (2006, LP Scenario) 148
Figure 7.4 Distribution of Net Load Deltas for Study Area (2006, LP Scenario) 149

Figure 7.5 Distribution of Extreme Hourly Wind Deltas for 2006 (2006, LP Scenario) 150
Figure 7.6 Study Footprint Characteristics for April QSS Period, Local Priority, 30% Wind Penetration. 155
Figure 7.7 Study Footprint Characteristics for October QSS Period, Local Priority, 30% Wind Penetration. 156
Figure 7.8. Arizona Input Profiles, Local Priority, April QSS Study Period. 157
Figure 7.9 Arizona Conventional Generation Hourly Schedule, Local Priority, April QSS Study Period. 158
Figure 7.10 Arizona Export Schedule, Local Priority, April QSS Study Period. 158
Figure 7.11 Arizona Dispatch, 10% Wind, Local Priority, April QSS Study Period. 160
Figure 7.12. Arizona Regulation, 10% Wind, Local Priority, April QSS Study Period. 160
Figure 7.13 Arizona Totals, 10% Wind, Local Priority, April QSS Study Period. 162
Figure 7.14 Arizona Regulation and ACE, 10% Wind, Local Priority, April QSS Study Period.162
Figure 7.15 Arizona Dispatch, 20% Wind, Local Priority, April QSS Study Period. 163
Figure 7.16 Arizona Dispatch, 20/20% Wind, Local Priority, April QSS Study Period. 164
Figure 7.17 Arizona Dispatch, 30% Wind, Local Priority, April QSS Study Period. 164
Figure 7.18 Arizona Regulation, 20% Wind, Local Priority, April QSS Study Period. 165
Figure 7.19 Arizona Regulation, 20/20% Wind, Local Priority, April QSS Study Period.....166
Figure 7.20 Arizona Regulation, 30% Wind, Local Priority, April QSS Study Period. 166
Figure 7.21 Arizona ACE, All Penetration Levels, Local Priority, April QSS Study Period. 167
Figure 7.22 Arizona and New Mexico ACEs, 30% Wind, Local Priority, April QSS Study Period.168
Figure 7.23 Transmission Area ACEs, 30% Wind, Local Priority, April QSS Study Period. 169
Figure 7.24 Footprint ACEs with and without Consolidation, 30% Wind, Local Priority, April QSS Study Period. 169
Figure 7.25 Colorado East Input Profiles, Local Priority, October QSS Study Period. 171
Figure 7.26 Colorado East Conventional Generation Hourly Schedule, Local Priority, October QSS Study Period. 171
Figure 7.27 Colorado East Export Schedule, Local Priority, October QSS Study Period. 172
Figure 7.28 Colorado East Dispatch, 10% Wind, Local Priority, October QSS Study Period. 173
Figure 7.29 Colorado East Dispatch, 20% Wind, Local Priority, October QSS Study Period. 174
Figure 7.30. Colorado East Dispatch, 20/20% Wind, Local Priority, October QSS Study Period.174
Figure 7.31 Colorado East Dispatch, 30% Wind, Local Priority, October QSS Study Period. 175
Figure 7.32 Colorado East Regulation, 10% Wind, Local Priority, October QSS Study Period...176
Figure 7.33 Colorado East Regulation, 20% Wind, Local Priority, October QSS Study Period...176
Figure 7.34. Colorado East Regulation, 20/20% Wind, Local Priority, October QSS Study Period.177
Figure 7.35 Colorado East Regulation, 30% Wind, Local Priority, October QSS Study Period...177
Figure 7.36 Colorado East ACE, All Penetration Levels, Local Priority, October QSS Study Period. 178
Figure 7.37 Colorado East Dispatch, Continuous Schedule, 30% Wind, Local Priority, October QSS Study Period. 180
Figure 7.38 Colorado East Regulation, Continuous Schedule, 30% Wind, Local Priority, October QSS Study Period. 180

Figure 7.39. Colorado East Dispatch, Perfect Forecast, 30% Wind, Local Priority, October QSS Study Period. 181
Figure 7.40. Colorado East Regulation, Perfect Forecast, 30% Wind, Local Priority, October QSS Study Period. 181
Figure 7.41. Colorado East Combined Cycle Usage, 30% Wind, Local Priority, October QSS Study Period. 183
Figure 7.42Colorado East Combined Cycle Usage, All Penetration Levels, Local Priority, October QSS Study Period. 183
Figure 7.43. Colorado East Combined Cycle Usage, Forecast and Schedule Variations, 30% Wind, Local Priority, October QSS Study Period. 184
Figure 7.44 Local Priority Case – Wind Variability for 2006 188
Figure 7.45 Local Priority Net Load Variability for 2006 188
Figure 7.46 10-minute Variability: Wind and Net Load - 3 Scenarios 189
Figure 7.47 Wind Variability: Normalized to Installed Rating to Installed Rating 190
Figure 7.48 Arizona and Wyoming: Average (MW) vs. Sigma of 10-min Delta (MW) 191
Figure 7.49 Variability and 3% Spinning Reserve Rule 192
Figure 7.50 Load - Wind - Net Load Relationship for L30 System 193
Figure 7.51 Relationship between Load Duration and Load Range for LP Scenario 194
Figure 7.52 Operations L30: Hours of Load and Wind Combinations 195
Figure 7.53 Wind Only Variability L30 196
Figure 7.54 Load Only Variability L30 197
Figure 7.55 Net Load Variability L30 197
Figure 7.56 Arizona L30R Load Variability 198
Figure 7.57 Arizona L30R Wind Variability 199
Figure 7.58 Arizona L30R Net Load Variability 199
Figure 7.59 Wyoming L30R Wind Variability 200
Figure 7.60 Wyoming L30R Load Variability 201
Figure 7.61 Wyoming L30R Net Load Variability 201
Figure 7.62 Wyoming L30R Time Space 202
Figure 7.63 Wyoming L30R Net Load Variability: $3\Delta\sigma$ vs. $\mu + 3\Delta\sigma$-rise 203
Figure 7.64 Average Reserve Requirements 204
Figure 7.65 Net Load Variability in Different Time Frames – Various GE Studies. 205
Figure 7.66 Regulation Reserve Requirements (by Area) 206
Figure 7.67 Average Up Range L30R Scenario 209
Figure 7.68 L30R Scenario Up Reserve Violations 209
Figure 7.69 Up Reserves vs. Forecast Error (Full Year) 210
Figure 7.70 Up Reserves vs. Wind Forecast Error (Selected Load – Wind Pairs) 210
Figure 7.71 L30R Scenario Down Reserve Violations 211
Figure 7.72 Arizona L30R Scenario Reserve Violations 212
Figure 7.73 Wyoming L30R Scenario up Reserve Violations 213
Figure 7.74 Arizona L30R Scenario April 15, 2009 Trajectory 216
Figure 7.75 Arizona L30R Scenario Results April 15 2006 216
Figure 7.76 Arizona L30R Scenario October 26 2006 Trajectory 217

Figure 7.77 Arizona L30R Scenario Results October 26 2006 217
Figure 7.78 Wyoming L30R Scenario April 15, 2006 Trajectory....218
Figure 7.79 Wyoming L30R Scenario – Regulation Allocation Detail – April 15 Results....218
Figure 7.80 Wyoming L30R Net Load Variability October 26 2006 Trajectory....219
Figure 7.81 Wyoming L30R Scenario October 26, 2006 Results 219
Figure 7.82 In Footprint L30R 3% Load plus 5% Wind Rule....221
Figure 7.83 Arizona L30R 3% Load plus 5% Wind Rule....222
Figure 7.84 Wyoming L30R 3% Load plus 5% Wind Rule 223
Figure 7.85 Colorado East L30R 3% Load plus 5% Wind Rule 224
Figure 7.86 Nevada L30R 3% Load plus 5% Wind Rule 225
Figure 7.87 New Mexico L30R 3% Load plus 5% Wind Rule....226
Figure 7.88 Colorado West L30R 3% Load plus 5% Wind Rule....227
Figure 7.89 In Footprint L30R Best RMS Fit X% Load plus Y% Wind Rule 230
Figure 7.90 Arizona L30R Best RMS Fit X% Load plus Y% Wind Rule....230
Figure 7.91 Wyoming L30R Best RMS Fit X% Load plus Y% Wind Rule....230
Figure 7.92 Wyoming L30R Heuristic 3% Load plus 10% Wind rule 231
Figure 7.93 Colorado East L30R Best RMS Fit X% Load plus Y% Wind Rule 231
Figure 7.94 Nevada L30R Best RMS Fit X% Load plus Y% Wind Rule 231
Figure 7.95 New Mexico L30R Best RMS Fit X% Load plus Y% Wind Rule....232
Figure 7.96 Colorado West L30R Best RMS Fit X% Load plus Y% Wind Rule....232
Figure 7.97 In Foot print L30R X% Load plus Y% Conditional Wind Rule 234
Figure 7.98 Arizona L30R X% Load plus Y% Conditional Wind Rule 234
Figure 7.99 Wyoming L30R X% Load plus Y% Conditional Wind Rule 235
Figure 7.100 Wyoming L30R X% Load plus Y% Conditional Wind Rule, low power priority...235
Figure 7.101 Colorado East L30R X% Load plus Y% Conditional Wind Rule....235
Figure 7.102 Nevada L30R X% Load plus Y% Conditional Wind Rule....236
Figure 7.103 New Mexico L30R X% Load plus Y% Conditional Wind Rule 236
Figure 7.104 New Mexico L30R Other heuristics on X+Y Conditional rule 237
Figure 7.105 Arizona L30R Load Only Variability 239
Figure 7.106 Arizona L30R Scenario Load Only Variability 239
Figure 7.107 Wyoming L30R Scenario Load Only Variability 240
Figure 7.108 Colorado East L30R Scenario Load Only Variability....240
Figure 7.109 Nevada L30R Scenario Load Only Variability....241
Figure 7.110 New Mexico L30R Scenario Load Only Variability 241
Figure 7.111 Colorado West L30R Scenario Load Only Variability 242
Figure 7.112 Regulation Reserve Requirements for Load Only (by Area) 242
Figure 7.113 Comparison of Peak Reserve Requirement Rules (by Area) 245
Figure 7.114 Incremental Reserves over 3% Load Rule 245
Figure 7.115 X% Load and Y% Wind Reserve Rule – Relationships to Penetration 246
Figure 7.116 Footprint - Polynomial Fits to Net Load Variability (L30 scenario) 247
Figure 7.117 Footprint - Polynomial Fits to Wind Variability....248
Figure 8.1 PSH annual duration curve 254
Figure 8.2 PSH operation with discounted pumping costs....254

Figure 8.3 Operational impact of forcing PSH operation 255
Figure 8.4 Arizona spot prices, week of April 10th, perfect forecasting.....256
Figure 8.5 Arizona spot prices, week of April 10th, S-o-A forecasting.....256
Figure 8.6 Incremental value of a 100 MW PSH plant 257
Figure 8.7 Sample energy shift for CSP "optimal" dispatch 258
Figure 8.8 Monthly CSP energy by zone.....259
Figure 8.9 Annual CSP energy by zone.....259
Figure 8.10 Annual CSP revenue increase vs. hours of storage.....260
Figure 8.11 Annual CSP revenue increase by zone due to optimal dispatch. 261
Figure 8.12 Monthly CSP % revenue increase by zone due to optimal dispatch 262
Figure 8.13 Total monthly CSP revenue increase 262
Figure 8.14 Distribution of PHEV load.....264
Figure 8.15 Cost impact of adding PHEV load 264
Figure 8.16 Operational impact of renewable energy 265
Figure 9.1 Study area risk vs. capacity additions.....269
Figure 9.2 Study area risk with renewable additions.....269
Figure 9.3 Hourly average wind and load shape.....270
Figure 9.4 Average solar and load shapes 271
Figure 9.5 Study area total monthly wind and solar energy.....271
Figure 9.6 Study area risk in hours/year 272
Figure 9.7 Study area risk in unserved energy.....273
Figure 9.8 Wind capacity values by scenario, 2006 shapes, perfect capacity.....274
Figure 9.9 CSP with storage capacity values by scenario, 2006 shapes, perfect capacity 275
Figure 9.10 PV capacity values by scenario, 2006 shapes, perfect capacity 275
Figure 9.11 Annual and monthly variation in renewable energy.....276
Figure 9.12 Capacity value for wind, perfect capacity, daily LOLE, all years.....276
Figure 9.13 Capacity value for CSP with 6 hours of storage, perfect capacity, daily LOLE, all years.....277
Figure 9.14 Capacity value for PV, perfect capacity, daily LOLE, all years.....277
Figure 9.15 Combined capacity value for wind, CSP and PV, perfect capacity, daily LOLE, all years.....277
Figure 9.16 Capacity value for wind only, 2006 load shapes, random wind shapes. 279
Figure 9.17 Capacity value for CSP with storage, 2006 load shapes, random solar shapes 280
Figure 9.18 Capacity value for PV only, 2006 load shapes, random solar shapes.....280
Figure 9.19 Capacity value for wind, CSP and PV, 2006 load shapes, random wind and solar shapes 280
Figure 9.20 Comparison of wind capacity values, random and aligned shapes.....281
Figure 9.21 Comparison of CSP capacity values, random and aligned shapes.....281
Figure 9.22 Comparison of PV capacity values, random and aligned shapes.....282

List of Tables

Table 2.1 Wind and Solar Energy Penetrations for WWSIS Scenarios....11
Table 2.2 Summary of Aggregated Wind and Solar MW Ratings by State for WWSIS Scenarios13
Table 3.1 Annual wind energy by state for three years, 30% in-area scenario 20
Table 3.2 Energy Summary for 30% In Area Scenario....22
Table 3.3 Power Summary for 30% In Area Scenario....22
Table 3.4 Transmission Zones and Areas....24
Table 3.5 Selected WECC Transmission Path Ratings....25
Table 3.6 Energy Summary for 30% Mega Project Scenario....28
Table 3.7 Power Summary for 30% Mega Project Scenario 28
Table 3.8 Energy Summary for 30% Local Priority Scenario....30
Table 3.9 Power Summary for 30% Local Priority Scenario 30
Table 4.1 Wind and Solar Combinations for Various Penetration Levels 33
Table 4.2 Monthly Energy Summary for 2004, 2005, and 2006, 30% In Area Scenario....35
Table 4.3 Summary of 2006 Percent Monthly Energy from Wind and Solar (30% Wind Energy in Footprint) 38
Table 5.1 Summary of 2006 Footprint Net Load Variability for the for LP Scenario 72
Table 5.2 Summary Statistics for In-Footprint States, Total Footprint and WECC for all Scenarios in 2006....76
Table 5.3 Summary of Forecast Errors by Area, 30% LP scenario 81
Table 6.1 Scenario naming conventions 84
Table 6.2 Wyoming to Colorado interface flow statistics 92
Table 7.1 10 minute Net Load Variability by Area, Footprint and WECC....146
Table 7.2 Summary Statistics for 10-Minute Delta for Wyoming 147
Table 7.3. Generic Ramp Rate Data by Unit Type....152
Table 7.4. Regulation Requirement by Transmission Area. 153
Table 7.5 Approximate CPS2 L10 Limits by Transmission Area. 153
Table 7.6 Economic Dispatch Priority for Arizona during April QSS Study Period. 159
Table 7.7 Regulation Priority and Capability for Arizona during April QSS Study Period. 159
Table 7.8 Economic Dispatch Priority for Colorado East during October QSS Study Period. 172
Table 7.9 Regulation Priority and Capability for Colorado East during October QSS Study Period....172
Table 7.10. Colorado East Regulation at Capability Limits. 178
Table 7.11. Colorado East Regulation at Capability Limits for Sensitivity Cases. 182
Table 7.12. Maximum Arizona Wind Curtailment for Various Penetration Levels, Local Priority, April QSS Study Period....185
Table 7.13 Maximum Colorado East Load Participation for Various Penetration Levels, Local Priority, October QSS Study Period. 185
Table 8.1 Annual PHEV energy by State....263
Table 9.1 Renewable capacities by type 270
Table 9.2 Renewable capacity values by type, 2006 shapes, perfect capacity, daily LOLE. 270
Table 9.3 Renewable capacity values by type, 2006 shapes, perfect capacity, hourly LOLE....272

Table 9.4 Renewable capacity values by type, 2006 shapes, perfect capacity 273
Table 9.5 Renewable capacity values by type, 2006 shapes, perfect capacity, average across indices 273
Table 9.6 Renewable capacity values by type, perfect capacity, daily LOLE, by Scenario. 274

Executive Summary

To be provided later

1 Introduction

The Western Wind and Solar Integration Study (WWSIS) was initiated in 2007 to examine the operational impact of up to 35% energy penetration of wind generation, photovoltaics (PV) and concentrating solar power (CSP) on the power system operated by the WestConnect (www.westconnect.com) group of utilities in Arizona, Colorado, Nevada, New Mexico and Wyoming. The WestConnect geographic footprint is shown in Figure 1.1 Although WestConnect includes utilities in California, they were not included in this study because California had already completed a renewable energy integration study for the state [1.1]. This study was set up to answer questions that utilities, PUCs, developers, and regional planning organizations had about the impacts of integrating more renewable energy in the WestConnect region:

- Can the system operate reliably and securely with large amounts of wind and solar generation?
- How do local wind and solar resources compare to out-of-state resources?
- Can balancing area cooperation help mitigate variability?
- What is the impact of wind and solar energy on the variable cost of energy production, fuel consumption, and emissions?
- How much of the available wind and solar energy can be delivered to energy users?
- What is the role and value of energy storage?
- How would increased penetration of wind and solar generation affect reserve requirements?
- What is the benefit of wind and solar forecasting?
- Does geographic diversity of renewable energy resources help mitigate variability?
- How can hydro resources help with integration of wind and solar generation?

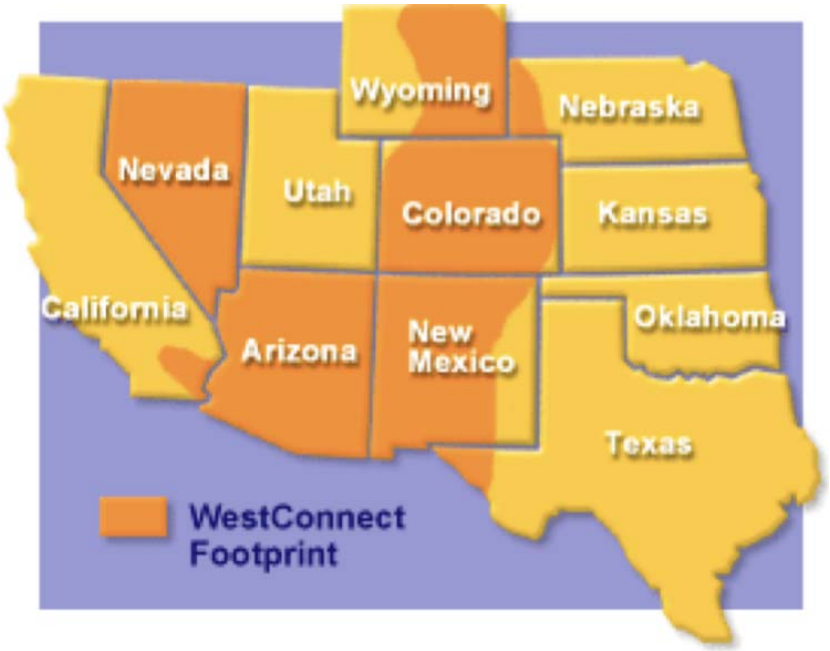


Figure 1.1 Geographic Footprint of WestConnect Utilities.

The WWSIS is sponsored by the U.S. Department of Energy (DOE) and managed by the National Renewable Energy Laboratory (NREL) with WestConnect as a partner organization. The study was originally established to build upon DOE's 20% Wind Energy by 2030 report [1.2], which did not find any technical barriers to reaching 20% wind energy in the continental United States by 2030. The WWSIS and its partner study, the Eastern Wind Integration and Transmission Study (EWITS), performed a more in-depth operating impact analysis to see if 20% wind energy was feasible from an operational level. In DOE/NREL's analysis, the 20% wind energy target required 25% wind energy in the western interconnection; therefore, this study considered 20% and 30% wind energy to bracket the DOE analysis. And since solar power is rapidly growing in the west, up to 5% solar energy was also considered in this study.

1.1 References

[1.1] Bai, X., Clark, K, Jordan, G., Miller, N, Piwko, R.; "Intermittency Analysis project: Appendix B Impact of Intermittent Generation on Operation of California Power Grid" CEC-500-2007-081-APB, July 2007.

[1.2] Lindenberg, S., Smith, B., O'Dell, K., DeMeo, E.; "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply", DOE/GO-102008-2567, July 2008.

2 Objectives and Technical Approach

2.1 Project Objectives

The goal of the WWSIS is to understand the economic and operating impacts due to increased penetration of wind, PV, and CSP generation resources on the power grid. This is mainly an operations study and not a transmission planning study, although several scenarios include inter-regional transmission expansions to deliver power. The study does not focus on the capital costs of developing wind or solar power resources but rather the overall operational costs and savings due to fuel and emissions.

2.2 Major Tasks

In the WWSIS, the major tasks consisted of utility data collection, wind and solar dataset development, scenario development, statistical analysis, production simulation analysis, reliability analysis, quasi-steady-state analysis, and analysis of mitigation options. The WWSIS was a large team effort, with Exeter Associates responsible for data collection, 3TIER Group developing the wind dataset and the solar forecasts, State University of New York (SUNY)/Albany modeling the solar resource, NREL modeling the PV and CSP power plants, Northern Arizona University (NAU) validating the wind dataset and hydro operation, and GE developing scenarios and conducting the main technical and economic analysis. Figure 2.1 shows a flowchart of the major project tasks.

The study examined grid operation for the year 2017. That is, system loads and generation expansion were projected to represent year 2017. The study examined inter-annual operability by modeling operations for year 2017 three times, using historical load and weather patterns from years 2004, 2005, and 2006.

The study focused on the WestConnect region with up to 35% energy penetration of wind and solar generation. And since renewable energy resources in neighboring regions can affect operations of the WestConnect region, up to 23% energy penetration of wind and solar generation was assumed for the rest of WECC. This addressed concerns of "exporting the variability," which affected other studies that ignored significant renewable energy penetrations outside the study area.

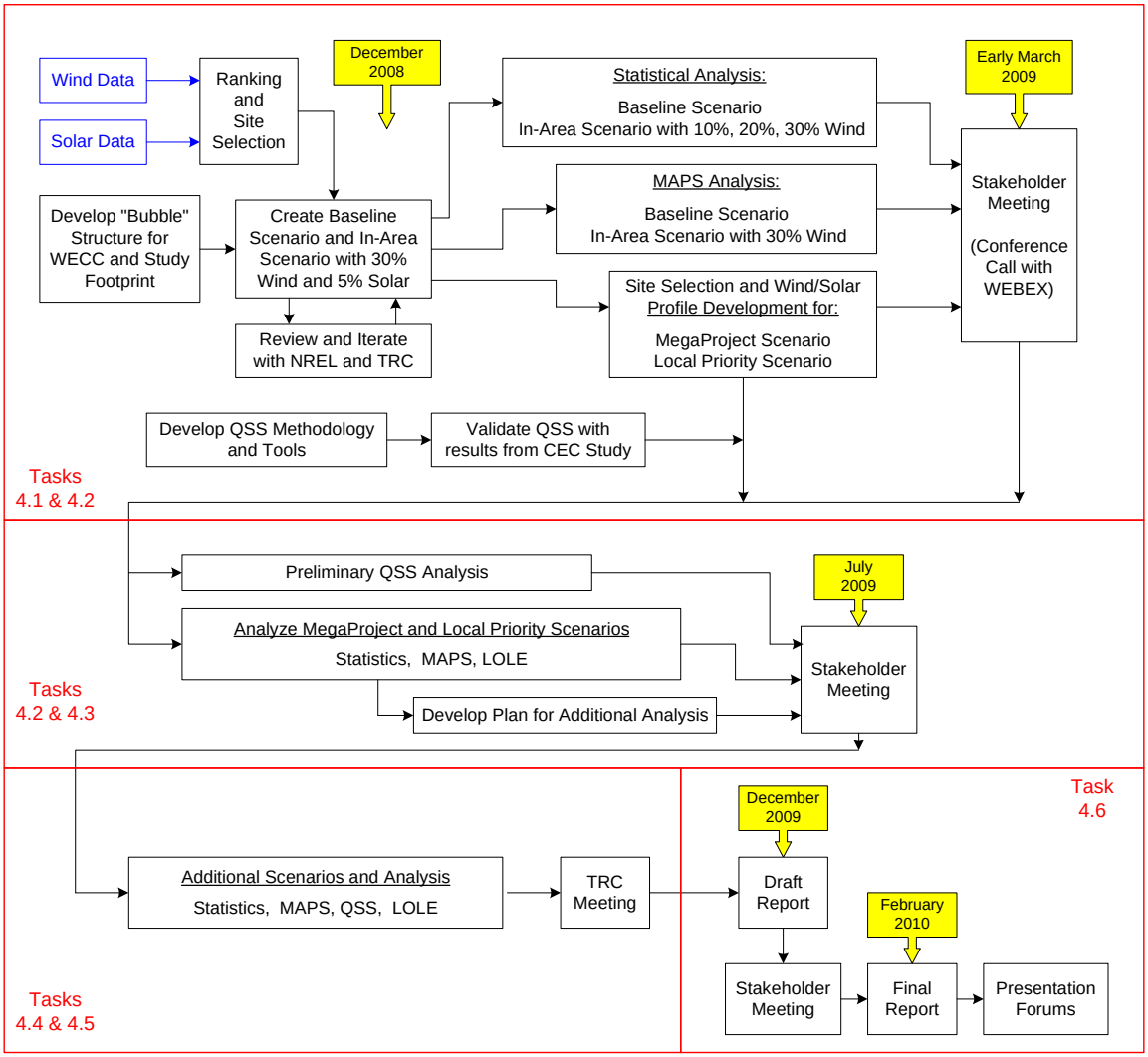
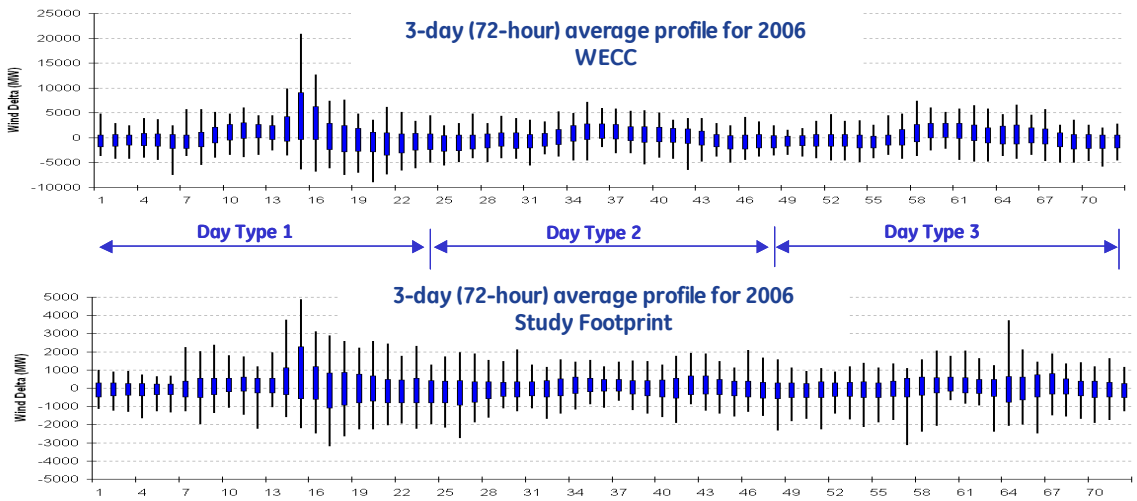


Figure 2.1 Flowchart of WWSIS Project Tasks

2.3 Wind Data Development

3TIER Group developed the wind dataset for the study [2.1]. Over 75 GW of wind generation sites needed to be modeled in the study. Lacking sufficient measured data to represent this level of wind generation, it was decided to model the wind resource across the entire western United States to generate a consistent wind dataset in space and time. 3TIER Group used the Weather Research and Forecasting (WRF) mesoscale Numerical Weather Prediction Model (NWP) over the western United States at a 2-km, 10- minute resolution for years 2004-2006. In order to run this large a region at such a high a resolution, it was necessary to divide it into four domains that were run independently and then merged. The domains were run in three-day blocks that were merged together and the seams smoothed. While the seams were smoothed so that variability did not exceed realistic limits, unfortunately the days with seams exhibited significantly more variability than the days with without seams. This issue is illustrated

in Figure 2.2. In order to work around this unfortunate data glitch, data from every third day was eliminated from the statistical analysis of hourly and 10-minute variability. The daily energy levels were judged to be reasonable so data for all days was used for energy analysis and production simulation analysis.



	Day 1 Sigma	Day 2 Sigma	Day 3 Sigma
WECC	2491	1675	1664
Footprint	1048	778	745

Figure 2.2 Statistical analysis showing data seam at hour 16 of every third day

3TIER Group also developed day-ahead wind forecasts for each hour. To eliminate any systematic errors that would result in the forecasts being 'too good', a different input dataset was used for these model runs. The forecasts were run using a coarser resolution than the 2-km resolution of the 'actuals' dataset. One unintended consequence of this approach was that the resulting wind forecasts were biased. That is, the total annual energy of aggregated wind plant forecasts was different than the aggregated annual energy of the 'actual' wind profiles. Annual wind forecast errors by area are summarized in Figure 2.3. On average, wind forecasts in the study footprint were about 10% high and forecasts in the rest of WECC were about 20% high. Figure 2.3 summarizes the wind forecast errors by area. Figure 2.4 shows how the wind energy forecast error varies by month.

Creating new unbiased forecasts was not feasible. The hourly wind forecasts were reduced by 10% in the study footprint and 20% in the rest of WECC. This removed the annual bias in total energy, but other forms of forecast bias remained.

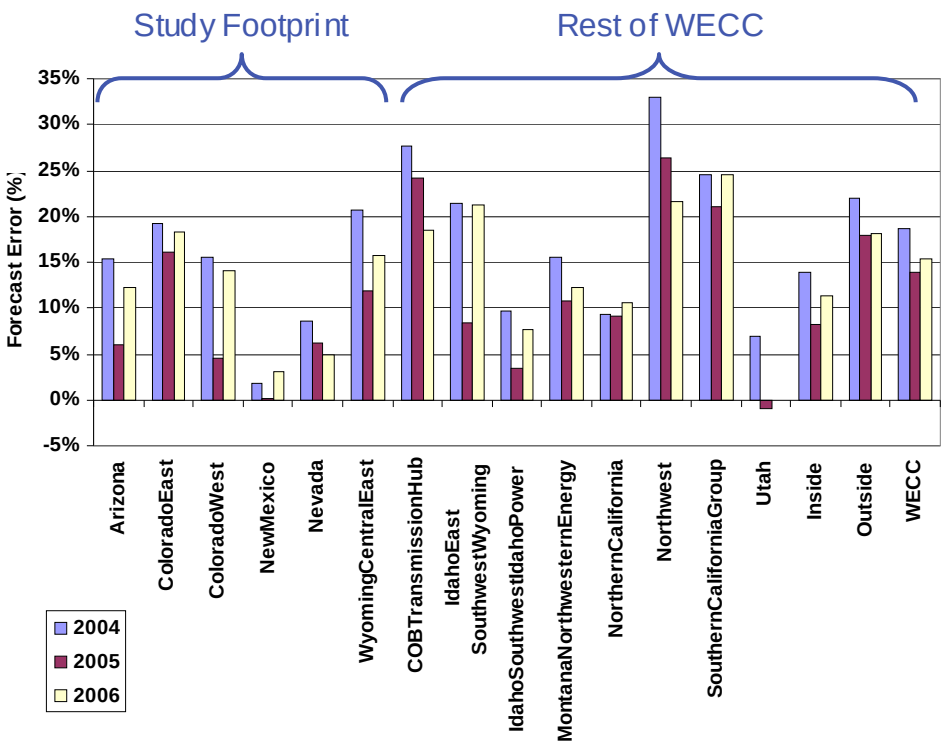


Figure 2.3 Annual wind energy forecast error by area.

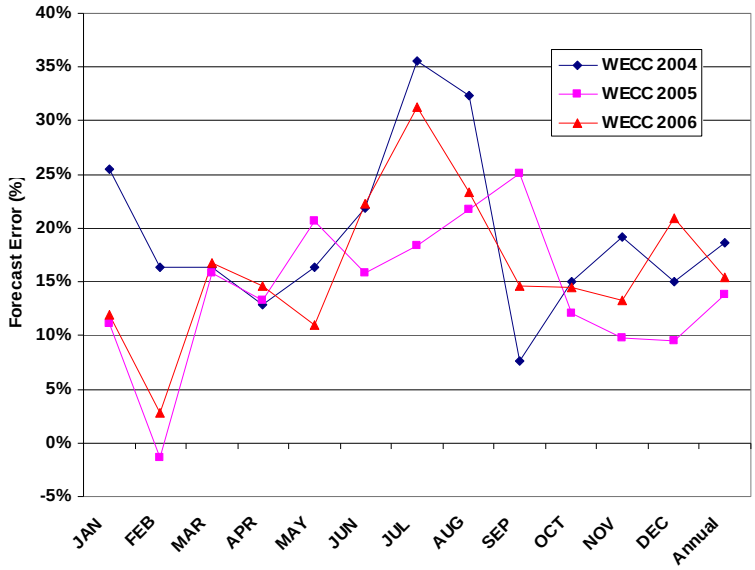


Figure 2.4 Monthly wind forecast error in WECC

Over 960 GW of wind sites (32,000 sites of 30 MW each) were modeled. This produced a data set that not only satisfied all the scenarios for this study, but will enable future studies of different scenarios representing different wind resources in different locations. Each 2-km x 2-km grid cell was assumed to contain 10 Vestas V90 3-MW wind turbines, yielding 30 MW per grid cell. Actual wind plants do not exhibit a

deterministic 'wind plant power curve,' so instead of using the sum of 10 Vestas V90 wind turbine power curves, 3TIER Group's stochastic SCORE methodology was used for power conversion [2.1]. The SCORE methodology uses measured probability density functions to produce the type of stochastic output that is observed in actual wind plants. While array and electrical losses were not explicitly taken into account in the power conversion, the wind plant output tended to correspond very closely to a net wind plant output and was used as such. The wind dataset is publicly available [2.2].

Validity analysis was conducted to assess the quality of the wind data. Because this was the first time such a large, high-resolution wind dataset had been created, it was critical to check the data in as many ways as possible. This included checks of the power curve, maximum and minimum output, largest ramps, average capacity factor, etc.

3TIER Group, NREL, and NAU validated the dataset against meteorological tower measurements of wind speed. In some cases, this was used to determine whether large wind ramps were real or artifacts of the model process. NREL also validated the dataset against wind plant output for over 1 GW of wind plants for which NREL could access data. The most critical check of a dataset for integration analysis is the accuracy of ramps, in this case, on a 10-minute and hourly timescale. A consistent over- or under-production bias is less important in assessing operational impacts.

Figure 2.5 shows validation results for the variability of the wind dataset, comparing the 10-minute wind plant output deltas of the actual wind plant output and the mesoscale modeled dataset over a three year period. ("Delta" is the change from one ten-minute period to the next.) The dataset is considered conservative because it overestimates the variability of the wind plant output, as compared to actual measurements.

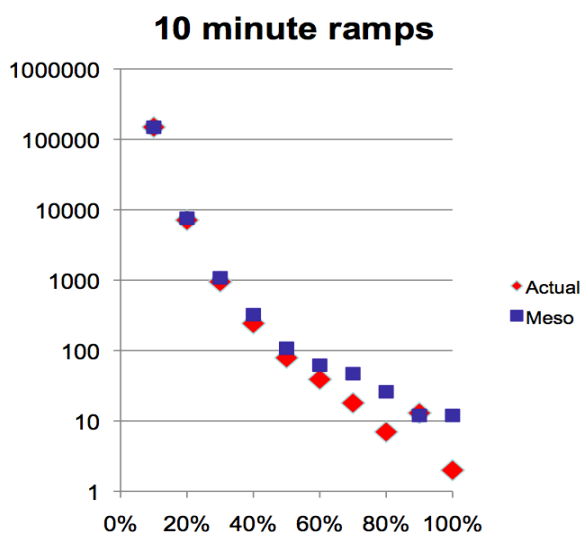


Figure 2.5 Example Result from Wind Dataset Validation Analysis

2.4 Solar Data Development

The State University of New York (SUNY)/Albany developed the solar resource dataset for the study. SUNY/Albany used a satellite cloud cover model to simulate the United States at a 10-km, hourly resolution [2.3]. This dataset includes global horizontal, direct normal and diffuse radiation, as well as hourly day-ahead solar forecasts.

PV was modeled in the WWSIS as distributed generation on rooftops. Modeling information for large, central station PV plants was not available at the time of the study. Preliminary data, analysis, and operating experience from the 4.6-MW Springerville Generating Station Solar System in Arizona indicated that central station PV could have significant impacts on the grid, but there was little other data to determine whether the Springerville climate was typical of other regions in the western USA. Weather stations in the western United States were modeled using PV Watts to create PV output in block sizes of 100 MW. In order to model distributed generation from multiple resources, PV Watts was run using 11 different configurations of tilt, orientation, and tracking/flat-plate. The outputs were aggregated. The hourly PV profiles are available on the web [2.4].

To downscale the PV output from hourly data to a 10-minute resolution, NREL developed a model that compared the hourly average PV output to the clear sky (no clouds) PV output and added variability. The amount of variability added was based on measured PV output from many small PV plants in Arizona Public Service's Solar Test and Research (STAR) program, the Springerville system, and several small PV plants in Colorado.

CSP was modeled in the WWSIS as 100-MW blocks of parabolic trough plants with six hours of thermal storage. Over 200 GW of CSP plants were included in the solar dataset and these profiles are also available on the web [2.4]. The storage was initially dispatched to a typical utility load pattern (in this case, Southern California Edison). Six hours of storage requires that the solar field (solar collectors) be approximately twice as large as a system without storage. The Solar Advisor Model [2.5] was used for the power conversion using NREL's Excelergy model to represent the parabolic trough plants with thermal storage. Losses associated with the thermal storage are estimated to be minimal for storage of several hours. Because the CSP with thermal storage produces a very stable output, the 10-minute dataset was created simply by interpolating the hourly dataset.

2.5 Load Data

It was not possible to obtain 10-minute load data for 2004-2006 from all operating areas in the study footprint. Therefore, hourly load profile data for all operating areas in WECC were obtained from a Ventyx database.

2.6 Overview of Study Scenarios

The WWSIS used a multidimensional scenario-based study approach to evaluate:

- Different levels of energy penetration for wind and solar generation, ranging from 11% to 35%.
- Different geographic locations for the wind and solar resources, and
- A wide array of sensitivities to assess issues such as fuel costs, operating reserve levels, unit commitment strategies, storage alternatives, PHEV, balancing area size, etc.

Table 2.1 shows the four levels of wind and solar energy penetration levels assumed for the study scenarios. The "10%" penetration level included 10% wind energy and 1% solar energy (relative to total annual load energy) in the study footprint as well as the rest of WECC. The "20%" penetration level included 20% wind energy and 3% solar energy in the study footprint, with 10% wind energy and 1% solar energy in the rest of WECC. The "20/20%" penetration level included 20% wind energy and 3% solar energy in the study footprint as well as the rest of WECC. The "30%" penetration level included 30% wind energy and 5% solar energy in the study footprint, with 20% wind energy and 3% solar energy in the rest of WECC.

Table 2.1 Wind and Solar Energy Penetrations for WWSIS Scenarios

Case Name	In Footprint Energy Penetration			Rest of WECC	
	Wind + Solar	Wind	Solar	Wind	Solar
10%	11%	10%	1%	10%	1%
20%	23%	20%	3%	10%	1%
20/20%	23%	20%	3%	20%	3%
30%	35%	30%	5%	20%	3%

The study evaluated three major scenarios with wind and solar resources in different geographic locations.

In-Area Scenario: Each state in the study footprint met its wind and solar energy targets using the best available wind and solar generation resources within its state boundary. Each state in the rest of WECC also met its renewable energy target using the best available resources within the state boundary. In some northern states, it was necessary to use solar resources from neighboring states due to the lack of good solar resources. The in-area siting was held constant for the rest of WECC, while the study footprint examined two additional scenarios.

Mega-Project Scenario: The study footprint met its wind and solar energy targets by using the best available wind and solar resources within the study footprint. Given that the many of the best wind resources are in Wyoming, this scenario

include a large penetration of wind generation in Wyoming (and other wind-rich areas), with new transmission lines to deliver the energy to load centers.

Local-Priority Scenario: This scenario used the best wind and solar sites within the entire footprint, but included a 10% capital cost advantage to "local" resources within each state. The result was a scenario that was about half-way between the In-Area and Mega-Project scenarios.

Table 2.2 shows a summary of the total wind and solar MW ratings by state for the study footprint. Section 3 provides additional details about the scenarios and how they were developed. It also provides data on wind and solar resources in the rest of WECC.

Table 2.2 Summary of Aggregated Wind and Solar MW Ratings by State for WWSIS Scenarios

In Area

Area	Load Minimum (MW)	Load Maximum (MW)	10% Wind Rating (MW)	1% Solar Rating (MW)	20% Wind Rating (MW)	3% Solar Rating (MW)	30% Wind Rating (MW)	5% Solar Rating (MW)
Arizona	6,995	23,051	3,600	400	7,350	1,200	11,220	2,000
Colorado East	4,493	11,589	2,040	300	3,780	800	5,640	1,400
Colorado West	712	1,526	300	0	600	200	900	300
New Mexico	2,571	5,320	1,080	200	1,920	400	2,790	700
Nevada	3,863	12,584	2,340	200	4,680	700	7,050	1,100
Wyoming	2,369	4,016	930	100	1,620	100	2,340	300
In Footprint	**21,249**	**58,087**	**10,290**	**1,200**	**19,950**	**3,400**	**29,940**	**5,800**

Local Priority

Area	Load Minimum (MW)	Load Maximum (MW)	10% Wind Rating (MW)	1% Solar Rating (MW)	20% Wind Rating (MW)	3% Solar Rating (MW)	30% Wind Rating (MW)	5% Solar Rating (MW)
Arizona	6,995	23,051	2,850	400	5,250	1,200	7,710	2,000
Colorado East	4,493	11,589	2,190	300	3,870	800	4,650	1,400
Colorado West	712	1,526	210	0	450	200	570	300
New Mexico	2,571	5,320	1,350	200	2,100	400	2,970	700
Nevada	3,863	12,584	1,350	200	2,490	700	3,450	1,100
Wyoming	2,369	4,016	1,650	100	4,020	100	7,410	300
In Footprint	**21,249**	**58,087**	**9,600**	**1,200**	**18,180**	**3,400**	**26,760**	**5,800**

Mega Project

Area	Load Minimum (MW)	Load Maximum (MW)	10% Wind Rating (MW)	1% Solar Rating (MW)	20% Wind Rating (MW)	3% Solar Rating (MW)	30% Wind Rating (MW)	5% Solar Rating (MW)
Arizona	6,995	23,051	810	400	1,260	1,800	1,890	2,600
Colorado East	4,493	11,589	2,010	300	2,400	400	2,490	1,200
Colorado West	712	1,526	60	0	90	0	90	200
New Mexico	2,571	5,320	1,860	400	2,700	1,000	4,350	1,000
Nevada	3,863	12,584	570	100	1,020	200	1,440	600
Wyoming	2,369	4,016	3,390	0	8,790	0	13,770	100
In Footprint	**21,249**	**58,087**	**8,700**	**1,200**	**16,260**	**3,400**	**24,030**	**5,700**

2.7 Analytical Methods

The primary objective of this study was to identify and quantify system performance and any operational problems, including load following, regulation, operation during low-load periods, etc. Four primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, sub-hourly analysis using quasi-steady-state simulations, and reliability analysis.

Statistical analysis was used to quantify variability due to system load, as well as wind and solar generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The power grid already has significant variability due to periodic and random changes to system load. Wind and solar generation add to that variability, and increase what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind and solar generation for each scenario. The statistical analysis also examined the forecast accuracy for wind generation.

Production simulation analysis with MAPS (Multi-Area Production Simulation program) was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind and load profiles. The WECC was represented as a set of 106 zones, each with its own load profile, portfolio of generating plants, and transmission capacity with neighboring areas. The zones were grouped into 20 transmission areas. The production simulation results quantified numerous impacts on grid operation including:

- Amount of maneuverable generation on-line during a given hour, including its available ramp-up and ramp-down capability to deal with grid variability due to load, wind and solar.
- Effects of day-ahead wind forecast alternatives in unit commitment
- Changes in dispatch of conventional generation resources due to the addition of new renewable generation
- Changes in emissions (NOx, SOx,CO2) due to renewable generation
- Changes in costs and revenues associated with grid operation, and changes in net cost of energy
- Changes in transmission path loadings
- Changes in utilization of hydro resources
- Changes in utilization and economic value of energy storage resources

Quasi-steady-state (QSS) simulation analysis was used to quantify grid performance trends and to investigate potential mitigation measures in the minute-to-minute time

frame. QSS analysis simulated the operation of dispatchable generation resources as well as variable wind and solar generation in the study footprint using one minute time steps, while enforcing constraints related to unit ramp rates, ramp range, intertie flow schedules, and regional AGC functions. These time simulations enabled examination of the impact of wind and solar generation during challenging time periods, such as:

- Large 1-hour, 3-hour and 6-hour changes in net load within the study footprint
- High levels of wind and solar penetration
- Low load levels with minimal maneuverable generation on line
- High wind forecast errors

Reliability analysis involved loss of load expectation (LOLE) calculations for the study footprint and all of WECC using the Multi-Area Reliability Simulation program, MARS. The analysis quantified the impact of wind and solar generation on overall reliability measures, as well as the capacity values of the wind and solar generation resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics, production simulation, and QSS simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind and solar generation into the WestConnect power grid.

2.8 References

[2.1] Potter, C.W.; Lew, D.; McCaa, J.; Cheng, S.; Eichelberger, S.; Grimit, E. "Creating the Dataset for the Western Wind and Solar Integration Study (U.S.A.)" Wind Engineering, Vol 32(4), pp. 325-338, 2008.

[2.2] http://www.nrel.gov/wind/westernwind or http://mercator.nrel.gov/wwsi

[2.3] Wilcox, S.; Anderberg, M.; George, R.; Marion, W.; Myers, D.; Renne, D.; Lott, N.; Whitehurst, T.; Beckman, W.; Gueymard, C.; Perez, R.; Stackhouse, P.; Vignola, F. "Completing Production of the Updated National Solar Radiation Database for the United States", NREL Report No. CP-581-41511, July 2007.

[2.4] http://mercator.nrel.gov/wwsi

[2.5] http://www.nrel.gov/analysis/sam

3 Study Scenarios

This study analyzed three scenarios representing different approaches to using the available wind and solar resources in the study footprint.

In Area: Each state within the study footprint meets its wind and solar energy penetration target using the best wind and solar resources within each state boundary.

Mega Project: The entire study footprint meets its wind and solar energy penetration target using the best wind and solar resources within the entire study footprint, regardless of state boundaries. New transmission was added to transport renewable energy from the generation areas to the load centers.

Local Priority: This scenario is similar to the Mega Project scenario; except that in-state wind and solar resources have a 10% capital cost advantage over resources in other states. This scenario falls between the In Area and Mega Project scenarios.

Section 2.5 provided a high-level overview of the study scenarios, including the range of wind and solar penetration considered. This chapter provides detailed information on how the scenarios were developed. Locations of available wind and solar sites are described, and the technical algorithms used to rank the sites selected for each scenario are explained. Mathematical details of the site selection algorithms are included in Appendix A.

This study was not intended to be a transmission system design study. Renewable generation resources within each state were assumed to include the necessary local transmission facilities to deliver the renewable energy from the plant sites to each state's bulk transmission network, per traditional engineering design practices and performance criteria. New inter-area transmission lines were added for the Mega Project and Local Priority scenarios to increase bulk power transfer capacities consistent with the locations of the new renewable generation and the existing load centers.

3.1 Development of In Area Scenario

The In Area scenario assumes that each state within the study footprint meets its wind and solar energy penetration target using the best wind and solar resources within each state boundary.

3.1.1 Objectives of the Site Selection Process

The wind and solar data sets included far more available sites than were needed to meet the study's energy penetration objectives. Therefore, an analytical method was

developed to select a subset of the available sites in accordance with the following objectives:

- Satisfy energy penetration targets
- Consider expected market value of energy produced
- Include capacity value of sites
- Recognize that geographic diversity within areas has value
- Include pre-selected wind plants
- Independently select wind, PV, and CSP with storage per specified renewable generation mix

3.1.2 Available Wind and Solar Sites

The wind database included 32,043 sites with 30 MW of capacity each. These sites were subjected to an exclusion screen that eliminated 5,523 sites that were in recreational areas, close to metropolitan areas, in inaccessible terrain, etc. The locations of the remaining 26,520 wind sites are shown in Figure 3.1. (Note that this includes 2004 sites that are outside of the WECC area, and were therefore excluded from this study.) The solar dataset included 275 PV sites and 501 CSP sites, each rated at 100 MW. Locations of the PV and CSP sites are shown in Figure 3.2.

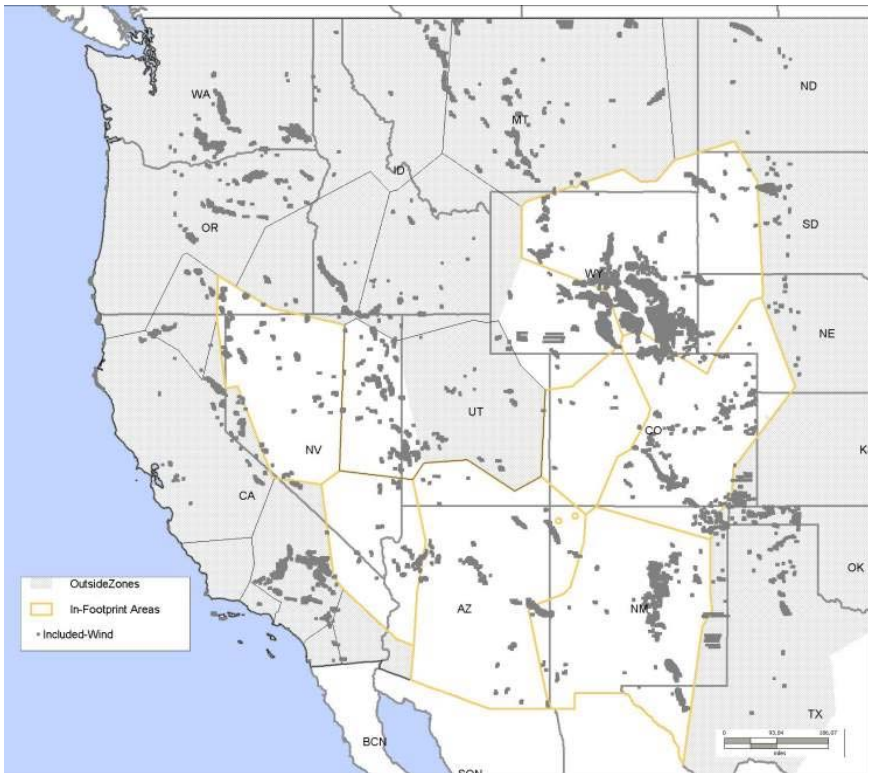


Figure 3.1 All available wind sites in WECC (each grey dot represents 30MW)

Figure 3.2 All available solar sites in WECC (each grey dot represents 100 MW)

3.1.3 Wind and Solar Site Selection

The selection of wind sites for the In Area scenario followed the process described below. For each state:

- Calculate average annual energy, capacity factor, energy value, and capacity value for each site from three years of data.
- Order the sites best to worst, independently by generation type, on the basis of:
  - Preselected (i.e., existing plants)
  - Energy value. Using a price strip of hourly historical hub spot prices, select the hub closest to a given site and calculate its energy value.
  - Capacity value. Apply a $100/kw-yr weighting factor on a capacity factor calculated between 2pm and 6pm.
  - Geographic diversity as proxy for temporal diversity. Apply a 2%/100-mile weighting factor based on the distance from center coordinates of the transmission area (latitude/longitude). East-West diversity was given more weight than North-South. North-South weighting: 1 for wind, 0 for solar. East-West weighting; 1 for wind, 1.41 for solar.

- o NOTE: Energy value was the dominant factor in the sorting algorithm, followed by capacity value. However, capacity value exceeded energy value for some sites. Geographic diversity had a secondary impact.

- Starting from the highest ranked sites, select the required number of wind and solar sites within the energy footprint to meet the energy target for the state (eg., 10%, 20%, 30%). Preselected sites are included to meet the energy target for the state regardless of their energy value.
- Using a similar approach, select sites outside of the study footprint to meet wind energy targets in the rest of WECC.

A similar process was used to select the solar CSP and PV sites for the In Area scenario.

Using this process, wind and solar sites were selected so that their three-year average energy would match annual energy targets. The same sites were used for all three load/weather years (2004, 2005, 2006) so the total wind and solar energy varied slightly between years. Table 3.1 shows the average annual wind energy by state for the 30% scenario, as well as the values for individual years.

Figure 3.3 shows the wind sites and Figure 3.4 shows the solar sites selected for the 30% In Area scenario. Table 3.2 shows a summary of annual load, wind, and solar energy by area. Note that the in-footprint energy penetration is 35% (30% wind and 5% solar) and the out-of-footprint energy penetration is 23% (20% wind and 3% solar).

Table 3.1 Annual wind energy by state for three years, 30% in-area scenario

					Annual Wind Energy (GWh)				Annual Wind Energy (% of load)			
WIND - 30%	Sites Available	Sites Used	Average Capacity Factor (%)	Average Load Energy (GWh)	2004	2005	2006	Average	2004	2005	2006	Average
Arizona	1,091	374	30.4%	99,437	28,690	31,376	29,624	29,897	28.9%	31.6%	29.8%	30.1%
Colorado East	1,673	188	37.4%	61,372	18,031	18,577	18,753	18,453	29.4%	30.3%	30.6%	30.1%
Colorado West	68	30	33.3%	8,708	2,560	2,674	2,632	2,622	29.4%	30.7%	30.2%	30.1%
New Mexico	3,062	93	38.4%	31,260	9,120	9,472	9,555	9,382	29.2%	30.3%	30.6%	30.0%
Nevada	1,591	235	28.0%	57,505	16,673	16,601	18,598	17,290	29.0%	28.9%	32.3%	30.1%
Wyoming	8,912	78	41.0%	27,697	8,169	8,466	8,608	8,414	29.5%	30.6%	31.1%	30.4%
In Footprint	**16,397**	**998**	**32.8%**	**285,979**	**83,242**	**87,166**	**87,769**	**86,059**	**29.1%**	**30.5%**	**30.7%**	**30.1%**
WIND - 20%												
COB	155	6	25.0%	1,759	351	379	451	394	20.0%	21.6%	25.6%	22.4%
Idaho East	185	26	20.6%	6,907	1,368	1,390	1,459	1,406	19.8%	20.1%	21.1%	20.3%
Idaho Southwest	448	50	27.8%	17,962	3,443	3,557	3,974	3,658	19.2%	19.8%	22.1%	20.4%
Montana	1,194	35	31.2%	14,143	2,805	2,825	2,990	2,873	19.8%	20.0%	21.1%	20.3%
N. California	472	393	25.0%	128,935	24,930	24,462	28,038	25,810	19.3%	19.0%	21.7%	20.0%
Northwest	3,195	431	31.5%	178,359	34,637	34,558	38,003	35,733	19.4%	19.4%	21.3%	20.0%
S.California	1,916	483	35.4%	224,197	44,447	46,298	43,924	44,890	19.8%	20.7%	19.6%	20.0%
Utah	554	91	32.0%	38,022	7,504	7,698	7,773	7,658	19.7%	20.2%	20.4%	20.1%
Out of Footprint	**8,119**	**1,515**	**30.7%**	**610,284**	**119,485**	**121,167**	**126,612**	**122,421**	**19.6%**	**19.9%**	**20.7%**	**20.1%**
Total	**24,516**	**2,513**	**31.6%**	**896,263**	**202,728**	**208,333**	**214,381**	**208,480**	**22.6%**	**23.2%**	**23.9%**	**23.3%**

Table 3.3 shows a corresponding summary by area of maximum/minimum load MW, wind MW rating, solar MW rating, and total renewable MW rating. The maximum and minimum penetration values in this table are capacity penetrations (not energy

penetrations). They are calculated as the ratio of renewable MW rating to area minimum or maximum load MW.

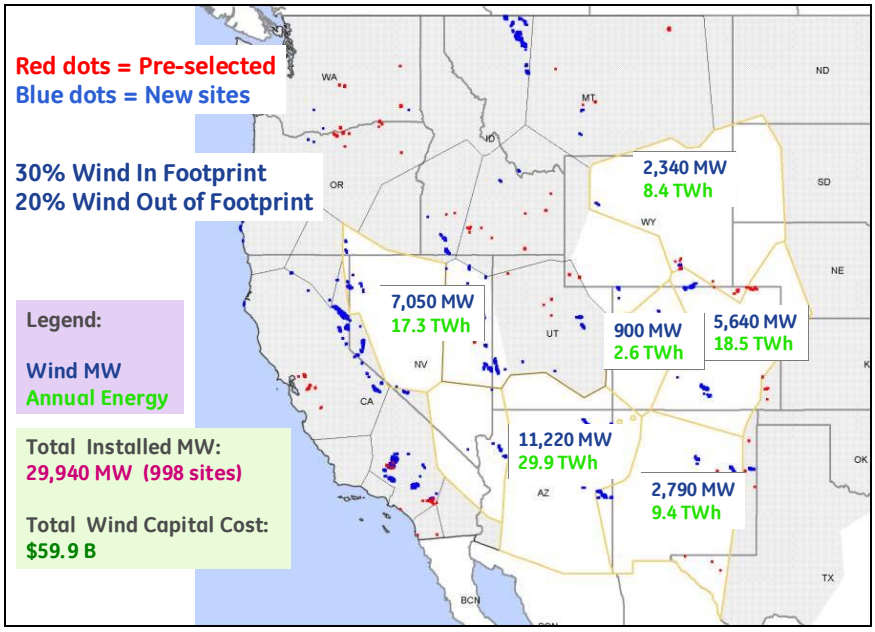


Figure 3.3 Wind sites for In Area Scenario with 30% wind energy and 5% solar energy.

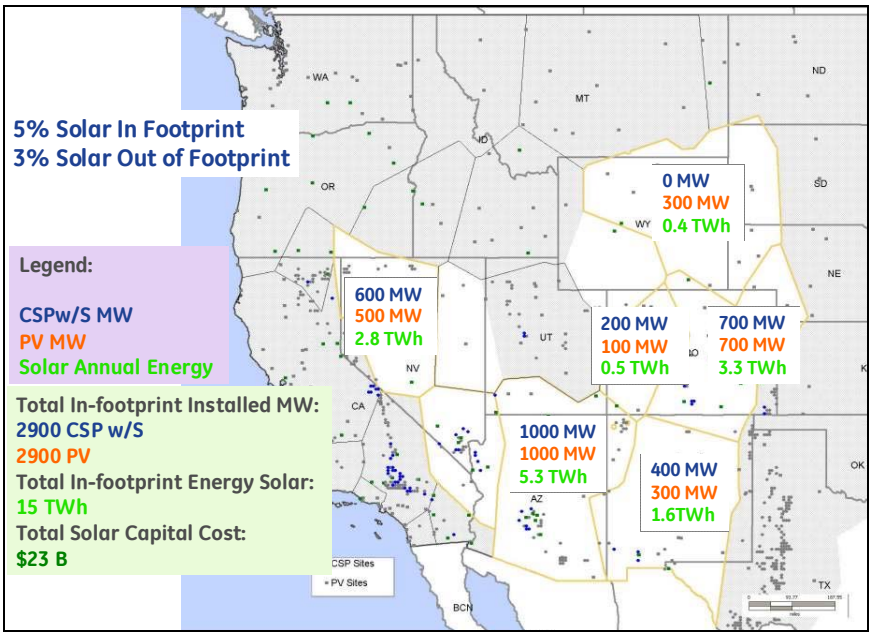


Figure 3.4 Solar sites for In Area Scenario with 30% wind energy and 5% solar energy.

Table 3.2 Energy Summary for 30% In Area Scenario

In Footprint

Areas	Load Energy (GWh)	Wind Energy (GWh)	Wind # Sites (Used/Available)	CSP with Storage Energy (GWh)	CSP with Storage # Sites (Used/Available)	PV Energy (GWh)	PV # Sites (Used/Available)	Total Renewable Energy (GWh)	
Arizona	99,437	29,897	374 / 1091	3,735	10 / 38	1,548	10 / 16	35,180	
Colorado East	61,372	18,453	188 / 1673	2,252	7 / 58	1,038	7 / 13	21,743	
Colorado West	8,708	2,622	30 / 68	564	2 / 8	151	1 / 11	3,337	
New Mexico	31,260	9,382	93 / 3062	1,421	4 / 35	473	3 / 19	11,276	
Nevada	57,505	17,290	235 / 1591	2,161	6 / 45	773	5 / 10	20,224	
Wyoming	27,697	8,414	78 / 8912	0	0 / 0	420	3 / 10	8,834	
In Footprint	**285,979**	**86,058**	**998 / 16397**	**10,133**	**29 / 184**	**4,403**	**29 / 79**	**100,594**	**35.2 %**

Out of Footprint

Areas	Load Energy (GWh)	Wind Energy (GWh)	Wind # Sites (Used/Available)	CSP with Storage Energy (GWh)	CSP with Storage # Sites (Used/Available)	PV Energy (GWh)	PV # Sites (Used/Available)	Total Renewable Energy (GWh)	
COB	1,759	394	6 / 155	294	1 / 22	142	1 / 2	830	
Idaho East	6,907	1,406	26 / 185	0	0 / 0	142	1 / 8	1,548	
Idaho Southwest	17,962	3,658	50 / 448	0	0 / 0	132	1 / 5	3,790	
Montana	14,143	2,873	35 / 1194	0	0 / 0	127	1 / 14	3,000	
Northern California	128,935	25,812	393 / 472	2,726	8 / 26	1,117	8 / 30	29,655	
Northwest	178,359	35,733	431 / 3195	0	0 / 0	1,645	13 / 54	37,378	
Southern California	224,197	44,890	483 / 1916	8,957	23 / 85	2,050	13 / 39	55,897	
Utah	38,022	7,658	91 / 554	937	3 / 24	303	2 / 14	8,898	
Out of Footprint	**610,284**	**122,424**	**1515 / 8119**	**12,914**	**35 / 157**	**5,658**	**40 / 166**	**140,996**	**23.1 %**

Table 3.3 Power Summary for 30% In Area Scenario

In Footprint

Areas	Load Minimum (MW)	Load Maximum (MW)	Wind Rating (MW)	Wind Penetration % Min	Wind Penetration %Max	CSP with Storage Rating (MW)	CSP with Storage Penetration % Min	CSP with Storage Penetration % Max	PV Rating (MW)	PV Penetration % Min	PV Penetration % Max	Total Renewable Rating (MW)	Total Renewable Penetration % Min	Total Renewable Penetration % Max
Arizona	6,995	23,051	11,220	160%	49%	1,000	14%	4%	1,000	14%	4%	13,220	189%	57%
Colorado East	4,493	11,589	5,640	126%	49%	700	16%	6%	700	16%	6%	7,040	157%	61%
Colorado West	712	1,526	900	126%	59%	200	28%	13%	100	14%	7%	1,200	169%	79%
New Mexico	2,571	5,320	2,790	109%	52%	400	16%	8%	300	12%	6%	3,490	136%	66%
Nevada	3,863	12,584	7,050	183%	56%	600	16%	5%	500	13%	4%	8,150	211%	65%
Wyoming	2,369	4,016	2,340	99%	58%	0	0%	0%	300	13%	7%	2,640	111%	66%
In Footprint	**21,249**	**58,087**	**29,940**	**141%**	**52%**	**2,900**	**14%**	**5%**	**2,900**	**14%**	**5%**	**35,740**	**168%**	**62%**

Out of Footprint

Areas	Load Minimum (MW)	Load Maximum (MW)	Wind Rating (MW)	Wind Penetration % Min	Wind Penetration %Max	CSP with Storage Rating (MW)	CSP with Storage Penetration % Min	CSP with Storage Penetration % Max	PV Rating (MW)	PV Penetration % Min	PV Penetration % Max	Total Renewable Rating (MW)	Total Renewable Penetration % Min	Total Renewable Penetration % Max
COB	138	294	180	131%	61%	100	73%	34%	100	73%	34%	380	276%	129%
Idaho East	460	1,365	780	170%	57%	0	0%	0%	100	22%	7%	880	191%	64%
Idaho Southwest	1,188	3,592	1,500	126%	42%	0	0%	0%	100	8%	3%	1,600	135%	45%
Montana	1,149	2,337	1,050	91%	45%	0	0%	0%	100	9%	4%	1,150	100%	49%
Northern California	10,297	28,319	11,790	114%	42%	800	8%	3%	800	8%	3%	13,390	130%	47%
Northwest	14,278	30,953	12,930	91%	42%	0	0%	0%	1,300	9%	4%	14,230	100%	46%
Southern California	9,557	26,864	14,490	152%	54%	2,300	24%	9%	1,300	14%	5%	18,090	189%	67%
Utah	2,263	7,274	2,730	121%	38%	300	13%	4%	200	9%	3%	3,230	143%	44%
Out of Footprint	**46,328**	**119,696**	**45,450**	**98%**	**38%**	**3,500**	**8%**	**3%**	**4,000**	**9%**	**3%**	**52,950**	**114%**	**44%**

3.1.4 Transmission Zones and Areas

Although this study focused primarily on the WestConnect footprint, the analytical models used in the study covered the entire WECC system with the exception of Canada. The WECC system was divided into 14 transmission areas. Each transmission area was further subdivided into transmission zones. Figure 3.5 shows a map of the transmission areas and zones. Table 3.4 summarizes the same information in tabular form.

In Figure 3.6, the WECC transmission areas have been reduced to dots and the inter-area transmission paths are emphasized. One rating is shown for each path, even though many paths have a different rating for each flow direction. Bi-directional ratings for the transmission paths within the study footprint for the In Area scenario are shown in Table 3.5. The Local Priority and Mega Project scenarios included significant expansion to the transmission system. The incremental path ratings associated with that expansion are described in Sections 3.2 and 3.3.

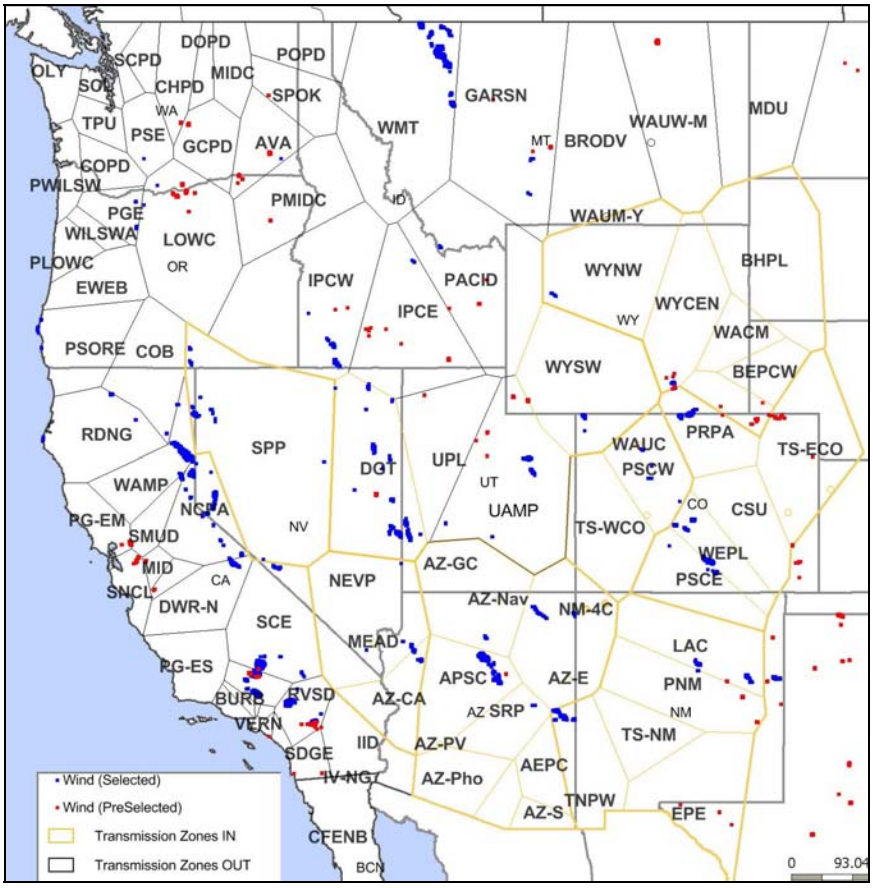


Figure 3.5 Map of Transmission Zones and Areas

Table 3.4 Transmission Zones and Areas

Transmission Area Name	Transmission Zone Name	Abbrev.	
Arizona	Arizona Electric Power Coop	AEPC	Within Study Footprint
	Arizona Public Service Co	APSC	
	Glen Canyon Area	AZ-GC	
	Salt River Project	SRP	
	Southern Arizona	AZ-S	
	Tucson Electric Power Co	TEP	
Colorado East	Sunflower Electric Power	CSUA	
	Colorado Springs Utilities	CSU	
	Platte River Power Authority	PRPA	
	Public Service of Colorado - East	PSCE	
	Tri-State G&T: in East CO	TS-ECO	
	WestPlains Energy Colorado	WEPL	
Colorado West	Public Service of Colorado - West	PSCW	
	Tri-State G&T: in West CO	TS-WCO	
New Mexico	Navajo Tribal Utility Authority	NAVTRUA	
	El Paso Electric	EPE	
	Los Alamos County	LAC	
	Public Service Co of New Mexico	PNM	
	Texas-New Mexico Power WECC	TNPW	
	Tri-State G&T: NM/Plains Electric	TS-NM	
	Southwestern Public Service Company	FARM	
Nevada	Sierra Pacific Power Co	SPP	
	Nevada Power Co	NEVP	
	Deseret G&T Cooperative	DGT	
Wyoming	PACE - Central Wyoming	WYCEN	
	PACE - Northwest Wyoming	WYNW	
	Tri-State G&T: in Wyoming	TRSTWYOA	
	WAPA - Colorado Missouri (Wyoming)	WACM	
	PACW - Soutwest Wyoming	WYSW	
COB	California-Oregon Border Area	COB	Rest of WECC
Idaho East	Idaho Power East	IPCE	
	PACE - Idaho	PACID	
Idaho West	Idaho Power West	IPCW	
Montana	Northwestern Energy - Broadview	BRODV	
	Northwestern Energy - Garrison	GARSN	
	WAPA - WAUW - MT North-Central	WAUW-M	
Northern California	Dept of Water Resources - North	DWR-N	
	Modesto Irrigation District	MID	
	Northern California Power Agency	NCPA	
	Pacific Gas & Electric - Main	PG-EM	
	Redding Electric Dept	RDNG	
	Sacramento Municipal Utilities District	SMUD	
	Santa Clara Electric Dept	SNCL	
	Turlock Irrigation District	TID	
	WAPA - Mid Pacific (CVP)	WAMP	
Northwest	Avista	AVA	
	BPA - Lower Columbia	LOWC	
	BPA - Olympia	OLY	
	BPA - Spokane	SPOK	
	BPA - Western Montana	WMT	
	Eugene Water and Electric Board	EWEB	
	PACW - Mid Columbia	PMIDC	
	PACW - Southern Oregon	PSORE	
	Portland General Electric	PGE	
	PUD No 1 of Chelan County	CHPD	
	PUD No 1 of Cowlitz County	COPD	
	PUD No 1 of Douglas County	DOPD	
	PUD No 1 of Pend Oreille County	POPD	
	PUD of Grant County	GCPD	
	Puget Sound Energy	PSE	
Southern California	Anaheim Public Utilities Dept.	ANHM	
	Dept of Water Resources - South	DWR-S	
	Riverside Utilities Dept	RVSD	
	Southern California Edison	SCE	
	San Diego Gas & Electric	SDGE	
	Imperial Irrigation District	IID	
	Los Angeles Dept of Water and Power	LDWP	
Utah	PACE - Utah	UPL	
	Utah Associated Municipal Power	UAMPA	
	Utah Municipal Power Agency	UMPAA	

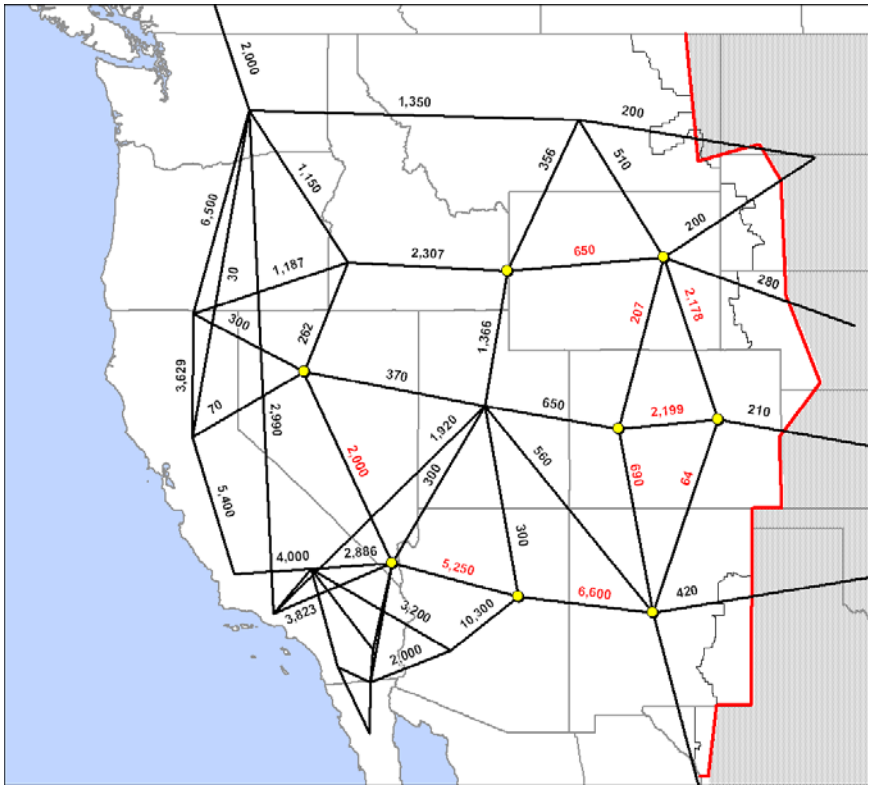


Figure 3.6 WECC Transmission Paths and Ratings.

Table 3.5 Selected WECC Transmission Path Ratings.

WECC Path	Rating (From-To, MW)	Rating (To-From, MW)
Arizona to Southern Nevada	5,250	5,250
Colorado East to New Mexico	64	1
Colorado East to Colorado West	2,199	1,468
Colorado West to New Mexico	690	690
New Mexico to Arizona	6,225	6,600
Northern Nevada to Southern Nevada	2,000	2,000
Wyoming to Colorado East	1,605	2,178
Wyoming to Colorado West	309	207

3.2 Development of Mega Project Scenario

The objective of the Mega Project scenario was to take advantage of the best wind and solar sites in the entire WestConnect footprint to meet the total renewable energy penetration targets of the region. Given that many of the highest capacity factor wind sites are in Wyoming, this scenario naturally includes a high concentration of wind

plants in Wyoming, with new transmission facilities to deliver the wind power to the large load centers in Arizona and Nevada.

The process to develop the Mega Project scenario started with the In Area scenario, which included the best wind and solar sites in each state. The concept was to swap less attractive local sites for more attractive remote sites. An algorithm was developed that displaced less attractive local sites in one area, making it a net importer, with the energy from higher-capacity sites in another area, making it a net exporter. Meanwhile, total renewable energy in the study footprint was held constant. The tradeoff of remote versus local sites accounted for the capital cost of generation equipment and transmission facilities, as well as the cost of transmission losses. The algorithm iterated towards a combination of resources that would meet the total renewable energy targets at minimum cost. The algorithm used the following assumptions and concepts:

- Capital cost for wind = $2000/kW
- Capital cost for PV = $4000/kW
- Capital cost for CSP plus storage = $4000/kW
- Existing transmission would not be used for new renewable energy. New transmission would be required to accommodate wind/solar generation. Given that all remote renewable generation sites would rarely be at maximum output simultaneously, the total transmission requirement was estimated to be 70% of the maximum possible wind and solar power transfer. Therefore, 0.7 MW of new transmission was added for each 1.0 MW of remote generation.
- New transmission was assumed to have a capital cost of $1600/MW-mi. With a 20% capital recovery factor, this translated to an annual carrying cost of $320/MW-mi-yr.
- Transmission losses on new intra-area facilities were assumed to be 1% per 100 miles, based on the distances between the center coordinates of the transmission areas.
- Transmission cost included a proxy for the cost of In Area transmission required to "collect" the energy from geographically diverse plants in exporting areas. A cost of 5% per 100 miles was applied to the distances from the plants to the center coordinates of the wind plants in the area.

Using this algorithm, the Mega Project scenario was developed to minimize the cost of generation equipment, new transmission, and losses. In addition to a list of wind and solar sites, the algorithm produced a set of inter-area transmission capacity requirements. These requirements were then manually adjusted to reflect practical constraints.

The transmission system developed by algorithm was rationalized using engineering judgment. Inter-area transfer requirements were rounded to match typical transmission line ratings; 1000 MW for 345 kV ac circuit, 1600 MW for 500 kV ac circuit, and 3600 MW for a 600 kV HVDC bipole were assumed. Inter-area transfer requirements that fell significantly below these MW values were ignored.

Similarly, wind plants were rationalized to multiples of 30 MW and solar plants were rationalized to multiples of 100 MW. This was necessary because of how the site-swapping algorithm worked. It maintained constant wind and solar energy in the study footprint. When the algorithm removed a less attractive 30 MW wind site in one area, it replaced it with a higher capacity factor site in another area, which meant adding a site smaller than 30 MW. Given this addition of fractional plants, it was necessary to round the final results into multiples of 30 MW wind sites and 100 MW solar sites.

Figure 3.7 shows a map of the Mega Project scenario. Table 3.6 summarizes the aggregated annual wind and solar energy for each area and Table 3.7 summarizes the aggregated wind and solar plant ratings. The red numbers on the map represent the total wind MW in each area. The change from the In Area scenario is shown in parentheses. Wyoming has a total of 13,770 MW of wind generation, and increase of 11,430 MW over the In Area scenario. Arizona has a total of 1,890 MW of wind generation, a decrease of 9,330 MW from the In Area scenario. It is economically advantageous for Arizona to import wind energy from Wyoming, since the higher capacity wind resources in Wyoming can more than compensate for the costs related to transmitting the energy to Arizona.

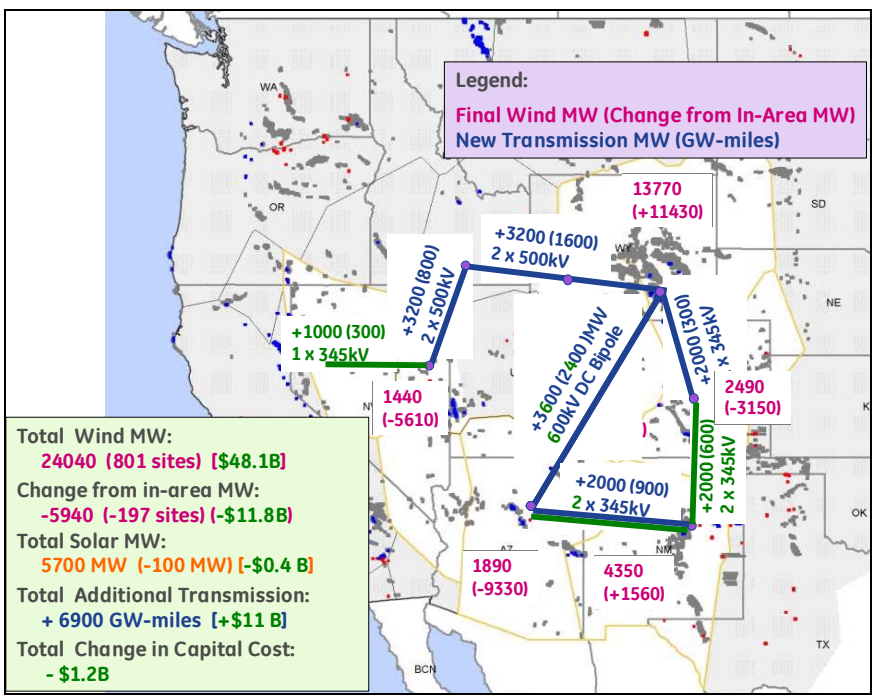


Figure 3.7 Map of Mega Project Scenario with Transmission Additions

Table 3.6 Energy Summary for 30% Mega Project Scenario

	Load	Wind		CSP with Storage		PV		Total Renewable	
Area	Energy (GWh)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	
Arizona	99,437	5,433	63 / 1091	5,503	15 / 38	1,690	11 / 16	12,626	
Colorado East	61,372	7,899	83 / 1673	1,639	5 / 58	1,035	7 / 13	10,573	
Colorado West	8,708	293	3 / 68	0	0 / 8	287	2 / 11	580	
New Mexico	31,260	14,921	145 / 3062	1,533	4 / 35	929	6 / 19	17,383	
Nevada	57,505	3,755	48 / 1591	1,457	4 / 45	320	2 / 10	5,532	
Wyoming	27,697	53,758	459 / 8912	0	0 / 0	142	1 / 10	53,900	
In Footprint	**285,979**	**86,059**	**801 / 16397**	**10,132**	**28 / 184**	**4,403**	**29 / 79**	**100,594**	**35.2 %**
	Load	Wind		CSP with Storage		PV		Total Renewable	
Area	Energy (GWh)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	
COB	1,759	394	6 / 155	294	1 / 22	142	1 / 2	830	
Idaho East	6,907	1,406	26 / 185	0	0 / 0	142	1 / 8	1,548	
Idaho Southwest	17,962	3,658	50 / 448	0	0 / 0	132	1 / 5	3,790	
Montana	14,143	2,873	35 / 1194	0	0 / 0	127	1 / 14	3,000	
Northern California	128,935	25,812	393 / 472	2,726	8 / 26	1,117	8 / 30	29,655	
Northwest	178,359	35,733	431 / 3195	0	0 / 0	1,645	13 / 54	37,378	
Southern California	224,197	44,890	483 / 1916	8,957	23 / 85	2,050	13 / 39	55,897	
Utah	38,022	7,658	91 / 554	937	3 / 24	303	2 / 14	8,898	
Out of Footprint	**610,284**	**122,424**	**1515 / 8119**	**12,914**	**35 / 157**	**5,658**	**40 / 166**	**140,996**	**23.1 %**
Total	**896,263**	**208,483**	**2316 / 24516**	**23,046**	**63 / 341**	**10,061**	**69 / 245**	**241,590**	**27.0 %**

Table 3.7 Power Summary for 30% Mega Project Scenario

	Load		Wind			CSP with Storage			PV			Total Renewable		
	Minimum	Maximum	Rating	Penetration		Rating	Penetration		Rating	Penetration		Rating	Penetration	
Area	(MW)	(MW)	(MW)	% Min	%Max	(MW)	% Min	% Max	(MW)	% Min	% Max	(MW)	% Min	% Max
Arizona	6,995	23,051	1,890	27%	8%	1,500	21%	7%	1,100	16%	5%	4,490	64%	19%
Colorado East	4,493	11,589	2,490	55%	21%	500	11%	4%	700	16%	6%	3,690	82%	32%
Colorado West	712	1,526	90	13%	6%	0	0%	0%	200	28%	13%	290	41%	19%
New Mexico	2,571	5,320	4,350	169%	82%	400	16%	8%	600	23%	11%	5,350	208%	101%
Nevada	3,863	12,584	1,440	37%	11%	400	10%	3%	200	5%	2%	2,040	53%	16%
Wyoming	2,369	4,016	13,770	581%	343%	0	0%	0%	100	4%	2%	13,870	586%	345%
In Footprint	**21,249**	**58,087**	**24,030**	**113%**	**41%**	**2,800**	**13%**	**5%**	**2,900**	**14%**	**5%**	**29,730**	**140%**	**51%**
	Load		Wind			CSP with Storage			PV			Total Renewable		
	Minimum	Maximum	Rating	Penetration		Rating	Penetration		Rating	Penetration		Rating	Penetration	
Area	(MW)	(MW)	(MW)	% Min	%Max	(MW)	% Min	% Max	(MW)	% Min	% Max	(MW)	% Min	% Max
COB	138	294	180	131%	61%	100	73%	34%	100	73%	34%	380	276%	129%
Idaho East	460	1,365	780	170%	57%	0	0%	0%	100	22%	7%	880	191%	64%
Idaho Southwest	1,188	3,592	1,500	126%	42%	0	0%	0%	100	8%	3%	1,600	135%	45%
Montana	1,149	2,337	1,050	91%	45%	0	0%	0%	100	9%	4%	1,150	100%	49%
Northern California	10,297	28,319	11,790	114%	42%	800	8%	3%	800	8%	3%	13,390	130%	47%
Northwest	14,278	30,953	12,930	91%	42%	0	0%	0%	1,300	9%	4%	14,230	100%	46%
Southern California	9,557	26,864	14,490	152%	54%	2,300	24%	9%	1,300	14%	5%	18,090	189%	67%
Utah	2,263	7,274	2,730	121%	38%	300	13%	4%	200	9%	3%	3,230	143%	44%
Out of Footprint	**46,328**	**119,696**	**45,450**	**98%**	**38%**	**3,500**	**8%**	**3%**	**4,000**	**9%**	**3%**	**52,950**	**114%**	**44%**
Total	**67,577**	**177,783**	**69,480**	**103%**	**39%**	**6,300**	**9%**	**4%**	**6,900**	**10%**	**4%**	**82,680**	**122%**	**47%**

3.3 Development of Local Priority Scenario

The Local Priority scenario was developed from the In Area scenario using the same algorithm and assumptions as for the Mega Project scenario. The only difference was that the capital cost of In Area wind and solar generation was assumed to be 10% lower

than for remote wind and solar sites in other areas. This served as a proxy for local incentive programs that would produce local social benefits such as jobs and tax revenue.

Figure 3.8 shows a map of the Local Priority scenario. Aggregated wind and solar generation energy and MW ratings for each area are shown in Table 3.8 and Table 3.9.

The distribution of wind and solar resources in the Local Priority scenario is about half-way between the In Area scenario and the Mega Project scenario. Of the three major scenarios in this study, the project team considers this to be the most realistic. It seems likely that states will want to produce a significant portion of their required renewable energy locally. But given the extraordinary quality of the wind resources in Wyoming and a few other locations, it seems likely that some renewable energy will be exported to other states.

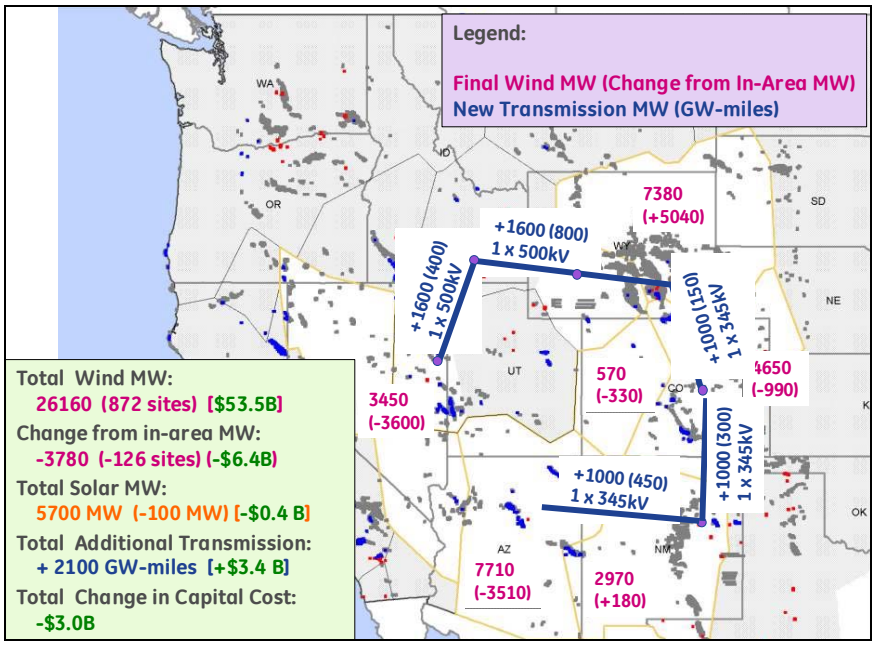


Figure 3.8 Map of Local Priority Scenario with Transmission Additions

Other power and energy summary tables for 10% and 20% penetration levels are included in Appendix A.

Table 3.8 Energy Summary for 30% Local Priority Scenario

	Load	Wind		CSP with Storage		PV		Total Renewable	
Area	Energy (GWh)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	
Arizona	99,437	21,138	257 / 1091	3,735	10 / 38	1,548	10 / 16	26,421	
Colorado East	61,372	15,320	155 / 1673	2,252	7 / 58	1,038	7 / 13	18,610	
Colorado West	8,708	1,736	19 / 68	564	2 / 8	151	1 / 11	2,451	
New Mexico	31,260	10,047	99 / 3062	1,421	4 / 35	473	3 / 19	11,941	
Nevada	57,505	9,101	115 / 1591	2,161	6 / 45	773	5 / 10	12,035	
Wyoming	27,697	28,716	247 / 8912	0	0 / 0	420	3 / 10	29,136	
In Footprint	**285,979**	**86,058**	**892 / 16397**	**10,133**	**29 / 184**	**4,403**	**29 / 79**	**100,594**	**35.2 %**

	Load	Wind		CSP with Storage		PV		Total Renewable	
Area	Energy (GWh)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	# Sites (Used/Available)	Energy (GWh)	
COB	1,759	394	6 / 155	294	1 / 22	142	1 / 2	830	
Idaho East	6,907	1,406	26 / 185	0	0 / 0	142	1 / 8	1,548	
Idaho Southwest	17,962	3,658	50 / 448	0	0 / 0	132	1 / 5	3,790	
Montana	14,143	2,873	35 / 1194	0	0 / 0	127	1 / 14	3,000	
Northern California	128,935	25,812	393 / 472	2,726	8 / 26	1,117	8 / 30	29,655	
Northwest	178,359	35,733	431 / 3195	0	0 / 0	1,645	13 / 54	37,378	
Southern California	224,197	44,890	483 / 1916	8,957	23 / 85	2,050	13 / 39	55,897	
Utah	38,022	7,658	91 / 554	937	3 / 24	303	2 / 14	8,898	
Out of Footprint	**610,284**	**122,424**	**1515 / 8119**	**12,914**	**35 / 157**	**5,658**	**40 / 166**	**140,996**	**23.1 %**

Table 3.9 Power Summary for 30% Local Priority Scenario

	Load		Wind			CSP with Storage			PV			Total Renewable		
	Minimum	Maximum	Rating	Penetration		Rating	Penetration		Rating	Penetration		Rating	Penetration	
Area	(MW)	(MW)	(MW)	% Min	%Max	(MW)	% Min	% Max	(MW)	% Min	% Max	(MW)	% Min	% Max
Arizona	6,995	23,051	7,710	110%	33%	1,000	14%	4%	1,000	14%	4%	9,710	139%	42%
Colorado East	4,493	11,589	4,650	103%	40%	700	16%	6%	700	16%	6%	6,050	135%	52%
Colorado West	712	1,526	570	80%	37%	200	28%	13%	100	14%	7%	870	122%	57%
New Mexico	2,571	5,320	2,970	116%	56%	400	16%	8%	300	12%	6%	3,670	143%	69%
Nevada	3,863	12,584	3,450	89%	27%	600	16%	5%	500	13%	4%	4,550	118%	36%
Wyoming	2,369	4,016	7,410	313%	184%	0	0%	0%	300	13%	7%	7,710	325%	192%
In Footprint	**21,249**	**58,087**	**26,760**	**126%**	**46%**	**2,900**	**14%**	**5%**	**2,900**	**14%**	**5%**	**32,560**	**153%**	**56%**

	Load		Wind			CSP with Storage			PV			Total Renewable		
	Minimum	Maximum	Rating	Penetration		Rating	Penetration		Rating	Penetration		Rating	Penetration	
Area	(MW)	(MW)	(MW)	% Min	%Max	(MW)	% Min	% Max	(MW)	% Min	% Max	(MW)	% Min	% Max
COB	138	294	180	131%	61%	100	73%	34%	100	73%	34%	380	276%	129%
Idaho East	460	1,365	780	170%	57%	0	0%	0%	100	22%	7%	880	191%	64%
Idaho Southwest	1,188	3,592	1,500	126%	42%	0	0%	0%	100	8%	3%	1,600	135%	45%
Montana	1,149	2,337	1,050	91%	45%	0	0%	0%	100	9%	4%	1,150	100%	49%
Northern California	10,297	28,319	11,790	114%	42%	800	8%	3%	800	8%	3%	13,390	130%	47%
Northwest	14,278	30,953	12,930	91%	42%	0	0%	0%	1,300	9%	4%	14,230	100%	46%
Southern California	9,557	26,864	14,490	152%	54%	2,300	24%	9%	1,300	14%	5%	18,090	189%	67%
Utah	2,263	7,274	2,730	121%	38%	300	13%	4%	200	9%	3%	3,230	143%	44%
Out of Footprint	**46,328**	**119,696**	**45,450**	**98%**	**38%**	**3,500**	**8%**	**3%**	**4,000**	**9%**	**3%**	**52,950**	**114%**	**44%**

4 Statistical Analysis: Seasonal Monthly, Daily Trends

One undeniable constant of power systems operation is that load is always changing – second-to-second, minute-to-minute, hourly, seasonally and yearly. The variability of load (or the degree to which it changes) is dependent on a wide range of factors, not the least among them being human behavior. The key goal of power systems operation is to maintain the crucial balance between system load and dispatchable generation.

As the amount of variable resources like wind and solar generation increases on the system, the balancing act becomes more intricate. Because they are not considered "firm" generation, wind and solar output contribute to the "net load"[1] seen by the balance of generation. As such, they increase the variability of the system load and consequently the ramp and range requirements for units committed to meet the load.

The goal of this chapter is to statistically characterize the hourly variability of the load, wind, solar, and net load in individual states/transmission areas, the study footprint, and WECC. The analysis will begin with an overall examination of broad trends and progressively delve into the nuances and implications of period-to-period changes.

As discussed earlier in Chapter 2, there is a tremendous amount of data available for analysis. The breakdown from a statistical point-of-view is as follows

- Three data years (2004, 2005, 2006)
- 14 transmission areas (6 in study footprint, 8 outside) comprising 108 load zones
- Four penetration levels (baseline, 10%, 20%, 30%)
- Three study scenarios (In Area, Local Priority, Mega Project)

These cases taken together lead to 504 unique combinations that could potentially be analyzed. This is shown graphically in Figure 4.1 below. For example, a plot of the average daily load, wind and solar profiles for year 2006 in Arizona for the 30% penetration level in the LP scenario may be interesting, but is only one of 504 such plots that convey similar information for other years, states, penetration levels and scenarios. Since it would be prohibitive to present this level of detail, the chapter focuses on meaningful representative samples of the analyses. Most often (though not always), the statistical characterization is illustrated using 2006 data, the LP scenario, 30% penetration level and the in-footprint states (blue path in Figure 4.1). The reasons for this are discussed throughout the chapter. Other illustrative charts and data are included in the appendices. However, even the appendix material is selected to give a broad

[1] Net load is defined as the instantaneous system load, minus the generation output of non-dispatchable wind and solar generation (Load-Wind-Solar), i.e. net load is the amount of generation required from dispatchable units.

overview of the work, as opposed to exhaustive detail of every chart and graph produced in the study.

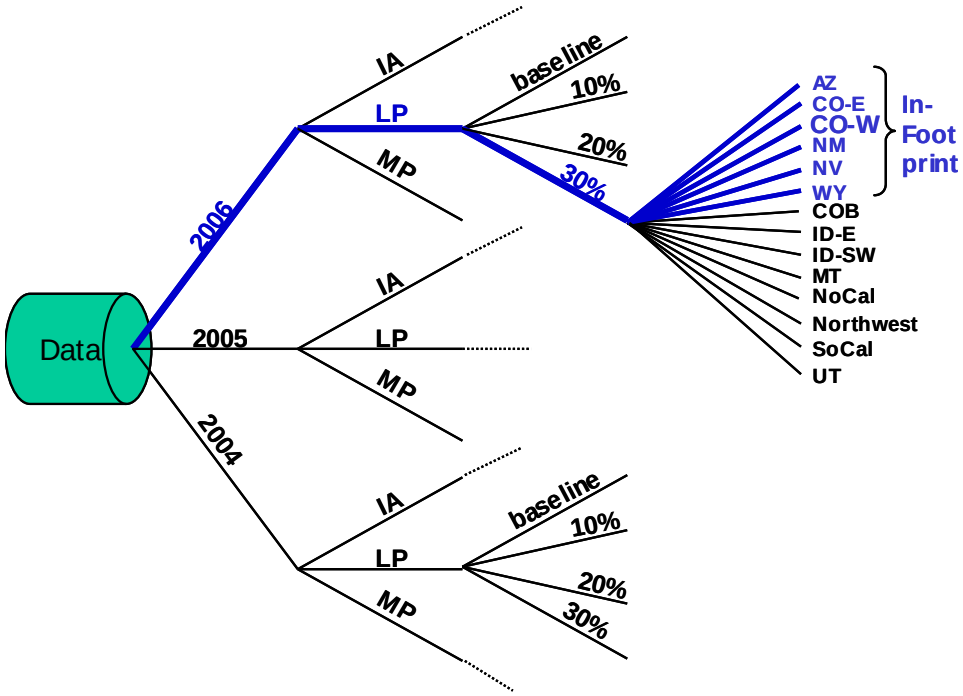


Figure 4.1 Graphical Representation of Statistical Study Permutations and Most Often Used Path

4.1 Monthly Energy from Wind and Solar

As discussed Chapter 3, The wind and solar sites were selected within the WECC region to produce the 10%, 20%, and 30% penetration levels under the three scenarios IA, LP and MP. Table 4.1 describes the wind and solar combinations for the penetration levels. For the 30% penetration level under the IA scenario, wind sites are selected such that the aggregate name-plate wind can supply on average 30% of the annual load energy inside the footprint and 20% of the annual load energy outside the footprint. Similarly CSP and PV sites are chosen to supply 5% of the annual load energy inside the footprint and 3% outside.

However, due to the variable nature of the wind and solar resources, one would not expect that they would meet 35% of the load energy at all times. A key question examined is this section is, what is the monthly/seasonal and yearly variation of wind and solar energy within footprint and across states/areas, and how closely does it correspond to the expectation in Table 4.1?

Table 4.1 Wind and Solar[2] Combinations for Various Penetration Levels

Penetration Level	Wind and Solar Energy (% of Load)
30%	30% Wind, 5% Solar In Footprint 20% Wind, 3% Solar Out of Footprint
20%	20% Wind, 3% Solar In Footprint 10% Wind, 1% Solar Out of Footprint
10%	10% Wind, 1% Solar In Footprint 10% Wind, 1% Solar Out of Footprint

4.1.1 Year-to-Year Comparison

Earlier in Chapter 3, wind and solar site selection was discussed, and Table 3.1 listed the annual wind energy by state in 2004, 2005 and 2006 for the 30% In-Area scenario. At the footprint level, the total annual wind and solar energy only varies slightly between years, but more variation is expected at higher spatial and temporal resolutions.

Figure 4.2 shows the study footprint monthly energy from wind and solar for 2004, 2005, and 2006 wind shapes in GWh. Figure 4.3 plots the monthly energy as a percentage of load energy in the month. In both plots the green sections of each bar indicate monthly energy from wind, the orange sections indicate monthly energy from CSP, and the magenta sections indicate monthly energy from PV. The height of the bar gives the total renewable energy for each month of the year. For illustration, the 30% penetration level for the In-Area scenario is shown. Similar plots for the other penetration levels and scenarios are included in Appendix B.

The data in the plots above (and Table 4.2 two pages over) and clearly indicate two salient points (1) there is significant year-to-year variation in the total monthly energies, and (2) *30% is not always 30%*!

On the first point, overall, there is 5% more wind and solar energy in 2006 than 2004, but the seasonal differences are even more evident. During winter and early spring there is over 30% more energy from 2006 wind and solar than for the same period in 2004. Conversely, in the late spring to summer period there is over 20% more wind and solar energy in 2004 than 2006. The highest monthly total energy (11,651 GWh) is recorded in March 2006, and the lowest (5,022 GWh) occurs in August 2006. The 2006 data posses much more dynamic range and deviation than other years, which makes 2006 a good year to illustrate the statistical variability.

On the second point, Figure 4.3 clearly shows the seasonal characteristic of the wind and solar energy and highlights its relationship to the load variation (this will be explored

[2] Solar mix is 70% concentrating solar plant with storage (CSP w/s) and 30% photo-voltaic (PV)

further in Section 4.3. Over each year, wind energy is 30% of the load, and solar energy is 5%, but the monthly penetration varies significantly from season to season regardless of the year. For example, in March and April 2006, wind and solar combine to meet 55% of the load, but in July and August 2006, they combine to meet just 17%. This is partially because the study footprint load is higher in summer than the fall, but also the wind energy content tends to be more in the spring months and less in the summer (reverse for solar). Later sections in this chapter will delve deeper into the load-wind coincidence and the potential operational issues, particularly during low load, high wind hours.

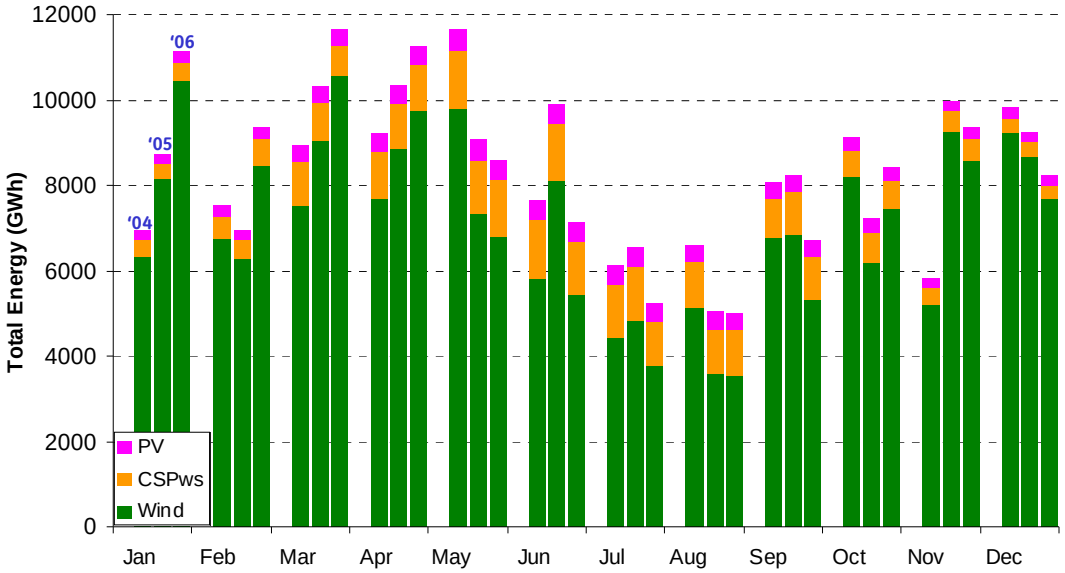


Figure 4.2 Total In-Footprint Monthly Energy from Wind and Solar for 2004 – 2006 (30% In Area Scenario)

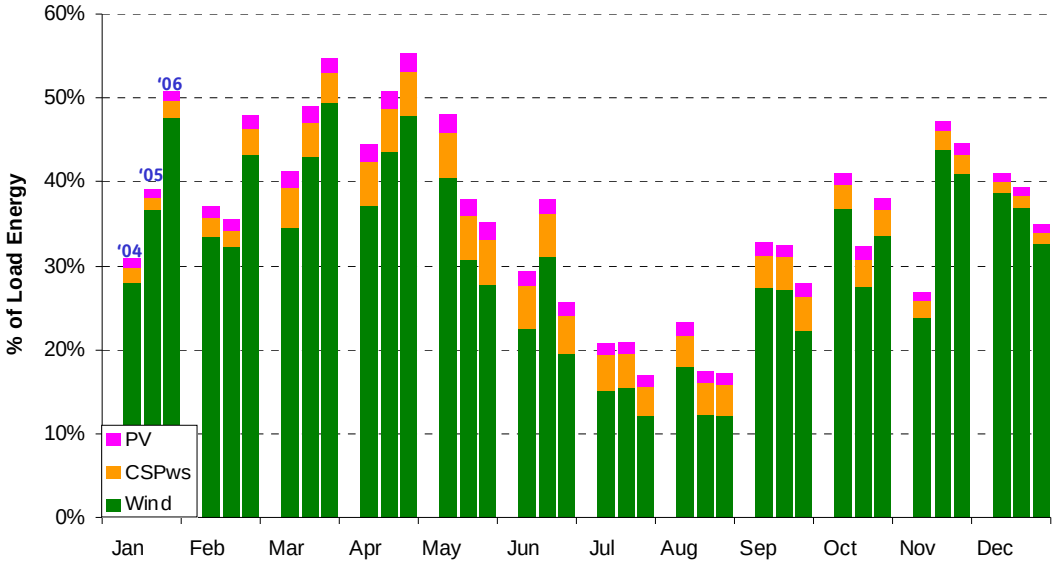


Figure 4.3 Total In-Footprint Monthly Energy from Wind and Solar for 2004 – 2006 (30% In Area Scenario)

Table 4.2, summarizes the monthly energies for individual states in the study footprint and the total footprint. This data supports the two salient points made earlier discussion. Within each area, there is significant year-to-year variation in the total monthly energies, and in some months, the energy penetration in certain states is well over 30%. The second point is discussed further in Section 4.1.3.

Table 4.2 Monthly Energy Summary for 2004, 2005, and 2006, 30% In Area Scenario

2004 GWh												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZ	1,779	2,681	2,637	3,638	4,273	2,812	2,020	2,207	3,023	3,519	2,356	2,890
CE	1,891	1,590	2,194	1,708	2,489	1,510	1,284	1,401	1,781	1,850	1,199	2,413
CW	227	208	338	284	433	280	236	231	278	283	132	328
NM	888	895	1,061	1,011	1,191	829	654	773	978	963	668	1,058
NV	1,204	1,570	1,767	1,945	2,302	1,601	1,404	1,496	1,430	1,876	986	2,046
WY	981	602	953	637	955	609	528	513	592	640	485	1,072
FP	6,970	7,546	8,951	9,222	11,643	7,641	6,127	6,620	8,082	9,131	5,827	9,807
2005 GWh												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZ	2,977	2,810	4,055	4,083	3,510	3,810	2,441	1,574	3,080	2,642	3,268	2,376
CE	1,938	1,512	2,002	2,085	1,873	1,901	1,294	1,112	1,654	1,505	2,414	2,569
CW	250	217	307	321	329	339	229	196	301	228	325	351
NM	1,103	754	1,127	1,139	956	1,017	788	586	926	884	1,099	999
NV	1,556	1,083	1,995	2,036	1,748	2,188	1,345	1,069	1,656	1,359	1,724	1,751
WY	914	589	853	683	673	663	477	500	601	590	1,168	1,186
FP	8,737	6,964	10,339	10,347	9,088	9,917	6,574	5,037	8,217	7,208	9,997	9,232
2006 GWh												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZ	3,657	2,890	4,629	4,213	3,261	2,440	1,723	1,568	2,234	2,988	2,816	2,430
CE	2,491	2,401	2,208	2,236	1,761	1,500	1,047	823	1,514	1,917	2,083	2,018
CW	340	340	323	396	288	273	167	166	225	271	311	255
NM	1,156	994	1,269	1,198	853	802	721	566	860	1,023	1,052	933
NV	2,325	1,657	2,485	2,461	1,739	1,602	1,237	1,528	1,279	1,415	2,099	1,670
WY	1,167	1,087	736	765	690	544	358	371	588	814	991	916
FP	11,135	9,370	11,651	11,269	8,592	7,162	5,253	5,022	6,700	8,429	9,352	8,222

4.1.2 Scenario Comparison

For the three study scenarios, suitable wind and solar sites were selected based on a number of factors, as discussed in Chapter 3. The distribution of the sites, capacity factor, and diversity are distinct enough to impact the overall energy profile. Figure 4.4 and Figure 4.5 plot the footprint total and percent monthly energy from wind and solar for the three scenarios, in 2006 for 30% penetration.

From a total and percent energy viewpoint, there is a much greater difference from month to month than from scenario to scenario. In fact, it's safe to say that there is relatively little difference among scenarios at this resolution. Having said that, the Mega Project scenario exhibits slightly more dynamic range over the year, with 58% energy from wind and solar in January, and 14% in July.

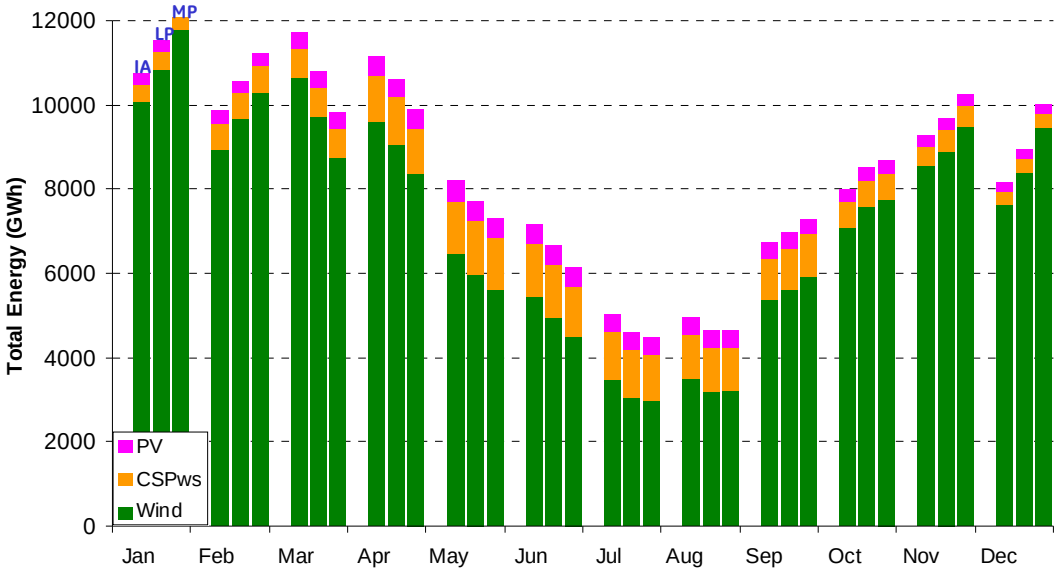


Figure 4.4 2006 Total In-Footprint Monthly Energy from Wind and Solar for all Scenarios (30% Penetration)

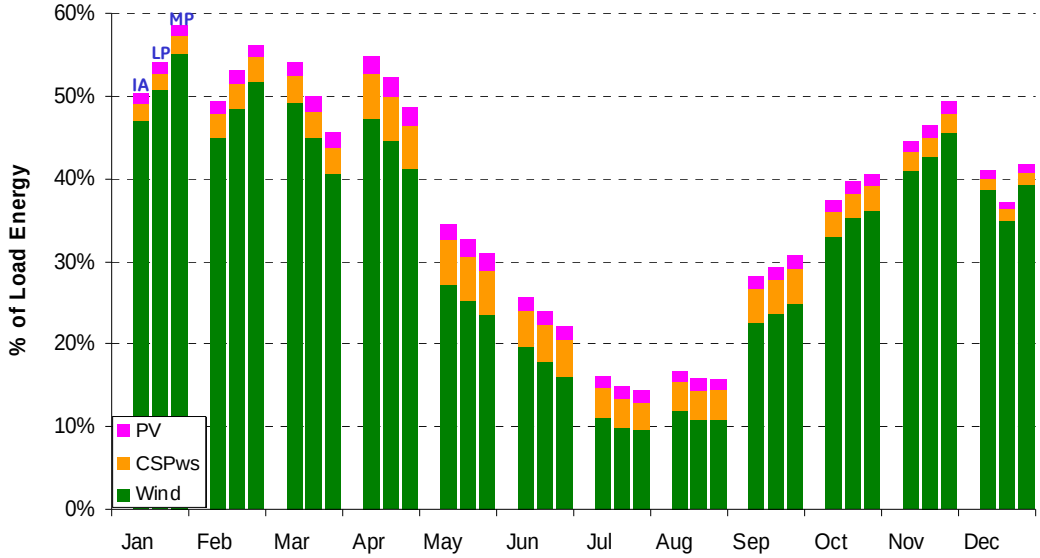


Figure 4.5 2006 Percent In-Footprint Monthly Energy from Wind and Solar for all Scenarios (30% Penetration)

4.1.3 State-by-State Comparison

The monthly energy at the footprint level tends to obscure some interesting differences among the states, due to size variances. Chapter 3 summarized the wind and solar energy in each state for the three scenarios. Figure 4.6 and Figure 4.7 plot the total monthly energy in Arizona and Wyoming for the 30% Local Priority scenario. The numbers above the bars indicate the renewable energy as a percent of the state load energy.

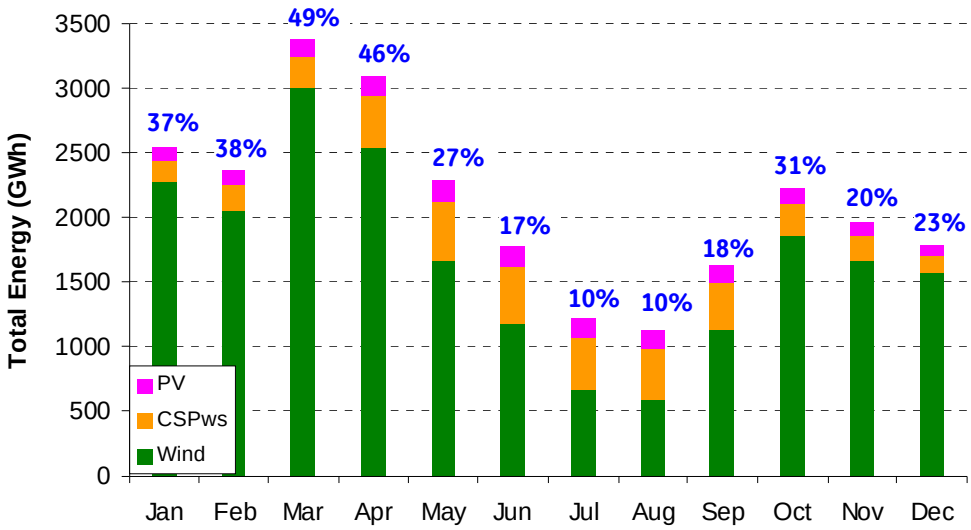


Figure 4.6 2006 Arizona Total and Percent Monthly Energy from Wind and Solar (30% LP Scenario)

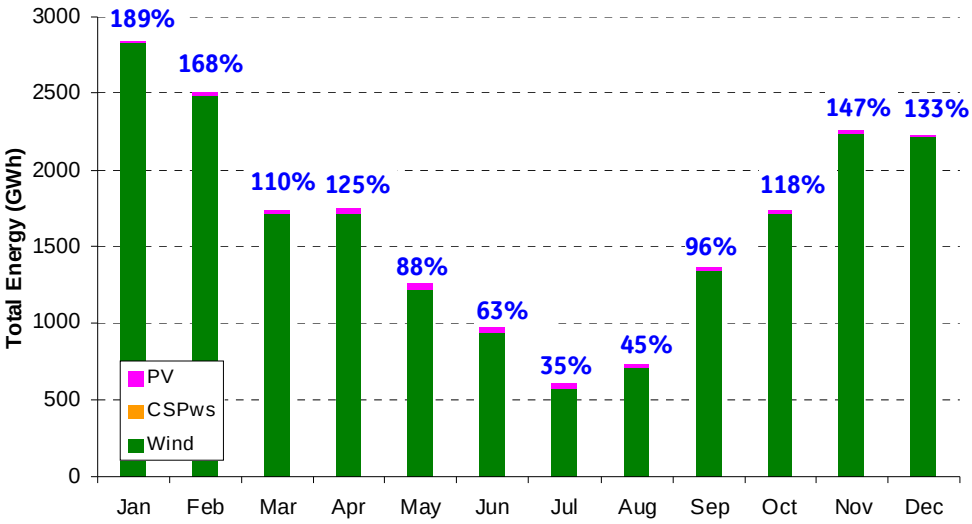


Figure 4.7 2006 Wyoming Total and Percent Monthly Energy from Wind and Solar (30% LP Scenario)

These two states are chosen for illustration because they have just about the same amount of installed wind capacity but are polar opposites with regard to the size of the load and the quality of wind and solar resources. As expected, the seasonal patterns observed at the footprint level are evident at the state level, but there is a dramatic difference in the monthly energy penetration. During the fall and winter months, wind and solar energy is well over 100% of Wyoming's load energy, reaching almost 200% in January. Similar wind capacity in Arizona, gives a high penetration value of less than 50% in March. This highlights the fact that a large amount of wind in a small area could lead to challenging operational issues, but larger balancing areas can better accommodate high wind penetration. This point is emphasized even more clearly by the data in Table 4.3. The table summarizes the percent monthly energy from wind and

solar for individual states in the study footprint, the total study area, and all of WECC. The areas are arranged in order of increasing size (load) from left to right.

Table 4.3 Summary of 2006 Percent Monthly Energy from Wind and Solar (30% Wind Energy in Footprint)

IA Scenario

	CO-W	WY	NM	CO-E	NV	Ariz	FP	WECC
Jan	47%	52%	45%	50%	54%	50%	50%	37%
Feb	53%	50%	44%	51%	48%	50%	49%	34%
Mar	47%	33%	53%	45%	60%	66%	54%	37%
Apr	62%	37%	51%	51%	60%	61%	55%	37%
May	40%	31%	33%	35%	34%	36%	35%	29%
Jun	36%	24%	27%	27%	30%	22%	26%	22%
Jul	18%	14%	24%	17%	17%	13%	16%	16%
Aug	20%	16%	20%	14%	24%	13%	17%	17%
Sep	35%	30%	35%	34%	27%	23%	28%	22%
Oct	40%	34%	42%	38%	31%	40%	37%	27%
Nov	47%	43%	41%	43%	57%	40%	45%	32%
Dec	33%	36%	34%	36%	35%	31%	34%	25%

LP Scenario

	CO-W	WY	NM	CO-E	NV	Ariz	FP	WECC
Jan	34%	189%	48%	42%	30%	37%	54%	38%
Feb	38%	168%	47%	44%	28%	38%	53%	35%
Mar	33%	110%	56%	38%	31%	49%	50%	35%
Apr	45%	125%	54%	43%	35%	46%	52%	36%
May	30%	88%	35%	30%	21%	27%	33%	28%
Jun	28%	63%	28%	24%	19%	17%	24%	22%
Jul	14%	35%	25%	15%	10%	10%	15%	15%
Aug	16%	45%	21%	13%	14%	10%	16%	16%
Sep	27%	96%	37%	29%	17%	18%	29%	22%
Oct	29%	118%	45%	33%	21%	31%	40%	27%
Nov	35%	147%	44%	37%	32%	30%	46%	33%
Dec	23%	133%	36%	30%	20%	23%	37%	26%

MP Scenario

	CO-W	WY	NM	CO-E	NV	Ariz	FP	WECC
Jan	8%	481%	73%	23%	12%	14%	59%	39%
Feb	9%	433%	71%	24%	13%	16%	56%	36%
Mar	8%	410%	82%	21%	13%	19%	46%	34%
Apr	11%	433%	78%	24%	16%	21%	49%	35%
May	8%	280%	49%	17%	10%	15%	31%	28%
Jun	7%	216%	39%	14%	9%	11%	22%	21%
Jul	4%	121%	33%	10%	5%	8%	14%	15%
Aug	4%	131%	29%	9%	7%	8%	16%	16%
Sep	7%	265%	53%	18%	8%	11%	31%	23%
Oct	7%	345%	64%	19%	10%	13%	41%	27%
Nov	8%	388%	67%	19%	13%	13%	49%	34%
Dec	6%	334%	60%	17%	8%	9%	42%	28%

In the Mega Project scenario, most of the wind capacity inside the study footprint is installed in Wyoming and New Mexico (13,770 MW and 4,350 MW respectively). This leads to large penetration levels in the winter and spring months, as shown in the bottom section of Table 4.3. In January, wind and solar energy is 481% of Wyoming's load energy. However, the penetration on a footprint-wide basis is 59% and 39% on a WECC-wide basis. Again, this reinforces the argument that balancing over a wider area would mitigate some of the variability issues that lead to operation difficulties. The next section uses duration plots to more closely examine some of these high wind, low load periods.

4.2 Yearly Duration Trends

The ability of the system to accommodate net load variations is in large part a function of the absolute net load level. Since system maneuverability tends to increase with the generation level, and vice versa, the generation mix is more flexible at high load hours and less flexible at low load hours. Past studies have shown, that during the hours when load is lowest, there tends to be more wind energy, which could lead to minimum load issues at high wind penetration levels. This section will examine the duration of wind and solar over the year and the correlation of net load variability with load levels throughout the year. For clarity and brevity, most of the charts and discussion will focus on year 2006, the 30% penetration level, the study footprint and a few selected states. Information on other years, penetration levels and states are included in Appendix B.

4.2.1 Wind Duration

Figure 4.8 below shows the 2006 wind duration plots for all three scenarios at the 30% penetration level. Each division on the x-axis represents deciles, or 10% of the yearly hours (876 hours). The highest instantaneous penetration achieved in the year is listed in the inset box.

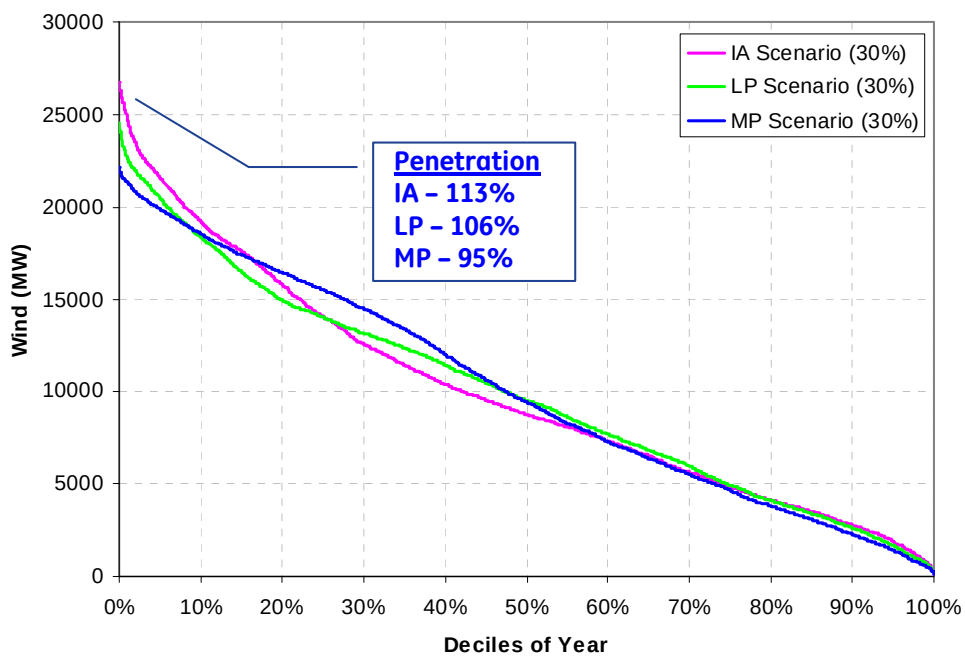


Figure 4.8 2006 Study Footprint Wind Duration Plots for all Three Scenarios (30% Penetration)

Not surprisingly, of the three, the In-Area scenario has the highest instantaneous penetration. There are 24 hours with over 100% instantaneous penetration, versus 5 hours for the LP scenario and none for the MP. This is due to the fact that the IA scenario has more installed capacity than the other scenarios. However, it tends to drop more

steeply than the others because the overall energy content of the wind resource is not as good as the other scenarios.

This is more clearly shown in Figure 4.9, which plots the same traces normalized as a percent of nameplate wind. It is clear that there is a distinct separation of traces due to difference in quality of wind resources. The IA scenario trace drops quite a bit faster than the MP trace, because there are more hours in the year when the wind output is high in the MP scenario. The MP wind is at or above 50% of nameplate capacity for 40% of the year, or 3504 hours. By comparison, the IA wind is at or above 50% of nameplate capacity for only 22% of the year, or 1927 hours. The LP scenario, as expected, is somewhere in between the IA and MP. On the flipside, all three scenarios exhibit similar characteristics at the low end. IA, LP and MP wind are less than 10% of nameplate capacity for approximately 10% of the yearly hours. Both Figure 4.8 and Figure 4.9 highlight the fact that the real difference between the three wind scenarios is at the mid-range to high wind levels.

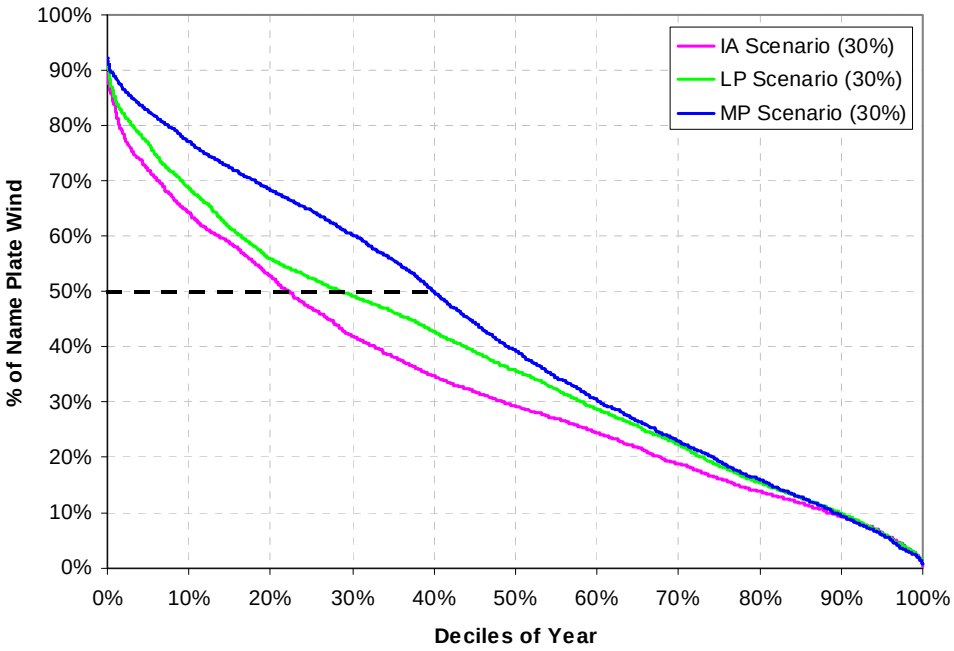


Figure 4.9 2006 Study Footprint Wind Duration Plots Normalized as % of Nameplate Wind

As pointed out in Chapter 3, the wind profiles for the 20% and 30% penetration levels were created by adding new sites to the 10% profile. For the each of the three scenarios, the 10% profiles generally contain the best available sites in terms of energy content. For the 20% and 30% profiles, the next *best* sites are added, subject to the rules of the site selection algorithm for the particular scenario.

The differences between the 10%, 20% and 30% penetration profiles for the Local Priority scenario are shown by the yearly duration plots in Figure 4.10. Each division on the x-axis represents deciles, or 10% of the yearly hours (876 hours).

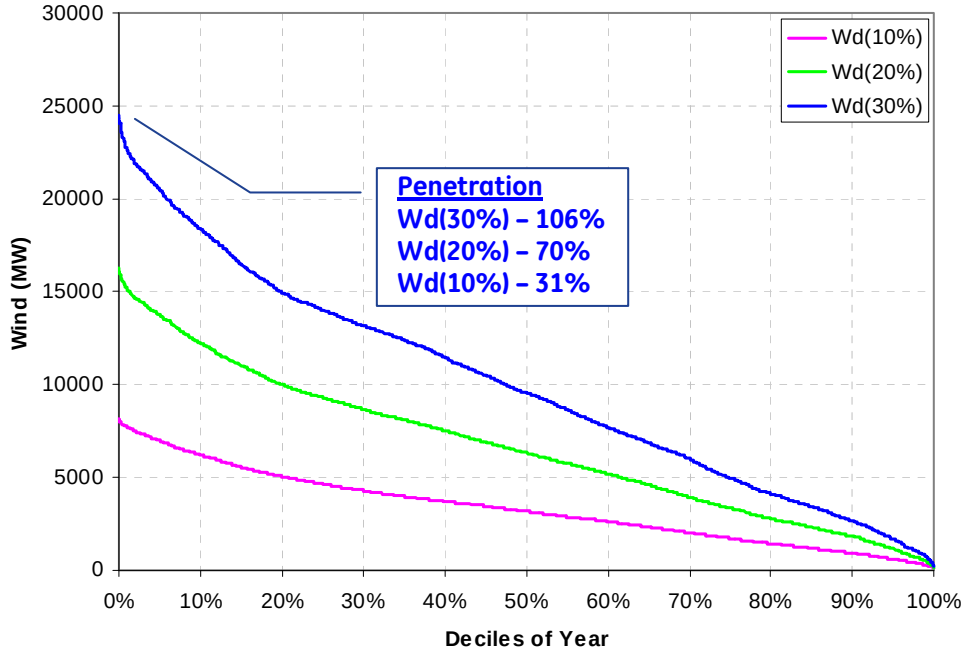


Figure 4.10 2006 Study Footprint Wind Duration Plots for all Three Penetration Levels (LP Scenario)

The data underscore the fact that high instantaneous wind penetrations can be achieved during the year even for the lowest energy penetration level. Figure 4.11 shows the duration plots normalized as a percent of nameplate wind capacity. The difference between the traces is small but nevertheless observable. The 10% profile is at or above 50% capacity for 22% of the year, while the 30% profile is at or above 50% capacity for 30% of the year.

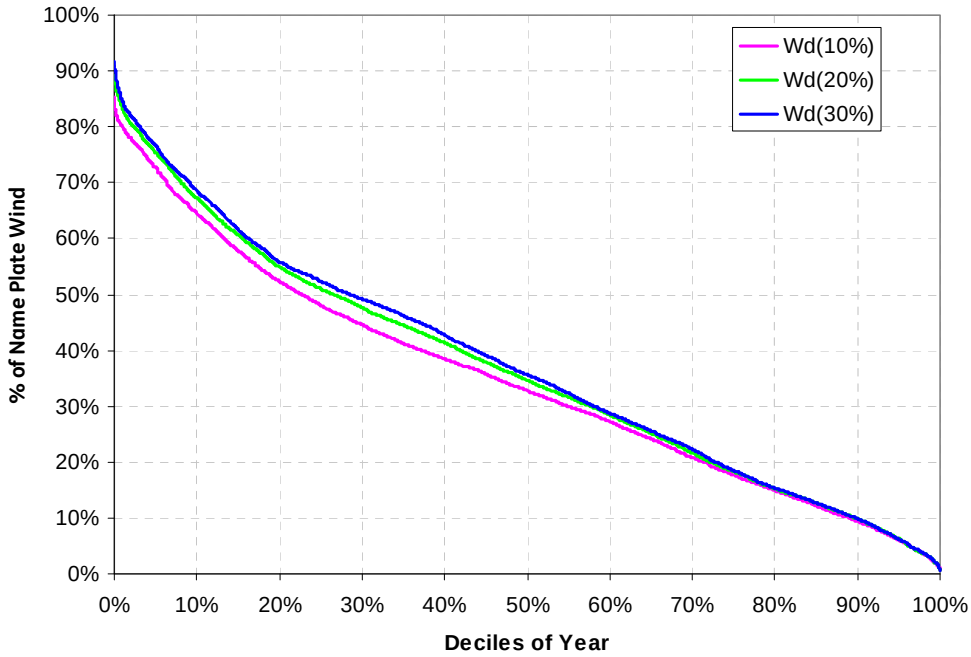


Figure 4.11 2006 Study Footprint Wind Duration Plots Normalized as % of Nameplate Wind

At the state/area level, one would expect the difference between individual wind profiles to be significant for all three scenarios. Figure 4.12 plots the 2006 wind duration curves for all states/areas in the footprint for the 30% Local Priority scenario. Figure 4.13 shows the same traces normalized as a percentage of the installed wind capacity in the area. The highest instantaneous penetration achieved in the year is listed in the inset box on Figure 4.12.

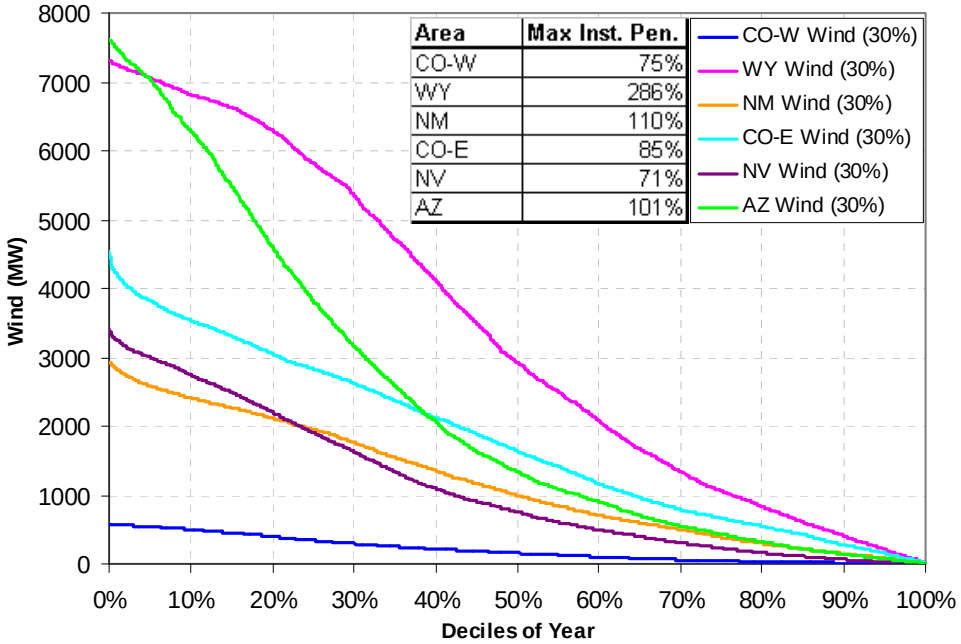


Figure 4.12 2006 In-Footprint Area Wind Duration Plots for the 30% LP Scenario

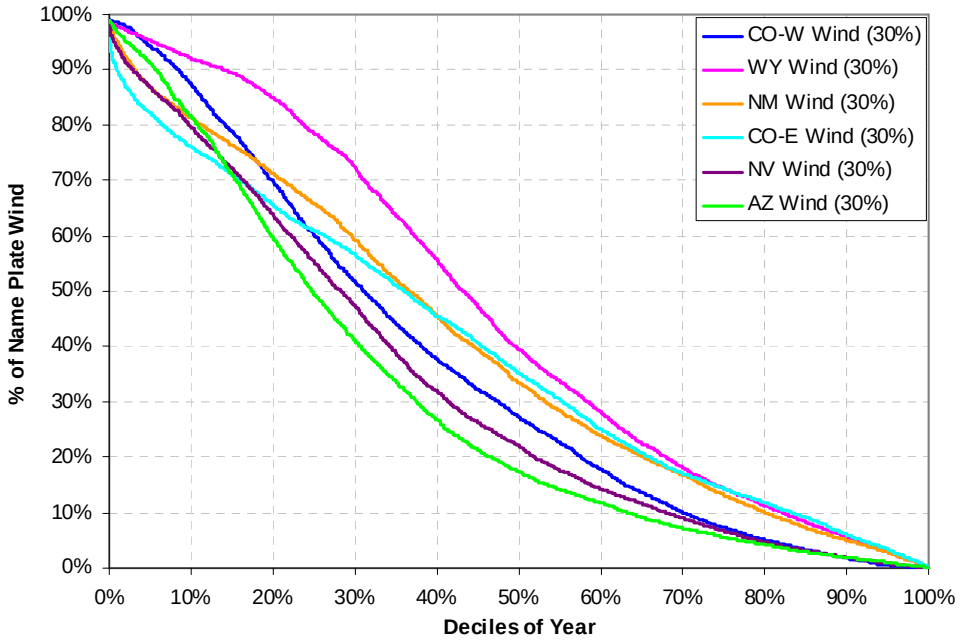


Figure 4.13 2006 In-Footprint Area Wind Duration Plots Normalized as % of Nameplate Wind

Recall that for the Local Priority scenario, Arizona and Wyoming have the largest installed base of wind while Colorado West and New Mexico have the least. On Figure 4.12 , the states/areas are arranged by load size (smallest to largest) in the legend. It is fairly obvious why Wyoming (with big wind and small load) would have very high instantaneous wind penetration (286%) during the year, while Arizona (big wind and big load), does not rise to this penetration level – though it's still very high at 101%. On the other hand Colorado West, despite the relatively small installed wind capacity, still has a fairly high instantaneous penetration due to the small load in the area.

The slope of the traces, especially in Figure 4.13, gives some insight into the quality of installed wind in each area for the LP scenario. Generally, the flatter the trace, the higher quality the wind resource. In Figure 4.13, Arizona has the steepest trace, while Wyoming has the flattest, confirming what we already know about the quality of the wind in these states for the LP scenario. The most curious trace is Colorado East which is fairly steep in the first decile, but flattens out considerably for other deciles – meaning wind in Colorado-East spends more time in 20% to 80% of nameplate range, than wind in other areas.

4.2.2 Solar Duration

Figure 4.14 shows the 2006 yearly duration and instantaneous penetration for the study footprint CSP under the 30% Local Priority scenario. The orange trace is the CSP output plotted against the left axis, and the blue trace is the instantaneous penetration plotted against the right axis.

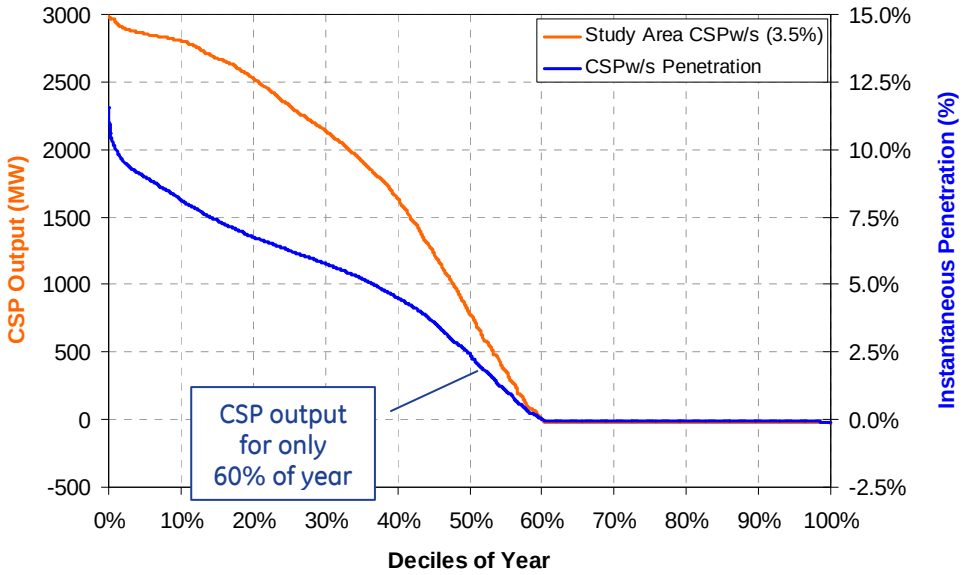


Figure 4.14 2006 Study Footprint CSP Duration and Penetration for the 30% LP Scenario

For the LP 30% scenario, sufficient CSP capacity is installed to supply only 3.5% of the load energy. However, over the course of the year, the instantaneous CSP penetration

reaches 11.5%, and is in fact greater than or equal to 5% for about 35% of the year. The CSP duration curve is strongly influenced by the built-in six hours of storage. This is evidenced by the fact that the orange trace is convex-shaped, so that it persists longer at its peak and rolls off quickly thereafter. With 2,900 MW of installed CSP (with storage) capacity, the output is at or above 2,500 MW for 20% of the year. However, this rolls off very quickly, such that CSP output is at or above 500 MW only 54% of the year. There is no output for 40% of the year, the hours when it's dark and storage is exhausted.

Figure 4.15 shows the 2006 yearly duration and instantaneous penetration for the study footprint PV under the 30% Local Priority scenario. The purple trace is the PV output plotted against the left axis, and the blue trace is the instantaneous penetration plotted against the right axis.

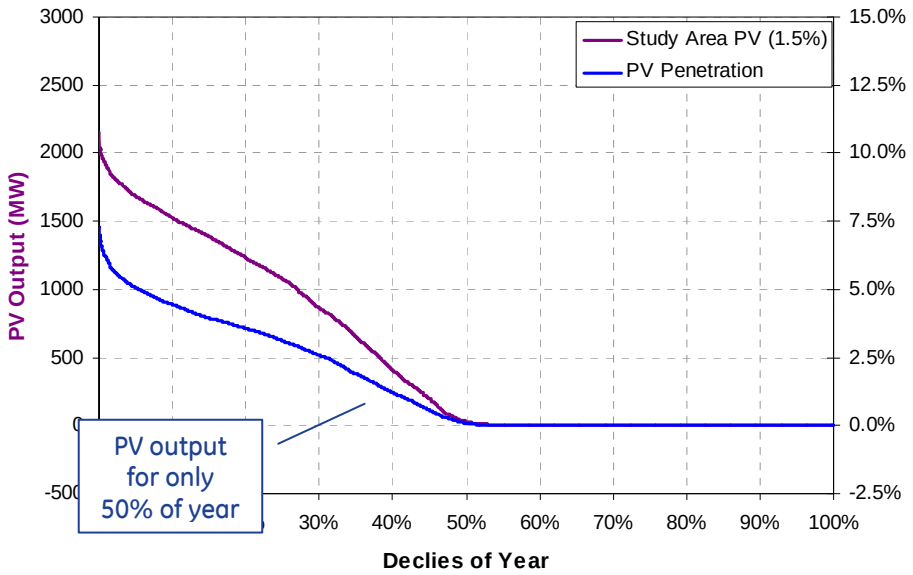


Figure 4.15 2006 Study Footprint PV Duration and Penetration for the 30% LP Scenario

PV resources are installed to supply 1.5% of load energy, but like the CSP, PV output also reaches a relatively high penetration of 7.3% during the year. A key difference between the two, however, is that PV has no storage so it tends to have a sharper peak than CSP (this will discussed further in the next section) and a more gentle roll-off. The purple trace in Figure 4.14 tends to drop very steeply during the peak output hours, but then ramp more gradually toward zero output. With 2,900 MW of installed PV capacity, the output is at or above 1,250 MW for 20% of the year, and at or above 500 MW only 38% of the year. There is no PV output for 50% of the year, 10% more zero output hours than CSP, which is extended by the storage capacity.

4.2.3 Net Load Duration

The wind and solar duration in isolation may be interesting and may give some insight into the quality of the resources, but the main goal is to determine their impact on load

variability and, by extension, generation requirements. The net load duration is more useful for looking at the trend in the coincident combinations of load, wind and solar over the year. As discussed earlier, net load is determined by subtracting the hourly chronological wind and solar generation from the corresponding hourly load. The data are then sorted to produce the net load duration curve for the year.

Figure 4.16 shows the 2006 study footprint net load duration curves for the In-Area scenario. The magenta trace is for the baseline or existing wind and solar, and the others, green, orange and blue, are for the 10%, 20% and 30% penetration levels respectively. The inset boxes list the maximum and minimum net load observed during the year for each penetration level. The horizontal black trace indicates the minimum load point (without existing wind) for the year.

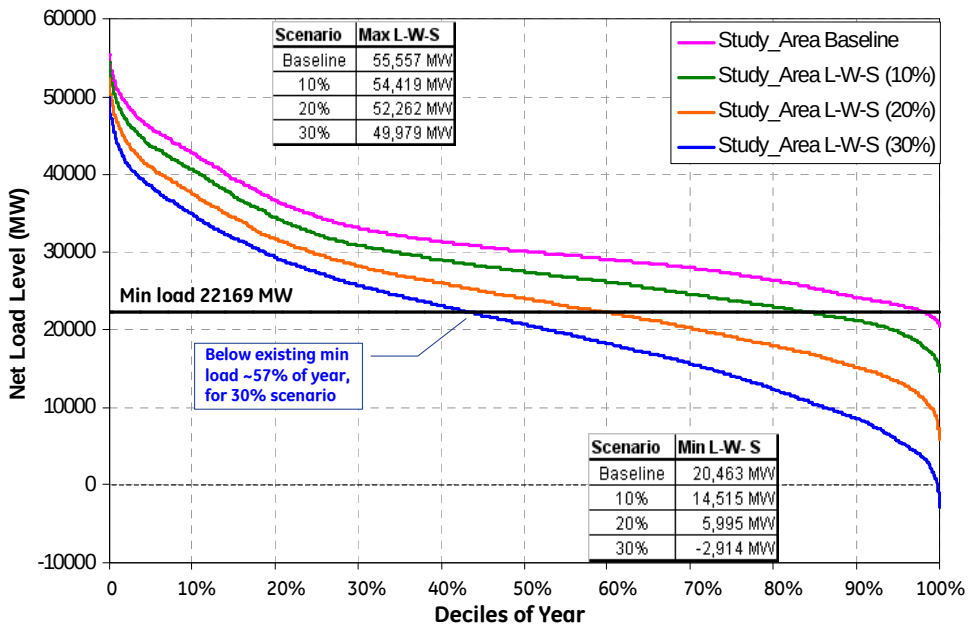


Figure 4.16 Study Footprint 2006 Net Load Duration for the In-Area Scenario

The duration curves illustrate the impact of increasing amounts of wind and solar generation on net load, especially during low load hours (the tenth decile). Over the year, regardless of wind penetration, there are several hours when net load dips below the minimum load point (22,169 MW). For the baseline, this is 1.68% of the year or 147 hours, but for 30% penetration it is 57% of the year or almost 5000 hours. Now, there may be nothing inherently critical about this minimum load threshold. The system may be able to operate well below this load level, but it simply serves as a reference point for illustration. During the absolute minimum net load hour for 30% penetration, the wind and solar generation push the net load down to –2,914 MW. In other words, during that hour there is 2,914 MW more renewable generation alone than load on the system footprint! Clearly, the footprint system must either export to the rest of WECC or spill renewable generation. This is an "interesting" operating problem to have, and it gets even more "interesting" at the state/area and zone level, especially if each area or zone

has to provide ancillary services to integrate these resources. Chapter 6, Operational Analysis, will demonstrate the system impact on this day and other challenging days, and discuss strategies to improve operations.

As we have seen earlier, the statistical character of the net load at the footprint level is not altogether dissimilar for the three scenarios (differences become more stark at the state level, as will be shown later). Figure 4.17 plots the 2006 study area net load duration curves for the three scenarios at 30% penetration on one chart. The figure also includes call-outs with the top and bottom ten percent of load hours, as well as the median load hours.

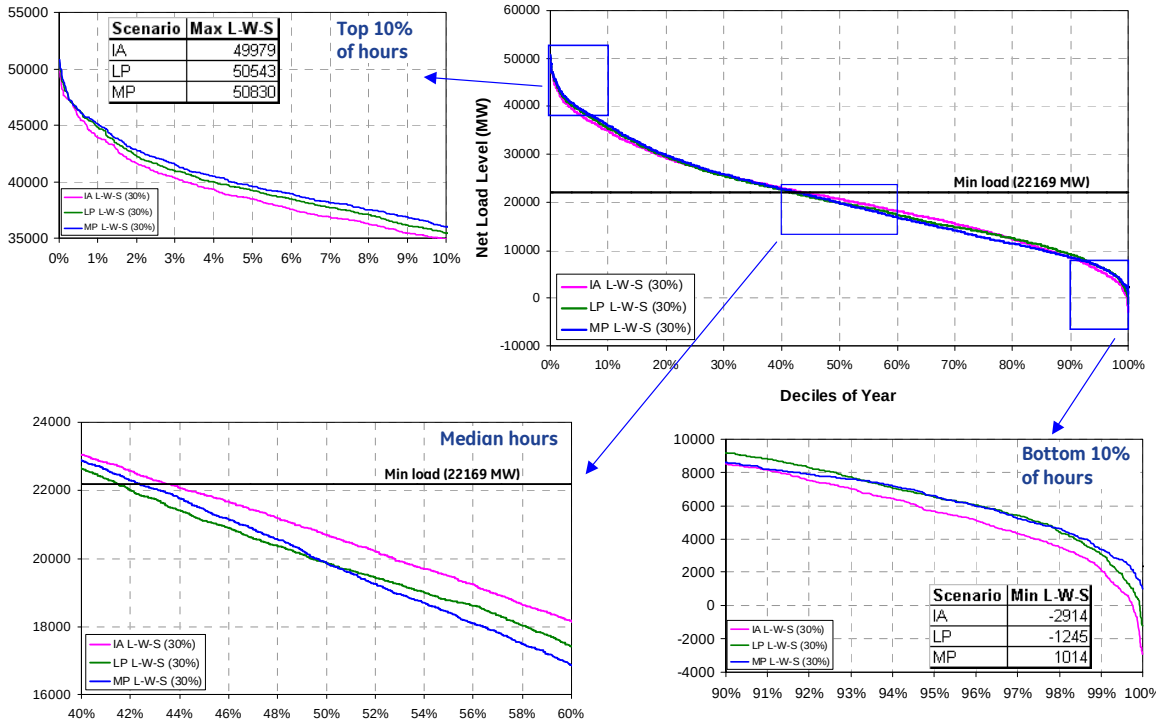


Figure 4.17 Study Footprint 2006 Net Load Duration for all Scenarios (30% Penetration)

The charts confirm that there is no significant differentiation between the three scenarios at the footprint level. During the low load hours a similar challenge is presented by all three scenarios. For the minimum load hour, the LP net load is –1,245 MW and the MP net load is 1,014 MW – not that much different qualitatively from the IA net load in that hour. The number of hours that net load is below the minimum load point is basically the same in all three scenarios, as is the maximum net load observed during the year.

The next few charts plot the 2006 net load duration curves for the three different scenarios in three selected states: IA in Arizona, LP in New Mexico, and MP in Wyoming. This combination of states and scenarios is selected to give a flavor of the stress imposed at the area level by the various scenarios.

In each of these states, the wind and solar output has an increasingly dramatic impact on the net load. In Arizona there is enough wind to supply 30% of Arizona's load. Since Arizona is a fairly large state and the wind resources are not particularly great (in terms of capacity factor), this leads to a large installation base and potential operation difficulties when the load is low. In Figure 4.18, for 30% penetration, Arizona's net load is below the observed state minimum load 45% of the year, and the minimum net load is almost –5,000 MW (wind and solar output is 5,000 MW more than load). In New Mexico, under the LP scenario, the installed wind and solar capacity pushes down the minimum load point considerably, as shown in Figure 4.19. For 30% penetration, New Mexico's net load is below the state minimum load 60% of the year. In Wyoming under the MP scenario, most of the wind resources are installed to supply load elsewhere in the footprint. With this large base of installed wind on a small load footprint, Figure 4.20 shows the resulting net load duration curves. The load in Wyoming is completely dominated by wind and solar generation even at the 10% penetration level. For 30% penetration, the net load is below the Wyoming minimum load 90% of the time, and is in fact negative for 65% of the year. The minimum net load observed under this scenario is about –10,400 MW. Needless to say, for Wyoming to balance this wind with generation resources in Wyoming is impossible. However, balancing on a wider area, regional, footprint or WECC-wide is more operationally tenable, and will be discussed further in Chapter 6, Operational Analysis.

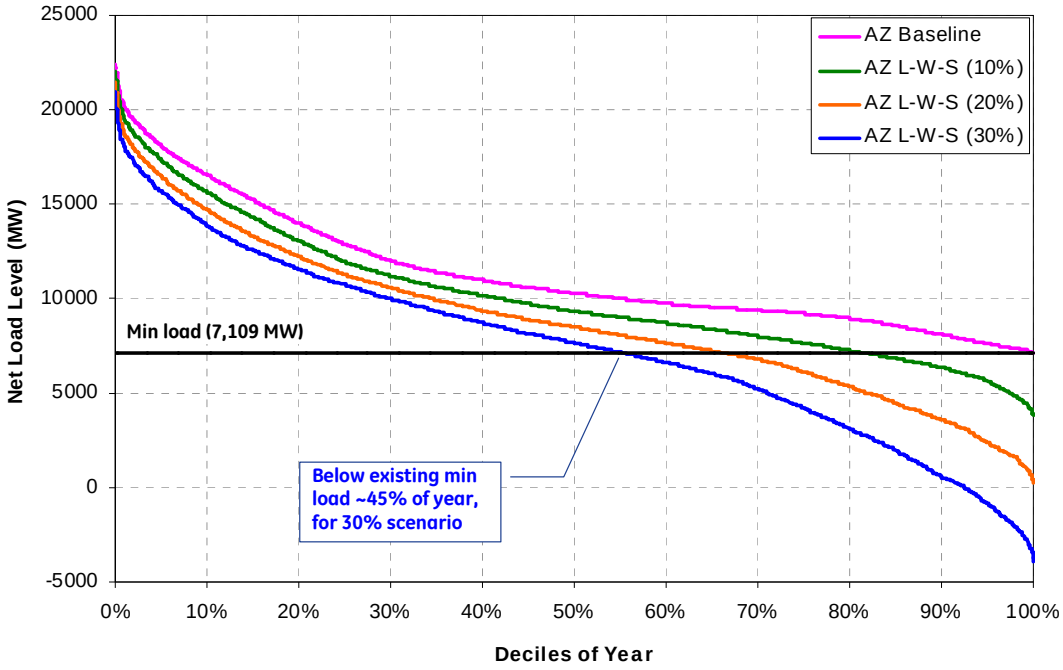


Figure 4.18 Arizona 2006 Net Load Duration for the IA Scenario

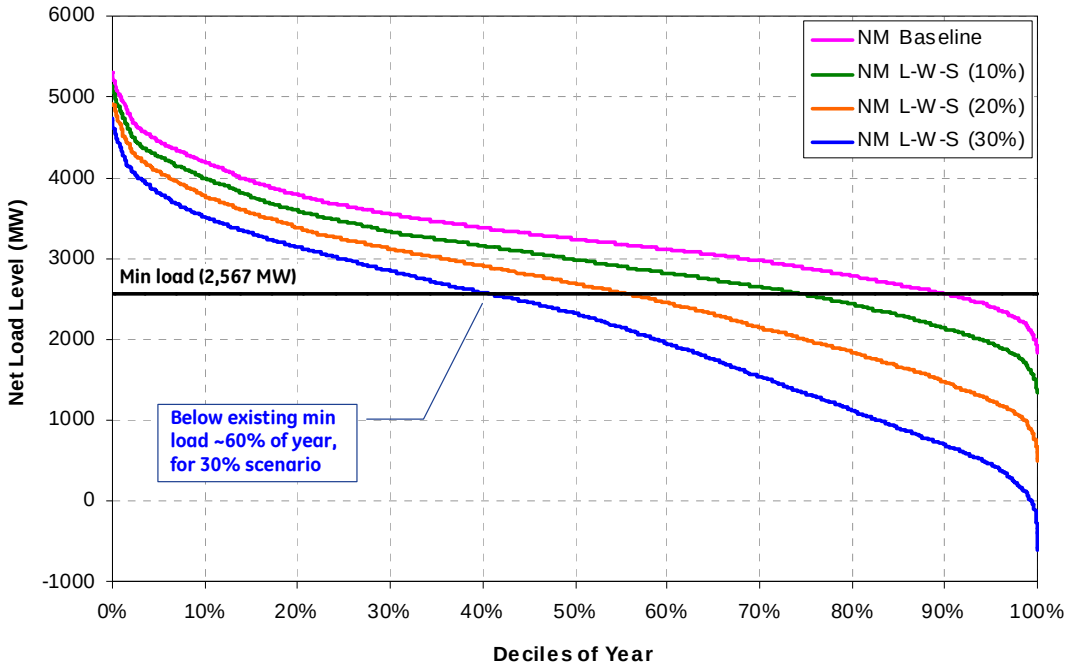


Figure 4.19 New Mexico 2006 Net Load Duration for the LP Scenario

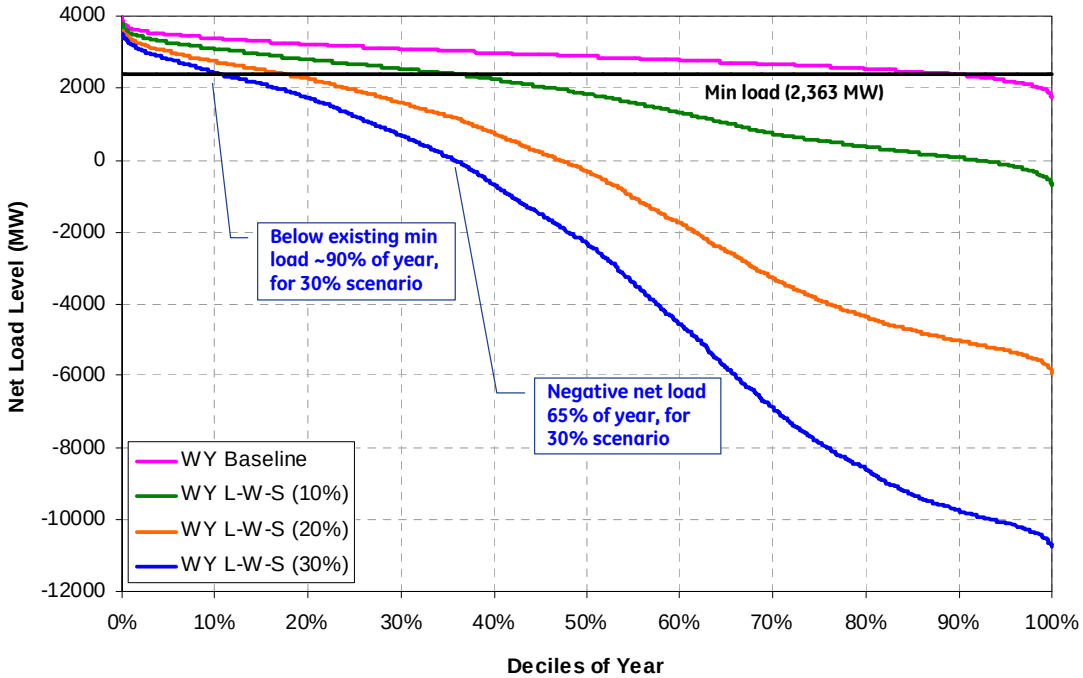


Figure 4.20 Wyoming 2006 Net Load Duration for the MP Scenario

The next section digs a little deeper into the net load characteristics dictated by load, wind and solar coincidence by looking at average daily profiles on a seasonal/monthly basis, typical day profiles, and time series profiles for selected periods.

4.3 Wind, Load and Solar Coincident Relationships

The temporal relationship between wind and solar output and load is the key driver for resulting net load variability. Depending on the nature of wind and solar, when load is rising or falling, the net variability could be better or worse than load alone. In some cases, wind and solar may exaggerate or curtail net load peaks and valleys, increase or decrease ramp rates (period-to-period changes), shift time-of-peak, and generally aggravate or mitigate operationally challenging periods. All of these are important factors when considering the impact of wind and solar on operational requirements such as regulation and operating reserves. Some of the key issues this section highlights are: coincidence of load, wind and solar; impacts on net load peaks and valleys; and increases on ramp rates during the daily cycle

4.3.1 Average Daily Profiles

Figure 4.21 on the next page plots the 2006 average daily profiles of load, wind and solar for the total study footprint under the 30% Local Priority scenario. Profiles are shown for four seasonally representative months: January, April, July and October. Plots for other scenarios and penetration levels are included in Appendix B. Load is plotted against the left scale and wind and solar against the right, amplified by three relative to the load.

The average daily profiles reveal several general trends with regard to the relationship between load, wind and solar output:

- At the footprint level, wind output is generally falling during the early-morning hours when load is rising most rapidly and tends to recover or flatten later in the morning. However, this inverse-phase relationship is not as strong during the summer as in other seasons.
- In the late evening to early morning hours when load is decreasing or at its minimum, the wind output is still fairly high across the seasons. This may require the balance of generation to quickly ramp down at a time when the stack is least maneuverable.
- The solar output complements the load as expected. It is either rising or at its peak around noon when the load is high, and rolls off in the late afternoon.
- The impact of the CSP storage can be seen in the shape of the profiles. CSP tends to persist a lot longer in the day than PV, even until midnight in April and July. While this is great for load support in most cases, it sometimes creates problems where it rolls off very quickly just as the load is ramping up (as in January). This could presumably be managed by smarter use of storage (see Section 8.3).

These observations have implications for net-load variability (and operational requirements) at different times of the day and during the various seasons of the year, as discussed later in this section.

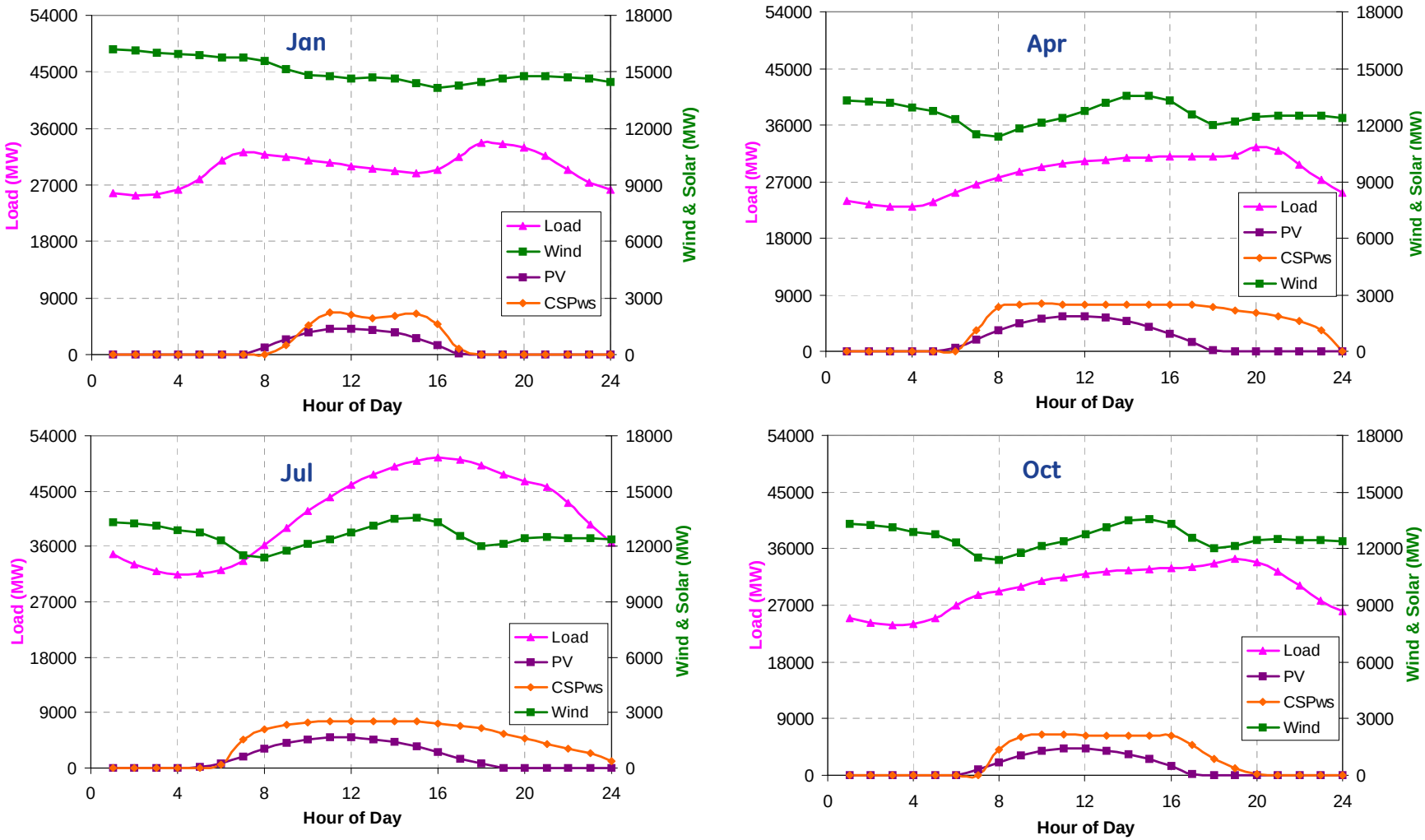


Figure 4.21 2006 Study Footprint Load, Wind and Solar Average Daily Profiles By Seasonal Month for the 30% Local Priority Scenario

The January and July average daily profiles in Arizona, Nevada, and Wyoming for the 30% LP scenario are shown in Figure 4.22 to Figure 4.24 below. What is clear from these figures is that the broad observations at the footprint level are even more relevant at the state level. Note that different scales and axes are used for load, wind and solar in each figure.

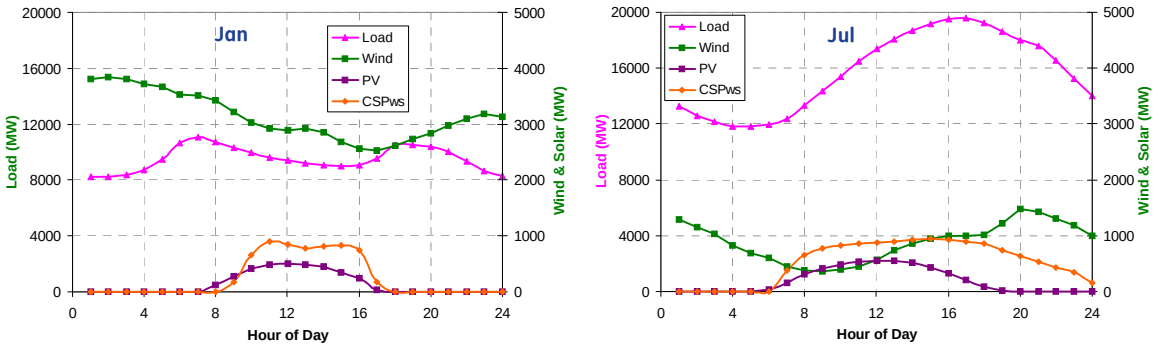


Figure 4.22 Arizona Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario

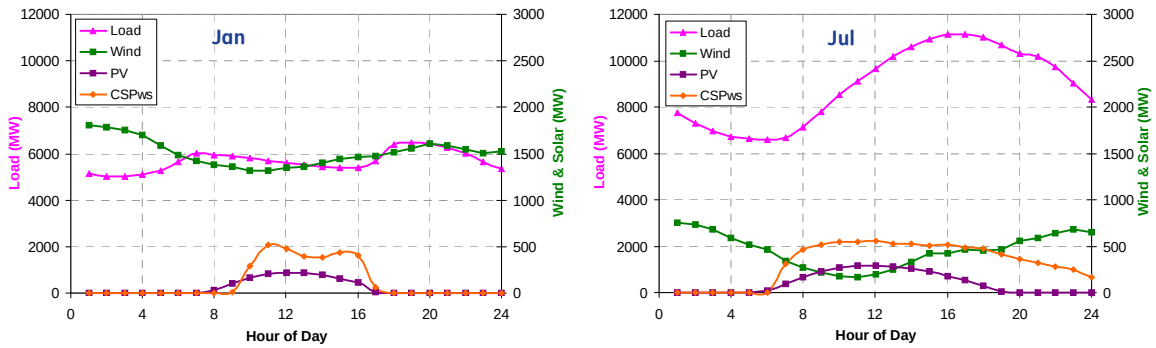


Figure 4.23 Nevada Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario

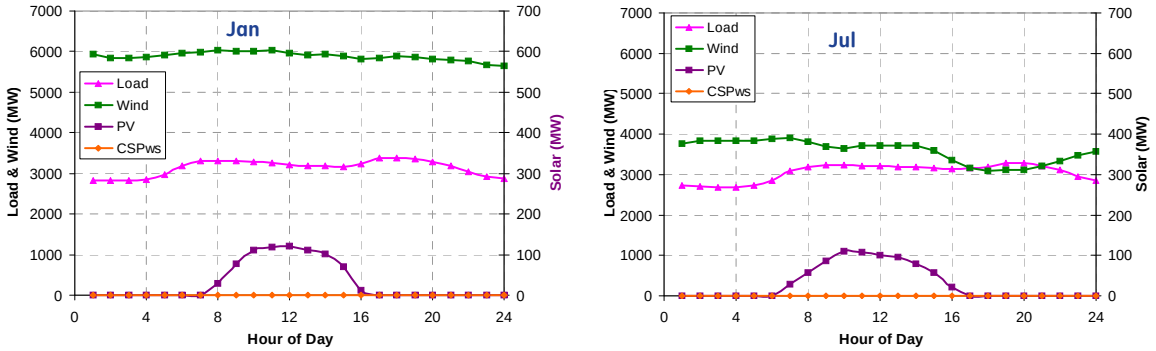


Figure 4.24 Wyoming Load, Wind, and Solar Average Daily Profiles for January and July, 30% LP Scenario

The general observations regarding average daily profiles at the footprint level become even more pointed when actual time series (as opposed to averages) are examined, especially at the state/area level. At this resolution, it is easier to see how wind and solar combine to impact the net load.

4.3.2 Weekly Time Series

Figure 4.25 and Figure 4.26 below show the footprint actual load, wind and solar series and the net load for the 30% Local Priority scenario during the third week in July 2006.

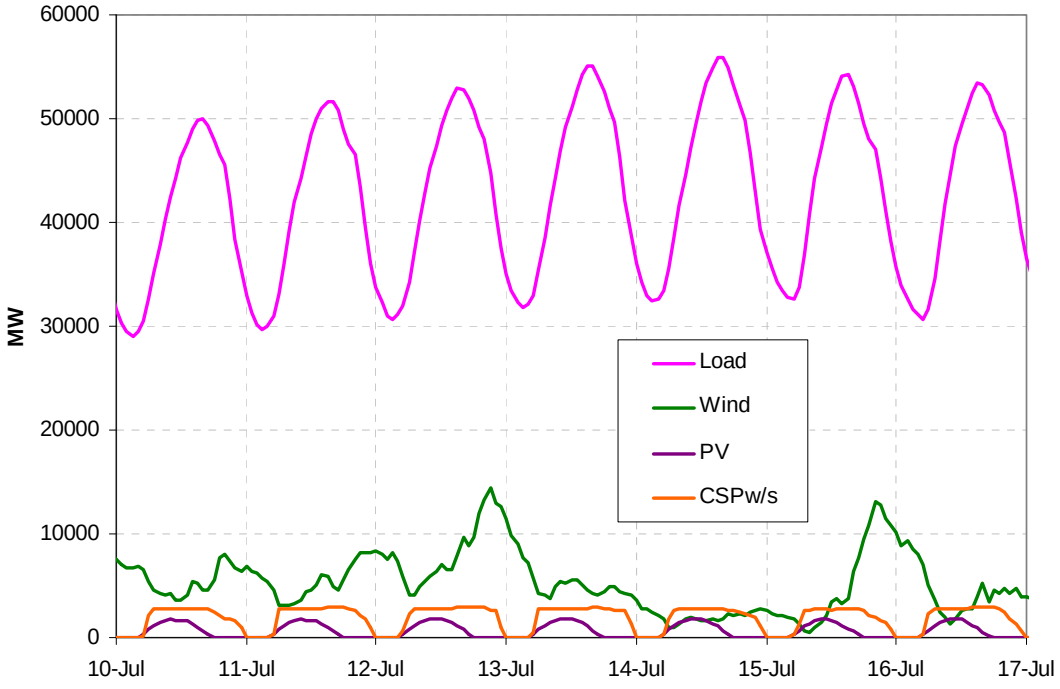


Figure 4.25 Study Footprint Total Load, Wind and Solar for a Week in July 2006 30% LP Scenario

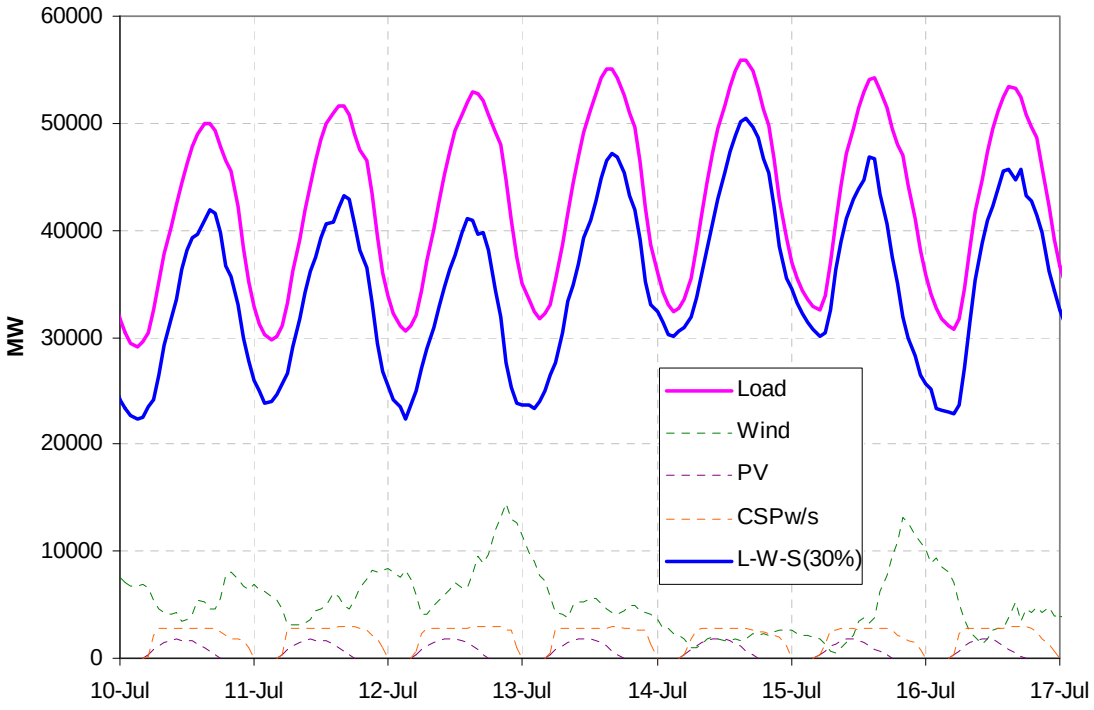


Figure 4.26 Study Footprint Total Load, Net Load for a Week in July 2006 30% LP Scenario

Figure 4.25 illustrates that over the course of the week, load, wind and solar output vary considerably from day to day and throughout the day. There is a very strong diurnal load and solar cycle, as expected but the wind output also displays an observable, though weaker, periodic characteristic. Overall, the wind output tends to be anti-correlated with the load, i.e. wind generation peaks tend to coincide with load valleys.

Figure 4.26 shows the net load resulting from the Load-Wind-Solar combination. In the summer months, we have seen that the load usually dominates the wind (see Figure 4.21) so it is not surprising that the net load shape is similar to the load, with some nuances due to the variability of wind. Wind and solar output produce an offset in the net load that varies in magnitude. The greatest offset is in the late evening to early morning hours when wind output is highest and the load is falling. The impact of the strong summer solar cycle is seen particularly in the mornings. At times when the wind is falling or at minimum, the solar output is rising, which mitigates the increase in net load up-ramp. In the evenings, the CSP roll-off tends to coincide with the load decline and wind drops. Consequently, there is not much apparent difference between load-alone and net load ramping requirements. Figure 4.27 plots the net load for each of the three penetration levels, 10%, 20% and 30%.

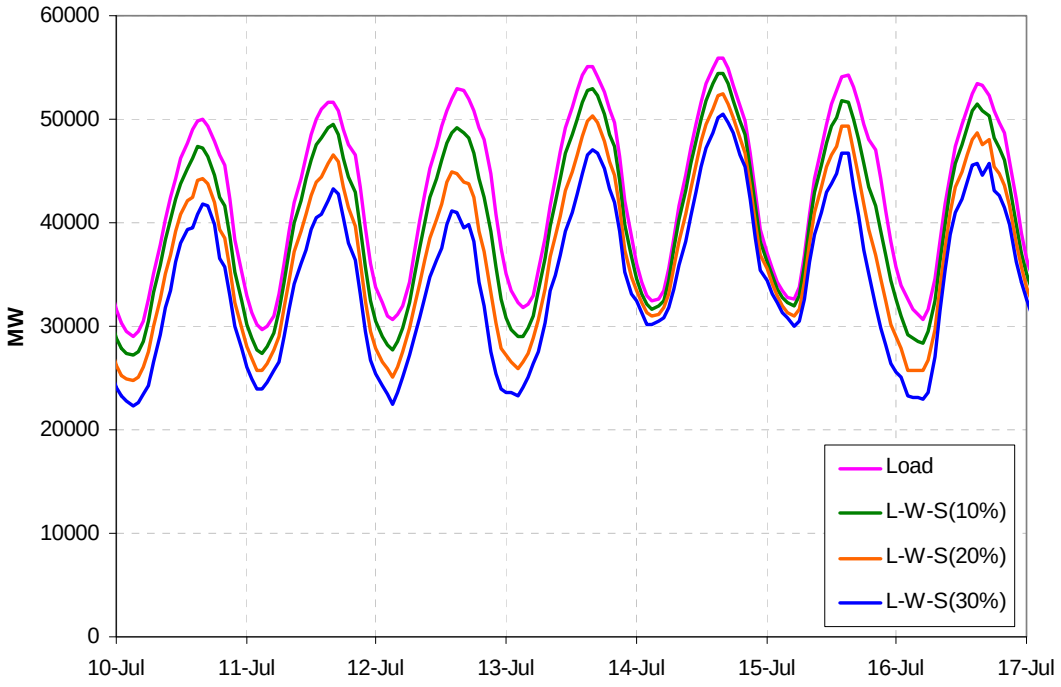


Figure 4.27 Study Footprint Net Load for a Week in July 2006 for 10%, 20% and 30% LP Scenario

The plot is almost remarkable in its homogeneity. At the 10% penetration level wind and solar has a small impact on the net load (green trace), causing some deeper valleys at low load and smaller peaks. As the penetration increases, the impact is more discernable, but even at the 30% level, it is hardly an operation concern, especially when sufficient generation has been committed to meet the summer peak.

The July week is in stark contrast to the April 2006 week shown in Figure 4.28 and Figure 4.29 below. In this week, the wind output is higher and more volatile, so load is not as dominant. The data shown is for the total footprint, 30% Local Priority scenario.

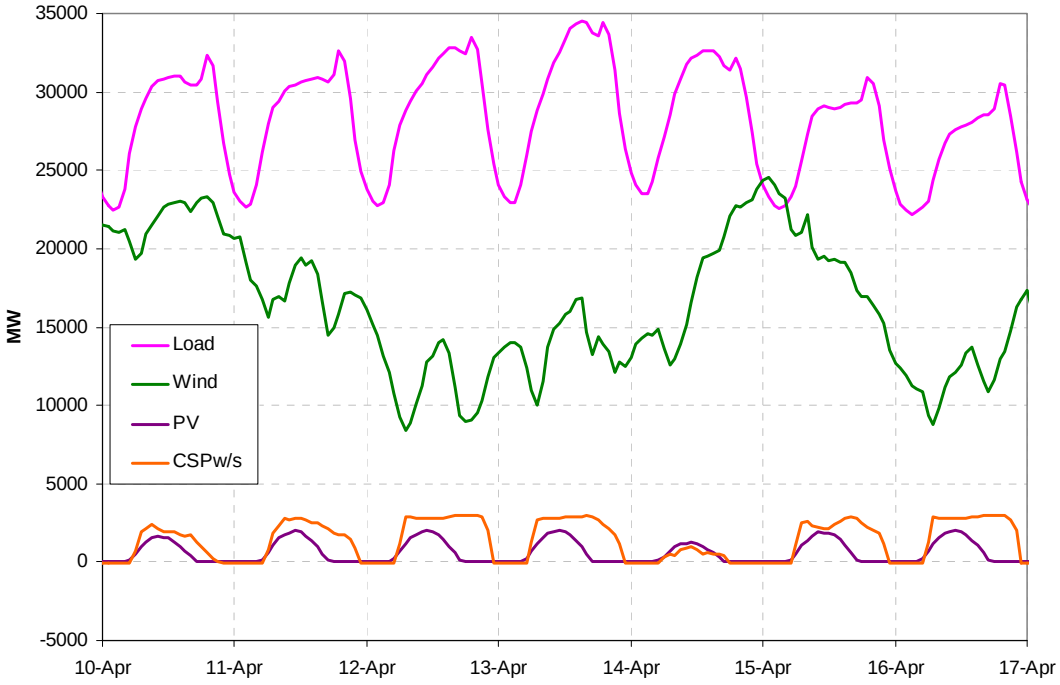


Figure 4.28 Study Footprint Total Load, Wind and Solar for a Week in April 2006 30% LP Scenario

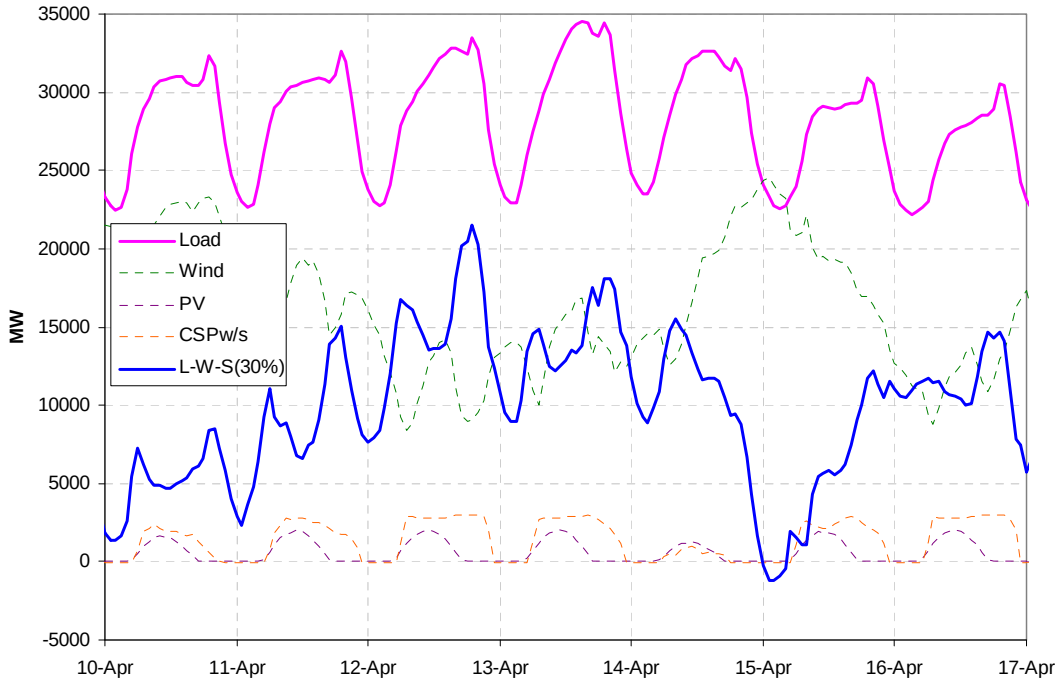


Figure 4.29 Study Footprint Total Load, Net Load for a Week in April 2006 30% LP Scenario

As in the July week, there is a strong diurnal cycle for load and solar, but now there is absolutely no recognizable pattern to the wind output in this week. At the beginning of the week, early in the morning of the 10th, wind generation is almost equal to the load, and later on the 15th actually exceeds the load for a few hours. The wind ramps up and down several times during the week with sustained ramps in one direction sometimes spanning an entire day. The impact of this "unusual" wind output is seen in the net load trace in Figure 4.29. The net load no longer resembles the load in any way, but has taken on variability characteristics of the wind output. Over the course of the week, there are days with extremely large and sustained net load ramps, the likes of which did not exist in the original load, and instances of rapid swings in ramping direction over a few hours. On three days the net load drops below 5,000 MW, including going negative on the 15th, and is less than 10,000 MW on every day of the week. Clearly, this is a week that might present some challenges to a generation portfolio accustomed to dealing with the usual April load profile. Results of the operation analysis of this April week (and the July week for that matter) are detailed in Section 6.3, Weekly Operational Analysis, and Section 7.2, Quasi-Steady State (QSS) Analysis.

Figure 4.30 plots the net load for the same week in April for each of the three penetration levels, 10%, 20% and 30%.

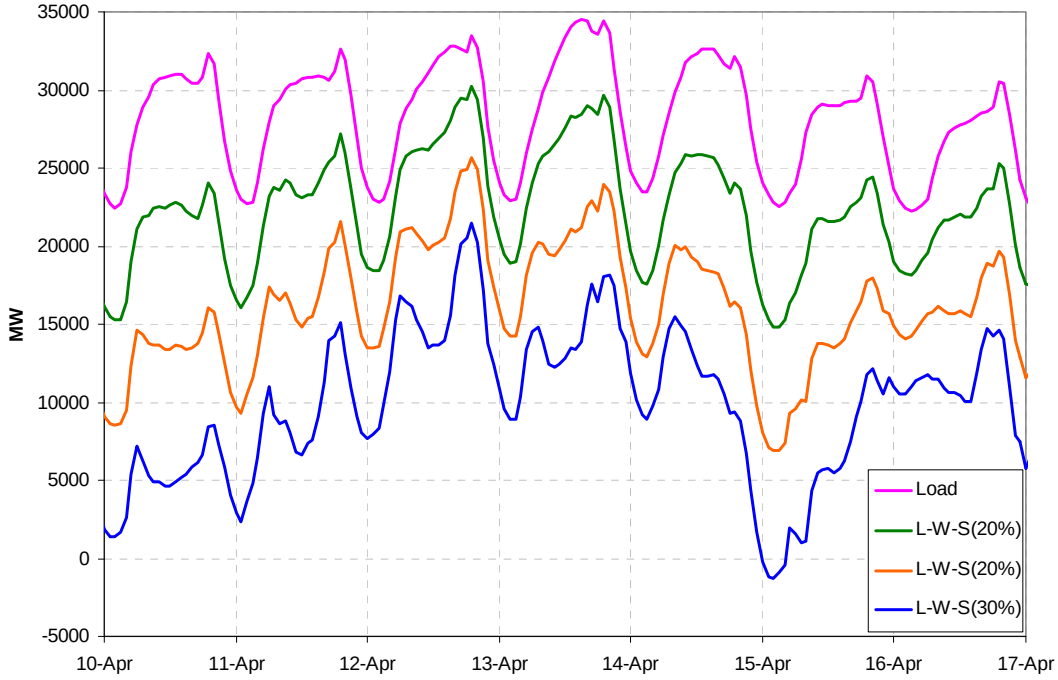


Figure 4.30 Study Footprint Net Load for a Week in April 2006 for 10%, 20% and 30% LP Scenario

The progressively disruptive impact of wind and solar on net load is seen in the traces above. For 10% penetration, the net load is distorted, but there is still some semblance of a diurnal cycle. With 20% penetration, the load cycle is less evident, net load valleys are

deeper and daily ramps are steeper and more sustained. There is no point at which everything falls off a cliff, but rather a gradual increase in the level of pain.

4.3.3 Selected Periods

Load, wind, solar, and net load for selected days are shown in the plots below. The impact of wind and solar on net load ramp and range are highlighted on the plots.

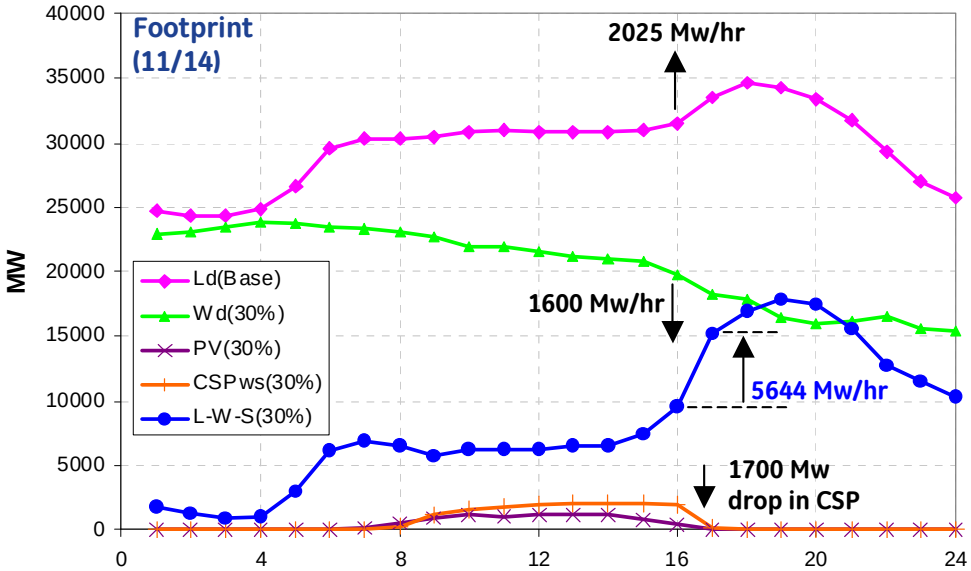


Figure 4.31 Study Footprint Net Load for November 14th, 2006, 30% LP Scenario

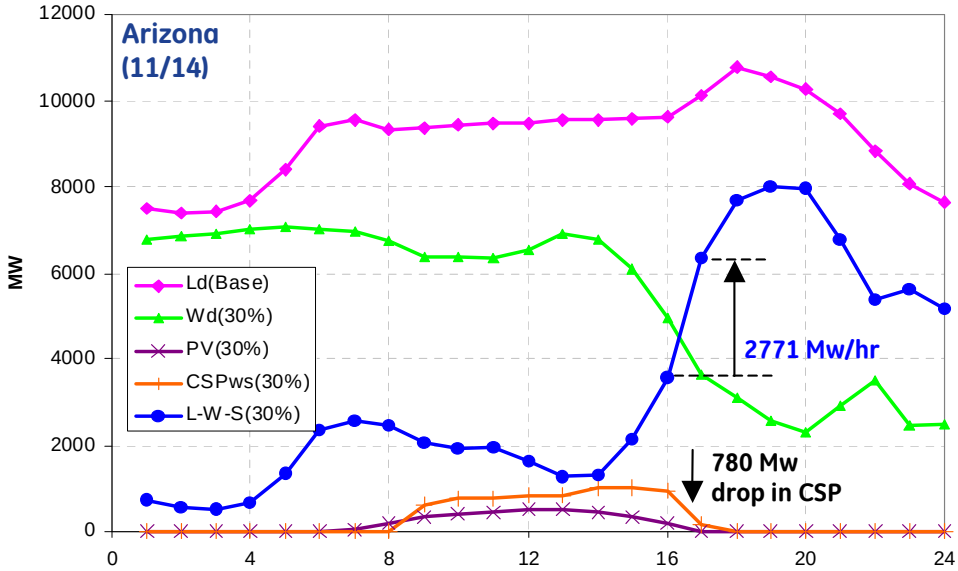


Figure 4.32 Arizona Net Load for November 14th, 2006, 30% LP Scenario

On November 14th, there is about a 180% increase in the footprint net load up-ramp during the late afternoon, around 4 PM. As the details on Figure 4.31 show, this is due to a simultaneous rise in load and a drop in wind and solar. As Figure 4.32 shows, the

main driver for this footprint event is the wind and solar in Arizona. During the 4 PM hour in Arizona, wind output drops by 1316 MW and CSP drops by 780 MW, causing a 2771 MW/hr up-ramp in Arizona net load. This is much more aggressive than the up-ramp without wind and solar, and also lasts a lot longer. In fact, the sustained up-ramp in net load spans 5 hours, (2 PM to 7PM), whereas the original load ramp was only 2 hours long. This sort of event might increase the ramp and range requirements for the balance of generation in Arizona or the study footprint.

Figure 4.33 and Figure 4.34 show the load, wind, solar, and net load traces for another large ramping event at the footprint and state/area level.

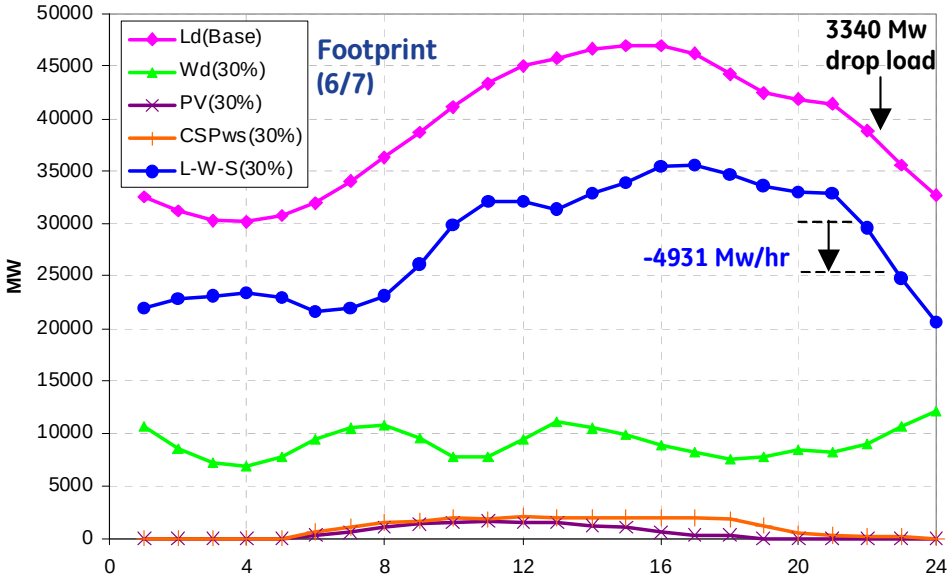


Figure 4.33 Study Footprint Net Load for June 6th, 2006, 30% LP Scenario

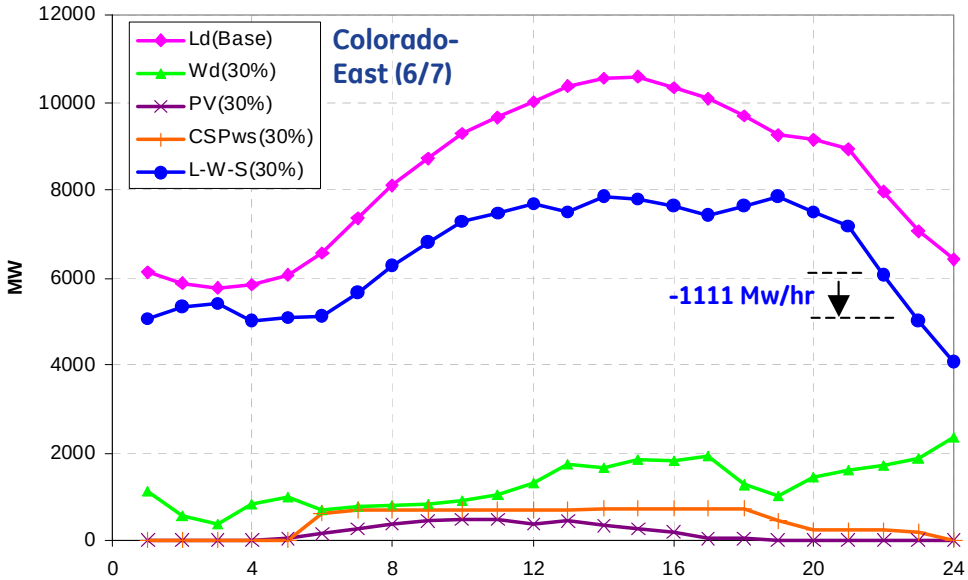


Figure 4.34 Colorado-East Footprint Net Load for June 6th, 2006, 30% LP Scenario

On June 6th, 2006, the net load in the study footprint drops precipitously around 9 PM evening due to a roll-off in load while the wind is picking up. At the state level, one of the key contributors is Colorado East wind which is ramping up pretty aggressively in that hour, while solar is basically flat. These are but a few examples of the operational challenges that manifest throughout the year. Other interesting days where wind and solar aggravate the net load are plotted in Appendix B.

Finally, as a lead-in to a discussion of period-to-period variability in the next Chapter, Figure 4.35 shows the time series for the entire month of April at the footprint level for the 30% Local Priority scenario. Recall that a week from this month was used earlier to illustrate the impact of wind and solar on net load.

Over the course of the month, rapid excursions can be seen in the net load as it goes through large changes from hour to hour. The obvious visual variability of this series can be statistically characterized by the number and size of the period-to-period changes. The next chapter will describe the variability of net load by analyzing the hour-to-hour changes (called deltas) that are driven by wind and solar.

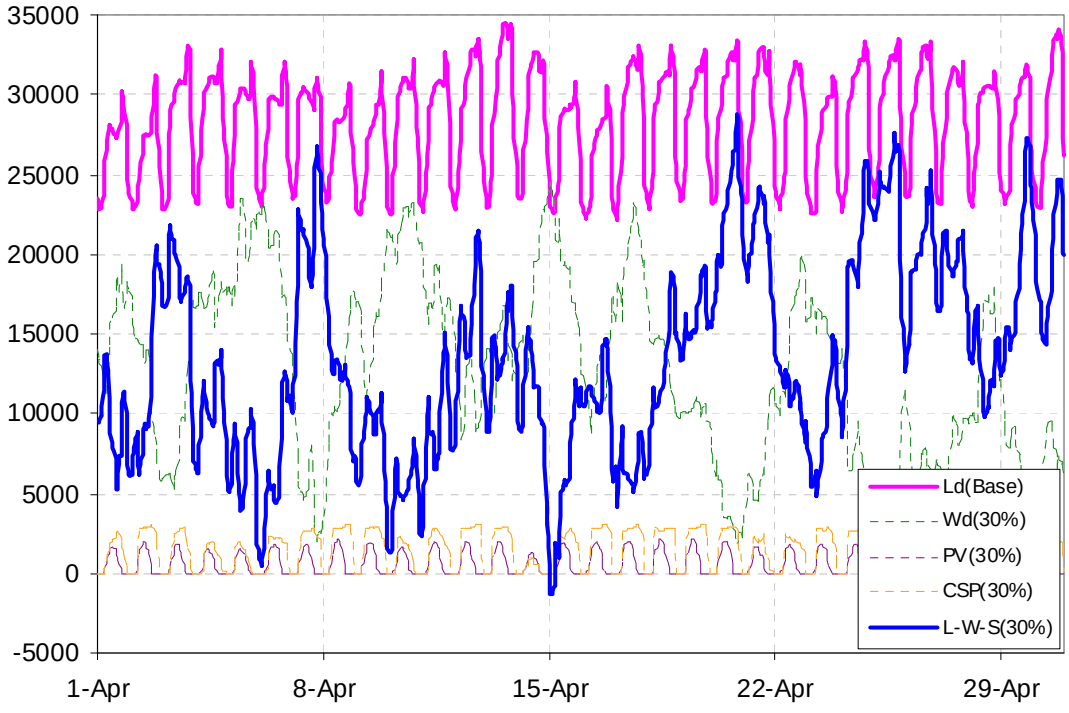


Figure 4.35 Study Footprint Total Load, Net Load for April 2006, 30% LP Scenario

4.4 Observations and Conclusions

This chapter has examined broad trends in wind and solar generation monthly energy, yearly duration, and daily profiles. The hourly coincident relationship between load,

wind and solar has been examined and the impacts on net load at the footprint level and within individual states has been discussed.

For 30% wind penetration, at the footprint level sufficient wind capacity is installed to supply 30% of the load energy in the footprint. However, an examination of the monthly energy output shows that 30% is not always 30%! For each of the scenarios, in a given month more than half the energy in the footprint may be derived from wind and solar especially in winter and spring months. At the state area level, the percent penetration can far exceed 100%, depending on the state and scenario.

The impact of wind and solar is a lot less dramatic at the aggregate footprint and WECC levels than at the individual state level, regardless of the scenario. In fact, in most cases there is relatively little observable difference among scenarios at the footprint level, despite the fact that there are significant differences in plant number and locations.

The analysis showed that area size (load and geography) is a key determinant of a state's ability to absorb the variability inherent in high wind and solar penetration. Large amounts of wind in a small area may lead to challenging operational issues, but larger balancing areas can better accommodate the variability from high wind and solar penetration.

Within each state and at the footprint level, the temporal relationship between wind and solar output and load is the key driver for resulting net load variability. Depending on the coincidence with load, wind and solar might exaggerate or curtail net load peaks and valleys, increase or decrease ramp rates (period-to-period changes), shift time-of-peak, and generally aggravate or mitigate operationally challenging periods. Some pertinent observations from the seasonal average daily profiles are:

- Wind output is generally falling during the early-morning hours when load is rising most rapidly
- In the late evening to early morning hours when load is decreasing or at its minimum, the wind output is still fairly strong across the seasons
- Solar output complements the load as expected, but CSP output tends to rolls off very quickly in late afternoons and evenings when storage is depleted. In months where the load is ramping up in late afternoons, this could increase balance of portfolio generation ramping requirements.

These general observations regarding average daily profiles at the footprint level become even more pointed when actual time's series (as opposed to averages) are examined and when the state/area level variability is considered.

5 Statistical Analysis: Hourly Variability and Day-Ahead Predictability

The variability of net load in different timeframes impacts various aspects of bulk power system operation. Implications for regulation requirements, ramp and range considerations, operating reserves and unit commitment issues can be drawn from an analysis of net load variability in various timeframes, depending on the ancillary service definitions and market rules. This chapter will focus on the statistical analysis of load and net load variability in the hourly timeframe and reserve a fuller discussion of operation impacts and requirements for later Chapters.

In this chapter several terms are used to characterize the load and net load variability. They include:

- Delta (Δ) – The difference between successive data points in a series, or period-to-period ramp rate.
  - Positive delta is a rise or up-ramp
  - Negative delta is a drop or down-ramp
- Mean (μ) – The average of the deltas (typically zero within a diurnal cycle)
- Sigma (σ) – The standard deviation of the deltas; measures spread about the mean

The standard deviation of the deltas, is a good indication of how much the series changes from period-to-period, therefore sigma of the deltas is used as the main measure of variability in this study. If the deltas are normally distributed, then sigma relates to the proportion of deltas within a certain distance of the meanμ, (as shown in Figure 5.1).

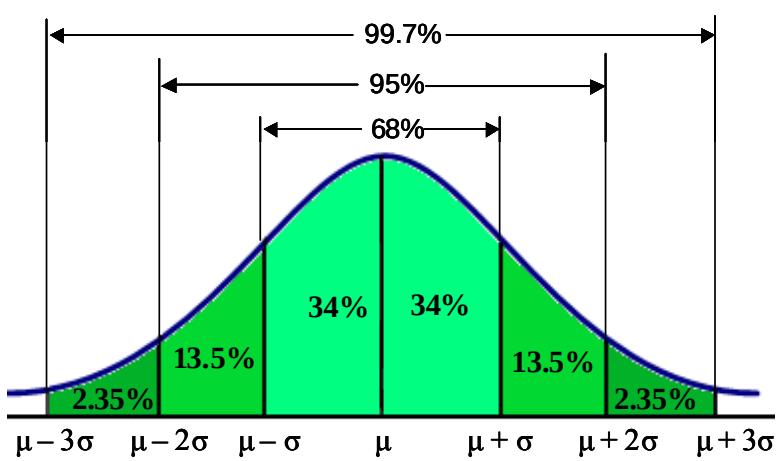


Figure 5.1 Relationship Between Standard Deviation and Area Under the Standard Normal Curve

5.1 Seasonal Trends in Variability

As we have seen earlier in Figure 4.21, wind, load and solar have distinct seasonal characteristics that influence the variability of net load at different times of year. Since the majority of net load variability is driven by the wind (solar is much smaller and more predictable), Figure 5.2 is a scatter plot of load and wind deltas that attempts to show when load and wind combine to exacerbate the net load.

On the chart, orange squares represent a *simultaneous* pair of load and wind deltas in the Fall, blue triangles are Winter load and wind deltas, green diamonds are Spring deltas, and pink circles are Summer. For example, the pink circle in the top left quadrant (Q2) labeled (-3339, 1611) indicates that during the Summer months of 2006, (June, July, August) there is an hour when the load drops by 3,339 MW while at the same time, the wind output rises by 1,611 MW. The combination of these two events (ignoring solar for now) creates a net load down-ramp of 4,950 MW in that hour. In Q2 and Q4 load and wind combine to increase net load ramps (down and up respectively), while in Q1 and Q3, they offset each other to reduce the resulting ramping requirements. The diagonal lines in Q2 and Q4 indicate boundaries of equal net load delta in the load-wind space, i.e. any load-wind pair along the line will combine to give the same net load value.

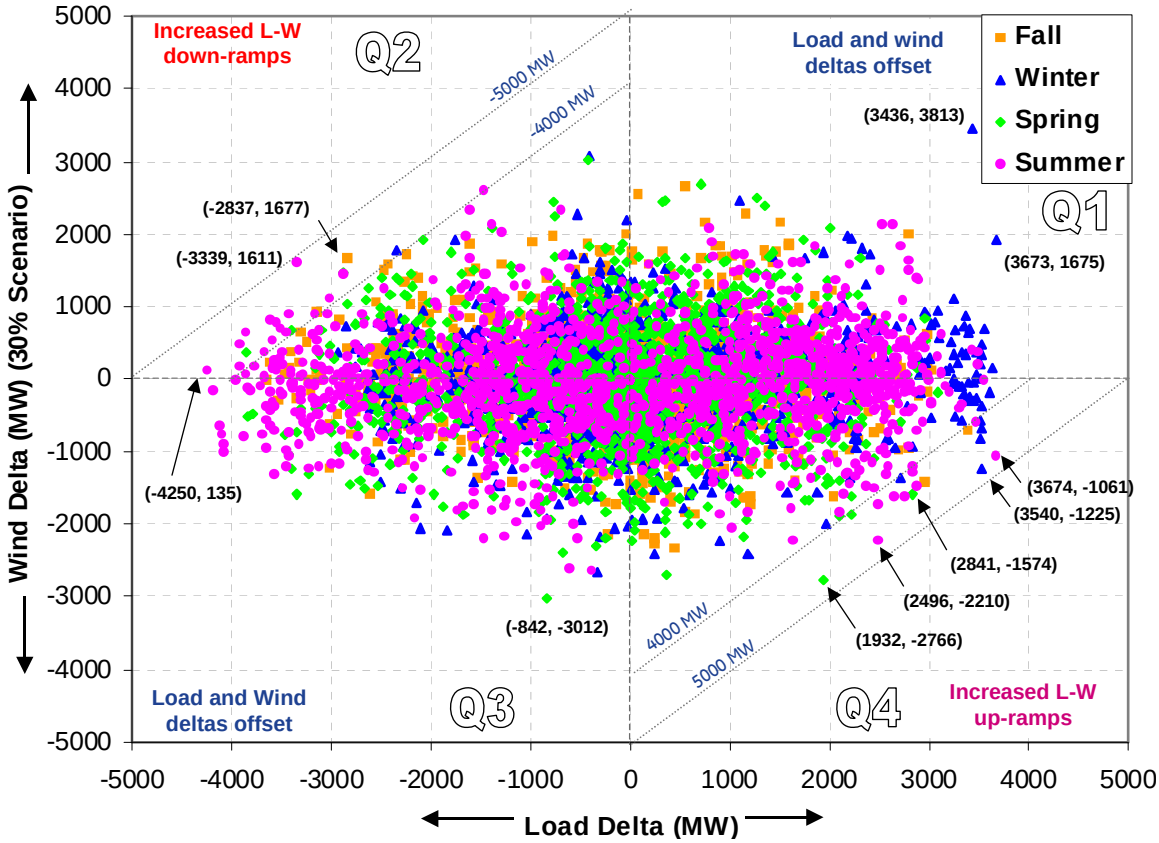


Figure 5.2 2006 Study Footprint Wind Deltas vs. Load Deltas by Season for 30% LP Scenario

The first noticeable thing about the scatter plot in Figure 5.2 is its shape. There is no obvious trend in the data which seems to indicate that over the year, load and wind deltas are not highly correlated at the footprint level. Moreover, the points are stretched along the x-axis, which implies that large load deltas are not usually accompanied by similarly large wind deltas, i.e. the risk of simultaneous delta reinforcement is small. A closer examination of the extreme load and wind deltas confirm that there are relatively few cases where simultaneous load and wind deltas create extreme net load deltas. In Q2, the quadrant where load and wind deltas combine to increase net load down-ramps, there are only a few instances where net load down-ramps are greater than the largest load-alone down-ramp. These all occur in the summer and fall, and are mostly driven by load changes. These events do not represent a great operational challenge as the wind can always be curtailed. In Q4, the quadrant where load and wind deltas combine to increase net load up-ramps, there are many more hours where net load up-ramps are greater than the largest load-alone up-ramp. These events are scattered over all seasons, and some are driven by large wind drops, which can create a significant operational challenge, especially when the generation mix at the time is not flexible.

Figure 5.3 is a similar scatter plot of load and wind deltas that includes all three scenarios at the 30%penetration level.

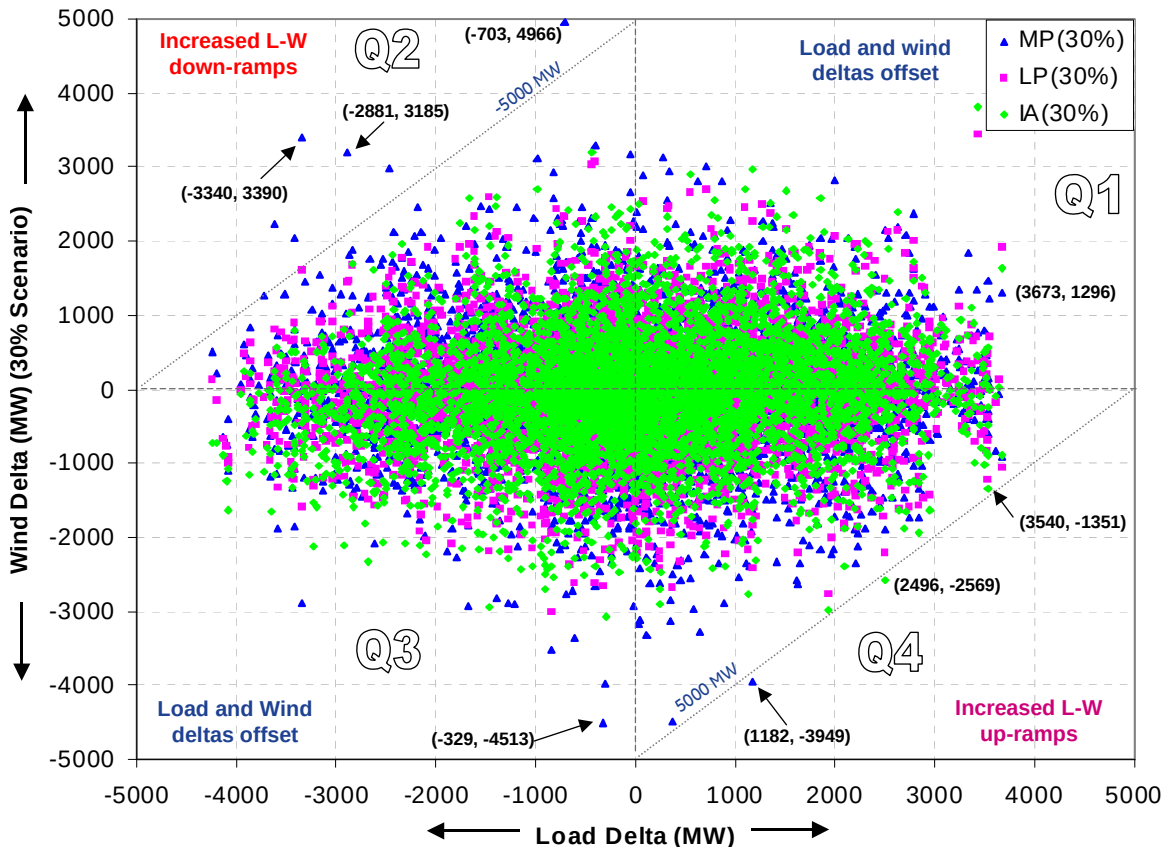


Figure 5.3 2006 Study Footprint Wind Deltas vs. Load Deltas by Scenario for 30% Penetration

In the scatter plot, most of the extreme deltas in Q1 and Q2 are from the Mega Project scenario and the In-Area scenario. A few of the more troubling ones in Q4 are driven by extremely large drops in wind output (4,000 MW or more) under the Mega Project scenario. However, none of these coincide with similarly large load rises, probably because they occur in low load hours. Also in Q4, there are a couple of instances under the In-Area scenario, where moderately large wind drops combine with moderately large load rises, to create large net load up-ramps. There are also a number of extreme Mega Project instances in Q1 driven by wind pickup, but these can always be mitigated by curtailment if necessary.

5.2 Variability by Hour-of-Day

Earlier sections have discussed broad trends in variability across the year and during different months and seasons. From an operation point of view, broad trends are not nearly as important as variability during particularly challenging periods. One such period is the minimum load period, which was discussed in Section 4.2.3. This section will discuss this and other challenging operating periods during the day created by large swings in net load.

In order to examine the variability by time of day, average daily profiles of load and net load are overlaid with the hourly variability. Figure 5.4 shows this plot at the footprint level for the 10% Local Priority scenario. The dashed magenta and blue curves are average daily load profiles, plotted against the right scale. The variability for each hour of the day, across the year, is captured by the box and whisker plot. The length of the rectangular boxes represents a spread of one standard deviation (σ) around the mean of the hourly change for a particular hour of the day. The whiskers show the maximum one-hour deltas over the year for a particular hour of the day.

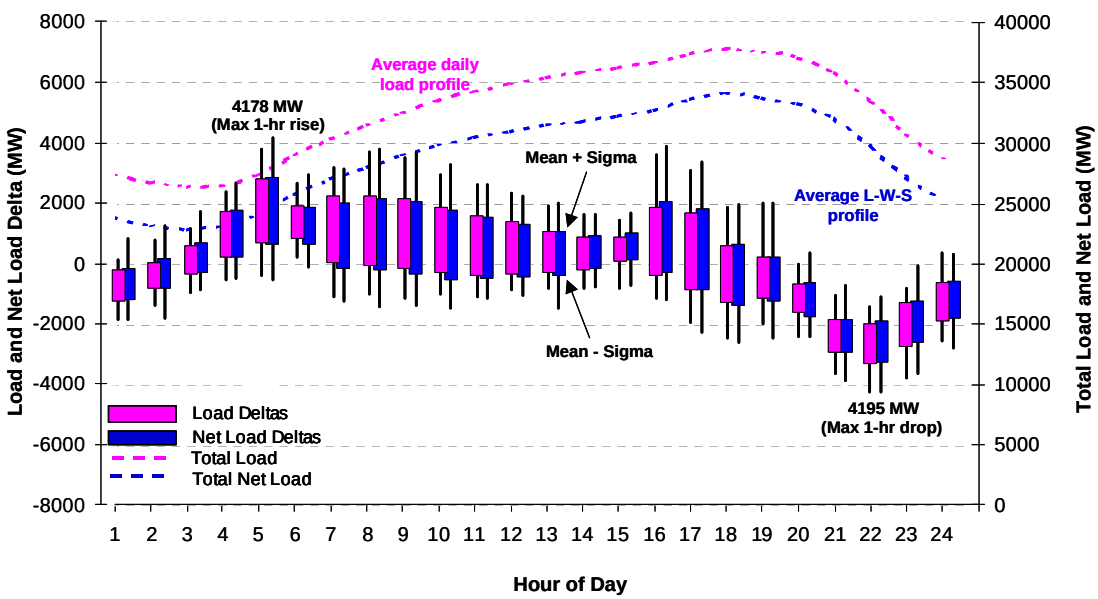


Figure 5.4 Study Footprint Average Daily Profile of Deltas Over Year 2006, 10% LP Scenario

Considering the relative length of the boxes in Figure 5.4, wind and solar generation do not increase the net load variability much over the baseline at 10% penetration, other than a slight increase in the morning and evening hours. Also, the extreme deltas (whiskers) across the day are mostly due to load. In the morning hours when load is ramping up, the maximum one-hour net load rise is 4,178 MW, 90% of which is due to the load. In the late evening when load is ramping down, the maximum one-hour drop is 4,195 MW. At this hour, the baseline ramp is actually greater than the net load ramp.

For 20% and 30% penetration, the impact of wind and solar at various hours of the day is more dramatic, as shown in Figure 5.5 and Figure 5.6 below.

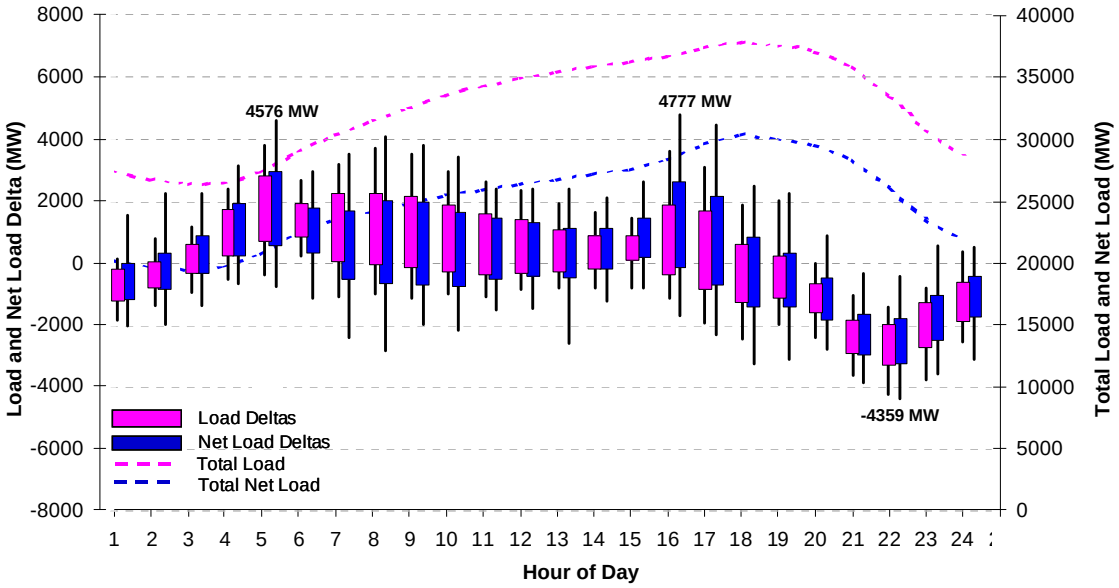


Figure 5.5 Study Footprint Average Daily Profile of Deltas Over Year 2006, 20% LP Scenario

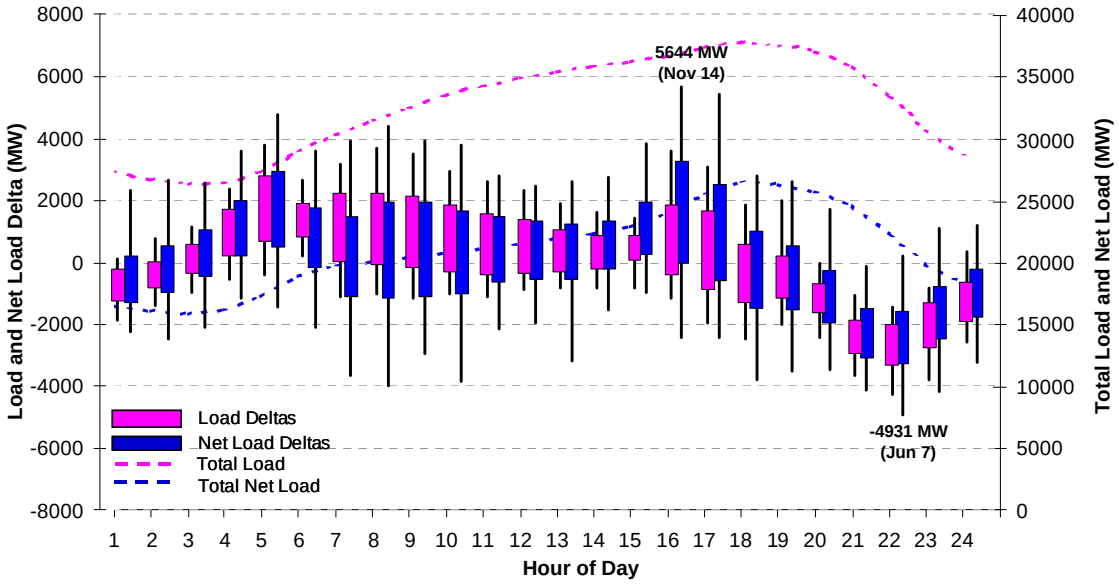


Figure 5.6 Study Footprint Average Daily Profile of Deltas Over Year 2006, 30% LP Scenario

These plots illustrate how wind and solar progressively affect the net load at larger penetration levels. At this temporal and spatial resolution the impact on the variability (sigma of the deltas) is not as dramatic as the impact on the extreme values. This is due to natural averaging over the year and the footprint. Nevertheless, the blue rectangles (net load delta sigma) grow larger than the magenta ones (baseline delta sigma), especially in the mid- morning early afternoon hours. Considering the average daily profiles shown earlier in Figure 4.21, these periods roughly correspond with times when the wind and solar are either ramping up or down.

At this resolution, the impact on deltas is more apparent because they are not impacted by averaging. However, note that the extreme delta is only the largest delta observed at that hour over the year, but it may not be representative of all deltas in that hour. Regardless, the extreme delta represents an event during the year that the system must get through, operationally. For 30% penetration, the extreme net load deltas are far greater than the baseline deltas. The maximum one-hour net load rise is 5,644 MW in the early afternoon, and the maximum one-hour net load drop is 4,931 MW in the late evening. Both have a significant wind and solar component superimposed on load.

Figure 5.7 shows the profile of load and net load deltas in April at the footprint level. Comparing this plot to Figure 5.6, one can see how the differences in variability are more pronounced when shorter time periods are considered. The month of April was previously shown (Figure 4.35) to have a tremendous amount of net load variability. This shows up as difference in the heights of the magenta and blue bars across the daily hours of April. The difference is more evident in the early morning and late evening hours, which is when wind is undergoing the most drastic changes.

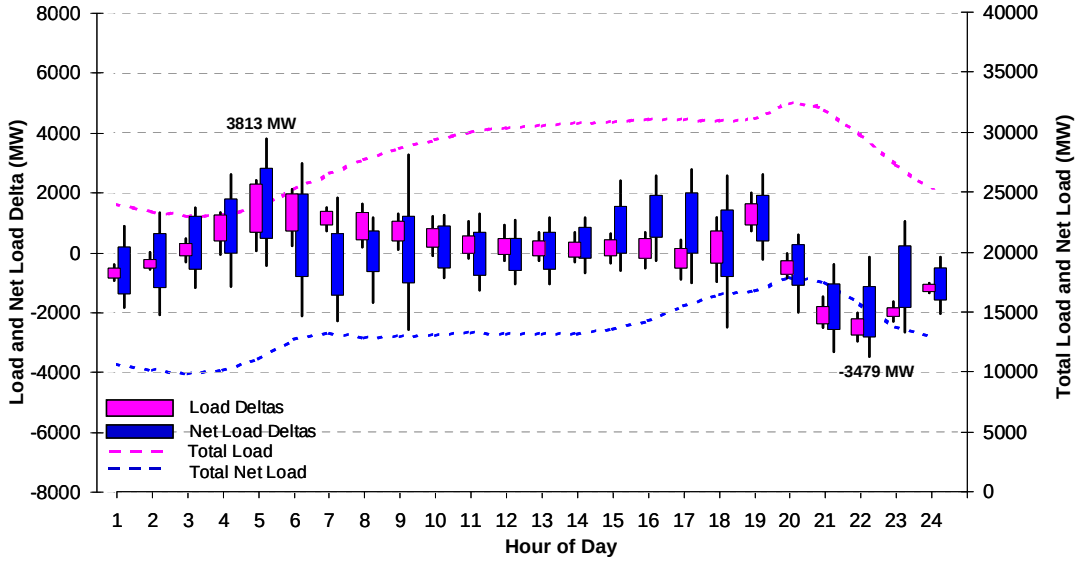


Figure 5.7 Study Footprint Average Daily Profile of Deltas Over April 2006, 30% LP Scenario

As discussed, higher spatial resolution will also reveal much about the time-of-day variability. The following plots show the profiles of deltas for several selected states.

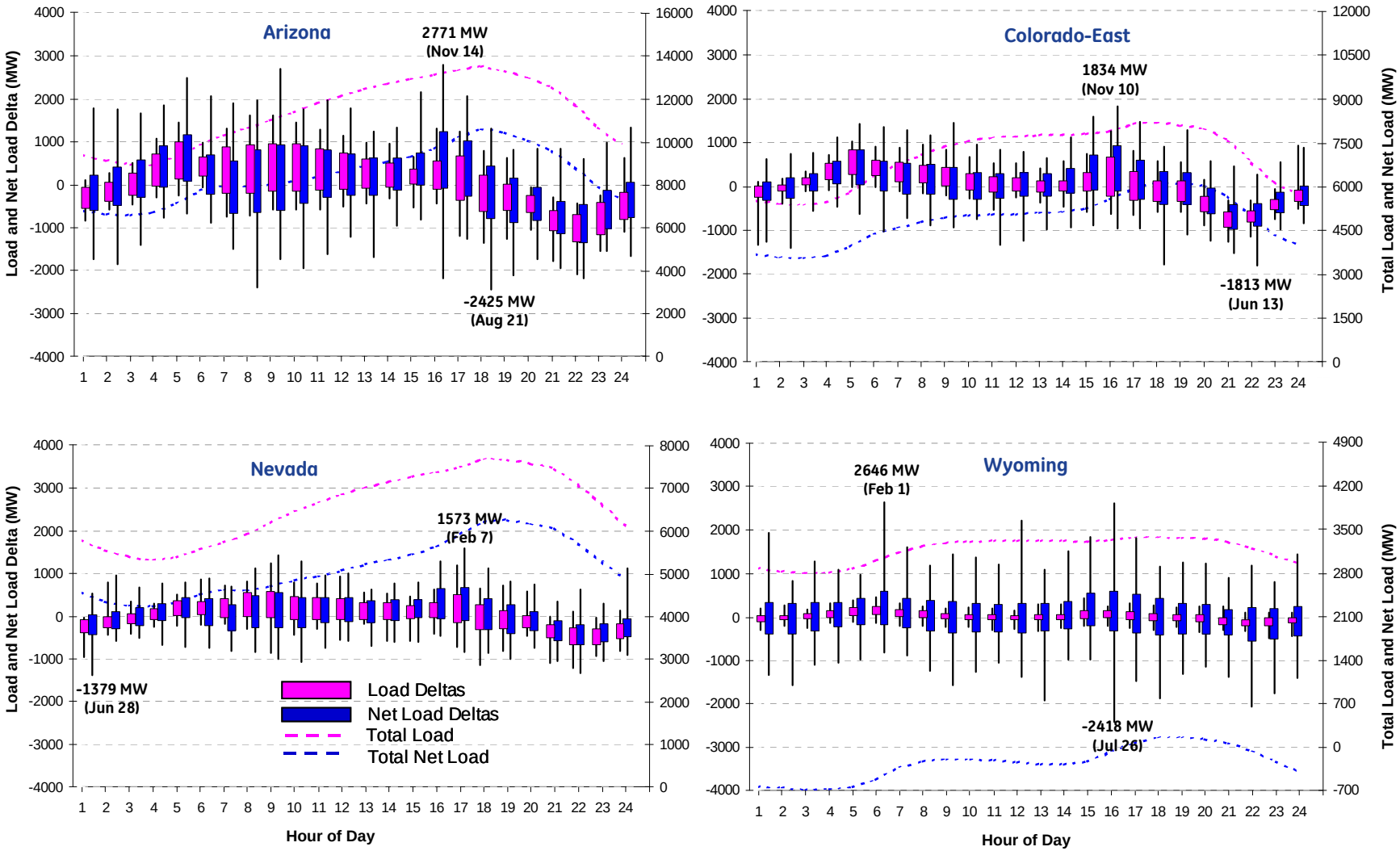


Figure 5.8 Average Daily Profile of Load and Net Load Deltas Over 2006 for Selected Areas, 30% LP Scenario

For the Local Priority scenario, each of the states in Figure 5.8 has a fairly large amount of wind, (as detailed in Section 2.5, but only Wyoming has an overwhelming amount compared to the load in the state. The delta profiles show that in each hour of the year, the load is insignificant compared to the net load variability. The same can be said of the net load extreme deltas compared to the load deltas. The maximum one-hour net load rise in Wyoming, 2,646 MW, occurs on the morning of February 1st, and the maximum one-hour drop of 2,418 MW, occurs in the afternoon of July 26th. In the other states shown, the ratio of installed wind to load is much smaller, so some patterns emerge. There is more net load variability in the early morning hours, afternoon, and late evening, all consistent with observations at the footprint level. As before, it is clear that even though the overall net load variability has increased, the largest (and most important) impact is on the extreme deltas, which increase dramatically in all hours, but especially during the mornings and afternoons. These are events that may place additional requirements on the ramp and range capability of the balance of generation.

Earlier in Section 4.3.3, the load, wind, solar and net load profiles for selected extreme delta days were examined to understand the drivers behind the magnitude and timing of large deltas seen at the footprint level. The profile of another such day, January 8th, 2006 is shown in Figure 5.9 below. The left plot reveals that the large afternoon ramp in the net load is due to the aggressive drop in wind and solar output around this time. The right plot indicates that a large portion of the wind roll-off is in Wyoming, and this creates a sustained afternoon net load ramp event in Wyoming that might be a challenge for Wyoming generation alone to follow — even at that time of day.

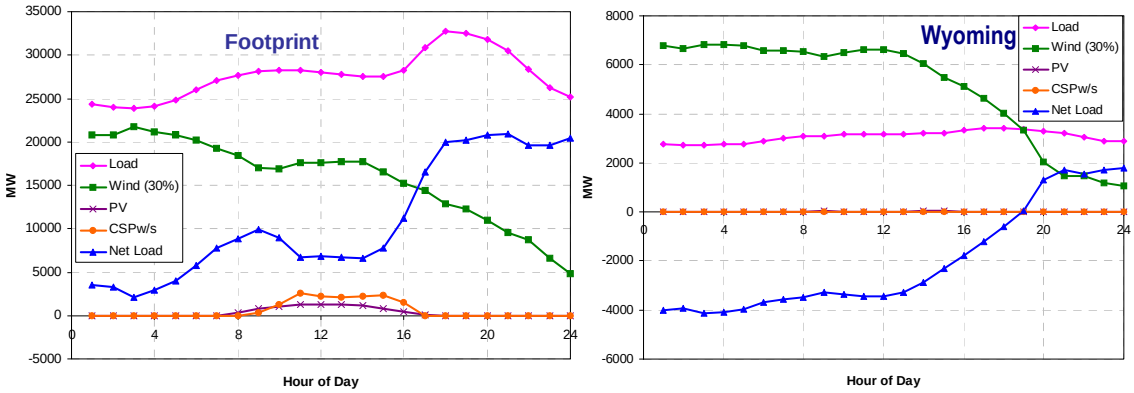


Figure 5.9 Study Footprint and Wyoming Net Load for January 8th, 2006, 30% LP Scenario

5.3 Variability by Time-of-Year

The timing of the net load deltas (both time-of-day and time-of-year) occur is just as important as the size of the deltas. A large net load up-ramp in the mid-morning may not be as challenging as a large up-ramp in the early morning hours. This is due to the fact that there is a more flexible mix of generation committed during the morning load rise hours than during the early morning hours when load is typically low. An examination of when large deltas occur should reveal some of the challenges presented by large penetration of wind and solar during specific times of the year.

Figure 5.10 shows the timing of the extreme positive load deltas in the footprint for 2006. The extreme deltas are presented in 24x12 surface plots using color intensity to represent the magnitude of the deltas. According to the legend, the areas of the plot shaded grey represent daily hours in particular months where the load is ramping down. Areas shaded dark yellow represent daily hours in particular months where the load increases by 3000 to 4000 MW in an hour.

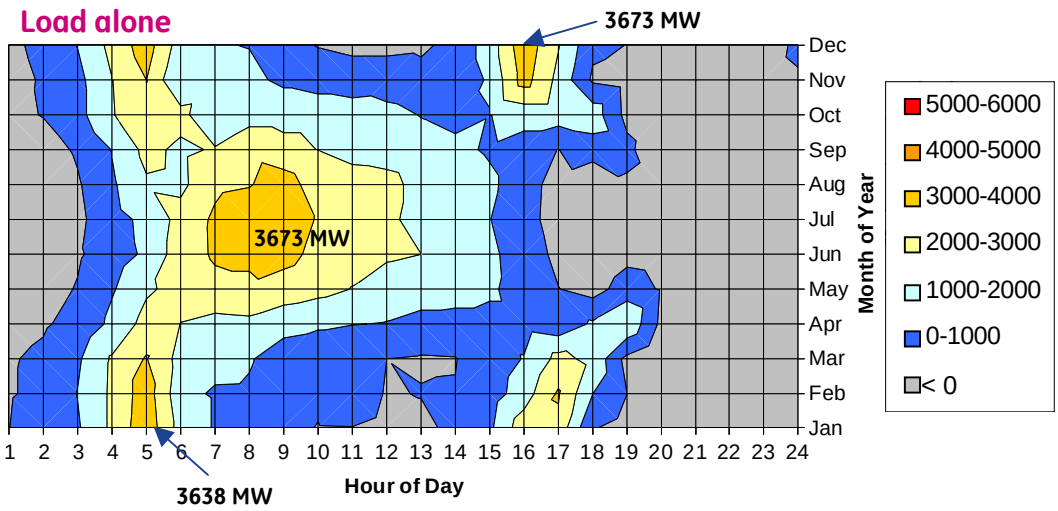


Figure 5.10 Timing of Extreme Load-Alone Positive Deltas in Study Footprint for 2006

This surface plot forms a basis for the comparison of net load deltas in the 10%, 20% and 30% penetration scenarios. With no additional wind or solar on the system (beyond the baseline), the largest one-hour load rises, at the footprint level, tend to occur during the summer morning and winter and winter afternoon hours. The largest such ramps, 3,673 MW, are observed in the 8-9 AM timeframe in July and the 4-5 PM hour in December. Across the year, the footprint load is ramping down from about 8 PM to 1 AM and there are practically no load up-ramps greater than 1,000 MW from about 7 PM to 3 AM.

Figure 5.11, Figure 5.12, and Figure 5.13, on the next page demonstrate how increasing amounts of wind and solar change the timing and magnitude of the extreme positive deltas across the year. The legend is kept the same as Figure 5.10 for all plots, so the color progression is a good indicator of incremental impact.

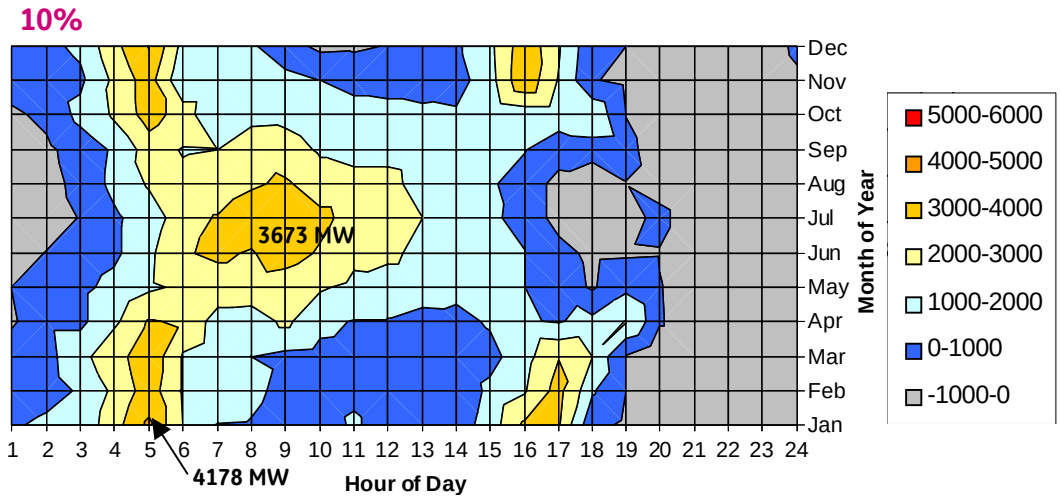


Figure 5.11 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 10% LP Scenario

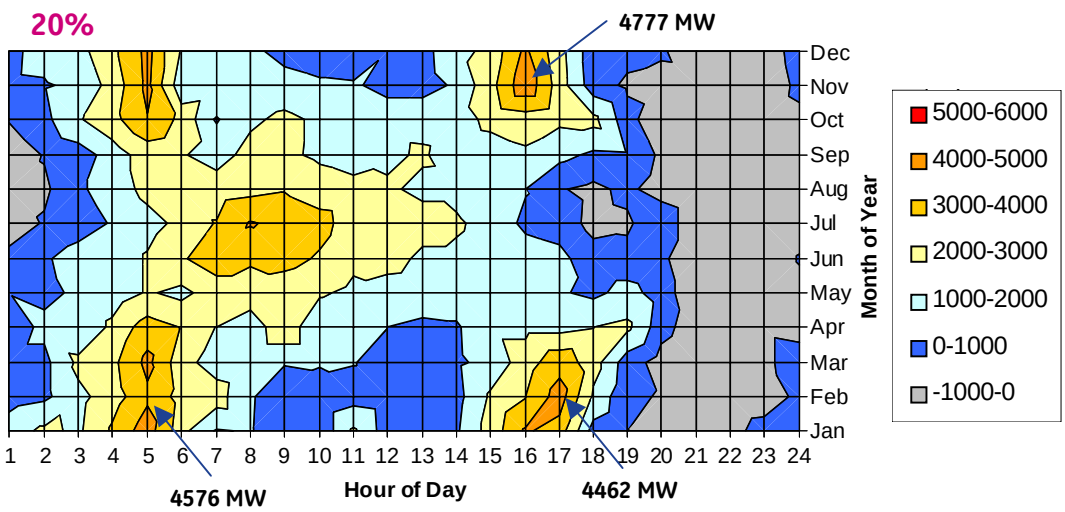


Figure 5.12 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 20% LP Scenario

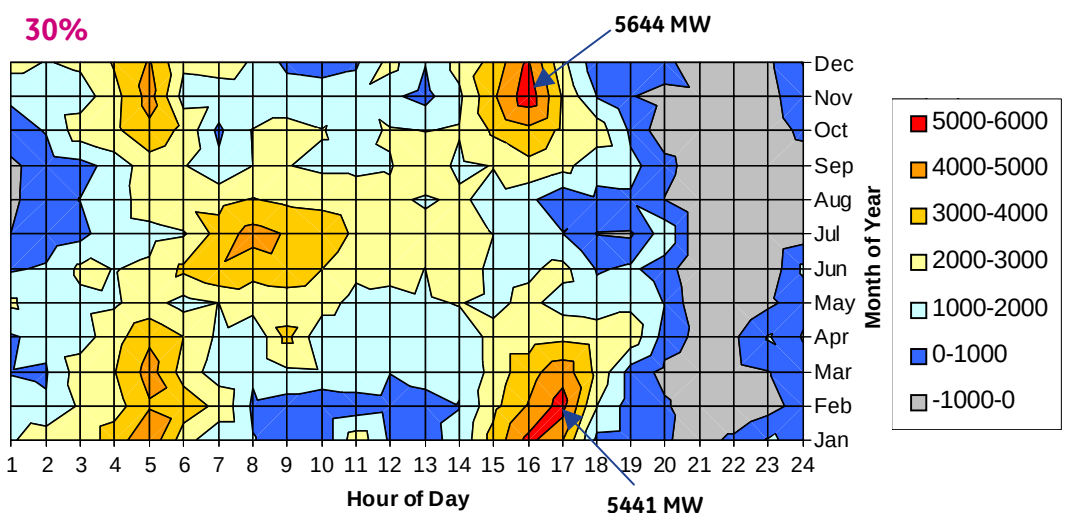


Figure 5.13 Timing of Extreme Net Load Positive Deltas in Study Footprint for 2006, 30% LP Scenario

As wind and solar penetration increases within the footprint, there is an overall shift in the timing and number and size of extreme net load deltas. At 30% large net load ramps show up in all months, but they tend to be more severe in the winter afternoon. This is consistent with the fact that wind and CSP drop-offs often coincide with the winter afternoon load rise, as shown earlier in Figure 4.32. Another observation is that the grey area which indicates the down-ramp times is squeezed down from about 5 hours in the baseline to about 3 hours between 9 PM and midnight. At 30%, there is now a greater requirement for ramping up capability during the minimum load hours, (less grey between 1-4 AM), than was present with no wind and solar output.

The surface plots below show the timing of the extreme negative load and net load deltas in the footprint for 2006. Admittedly, down-ramps are less of an operational concern as large wind up-ramps can always be curtailed. Nevertheless, the data shows that even with load alone, there are very substantial negative deltas in the late evenings, especially in summer months, driven by the customary load decline. With increasing wind and solar penetration, these extreme down-ramps progressively show up all across the year in the evening hours, and even in the late afternoons. However, even at the 30% penetration level, the worst net load down-ramp is only 16% worse that the load-alone down-ramp at that hour. This is entirely consistent with the earlier observations from Figure 5.2 that where there are only a few instances where wind and solar increases the net-load down-ramps beyond the ramps with load alone. Surface plots for other scenarios and areas are included in Appendix C.

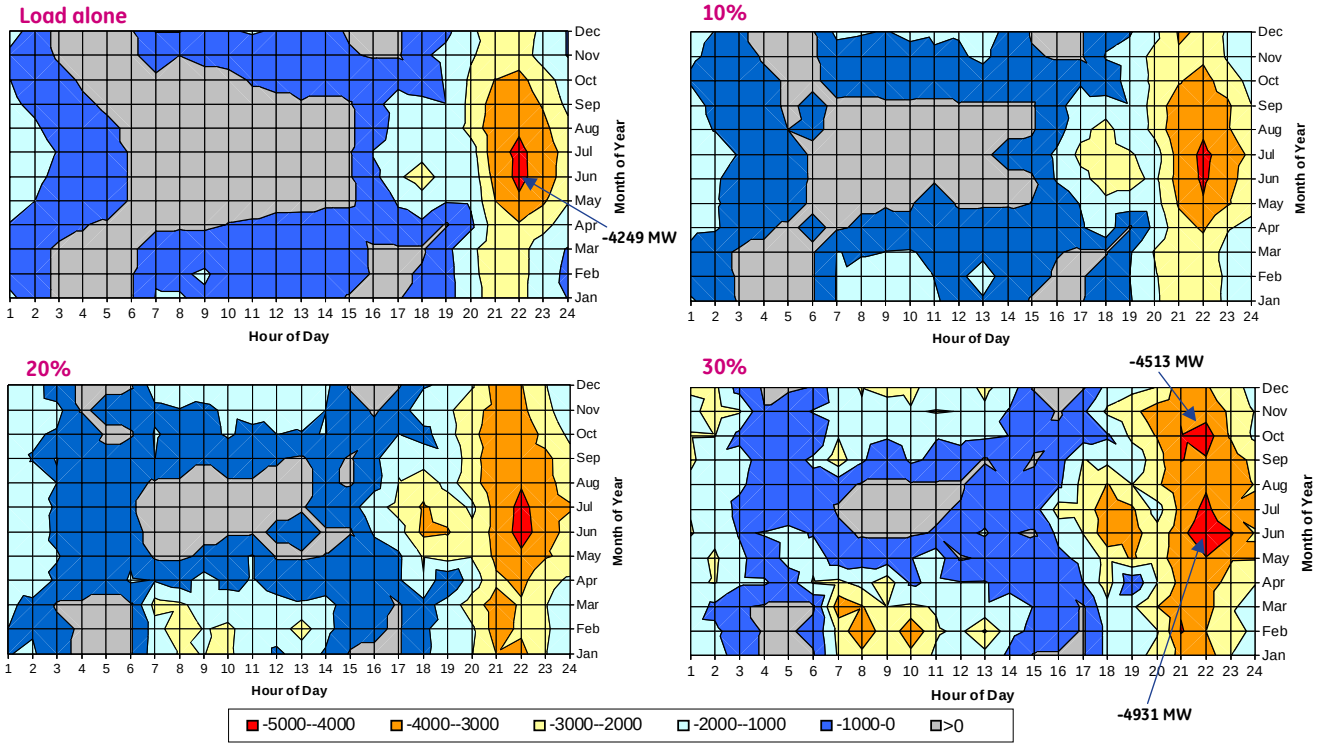


Figure 5.14 Timing of Extreme Net Load Negative Deltas in Study Footprint for 2006 LP Scenario

5.4 Analysis of Extreme Deltas

Figure 5.15 shows the distribution of one-hour deltas for the baseline, and net load at the footprint level for the 10%, 20% and 30% Local Priority scenario. The heights of the magenta bars represent the number of hours during 2006 when baseline deltas are in the range given by the bin on the x-axis. Similarly, the dark blue bars represent the number of hours during 2006 when net load deltas in the 30% scenario are in the range given by the bin on the x-axis. The top half of the plot shows the overall distribution of net load deltas, and the bottom half focuses on the tails of the distribution so the extreme deltas can be clearly seen. Table 5.1 is a summary of the footprint net load variability.

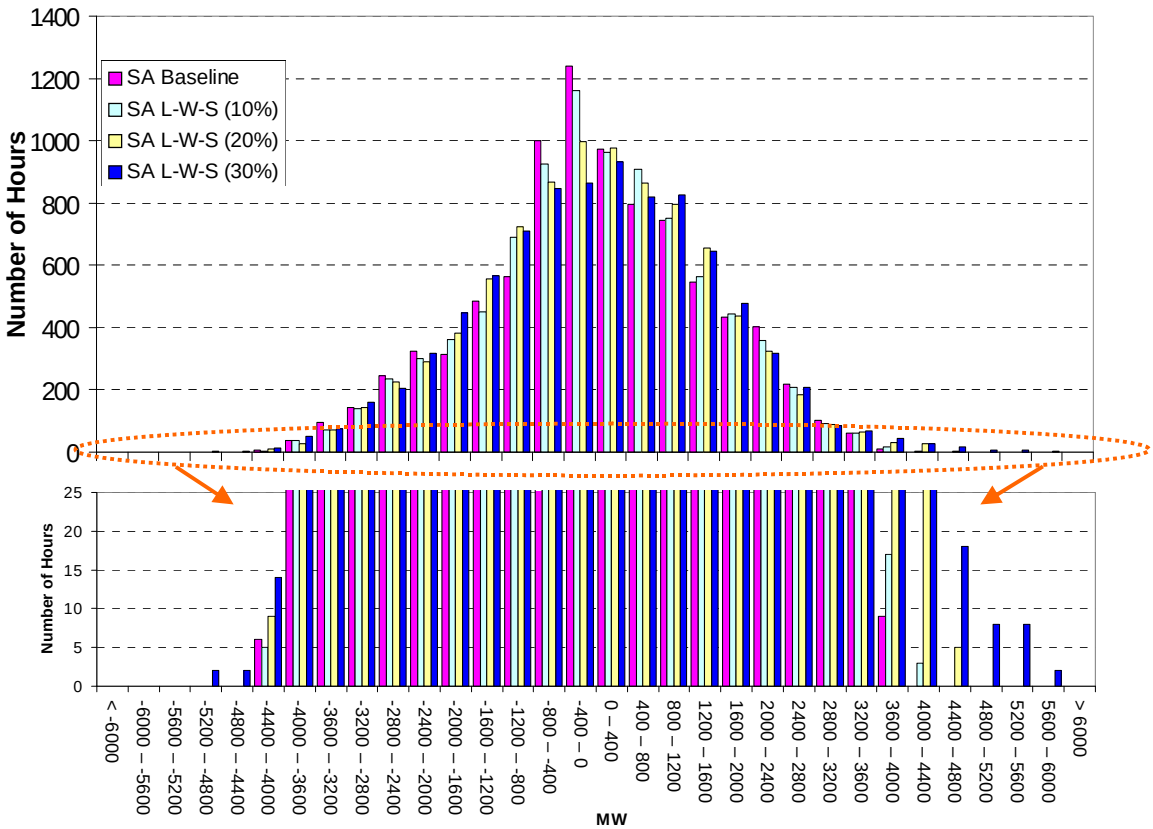


Figure 5.15 2006 Study Footprint Distribution of Net Load Deltas for LP Scenario)

Table 5.1 Summary of 2006 Footprint Net Load Variability for the for LP Scenario

Scenario	Sigma (σ) of Net Load Deltas (MW/hr)	Max. Negative Net Load Delta (MW/hr)	Max. Positive Net Load Delta (MW/hr)	No. Deltas > 3 * (load σ)	σ % Increase with Wind & Solar
Baseline	1,429	-4,282	3,793	0 / 0	--
10% LP Scenario	1,414	-4,195	4,178	0 / 0	-1.0%
20% LP Scenario	1,437	-4,359	4,777	1 / 2	0.6%
30% LP Scenario	1,523	-4,931	5,644	3 / 28	6.6%

For a particular penetration level, the shape of the overall distribution appears to be approximately normal. For a normal distribution, one would expect 99.7% of the deltas to be with 3 sigma of the mean. For the 30% scenario, $3\sigma = 4{,}569$ MW, and from the bottom half of Figure 5.15, one can see that approximately 99% of the deltas are within 4,400 MW of the mean. The bottom section confirms that there are significantly more extreme net-load deltas beyond the largest baseline delta, especially up-ramps (positive deltas). There are about nine baseline deltas between 3,600 MW and 4,000 MW, but several times more for the 30% LP Scenario – the largest being larger than 5,600 MW.

The spread in the distribution of deltas going from the baseline to 30% indicates that the net load variability increases with higher wind and solar penetration. The data in Table 5.1 bears this out, but at the footprint level the overall increase in variability is not dramatic. The sigma of the deltas actually decreases from the baseline to 10% penetration, and is 6.6% greater than the baseline at 30% penetration. The difference in variability between 10% and 20% penetration is significantly less than between 20% and 30% penetration.

Power system operations are predominately focused on managing the extreme events rather than the average system behavior. Table 5.1 shows that the increase in the number and severity of extreme deltas at the footprint level (as penetration goes from baseline to 30%) is much more impressive than the increase in overall sigma. At 30% penetration, the largest net load up-ramp is almost 50% larger than at the baseline, and there are many more of these on the tails of the distribution. To better illustrate this point, Figure 5.16 on the next page plots the cumulative distribution of the deltas on the tails of the distribution. For a point on the curves, the y-axis gives the number of one-hour large drops or rises in net load that are equal to or larger than the corresponding value on the x-axis.

Figure 5.16 makes a great case for load participation in managing the impact of extreme positive delta on operations. Consider the right half of the figure where wind and solar drops increase net load up-ramps. In the baseline case, there are nine up-ramps of 3,600 MW/hr or more. Contrast this to the 30% penetration case, where there are 152 up-ramps of 3600 MW/hr or more. As you move along the blue trace, the size of the extreme deltas increase, but the frequency also decreases. Instead of carrying reserves to cover all large infrequent events, demand-side participation could alleviate the need for additional resources and ensure reliable and economic power system operation. Further analysis in Chapter 6 and Chapter 7 underscore this point.

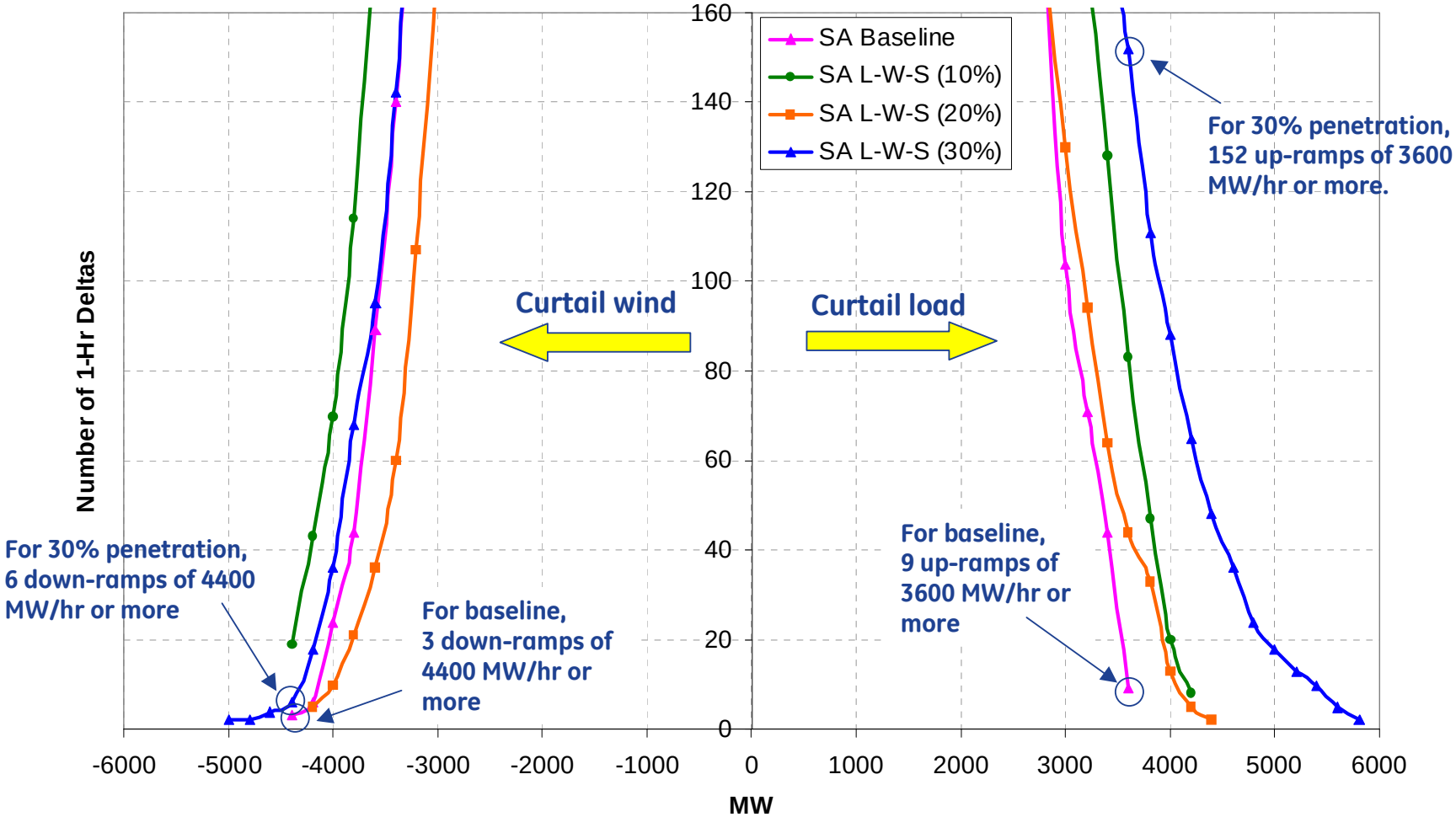


Figure 5.16 Study Footprint Distribution of Extreme Hourly Net Load Deltas 2006 Local Priority Scenario

5.5 Area-to-Area Variability

Up to this point, most of the discussion of deltas has focused on the total footprint wind, under the assumption that balancing on a wider area has certain operational merits. This section discusses variability within individual states for the three scenarios and contrasts the experiences at this level with the experiences at the footprint and WECC level. Table 5.2 summarizes the net load statistical variability measures for the states in the study footprint, the total footprint and WECC for all scenarios.

The first section of Table 5.2 shows sigma of the one-hour deltas for increasing levels of wind and solar. As discussed the previous section, variability increases with wind and solar penetration regardless of area or scenario. This is not surprising. What is interesting, however, is the rate at which the variability increases relative to the size of the area and the amount of renewables it contains. Figure 5.21 shows the percent increase in net load variability (over the load-alone case) for the In-Area scenario.

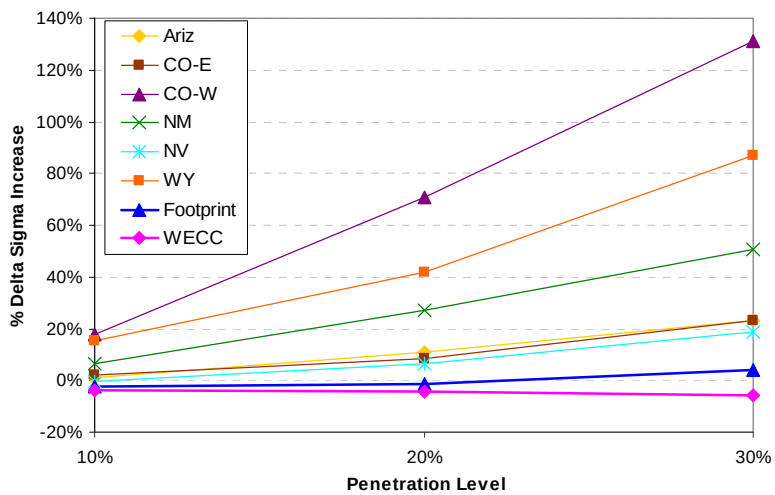


Figure 5.17 Percent Increase in Net Load Delta Sigma in all Areas for In-Area Scenario

The three smallest areas by load (and wind in the In-Area scenario), Colorado-West, Wyoming and New Mexico, show the largest relative increase in variability with penetration. At the 30% penetration level, sigma of the one-hour deltas in Wyoming is 87% larger than with load-alone. As the area size becomes larger, the variability grows a lot slower. At the footprint level, sigma at 30% penetration is only 4% higher than sigma with load-alone. For all of WECC, sigma at 30% penetration is actually less than the sigma with load alone. This observation speaks volumes about the impact of diversity and wide-area aggregation on variability. For the Local Priority and Mega Project scenarios, the impact of wide-area aggregation is even clearer for Wyoming. For LP and MP at the 30% penetration level, sigma of the one-hour deltas in Wyoming is 318% and 652% larger than with load-alone respectively. However, at the footprint level, the growth is only 6% and 11% respectively.

Table 5.2 Summary Statistics for In-Footprint States, Total Footprint and WECC for all Scenarios in 2006

Area:	Ariz			CO-E			CO-W			NM			NV			WY			Footprint			WECC		
Scenario	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**	**IA**	**LP**	**MP**
Sigma (MW)																								
Load-alone	584	584	584	368	367	367	37	37	37	152	152	152	312	312	312	87	87	87	1433	1433	1433	4387	4384	4384
Baseline (Existing)	583	583	583	375	374	374	37	37	37	158	158	158	311	311	311	101	101	101	1429	1429	1429	4392	4392	4392
10% In FP Scenario	591	587	573	376	377	376	44	41	38	162	170	192	311	315	311	101	118	188	1401	1414	1426	4229	4240	4248
20% In FP Scenario	647	613	587	399	401	379	64	57	38	194	203	228	333	331	313	124	212	434	1417	1437	1480	4190	4209	4230
30% In FP Scenario	719	657	616	453	427	380	86	73	40	230	240	288	370	352	317	164	366	658	1491	1523	1594	4137	4153	4182
	Ariz			CO-E			CO-W			NM			NV			WY			In Foot Print			WECC		
Max Neg Delta (MW)	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP
Load-alone	-2088	-2088	-2088	-1340	-1340	-1340	-120	-120	-120	-515	-515	-515	-1201	-1201	-1201	-316	-316	-316	-4250	-4250	-4250	-13448	-13435	-13435
Baseline (Existing)	-2087	-2087	-2087	-1337	-1337	-1337	-120	-120	-120	-522	-522	-522	-1201	-1201	-1201	-529	-492	-492	-4282	-4282	-4282	-13385	-13385	-13385
10% In FP Scenario	-2184	-1886	-1941	-1321	-1317	-1323	-199	-151	-128	-514	-571	-874	-1660	-1342	-1156	-508	-547	-1359	-4053	-4195	-4434	-12724	-12861	-13157
20% In FP Scenario	-2492	-2115	-1867	-1624	-1627	-1306	-312	-255	-135	-869	-982	-1186	-1252	-1368	-1260	-650	-1412	-3204	-4168	-4359	-5511	-12401	-12396	-12840
30% In FP Scenario	-3043	-2425	-2354	-1913	-1813	-1298	-460	-404	-135	-1146	-1242	-1427	-1407	-1379	-1327	-1086	-2418	-4798	-4534	-4931	-6729	-12274	-12532	-12552
	Ariz			CO-E			CO-W			NM			NV			WY			In Foot Print			WECC		
Max Pos Delta (MW)	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP
Load-alone	1601	1601	1601	1172	1172	1172	130	130	130	636	636	636	1234	1234	1234	505	505	505	3674	3674	3674	10722	10715	10715
Baseline (Existing)	1600	1600	1600	1692	1257	1257	130	130	130	605	605	605	1229	1229	1229	435	435	435	3793	3793	3793	10896	10896	10896
10% In FP Scenario	1858	1852	1642	1479	1280	1266	202	157	131	616	626	887	1185	1170	1200	429	539	1290	4178	4178	3898	10967	10959	10983
20% In FP Scenario	2732	2295	2165	1416	1445	1281	351	281	131	875	957	1120	1492	1394	1176	506	1537	3085	4853	4777	4499	11676	11366	12202
30% In FP Scenario	3483	2771	2564	2097	1834	1364	512	373	152	1047	1129	1355	1711	1573	1383	809	2646	4487	5820	5644	5864	15271	14383	14318
	Ariz			CO-E			CO-W			NM			NV			WY			In Foot Print			WECC		
No. Drops > 3* Ld Sigma	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP
Load-alone	2	2	2	4	4	4	10	10	10	5	5	5	6	6	6	5	5	5	0	0	0	1	0	1
Baseline (Existing)	2	2	2	5	5	5	10	10	10	5	5	5	6	6	6	39	38	38	0	0	0	1	0	1
10% In FP Scenario	3	2	1	11	13	13	38	24	10	15	27	73	8	8	6	35	98	367	0	0	1	0	0	0
20% In FP Scenario	23	7	3	24	25	14	218	133	11	72	90	143	17	12	6	112	469	1164	0	1	9	0	0	0
30% In FP Scenario	52	20	13	45	31	13	485	310	11	144	176	300	34	16	6	278	1009	1492	3	3	15	0	3	0
	Ariz			CO-E			CO-W			NM			NV			WYCE			In Foot Print			WECC		
No. Rises > 3* Ld Sigma	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP
Load-alone	0	0	0	4	4	4	8	8	8	12	11	11	3	3	3	45	45	45	0	0	0	0	1	0
Baseline (Existing)	0	0	0	3	2	2	8	8	8	13	13	13	3	3	3	65	65	65	0	0	0	0	1	0
10% In FP Scenario	3	3	0	2	3	2	38	26	10	26	37	83	7	8	6	69	118	417	0	0	0	0	0	0
20% In FP Scenario	30	12	7	22	21	7	249	178	11	84	100	162	22	22	7	140	530	1198	10	2	5	0	0	0
30% In FP Scenario	63	32	32	81	56	12	491	340	35	168	187	328	67	43	10	326	1061	1555	29	28	26	4	0	3

The second and third sections of Table 5.2 list the largest negative and positive deltas in each area for all scenarios. A similar observation can be made about these extreme deltas. As the penetration of wind and solar increases, the magnitude of the extreme delta grows much faster in small areas than in large areas and on a aggregated basis. Figure 5.18 shows the percent increase in net load extreme deltas (over the load-alone case) for the In-Area scenario.

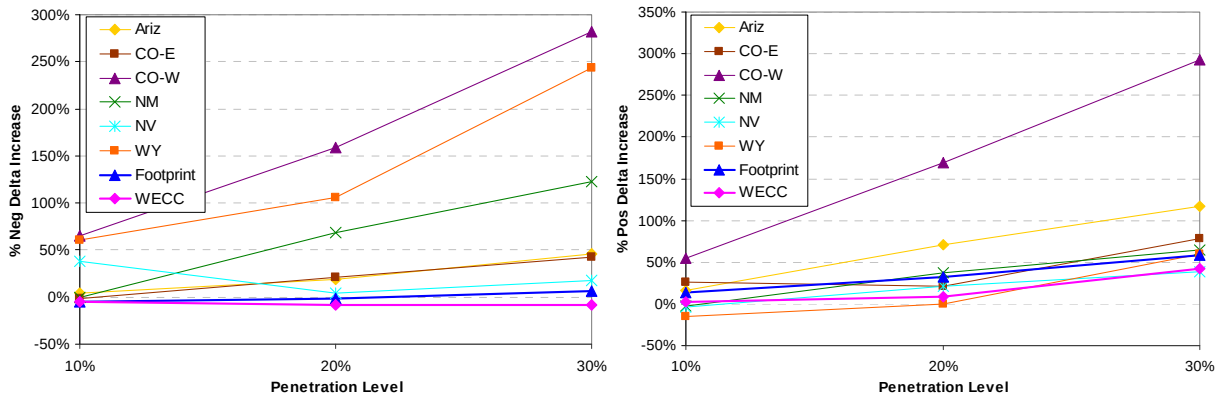


Figure 5.18 Percent Increase in Net Load Negative and Positive Deltas in all Areas for In-Area Scenario

In general, the smaller the area, the more the extreme deltas increase with larger amounts of wind and solar on the system. In Colorado-West for example, the largest drop in net load with 30% penetration is 460 MW, 282% higher than with load alone (120 MW). By contrast, in Arizona the largest drop in net load with 30% penetration (3043 MW) is 46% higher than with load alone (2088 MW). At the aggregate footprint level, the increase in the largest net load drop at 30% penetration is only 7%.

Drops in net load are caused by sudden increases in wind and solar. What is more operationally challenging are sudden drops in wind and solar which lead to increases in net load or positive deltas. The second chart in Figure 5.18 shows that large increases in net load are also mitigate over wide areas, though not as much as large drops. Previous analysis has demonstrated that there are many more extreme positive deltas than negative ones, and that they tend to be larger. This chart also suggests that large wind and solar drops tend to be more coincident across wide areas than large rises. This is consistent with earlier observations that wind and CSP drop-offs often coincide with the winter late afternoon load rise, to create large net load up-ramps in those hours. Therefore, in a large area and at the footprint level, the reduction in the growth of the largest positive delta is not as dramatic. In Colorado-West, the largest rise in net load with 30% penetration (512 MW) is 292% higher than with load alone (130 MW). However, at the aggregate footprint level, the increase in the largest net load rise at 30% penetration is still a pretty robust 58%. It's interesting to note that in this case, the largest area, Arizona, has the second largest rate of increase in positive net load deltas. This may be due to the relatively large amount of CSP with storage in Arizona that contributes to increased positive net load deltas when it rolls off in the late afternoon.

Nevertheless, data from this scenario and the other two confirm the fact that extreme drops and rises in net load are mitigated over wide areas.

The last two sections of Table 5.2 list the number of negative and positive deltas larger than a certain value in each area for all scenarios. In this case the value is defined as three times the sigma of the load delta (3* load sigma). Since the load is the same for each penetration level, 3* load sigma defines the default level of variability, and serves as a yardstick to measure how much wind and solar increase the number of extreme deltas. Once again the data highlights the fact that smaller areas have more extreme deltas than larger ones, and as penetration increases, the number grows faster. For the In-Area scenario, Colorado-West has 491 large net load up-ramps at 30% penetration, but at the footprint level, there are only 29 instances where wind and solar increase the net load up-ramps beyond those experienced with load alone.

Finally, to summarize the case for wide-area aggregation, Figure 5.19 plots the duration of all the net load deltas for the 30% Local Priority scenario. The chart includes a blow-up of the area around the largest positive deltas and the largest negative deltas. The top chart in Figure 5.19 shows the overall duration of the deltas for the year. At the footprint level, the one-hour net load rises are at least 2,000 MW for 10% of the year and the one-hour drops are also 2,000 MW or more for 10% of the year. The plot appears to roughly symmetrical, but with slightly more positive deltas than negative ones (i.e. crossover is not at 50%).

The bottom left inset shows the top 1% of positive deltas in each area. At the footprint level, net load positive deltas are 4,800 MW or more for .2% of the year (175 hours), whereas in Arizona, net load positive deltas are 2,100 MW or more for .2% of the year. The key observation, however, is that the maximum positive deltas in each area do not occur simultaneously across the footprint. If they did, the maximum one-hour rise in aggregate net load would be 10,300 MW. Even though more than half the wind and solar in this scenario is in Arizona and Wyoming, geographic diversity in the output ensures that the observed maximum one-hour rise at the footprint level is 5,644 MW, 45% less than the maximum possible one-hour rise. The bottom right inset tells a similar story for the negative deltas. At the footprint level, the largest one-hour net load drop is 4,931 MW. If all the largest drops in each area across the footprint coincided, the aggregate one-hour drop would be 9,682 MW. Geographic diversity over the footprint ensures that this is never the case in the 2006 data. These observations are consistent with earlier observations in this chapter and analysis in Chapter 6 which shows that balancing over a wider area leads to greater diversity, less relative variability and improved operations.

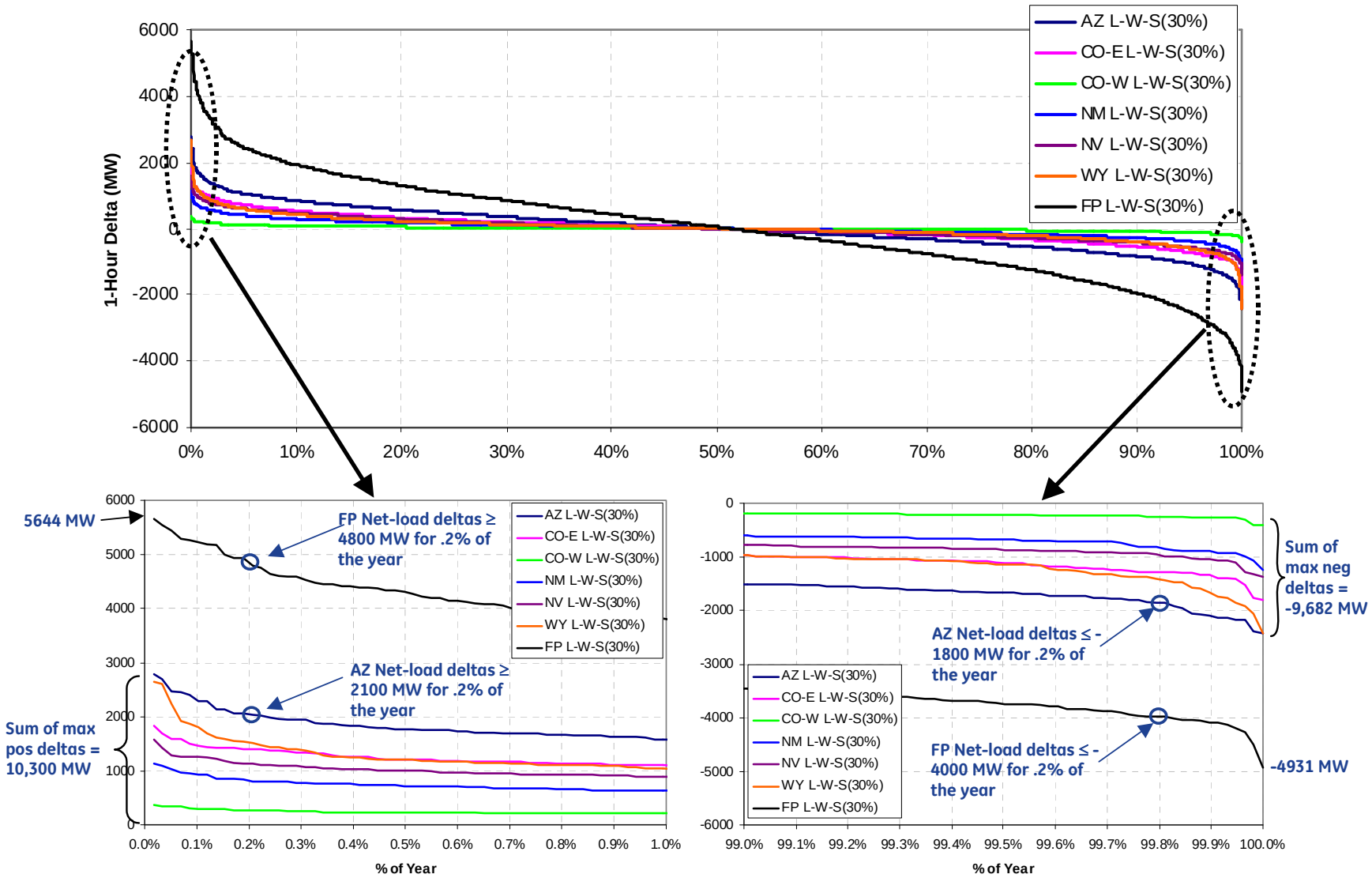


Figure 5.19 2006 Duration of Extreme Hourly Net Load Deltas in all Areas for 30% Wind LP Scenario

5.6 Forecast Error Analysis

Day-ahead predictability of net load is important to the unit commitment process. Inaccuracies (large forecast errors) may compromise reliability, increase operating costs and require greater ancillary service procurement.

For the purposes of this study, "forecast error" is defined as forecast minus actual. Therefore positive forecast error (forecasted quantity greater than actual) is defined as over-forecast and negative forecast error (forecasted quantity less than actual) is defined as under-forecast. Over-forecasting load may lead to more generation being committed than needed (which has potential economic consequences), while under-forecasting load may lead to under-commitment, which is a potential reliability problem. From a system operation point of view, net load under-forecasting is a more serious issue. Net load under-forecast errors are driven by wind over-forecast errors. Therefore positive wind forecast errors (times when wind is expected to show up and it does not) are more critical in this study.

Two statistical measures are normally used to characterize forecast accuracy. They are:

- **Mean Absolute Error (MAE)** – measures the average magnitude of the forecast errors considering their direction; mean of the absolute value of the errors.
- **Root Mean Square Error (RMSE)** – characterizes forecast error by measuring the "average" of the square of the deviations. RMSE will always be larger than MAE because it penalizes large deviations more.

Figure 5.20 shows the distribution of wind generation forecast errors for the total footprint during 2006, for the 10%, 20% and 30% Local Priority scenarios.

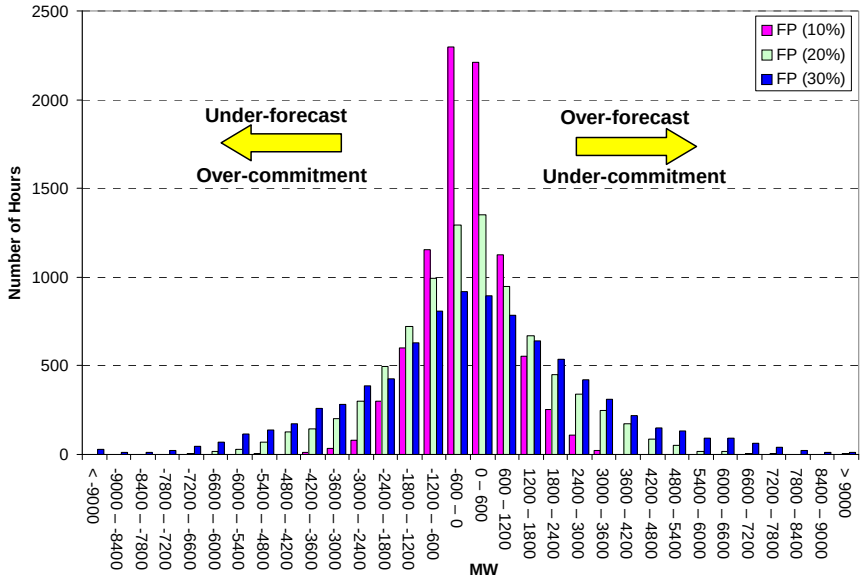


Figure 5.20 Distribution of Footprint Day-Ahead Wind Forecast Errors for 2006 10%, 20%, 30% LP Scenario

The distribution of forecast errors appears to quite symmetric, meaning that there is a general tendency to over-forecast as much as under-forecast wind output. As wind penetration increases, the number and size of large forecast errors also increase. On both tails, there is a significant increase in large errors going from 10% penetration to 30% penetration. At 10% penetration, there are no over-forecast errors greater than 4,300 MW (3*load sigma), but at 30% penetration there are 587 such errors. The largest over-forecast error at 30% penetration is 11,771 MW, compared with 3,603 MW at 10%.

As we saw in the variability analysis, the ability of an area to absorb large forecast errors improves as the area size gets larger. Table 5.3 shows a summary of the wind forecast errors in each area, at the footprint level and all of WECC for the 30% Local priority scenario. The data confirms that as we move from state to footprint to WECC, the error as a percent of the installed base becomes progressively smaller.

Table 5.3 Summary of Forecast Errors by Area, 30% LP scenario

	Installed MW	MAE MW	MAE %	RMSE MW	RMSE %	Max Neg Err MW	Max Neg Err %	Max Pos Err MW	Max Pos Err %
AZ	7,710	934	12.1%	1,333	17.3%	-6,909	-89.6%	5,357	69.5%
CE	4,650	570	12.3%	756	16.3%	-3,102	-66.7%	3,471	74.6%
CW	570	92	16.2%	128	22.5%	-489	-85.8%	475	83.4%
NM	2,970	450	15.1%	620	20.9%	-2,450	-82.5%	2,233	75.2%
NV	3,450	426	12.4%	612	17.7%	-3,048	-88.4%	2,144	62.1%
WY	7,410	1,018	13.7%	1,380	18.6%	-5,591	-75.5%	5,707	77.0%
FP	26,760	2,059	7.7%	2,694	10.1%	-11,515	-43.0%	11,771	44.0%
WECC	72,210	4,667	6.5%	6,012	8.3%	-30,934	-42.8%	19,337	26.8%

Figure 5.21 shows a scatter plot of the study footprint forecast errors and the wind forecast as a percent of the maximum forecast. For each 10% bin of wind forecasts, the blue, magenta and green lines show the 50th, 80th and 90th percentile forecast error. The shape of the plot suggests that forecast error is not a linear function of the wind forecast. Chapter 6, discusses the implications of discounting forecast to increase spin.

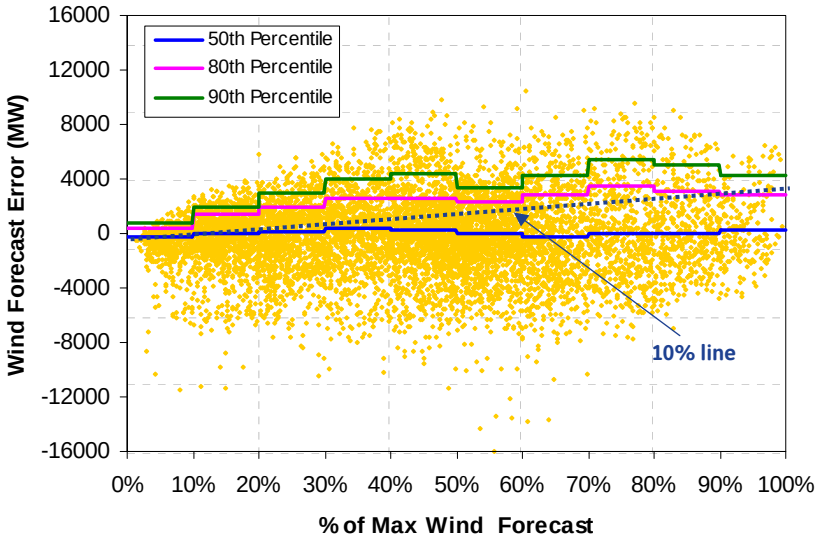


Figure 5.21 Study Footprint Next Day Wind Forecast Errors vs. Forecast, 30% LP Scenario

5.7 Observations and Conclusions

The variability of net load in the one-hour timeframe impacts various aspects of bulk power system operation including ramp and range requirements, operating reserves and unit commitment issues. Consequently, this chapter focused on the statistical character of load and net load variability in the hourly timeframe. Deltas or hour-to-hour differences are used to determine ramping requirements, and the standard deviation of the deltas is used as a measure of hourly variability.

Considering the wind and load deltas over several years of data, the study concluded that load and wind deltas are not highly correlated at the footprint level, and moreover large load deltas are not usually accompanied by similarly large wind deltas, i.e. the risk of simultaneous delta reinforcement is relatively small. Nevertheless, there are a few hours during the year when load and wind deltas combine to increase net load down-ramps, and many more hours where net load up-ramps are greater than the largest load-alone up-ramp. The latter events are driven by large wind drops and are more of an operational concern than the former.

At footprint and state level, more and larger extreme net load ramps tend to occur (1) during fall and winter late afternoons due to simultaneous load rise, and wind and solar (especially CSP) drops, and (2) during summer and early fall evenings driven by mostly evening load roll-off.

The size and number of extreme ramp events increase dramatically with wind and solar penetration. At 30% penetration, the largest net load up-ramp is almost 50% larger than at the baseline, and there are many more of these on the tails of the distribution. There is a good case to be made for load participation to reduce ramping requirements and alleviate the need for large amounts of reserves to extreme infrequent events.

Due to geographic diversity, extreme events and overall variability are mitigated when wind and solar generation is aggregated over a wide area. In each scenario the variability more than doubles for certain states, from baseline to 30% penetration. However and the footprint and WECC level, the increase in variability is relatively modest. The study concluded that wide area balancing leads to greater diversity, less relative variability, and reduced ramping requirements.

Day-ahead predictability of net load is important to the unit commitment process. Inaccuracies (large forecast errors) may compromise reliability, increase operating costs and require greater ancillary service procurement. At the footprint level, the distribution of forecast errors is symmetric, and the size and number of large errors increase as wind penetration increases. As with variability, the ability of an area to absorb large forecast errors improves as the area size gets larger. Forecast error is not a linear function of the wind forecast.

6 Operational Analysis

The purpose of the operational analysis is to evaluate the operational feasibility of integrating large amounts of intermittent renewable generation into the study area footprint and WECC. A range of renewable penetrations were considered as well as various system sensitivities such as fuel prices, hydro flexibility and non-renewable generation expansion plans. The analysis was performed using the GE Multi Area Production Simulation program, MAPS, which performs a day ahead unit commitment and an hourly dispatch recognizing transmission constraints within the system and individual unit operating characteristics. As a bi-product of the analysis the cost and emission impact of the renewables were also determined. While that information is useful and of interest to many it is important to recognize that it is not the intent of this study to economically justify renewable generation. This study seeks to determine the overall feasibility of incorporating large amounts of wind and solar generation into the operation of WECC, what operational challenges might arise and what changes might be required to facilitate this integration.

6.1 Assumptions

The operation of WECC was simulated for the year 2017 with the renewable scenarios described in Chapter 3. The basic WECC system was developed from publically available generation and data from the Velocity Suite database of Ventyx along with transmission interface data from WECC and load forecasts based on NERC peak load projections. An additional 24 GW of thermal capacity was added to the roughly 200 GW of existing generation to cover the load growth through 2017. Over half of this was specific units that are currently under construction or in advanced development stages. Additional combined cycle and peaking generation was added to maintain historical regional reserve margins. No changes were made to the base expansion plan when renewable generation was added in order to avoid clouding the results with secondary changes. A sensitivity case was examined which excluded the additional unit additions to match the capacity value of the renewable units based on the reliability analysis discussed in Chapter 9.

The key 2017 fuel prices were coal at roughly $2/Mbtu and natural gas at $9.5/Mbtu with some seasonal and regional variations as appropriate. An initial carbon tax of $30/ton was assumed. Gas prices have dropped some since the start of the study so a sensitivity case examined the operation of the system if gas prices drop enough to make the operating costs of combined cycle units attractive relative to coal generation with a carbon tax. The WECC system was modeled as over 100 separate load areas with transfer limits between the areas. These areas were grouped into five regions for operations and summary purposes. The base spinning reserve was assumed to be 3% of the hourly load. The base cases did not change the spinning reserve as renewables were

added to the system. Sensitivity cases examined the impact of increasing the spinning reserve requirement based on renewable penetration. The system was committed and dispatched in an economically rational manner for all of WECC, recognizing the limitations of the transmission system and the cycling capability of the individual generators. The WECC system was divided into 106 load zones that were assigned to 20 transmission areas. Interface constraints were defined between neighboring transmission areas. The load zones were also grouped into five regions for operating reserves. As the statistical analysis showed, incorporating large amounts of intermittent renewable generation without consolidation of the smaller balancing areas in either a real or virtual sense is a non-starter.

The important assumptions in this analysis surrounded the treatment of the wind and solar generation. Hourly generation profiles were generated for each of the sites based on historical weather data for the study years 2004, 2005 and 2006. These were then time -synchronized with historical load profiles from the same years in order to capture any correlation between the load and the wind and solar generation. The load profiles were escalated to the 2017 peak and energy projections as mentioned above. Of prime importance is that a second set of wind and solar profiles was also created for each site that specified the day ahead forecast of the renewable generation based on the day-ahead weather forecast. The MAPS model uses a separate renewable generator forecast profile for the day-ahead commitment decision as compared to the real time dispatch.

The various penetration scenarios were examined using these "State-of-the-Art" forecasts as well as with perfect forecasts in order to evaluate the impact of the variability independent of the forecast accuracy. Sensitivity cases were also examined which considered zero forecasts in the day-ahead operations.

The bulk of the cases and sensitivities were run using the 2006 shape and the In-Area site selection scenario. Results for the other annual shapes and siting are shown as additional sensitivities.

6.1.1 Scenario Naming Conventions

For the summary results it was necessary to develop a shorthand naming convention to describe the various cases. The convention is: Scenario – Penetration – Forecast – Sensitivity. The allowable options for the first three categories are shown in Table 6.1. The sensitivities will be explained as they are introduced.

Table 6.1 Scenario naming conventions

Scenario	Penetration	Forecast
I – In Area	Pre – Preselected Sites	P – Perfect Forecast
M – Mega Project	10 – 10% Scenario	R – State of the Art Forecast
L – Local Priority	20 – 20% Scenario	N – No Forecast
	2020 – 20/20% Scenario	
	30 – 30% Scenario	

As an example, a case labeled I10P would refer to the In-Area scenario, 10% penetration with a perfect forecast. In addition a "No wind" case was run for comparison purposes.

6.2 Annual Operational Impacts

A variety of metrics are presented to address the question "What happens to the operation of the system with high levels of intermittent renewable generation?" These include annual generation displacement by type, system operating costs and spilled energy. An important measure is the hourly marginal cost of energy, or spot price. In a deregulated market this is the price paid for energy each hour, but it is useful in a regulated market as an hourly measure of the value of the energy. When transmission constraints are present, these values will vary across the system for any given hour but they can be weighted by the hourly load in the area to produce a system spot price. These were calculated chronologically for each hour of each year for each scenario. They were then sorted for easy comparison of the overall impacts. Figure 6.1 shows these annual system spot prices for five levels of renewable penetration for the In-Area scenario assuming perfect day-ahead forecasting of the wind and solar generation.

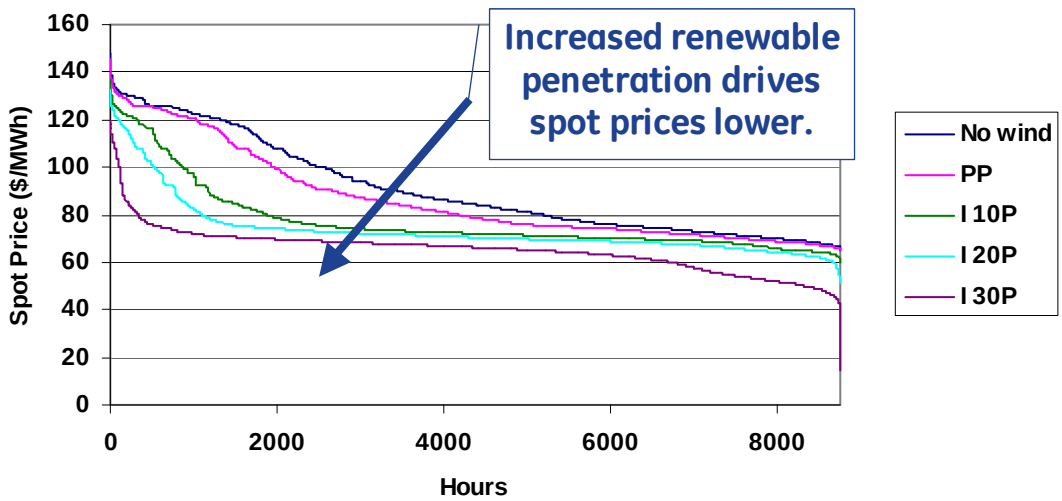


Figure 6.1 Annual spot price duration curve, perfect forecast, In-Area scenarios

With no renewable generation on the system, the spot price ranges from a high of roughly $150/MWh to a low of about $65/MWh. The Preselected case (P) caused a slight drop in prices because the highest cost units in the system are being displaced. As the penetration levels increase, the spot prices are driven down even further as the more expensive generation is eliminated from the hourly dispatch. At the 30% penetration level the highest cost is about $120/MWh and the lowest is about $40/MWh with a few hours going as low as $15/MWh.

Figure 6.2 shows the same scenarios when an unbiased State-of-the-Art (S-o-A) forecast is assumed. The initial trend is the same for low levels of penetration because the forecast errors are less than the spinning reserve and therefore can be covered without

stressing the system. But as the penetration levels increase, the forecast error starts to have an impact. When the wind and solar forecast is too high, peaking generation must come on to cover the shortfall, and in some hours there may be unserved energy because there is not enough local peaking generation available. At the other extreme when the wind and solar forecast is too low, then too many generators will be committed that must then be backed down to minimum operating levels and some spillage of the wind generation may occur during off-peak periods when the loads are low. The 30% case has over 100 hours when the spot price has dropped below $20/MWh.

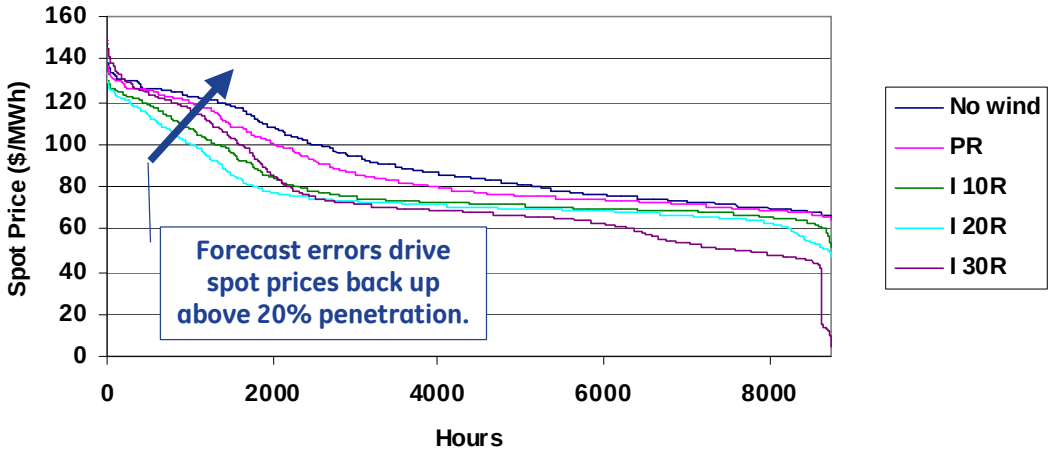


Figure 6.2 Annual spot price duration curve, S-o-A forecast, In-Area scenarios

Figure 6.3 shows the total generation by type for all of WECC for various In-Area scenarios. The bulk of the energy that is displaced by the renewable generation is coming out of the combined cycle (CC) units with some slight variations in the simple cycle gas turbines (GT), pumped storage hydro (PSH), and steam oil and gas units (ST). The steam coal units (ST-COAL) are only affected at the higher penetrations. The hydro generation (HY) did not change their annual energy output but their hourly output patterns were shifted, as will be examined later. Figure 6.4 shows that the results are similar for the study footprint.

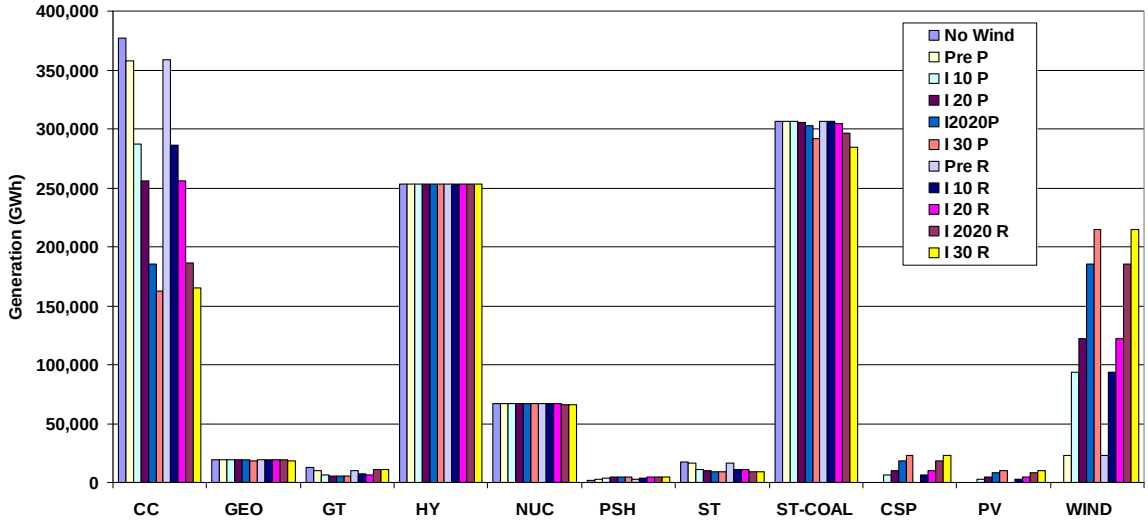


Figure 6.3 Generation by type - WECC – 2006

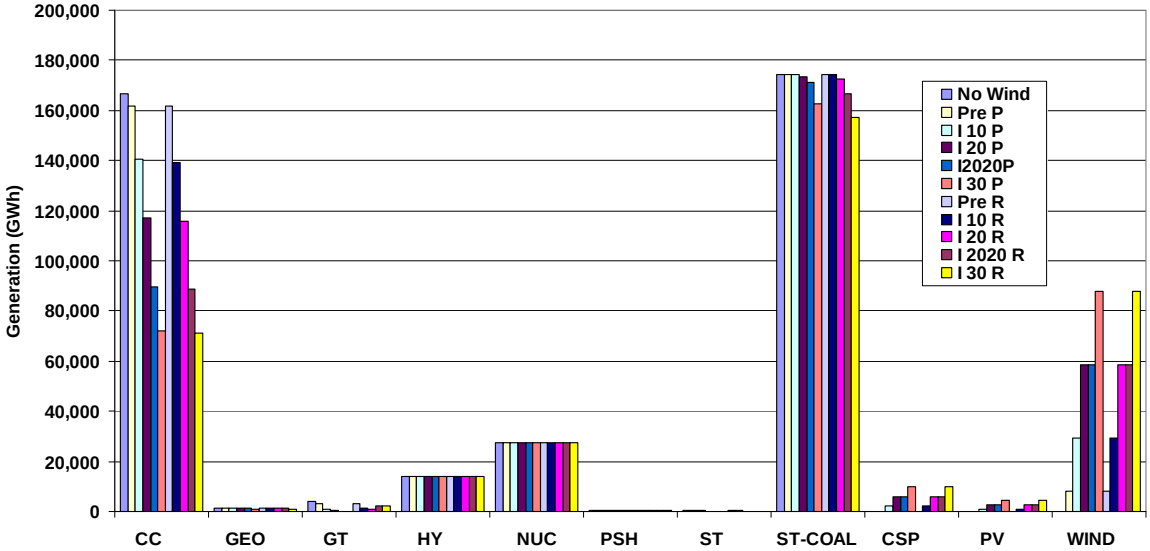


Figure 6.4 Generation by type - study area - 2006

Figure 6.5 shows the WECC-wide operational cost savings, that is, the reduction in fuel, variable O&M and startup costs for the various cases. These reductions, or operational savings, are all relative to the "No Wind" case.

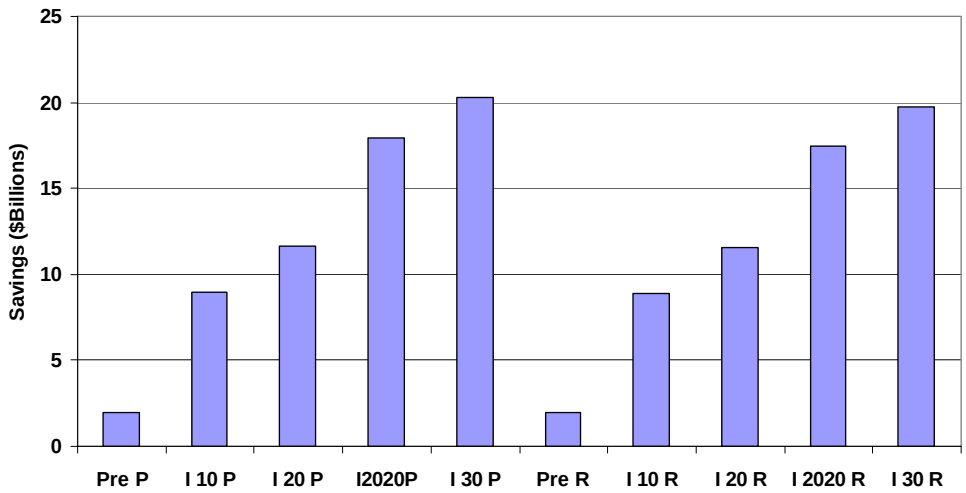


Figure 6.5 Operating cost savings ($B) - WECC – 2006

If we divide the savings in this figure by the amount of renewable energy in each case then we get the results shown in Figure 6.6. This shows the average value of the renewable energy in each case. As might be expected, as the amount of renewable energy is increased, its average value decreases slightly. It is also not surprising that the cases with a perfect day-ahead forecast show slightly higher value than the corresponding cases using the S-o-A forecast.

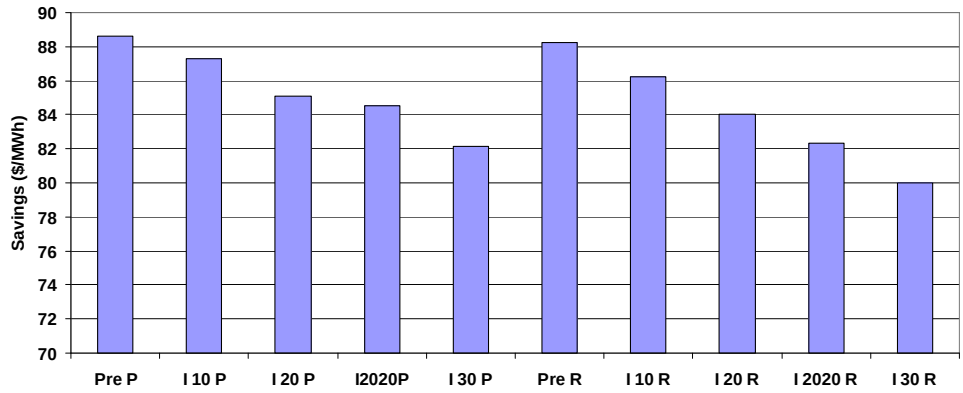


Figure 6.6 Operating cost savings per MWh of renewable energy, WECC – 2006

Figure 6.7 looks at the incremental savings between each case divided by the incremental renewable energy. So while the previous figure was relative to the no wind case, these results are relative to the preceding case. The incremental values for the 30% case relative to the 20/20% case have dropped significantly.

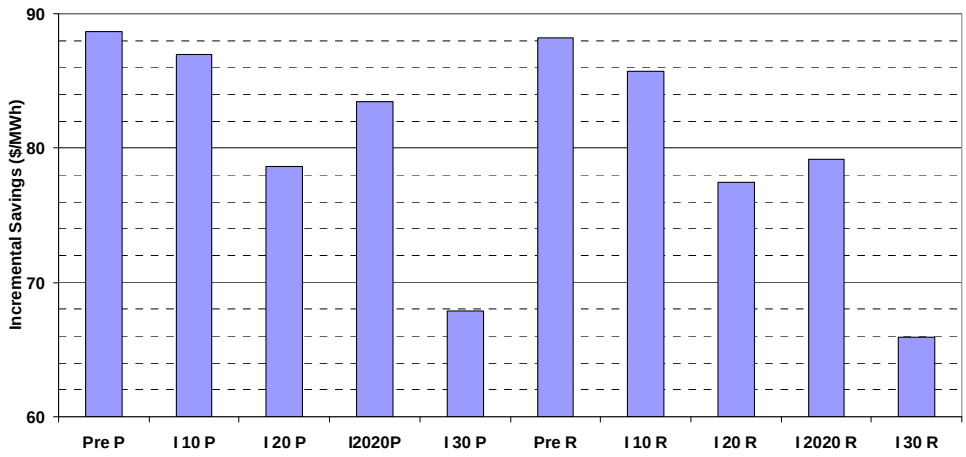


Figure 6.7 Incremental savings per incremental renewable energy ($/MWh). WECC – 2006

Many previous renewable integration studies have concentrated on adding renewable generation to the area of interest without much concern for the neighboring regions. This often allowed the neighbors to provide a large buffer to either absorb the excess generation in times of high wind or to provide additional backup if the wind suddenly drops off or falls significantly short of the forecast. That is why it was so important in this study to not only examine the WestConnect footprint as a part of WECC but also to recognize that the rest of WECC would also be adding significant amounts of wind and solar generation. In the initial scenario matrix there was an I20R scenario that had 20% wind penetration in the study area footprint and 10% penetration in the rest of WECC. The next level was the I30R scenario that increased the wind penetration to 30% in the footprint and 20% penetration in the rest of WECC. When examining the changes between the two cases it was difficult to separate the changes due to the additional 10% in the footprint from those due to the additional 10% in the rest of WECC. To address that concern the I2020R scenario was developed which had 20% penetration throughout all of WECC. Comparing the I20R and the I2020R cases in Figure 6.8 shows the impact on footprint exports of only increasing the wind penetration outside the study footprint and comparing the I2020R with the I30R case shows the impact of only increasing the wind penetration inside the study footprint.

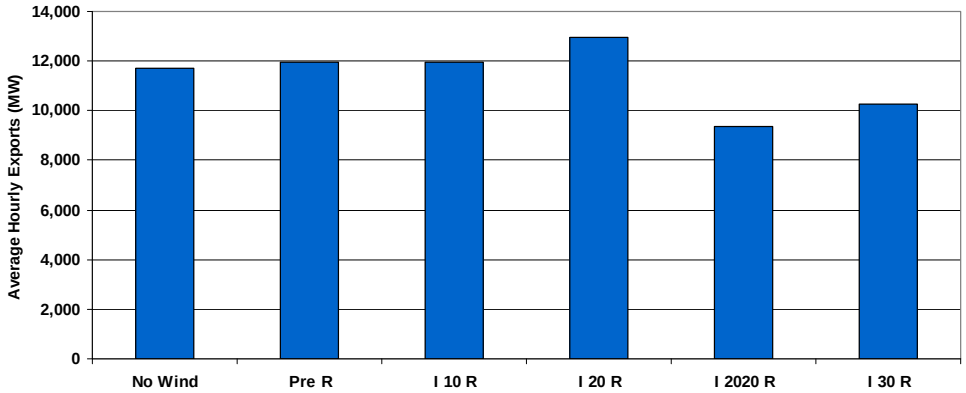


Figure 6.8 Average hourly exports from study footprint.

The day-ahead forecast and renewable penetration levels have operational impacts beyond just the cost. As the penetration levels increase, the system can become "overloaded" with generation, at times requiring the system to "spill" some of the excess wind energy. In addition, the changes in commitment due to the renewable generation may sometimes result in shortfalls in generation and cause some energy to be unserved in certain hours. Figure 6.9 shows the change in spilled and unserved energy for these cases. Most of the growth in unserved energy from the I20R to the I30R scenarios occurred due to the growth in renewable generation outside the study footprint. To put these values in perspective, the 800 GWh of spilled energy in the 30% case is less that 0.4% of the total wind energy generated. The 50 GWh of unserved energy is less than 0.005% of the total load energy.

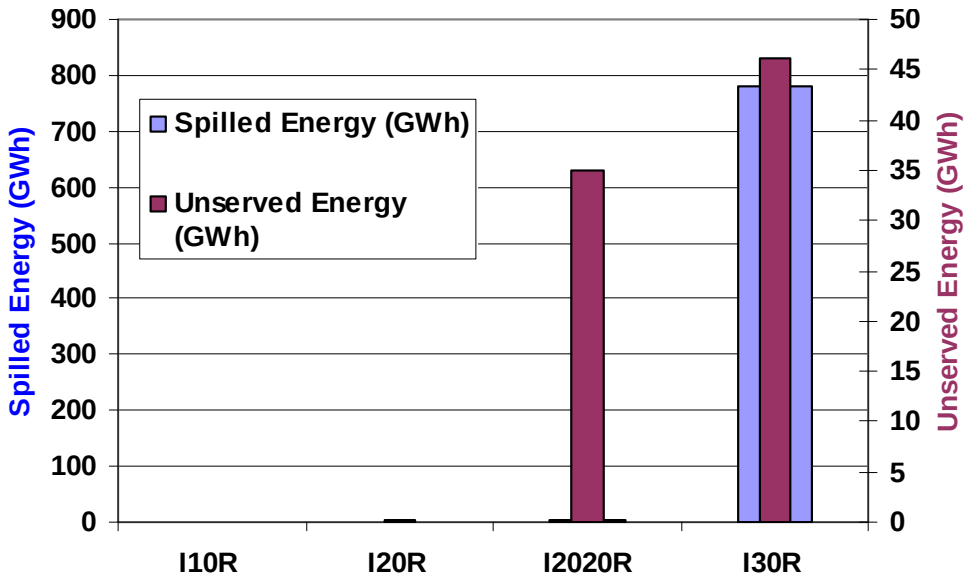


Figure 6.9 Impact of renewables in neighboring areas

Figure 6.10 and Figure 6.11 show additional statistics that were being tracked for the various cases. The coal units maintained a fairly constant number of starts, hours on line and capacity factor out through the 20% penetration scenario, although the revenue was dropping due to decreased spot prices. At the 30% level the number of starts increases significantly, particularly for the smaller units. Also the capacity factor and hours on line begin to drop. In contrast, the combined cycle units have their hours on line and capacity factors dropping immediately as the renewable penetration begins to rise.

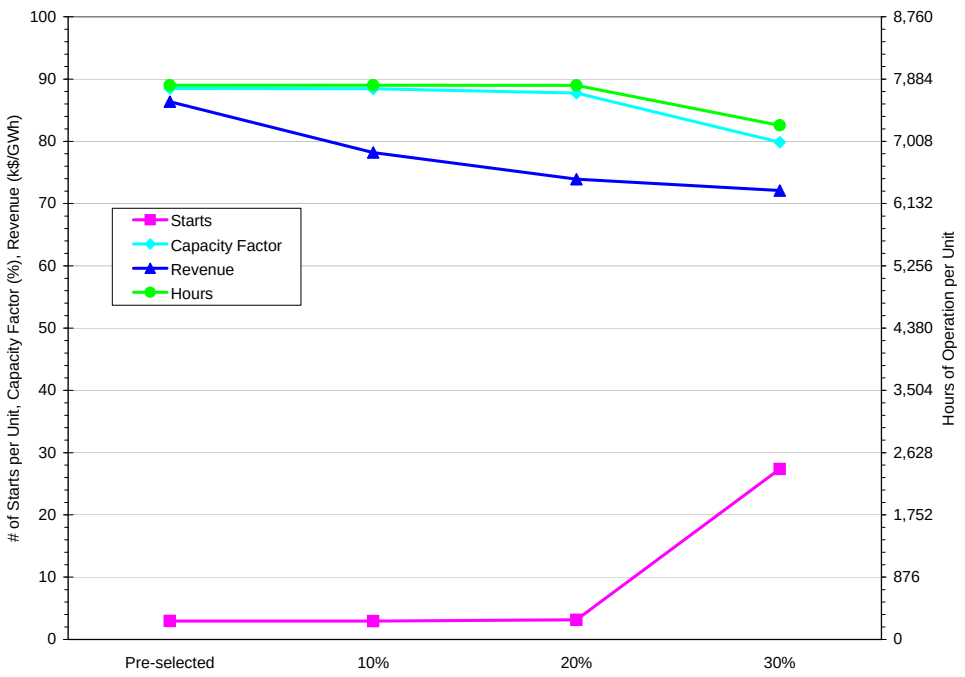


Figure 6.10 Coal plant statistics, Local Priority scenario

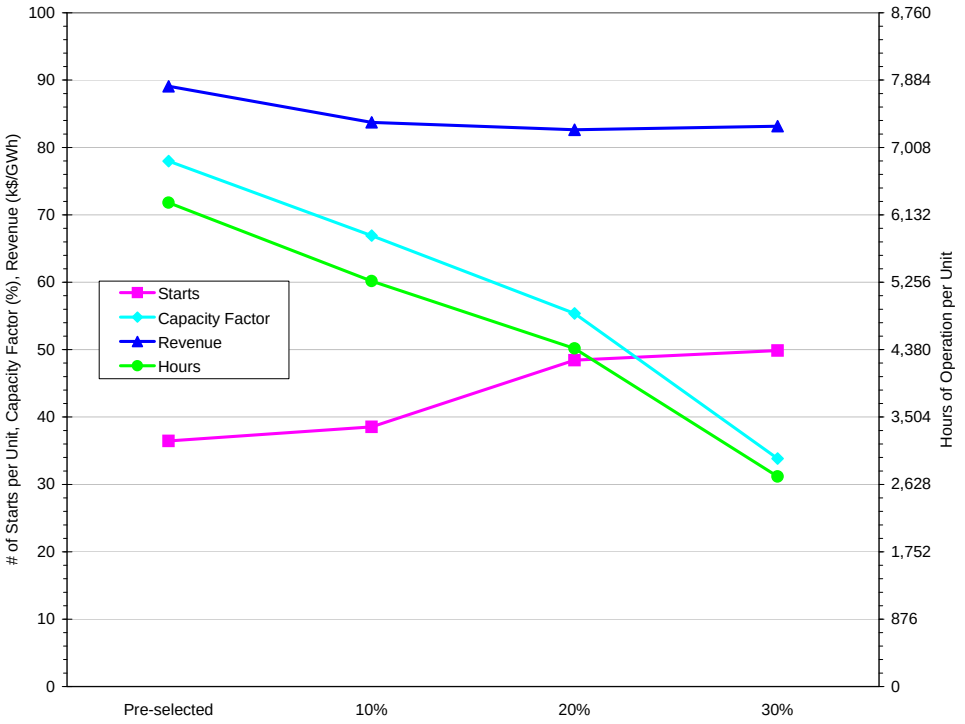


Figure 6.11 Combined Cycle plant statistics, Local Priority scenario

Figure 6.12 is an example of the transmission flows being tracked for the key interfaces. This figure shows the flow duration curves for the Wyoming to Colorado interface. The base flow limit was seldom reached on any of the In-Area scenarios. Flows, as well as ratings, increased with the Local Priority and Mega-Project scenarios, but were

essentially only limiting with the 30% cases. Flat spots on the beginning of the curves are hours with the interface at saturation. Not surprisingly, Wyoming heavily exports most of the time in the L30 and M30 scenarios. Table 6.2 lists key statistics for each of the cases. More of these summaries for other interfaces are included in Appendix D.

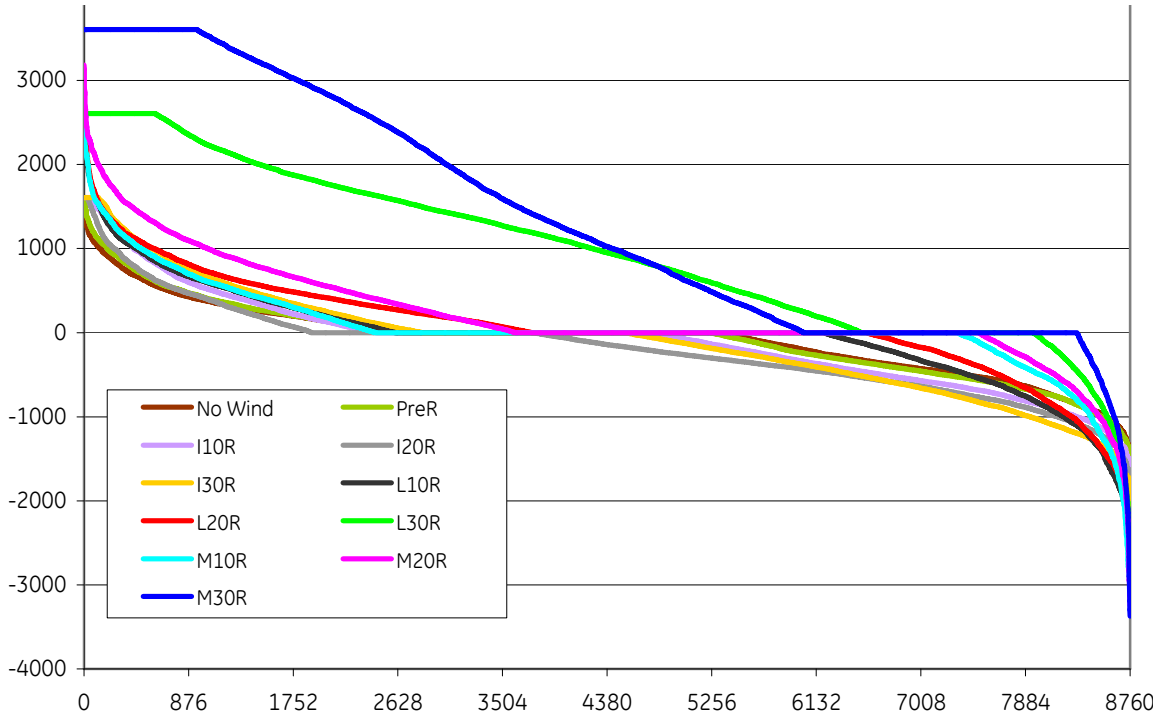


Figure 6.12 Wyoming to Colorado interface flows

Table 6.2 Wyoming to Colorado interface flow statistics

	No Wind	PreR	I10R	I20R	I30R	L10R	L20R	L30R	M10R	M20R	M30R
Max	1605	1605	1605	1605	1605	2605	2605	2605	3605	3605	3605
# hrs at Max	0	4	58	29	120	1	5	598	0	0	950
# hrs Pos	2599	2674	2451	1903	2827	2608	3747	6506	2438	3604	6026
# hrs Neg	3432	3518	3965	4987	4231	2573	2205	814	1451	1270	446
CF Abs	18	20	25	26	30	14	15	41	8	11	40
CF	-5	-5	-6	-12	-7	-1	3	37	2	6	37
Avg	-72	-74	-96	-196	-105	-21	79	953	62	218	1351

6.2.1 Impact of Renewable Forecasts

The next two figures, Figure 6.13 and Figure 6.14, examine the value of the wind and solar forecasts. The first figure shows the difference in WECC operating costs between a case with a perfect day-ahead forecast and the corresponding case using a State-of-the-Art forecast. The second figure then divides these savings by the amount of renewable energy in each case. Not surprisingly, the importance of the forecast increases at higher penetration levels.

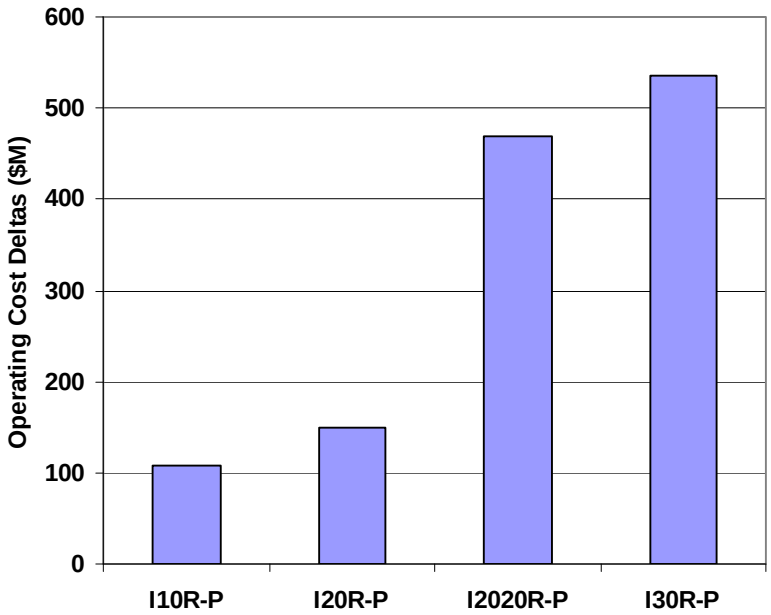


Figure 6.13 WECC operating cost impact of forecasts ($M)

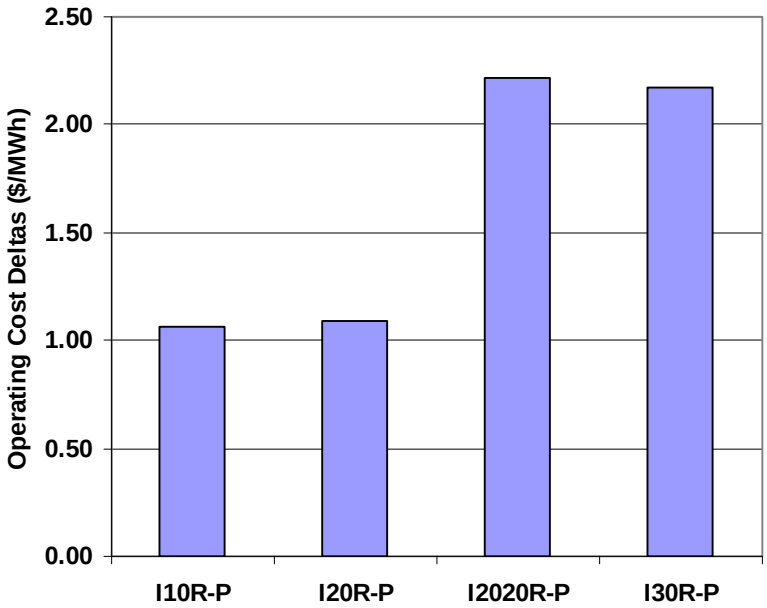


Figure 6.14 Operating cost impact of forecast ($/MWh)

Figure 6.15 presents a summary of the spilled and unserved energy values for the perfect and S-o-A forecasts. As can be seen, the unserved energy is essentially zero with the perfect forecast. Over-forecasting the day-ahead renewable generation causes less thermal generation to be committed, which can result in more unserved energy at higher penetrations. As noted before, these values are still a very small percentage (~0.005%) of the total load energy. The spilled energy occurs in both of the 30% scenarios. When the day-ahead forecast is low then additional thermal generation will be committed, which causes the spilled energy to be slightly larger.

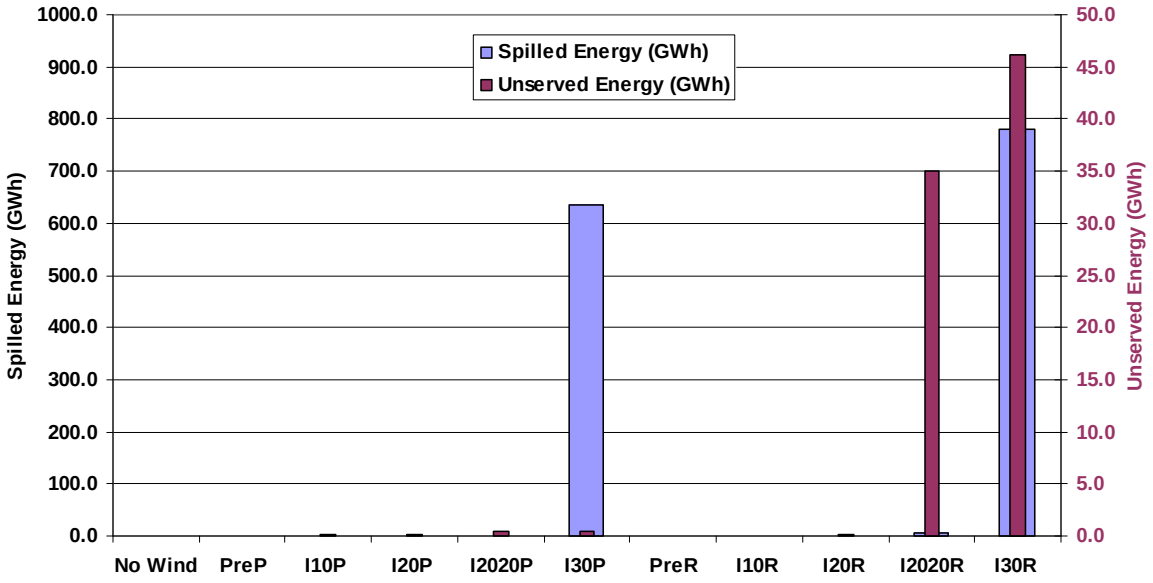


Figure 6.15 Impact of Forecast on Spilled and Unserved Energy

Figure 6.16 shows a comparison between the operating costs for the no Forecast and S-o-A Forecast scenarios. Again there is a jump at the higher penetrations. It is also important to note that the values are an order of magnitude greater than the deltas between the S-o-A and perfect forecasts.

Often the system operators will ignore renewables, particularly wind, in the day-ahead operation due to the lack of confidence in the forecast. Figure 6.17 shows this impact per MWh of renewable energy. As the chart shows, recognizing the day-ahead forecast, even with its inherent errors, can add $12/MWh to $20/MWh to the value of the renewable energy.

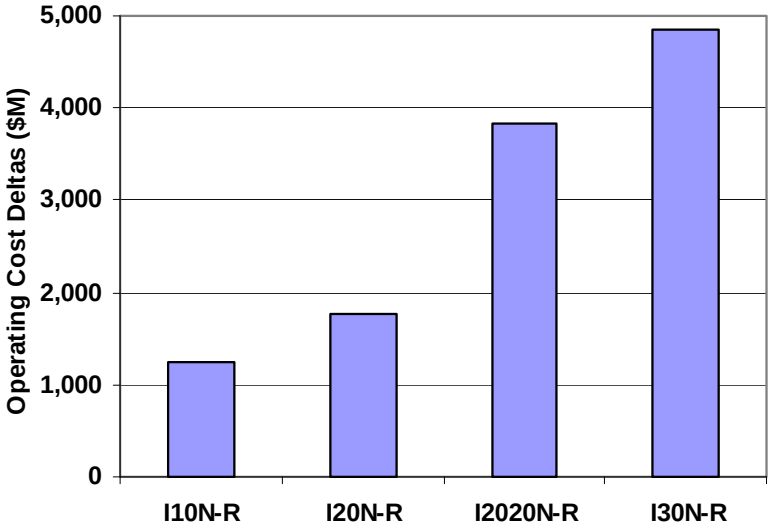


Figure 6.16 WECC operating cost impact of no forecasts ($M)

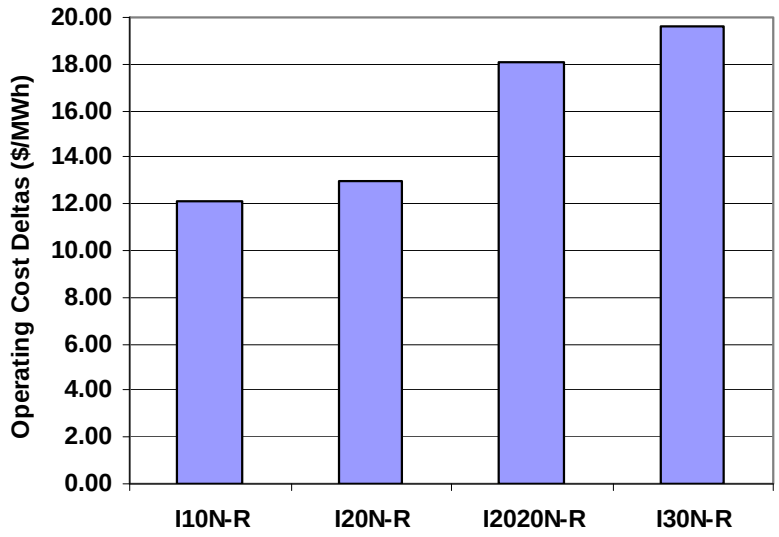


Figure 6.17 WECC operating cost impact of no forecasts ($/MWh)

Figure 6.18 shows "the rest of the story." By ignoring the wind forecast the system has avoided the almost 50 GWh of unserved energy due to over forecasts in the 30% scenario. However, it has done that at the expense of greatly increasing the amount of spilled wind energy. Note that the scale on the left is 200 times greater than the one on the right.

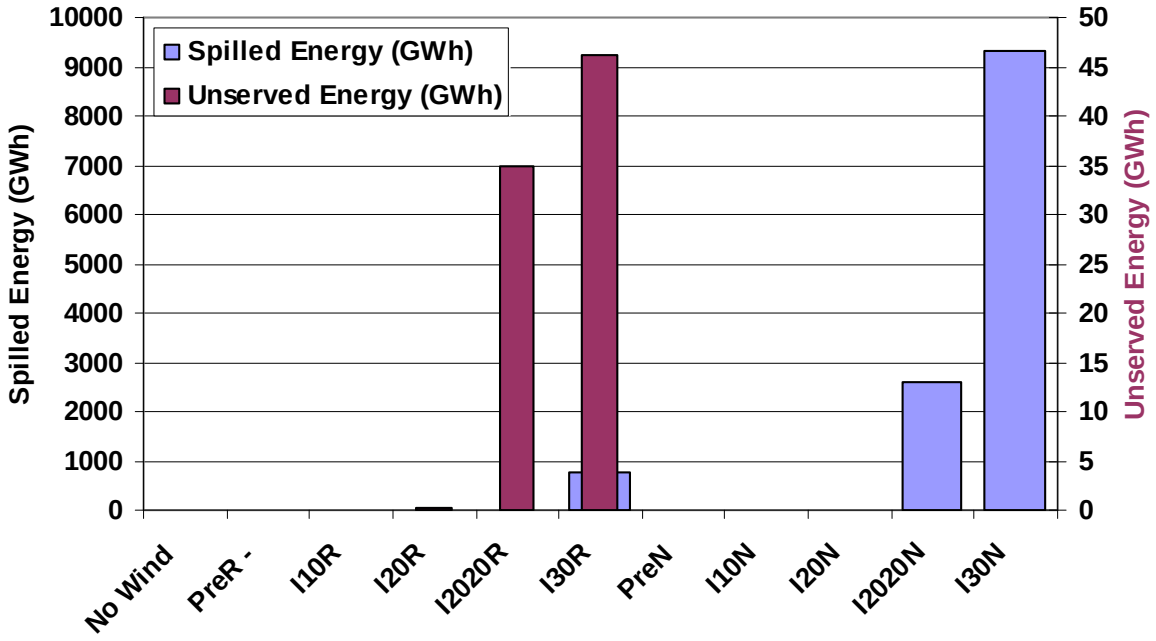


Figure 6.18 WECC impact of no forecast on spilled and unserved energy

Figure 6.19 shows the total generation in the study area for renewable and nonrenewable generators. In both the perfect and S-o-A forecasts the non-renewable generation drops when going from the 20% to the 20/20% scenarios due to the increase in renewable generation outside the study footprint. Overall the total generation within

the study area remains relatively constant across all of the scenarios. Variations in the total generation were due to changes in the net exports from the study area. This can be seen most clearly in the difference between the "20" and "2020" cases.

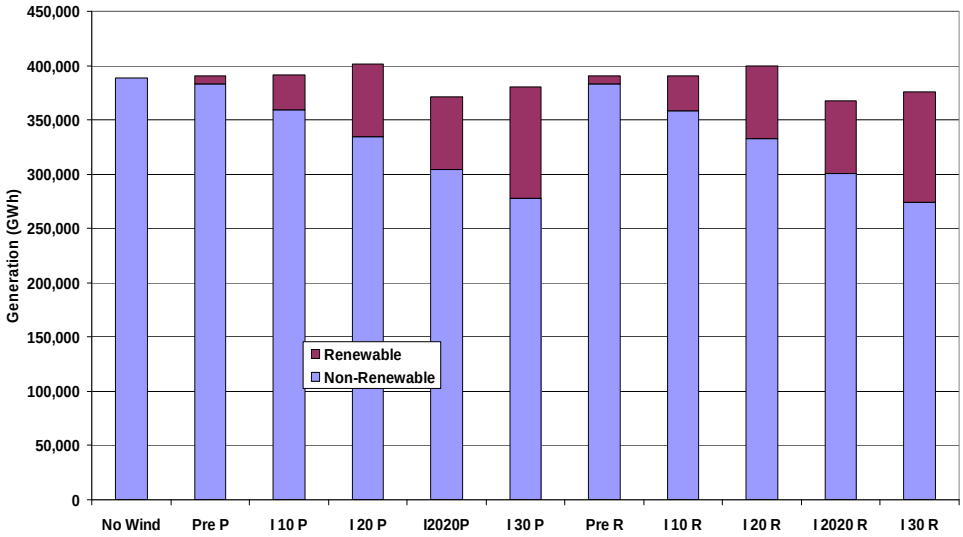


Figure 6.19 Total generation, study area – 2006

Figure 6.20 shows the generator revenue for the study area. The revenue is calculated by multiplying the hourly generation times the hourly spot price at each location and then summing this product over the entire year. Although the total generation stayed roughly constant, the revenue drops as renewable penetration increases due to the fact that the spot prices are decreasing.

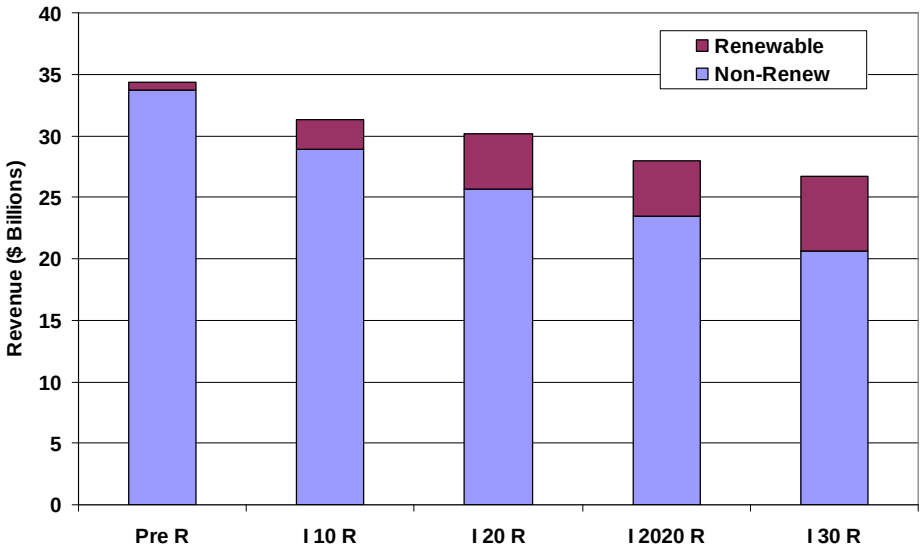


Figure 6.20 Generator revenue, study area – 2006

Earlier figures looked at the value of the renewable generation based on the change in overall operating costs. We can also look at the value based on the hourly spot price of

the generation. This also allows differentiation between the different types of renewable generation since each plant has its own spot price and hourly dispatch pattern. Figure 6.21 shows the change in revenue per the change in renewable energy between the penetration levels. These are similar to the values shown in Figure 6.7, but now they are being calculated on a spot price basis rather than displaced operating costs. Note that the wind has a lower value than solar due to the fact that much of the wind energy occurs in the nighttime when spot prices are lower. The low spot prices in the 30% penetration scenario drive down the value of all of the renewables so that the incremental value drops particularly low. Figure 6.22 shows similar results for all of WECC.

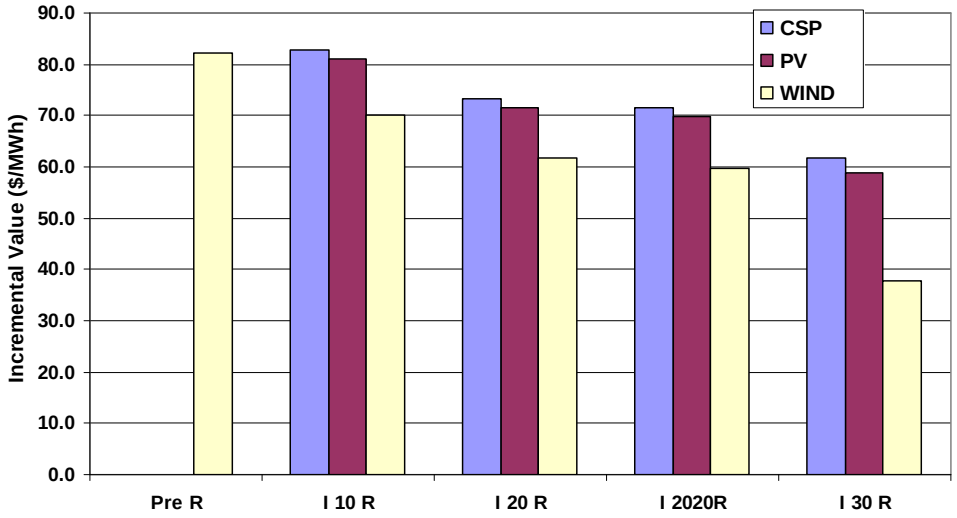


Figure 6.21 Incremental value of renewable energy based on spot price revenue, Study area

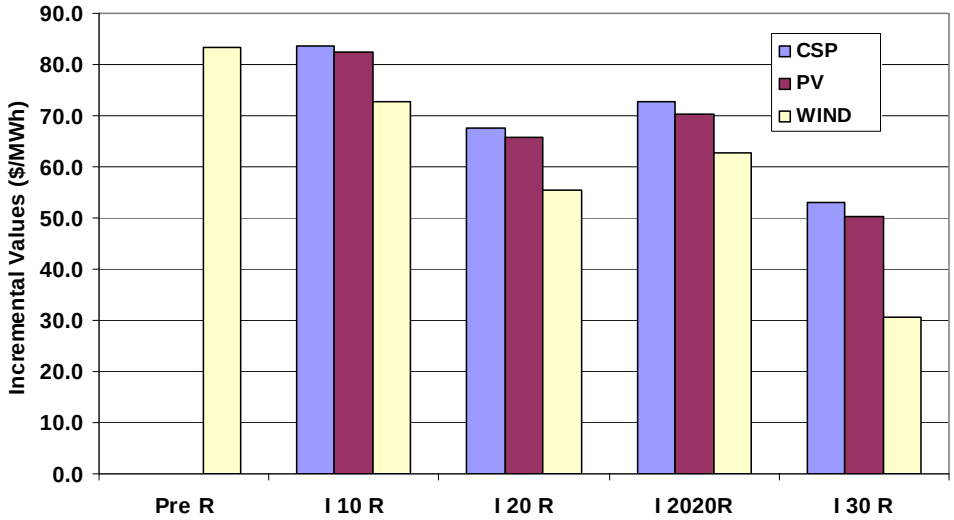


Figure 6.22 Incremental value of renewable energy based on spot price revenue, WECC

Figure 6.23 shows the total WECC emission reductions as the renewable penetration is increased. These correspond to the reductions in generation shown in Figure 6.3. The

SOX emission reductions only occur in the higher penetrations when coal generation is displaced. Figure 6.24 expresses the emission reductions per MWh of renewable generation.

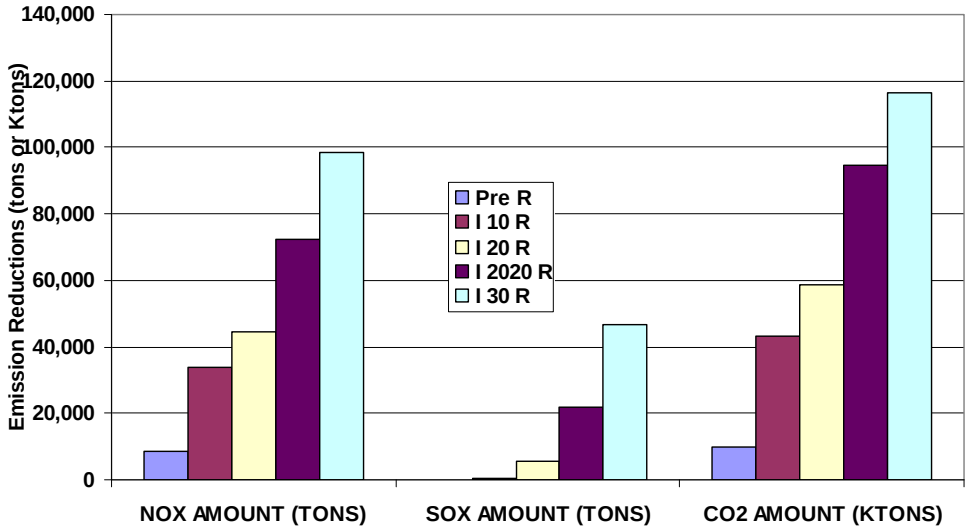


Figure 6.23 Total emission reductions, WECC - 2006.

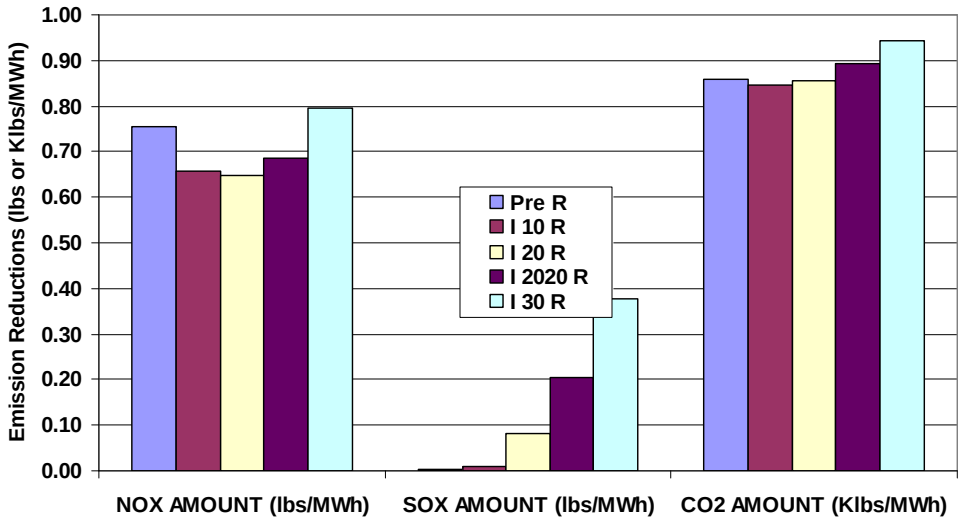


Figure 6.24 Total emission reductions per MWh of renewable generation, WECC – 2006

6.2.2 Spinning Reserve

Figure 6.25 shows a distribution of the annual wind forecast error for the study footprint and all of WECC. Although the averages were near zero the extremes were rather large. When the wind was over-forecasted then insufficient thermal generation would be committed to meet the load. The base scenarios held the regional spinning reserve requirements constant at 3% of the load regardless of the amount of renewable generation. Spinning reserves and quick-start generation could respond to cover the shortfall, but at times they might not be sufficient. Conversely, when the wind was

under-forecasted then excess thermal generation would be committed which could lead to minimum operating constraints and possibly the need to spill or export the excess wind. Although there was some forecast error associated with the solar generation as well, the bulk of the error was due to the wind.

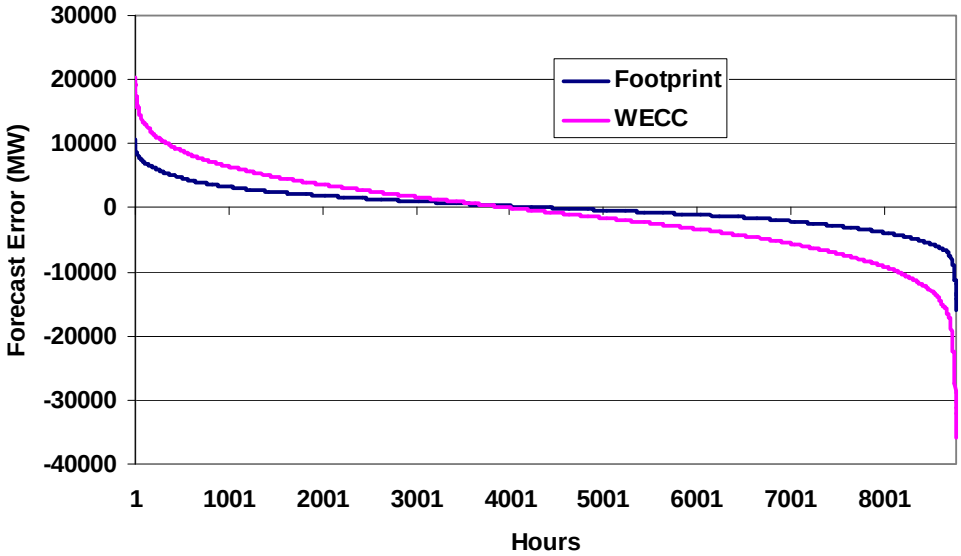


Figure 6.25 Adjusted wind forecast error, I30R scenario

One way to reduce the shortages due to the over-forecasting of the wind would be to increase the amount of spinning reserve planned in the day-ahead unit commitment. This was accomplished by discounting the wind forecast by varying amounts up to 25%. This means that the spinning reserves would be increased proportional to the day-ahead wind forecast. At the 25% level this would increase the total WECC spinning reserve by over 13,000 MW in some high wind hours. Figure 6.26 shows the resulting impact on spilled and unserved energy for the 30% scenario. Increasing the spinning reserve had the desired effect of reducing the unserved energy by roughly an order of magnitude. Figure 6.27 shows a duration curve of how these outages were distributed throughout the year. In the base I30R case the maximum outage was roughly 1300 MW and the maximum number of hours in the year during which there was any unserved load was about 90 hours. These curves can be viewed as the requirements for a demand response program. If the area under the curve is divided by the maximum outage we can determine the expected number of hours that each demand response participant would be called upon. For the base system with 1300 MW of load participating in demand response, this represents about 35 hours/year for each participant. If more participants are signed up for the program then the number of hours for each participant will decrease. If fewer participants are signed up then there will still be some remaining unserved energy and the number of hours required per participant will increase. This relationship is depicted in Figure 6.28.

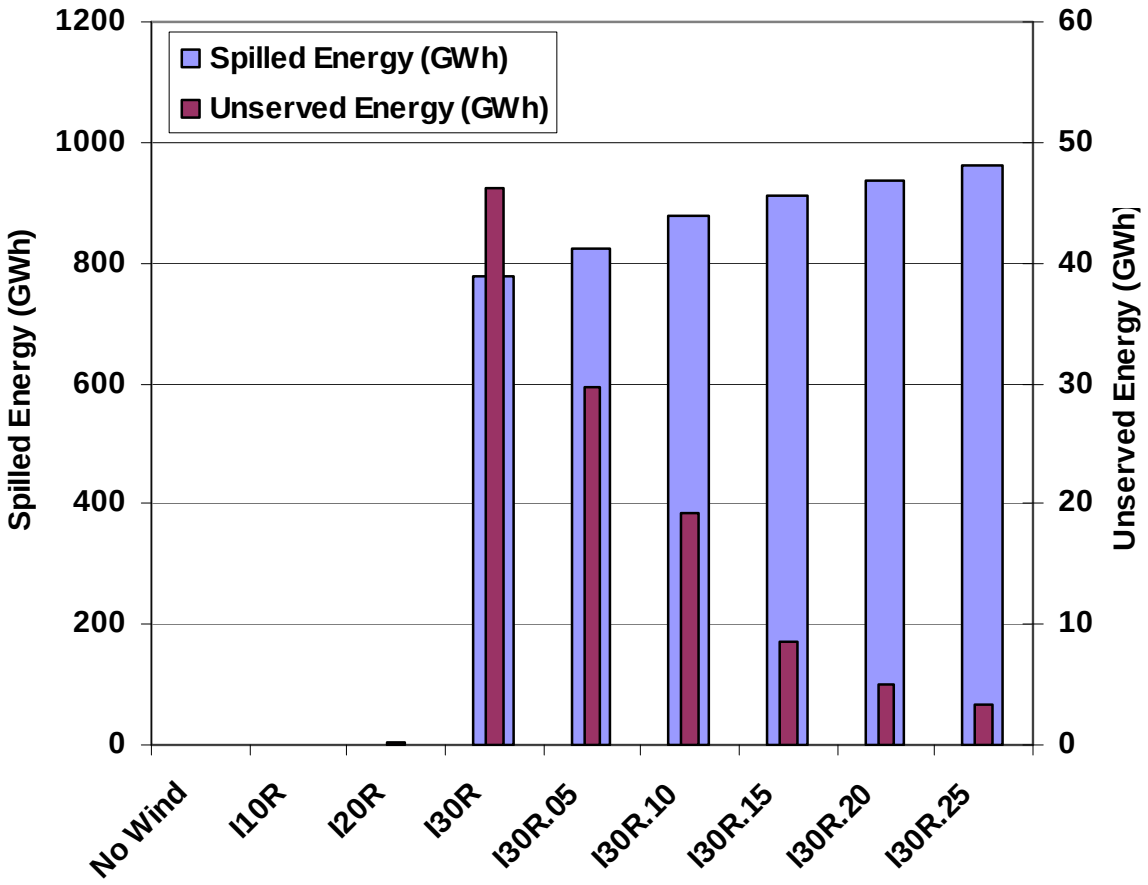


Figure 6.26 Spilled and unserved energy when discounting forecast

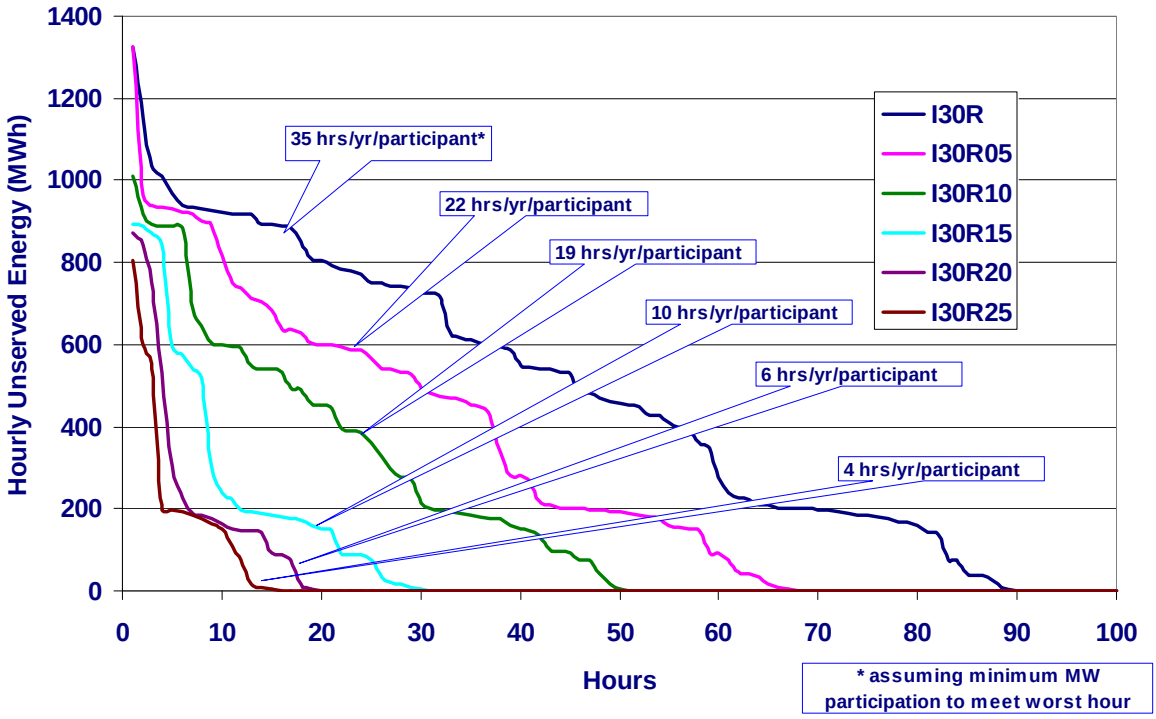


Figure 6.27 Distribution of unserved energy versus discounting of wind forecasts

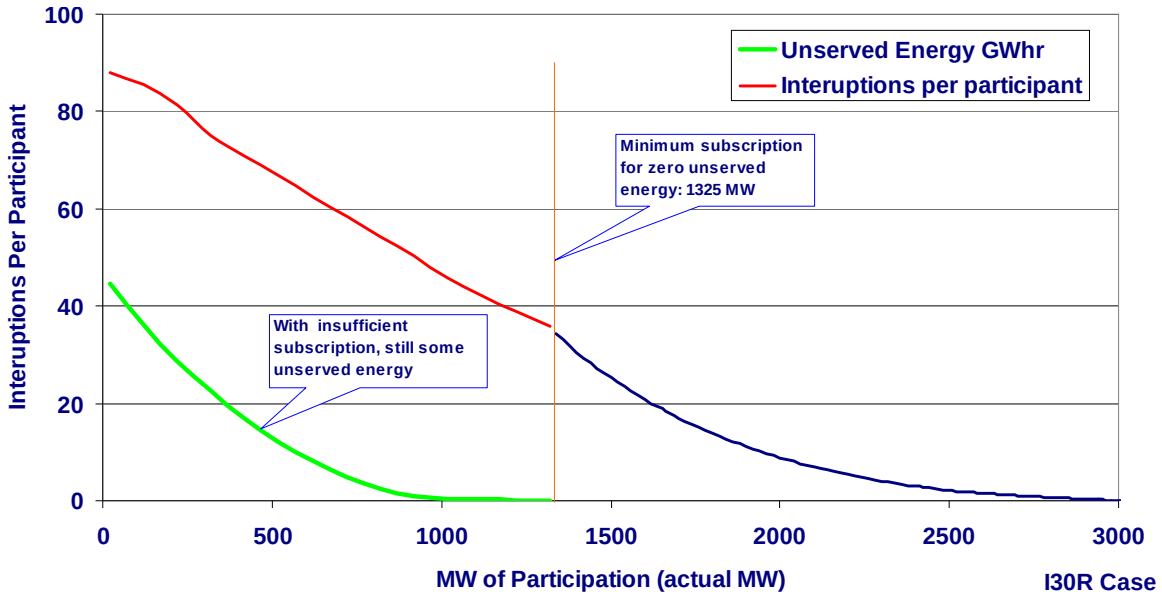


Figure 6.28 Hours of interruption versus MW of demand response participation

Figure 6.29 shows the resulting impact on the hourly spot price duration curve for the 30% scenario. The impact of increasing the spinning reserve as a function of the forecasted wind is to consistently commit more capacity for the same total load, which will therefore drive the spot prices down and total operating costs up.

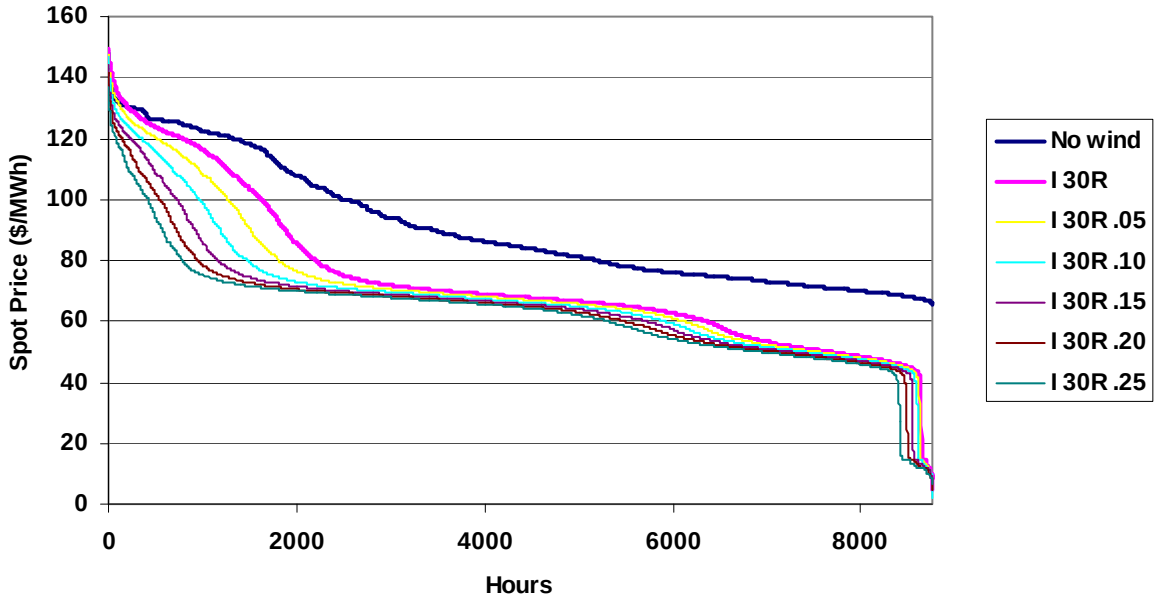


Figure 6.29 Annual spot price duration curve - I30R scenario - impact of discounting forecast

Figure 6.30 shows the total WECC operating costs for a range of scenarios with discounted wind forecasts and increased reserves. Although the impact looks relatively small on the scale of the total WECC costs, there is a cost increase for committing to additional spinning reserve.

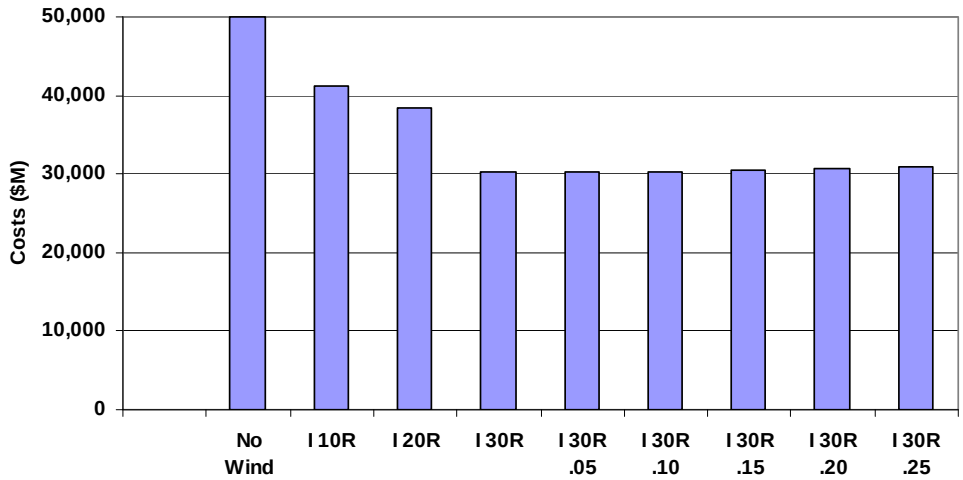


Figure 6.30 Total WECC operating costs as a function of discounting the wind forecast ($M)

The operating cost increases from Figure 6.30 are combined with the unserved energy reductions in Figure 6.26 to produce Figure 6.31 Increasing the spinning reserve in the commitment by 5% of the wind forecast increases the total operating costs by about $50 million for the year and reduces the unserved energy by about 17 GWh annually.

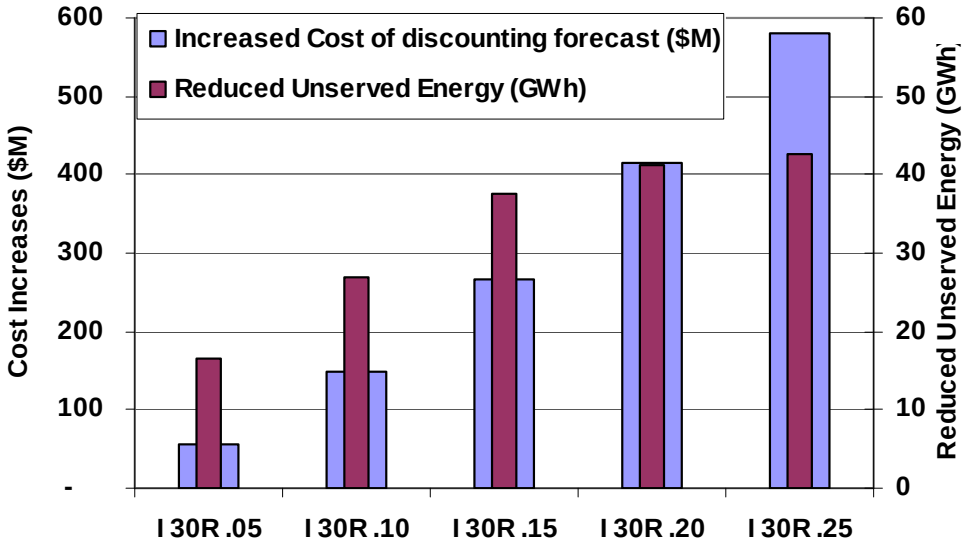


Figure 6.31 Reduced unserved energy with increased reserves committed for wind generation

Dividing one curve by the other produces the average cost of reducing the unserved energy shown in Figure 6.32. Increasing the committed spinning reserve by 5% of the wind forecast increases the WECC operating costs by over $3,000 per MWh of reduced unserved load. Expressed another way, it would be comparable to pay some of the load $3,000/MWh to drop off rather than to increase the spinning reserve by 5% of the forecast. At the other extreme if we want to eliminate as much unserved energy as could be achieved by increasing the spinning reserve by 25%, it would cost an average of roughly $13,600/MWh of unserved energy. The incremental reduction in unserved

energy achieved by increasing the spinning reserve from 20% to 25% of the forecast would cost over $100,000/MWh. Clearly it would be more economically attractive to utilize demand response than to increase the spinning reserves to achieve the same objectives.

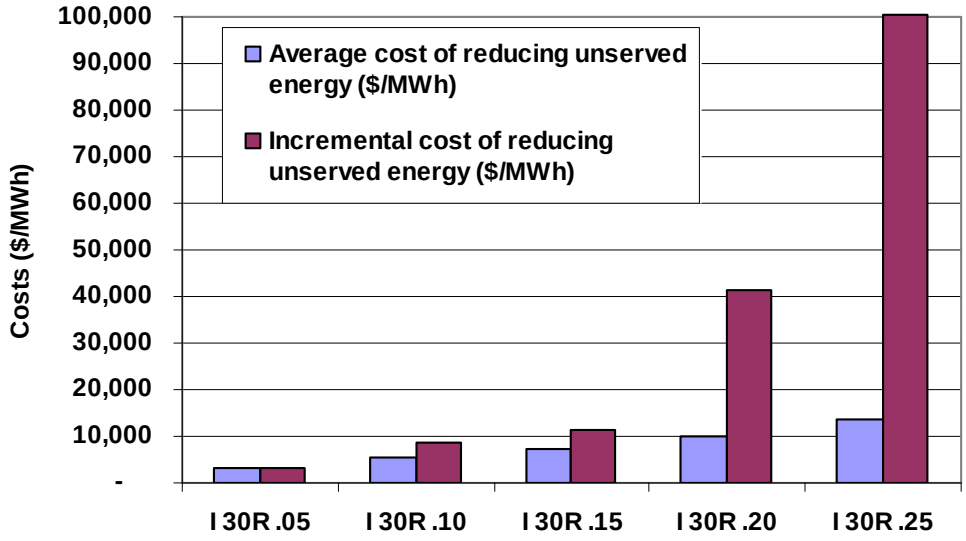


Figure 6.32 Cost of reducing unserved energy by increasing reserve commitment for renewables.

Another way of looking at the cost increase is to divide the dollars in Figure 6.31 by the amount of wind energy that is provided. This result is shown in Figure 6.32. This could be viewed as a range of the "integration cost" that is often calculated for renewable energy. For example, if it is determined that spinning reserves need to be increased by 10% of the forecasted wind, then that would result in a cost of about 70 cents per MWh. This would reduce the savings shown in Figure 6.6 by less than 1%.

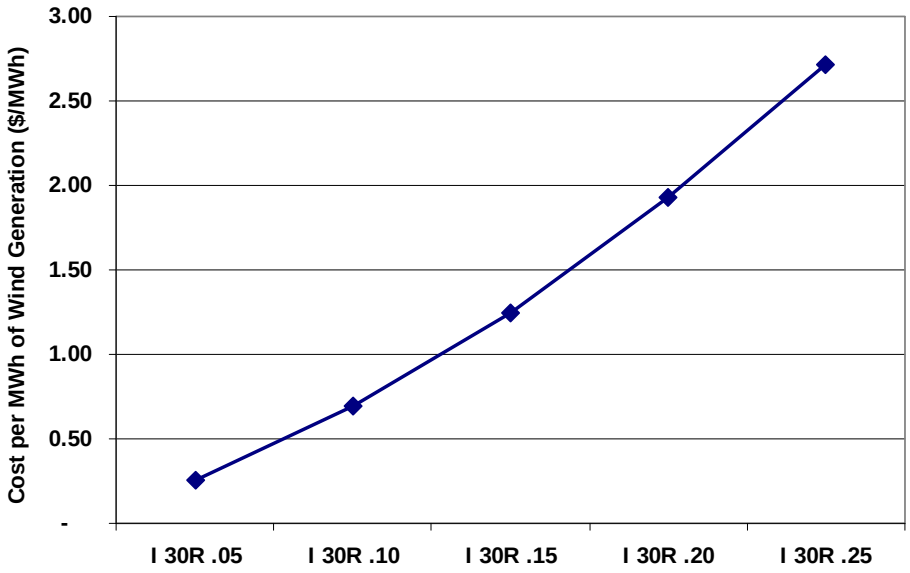


Figure 6.33 Cost of increasing committed spinning reserve per MWh of wind generation ($/MWh)

6.2.3 Annual Profile Sensitivities

Most of the analysis was performed using the load, wind and solar profiles from 2006. All of the primary scenarios were also run using the shapes from 2004 and 2005. Figure 6.34 shows the WECC generation by type for the no wind and 10, 20 and 30 percent scenarios with S-o-A forecasts for the three shape years.(key: last digit of case name refers to the year) The slight variation between the cases seems to be driven by the variation in wind energy for the three years. Figure 6.35 shows the generation by renewable type for the 30% scenario. Both types of solar generation were fairly constant over the three weather years. The wind generation varied about +/- 3% over the three year period. The same nameplate capacities were used for all three years.

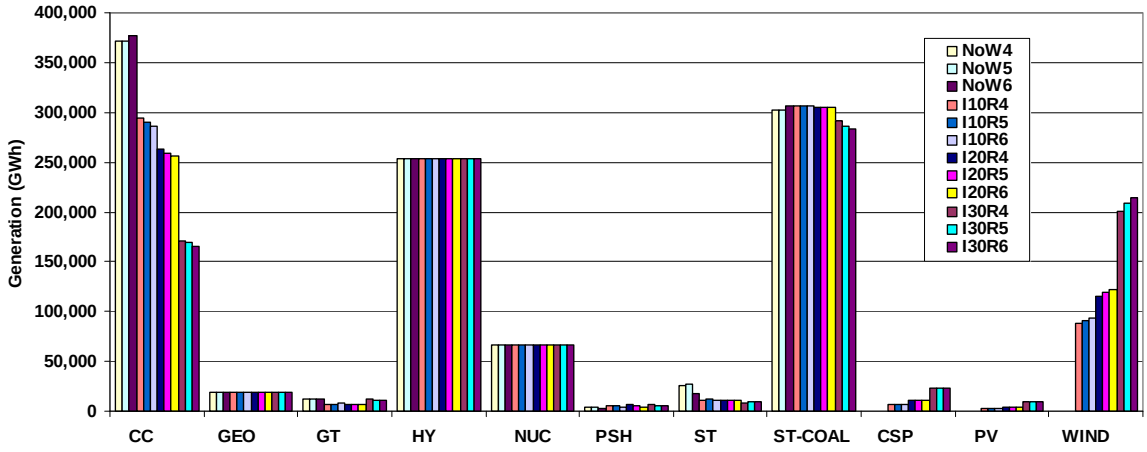


Figure 6.34 Generation by type, WECC, by scenario and shape year

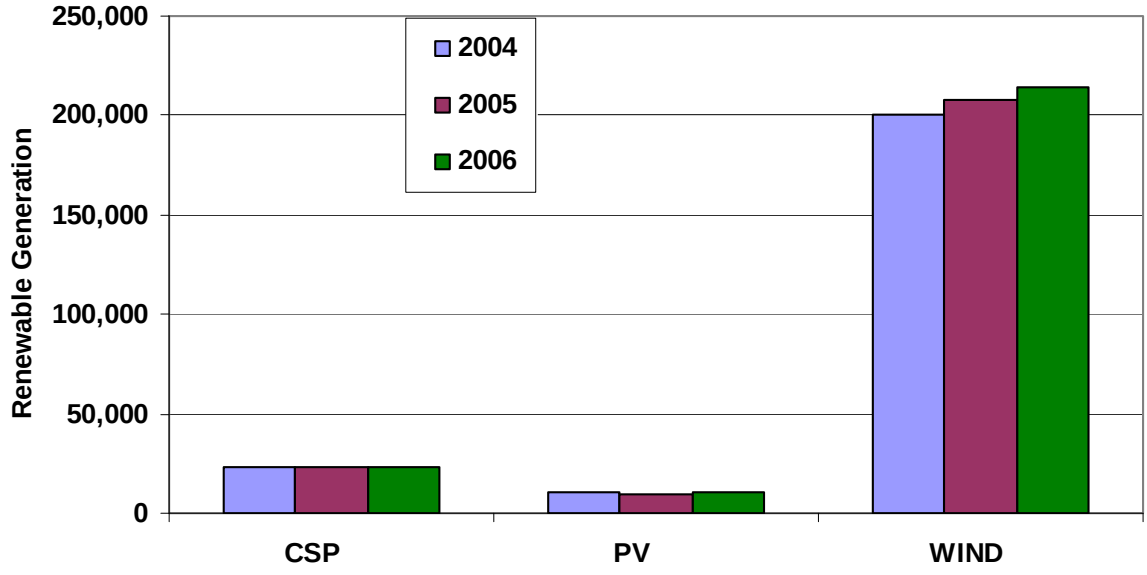


Figure 6.35 Variation in renewable generation by weather year for 30% scenario

Figure 6.36 shows the variation in the incremental value of the renewable generation as a function of penetration and shape year. The annual variations are within a few dollars per MWh.

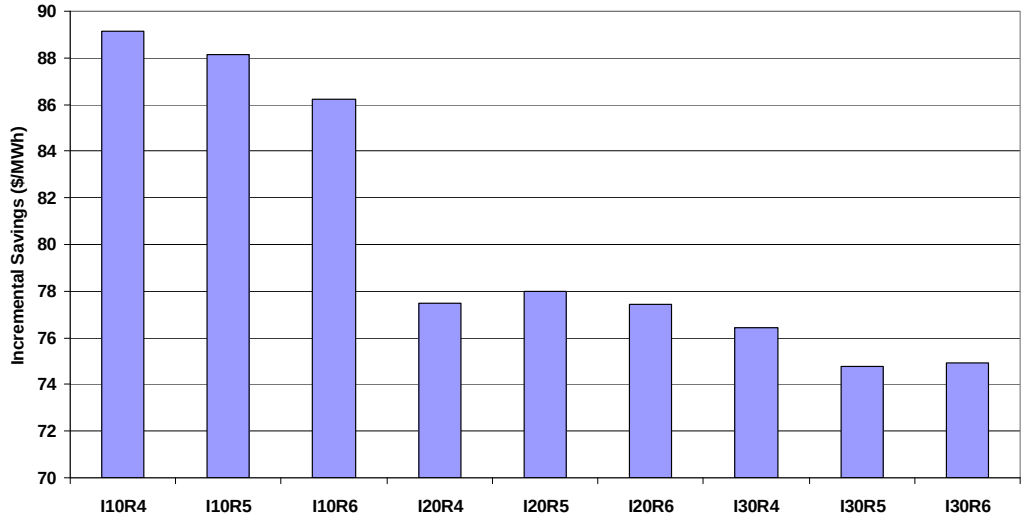


Figure 6.36 Incremental savings per incremental renewable energy, WECC

Figure 6.37 shows the total study area generation for the three shape years. Although the renewable generation varied somewhat, the total generation changed by less than 0.1% from the average value over the three years.

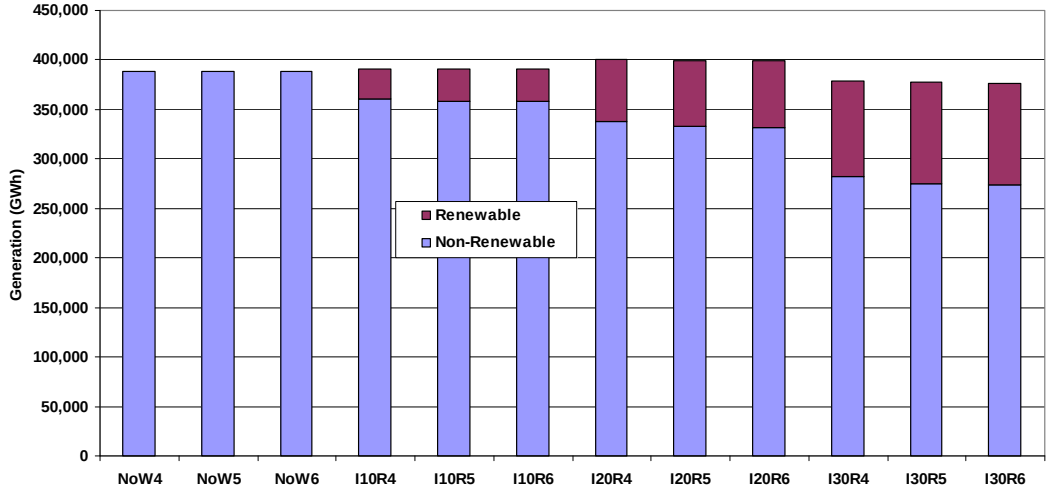


Figure 6.37 Total generation, study area, for different annual shapes

Figure 6.38 shows the change in emissions over the three shape years. The emission reductions tended to be slightly higher in the years with higher renewable generation, as would be expected.

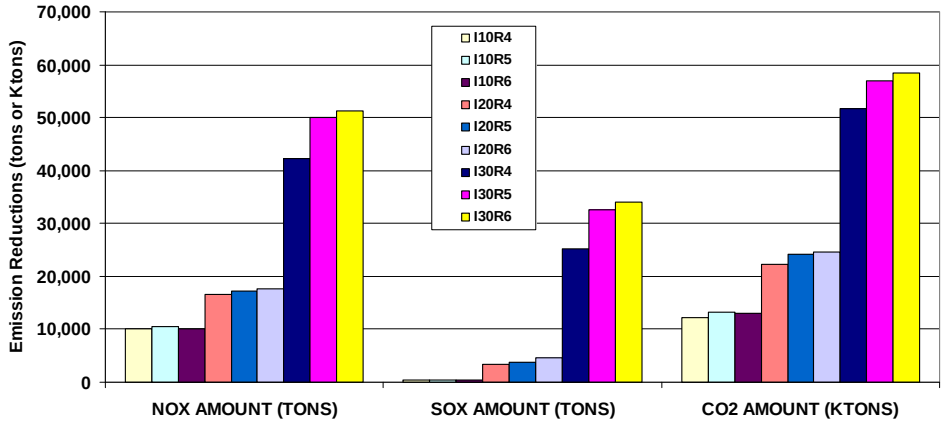


Figure 6.38 Emission reductions, study area, for different annual shapes

6.3 Weekly Operational Analysis

The previous section examined the operational impacts of renewable generation from an annual basis. This section examines a spring and summer week to look at the changes in operation more closely. The dark blue line in the center of Figure 6.39 shows the hourly study area load for the week of April 10th. The green line on the bottom is the sum of the Wind, CSP and PV generation inside the study area for each hour for the 10% scenario. The teal line (Load –W/C/P) between the two is the hourly "load minus renewables" or net load that must be served. If the study area were not interconnected to the rest of WECC, this is the profile that the rest of the generation in the study footprint would be required to follow. The remaining two curves show the load and net load including the net hourly exports from the study area. Figure 6.40 shows the operation of the generation by type within the study area when there is no renewable generation present. The nuclear generation was flat except for the start of planned maintenance on Saturday. The coal generation was relatively constant, the hydro provided the bulk of the peaking operation and the combined cycle filled in the intermediate operation.

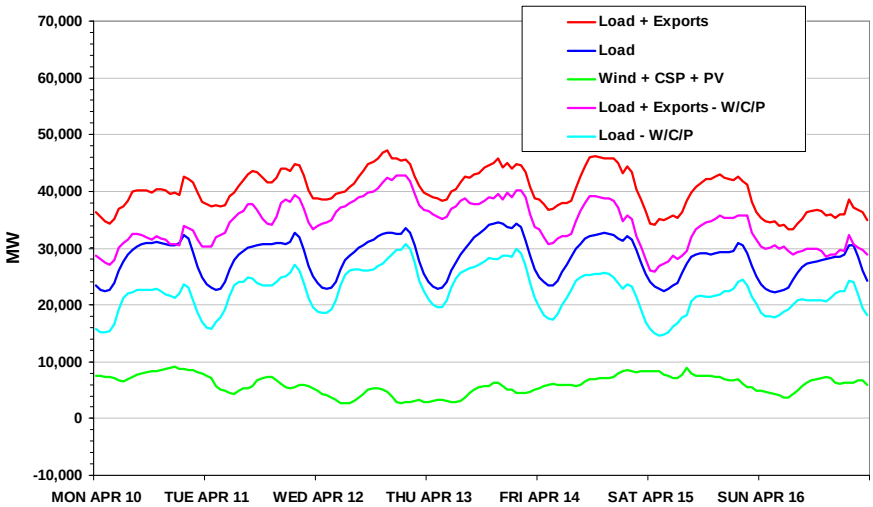


Figure 6.39 Week of April 10th - Hourly load, renewables and exports for 10% scenario

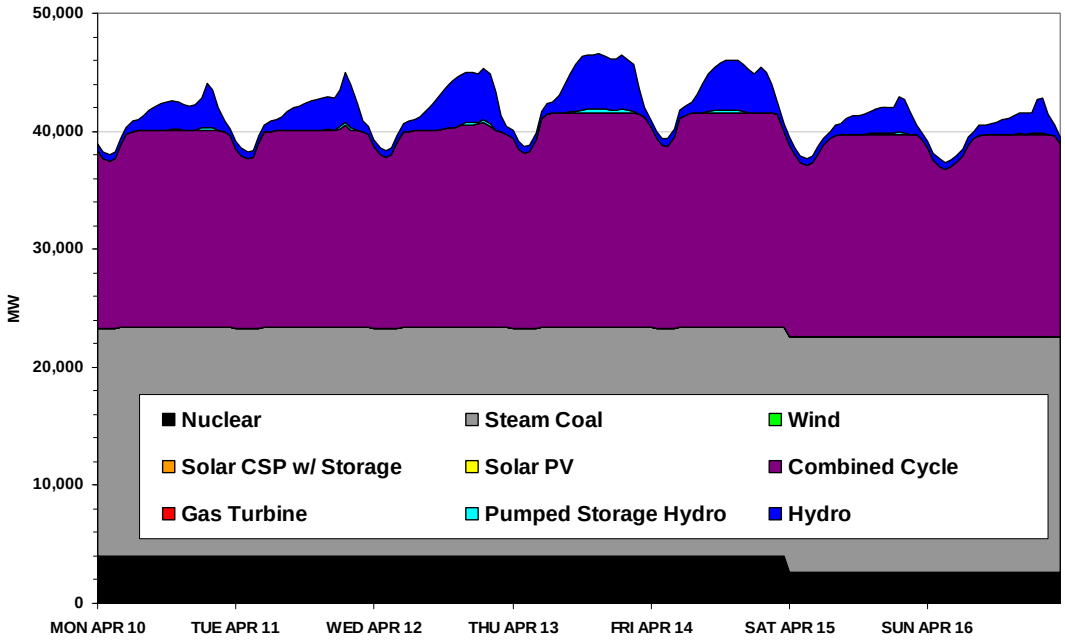


Figure 6.40 Study area dispatch - week of April 10th - no renewables.

Figure 6.41 shows how this operation changed for the 10% scenario. The nuclear generation is unchanged and the coal is still mostly constant but the dispatch of the other generation has begun to change. The most noticeable shift is the introduction of the green band which represents the wind generation. Thin orange and yellow bands can also be seen for the solar generation. The hydro generation has shifted slightly. Each hydro plant was scheduled to meet specific monthly energy targets. Introduction of renewable generation could cause the hydro to shift the hourly schedule but the monthly energy production would remain constant. More consideration of the hydro will be discussed later in this chapter. The bulk of the displacement came from the combined cycle units, which is consistent with what was seen on an annual basis. Also, it is interesting to note the small patch of red introduced on Wednesday. This is simple cycle gas turbine operation caused by an over-forecast of the wind generation. When the expected wind generation did not materialize some of the imbalance could be provided by generation on units already committed. However, it was necessary to turn on some quick start peaking generators to balance the mismatch. As was shown earlier, more combined cycle units could have been committed in those hours in anticipation of an over-forecast. This would have lowered the fuel costs in this particular hour but would be less economic overall due to the over commitment in other hours. Also note that the total generation each hour changed slightly from the previous figure. This was because the exports changed when the renewable generation was added.

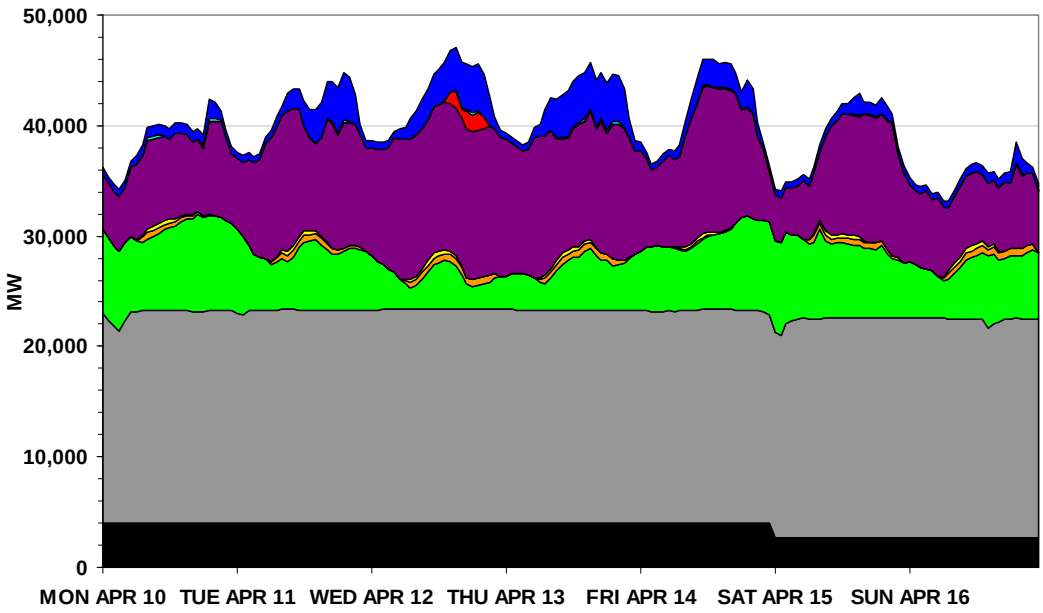


Figure 6.41 Study area dispatch - week of April 10th – 10% R scenario

Figure 6.42 compares the hourly load profile for the week to the sum of the renewable generation in the study area for the 10%, 20% and 30% cases. Note how the 30% wind + solar profile crosses over the load profile on Saturday. Figure 6.43 subtracts the renewable generation from the load to present the load and net loads for the various penetrations. Finally, Figure 6.44 adds the regional exports to the net loads. This is the total generation needed from the non-renewable generators in the study area. Although this net demand dips lower as the renewable generation increases, it never goes negative.

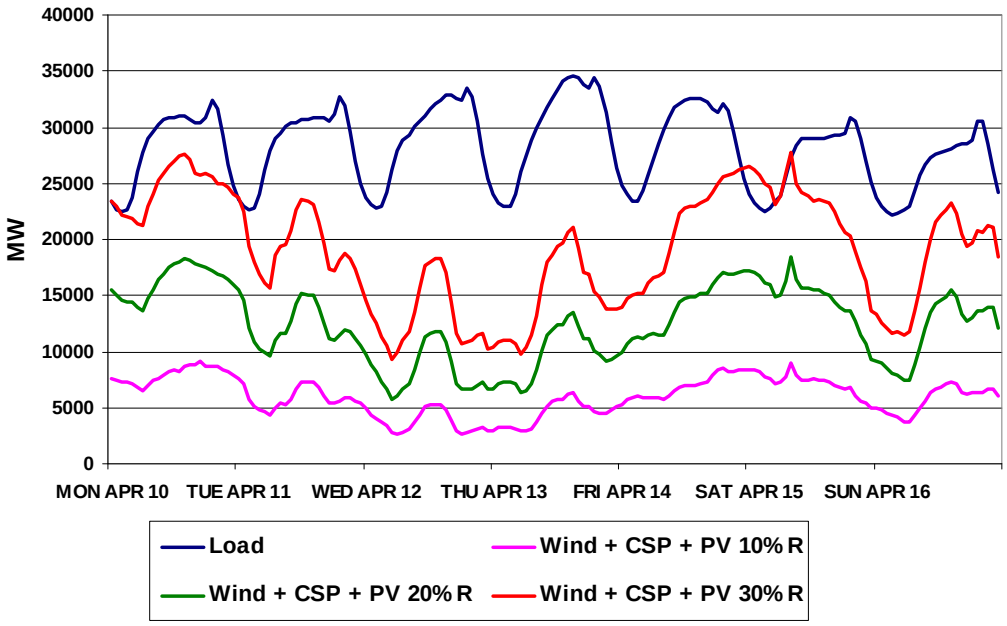


Figure 6.42 Study area - week of April 10th – load and renewables by penetration

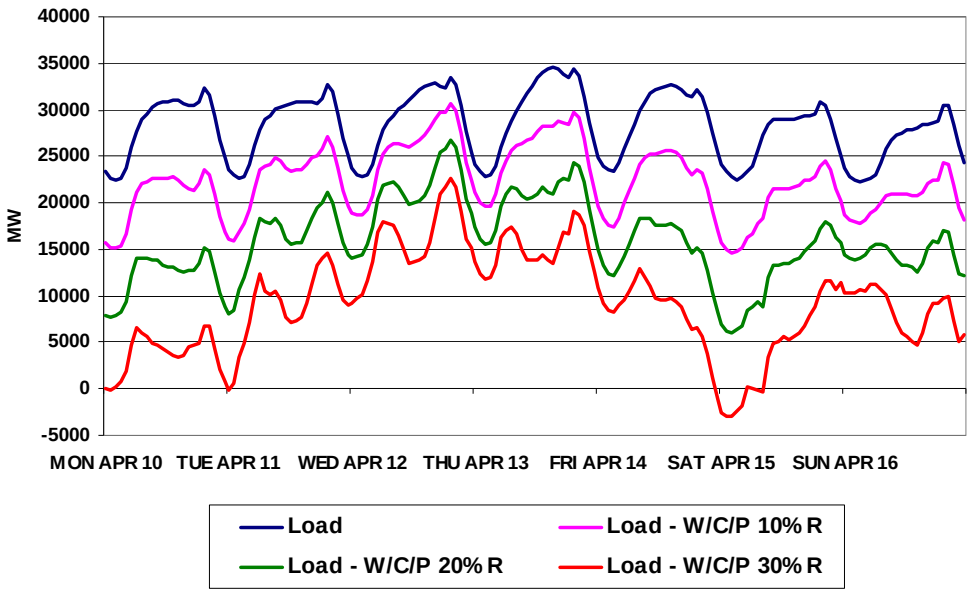


Figure 6.43 Study area - week of April 10th - net load by penetration

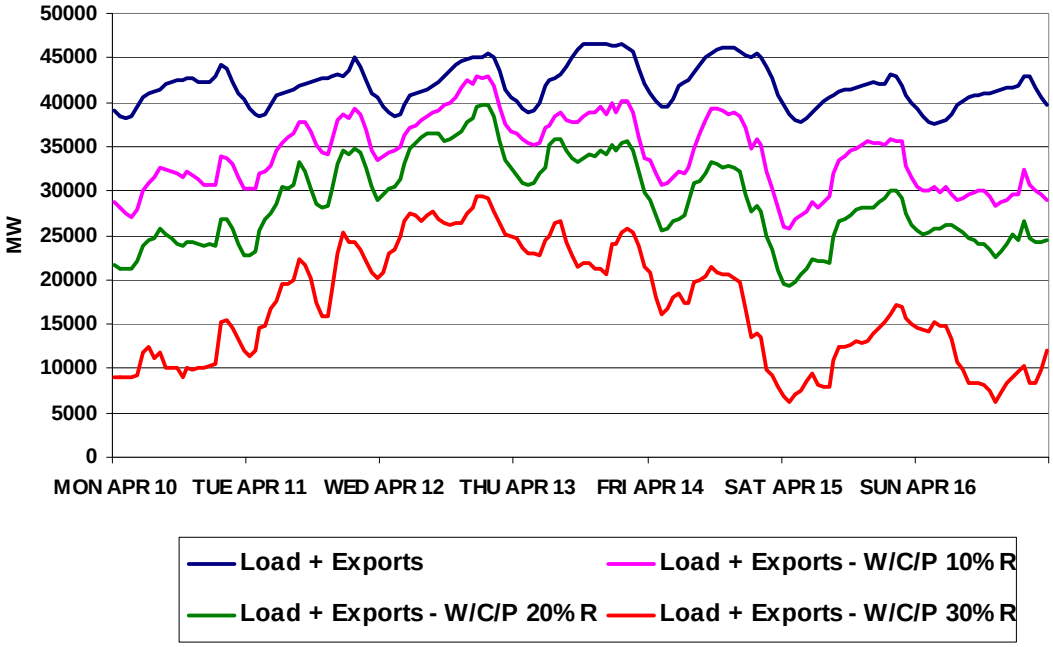


Figure 6.44 Study area - week of April 10th - net loads plus exports by penetration

Figure 6.45 shows how the generation by type shifts for the 20% scenario. The coal is now doing some cycling in the top 10 to 20 percent of its operating range. Not only has the wind generation grown significantly but the solar generation is now much more noticeable. The combined cycle operation has dropped to a third of its value with no renewables on the system.

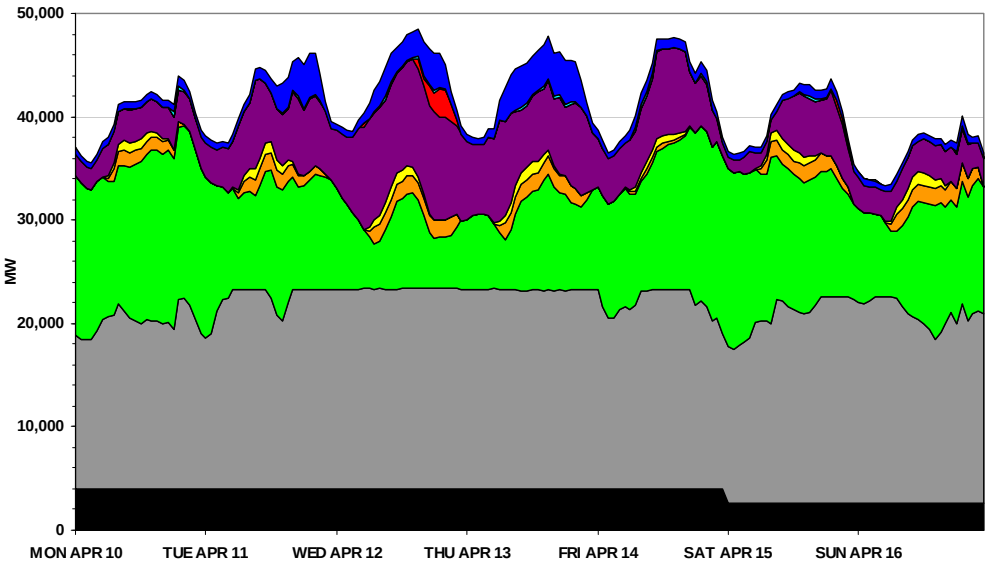


Figure 6.45 Study area dispatch - week of April 10th – 20% R scenario

Figure 6.46 shows the operation under the 30% scenario. Combined cycle units are now down to about 1% of their original output and coal generation has dropped 40%. In addition to much of the coal being decommitted for the week, the remaining units are required to do a lot more cycling. This may have a significant impact on the life of the generating units and cost of operations. Figure 6.47 shows how the combined cycle and coal units have changed for this week of operations compared to the case with no wind or solar generation.

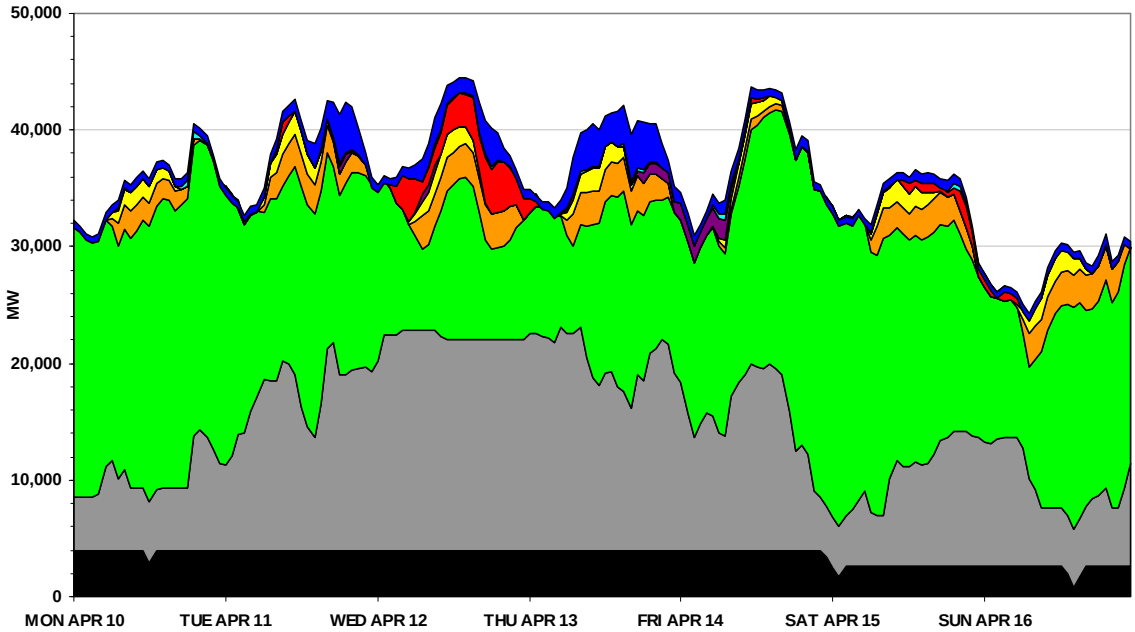


Figure 6.46 Study area dispatch - week of April 10th – 30% R scenario

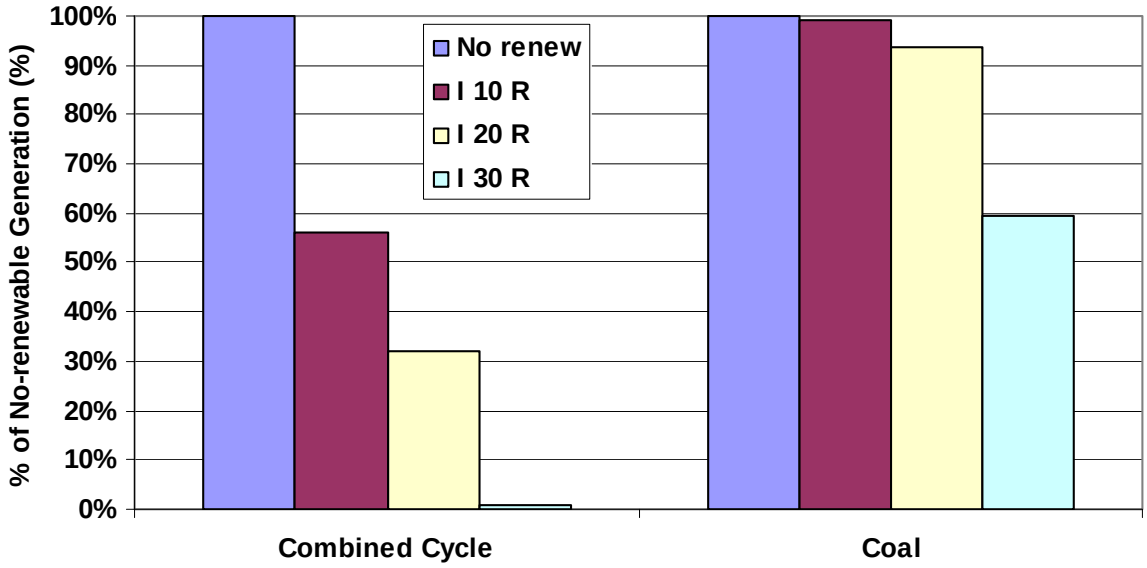


Figure 6.47 Change in operation - Week of April 10th

The graphs in Figure 6.48, Figure 6.49 and Figure 6.50 show a similar set of renewable operation, net load and net load plus exports for the week of July 10th. In this month the variation between penetration levels is far less, because load is higher and wind generation is lower.

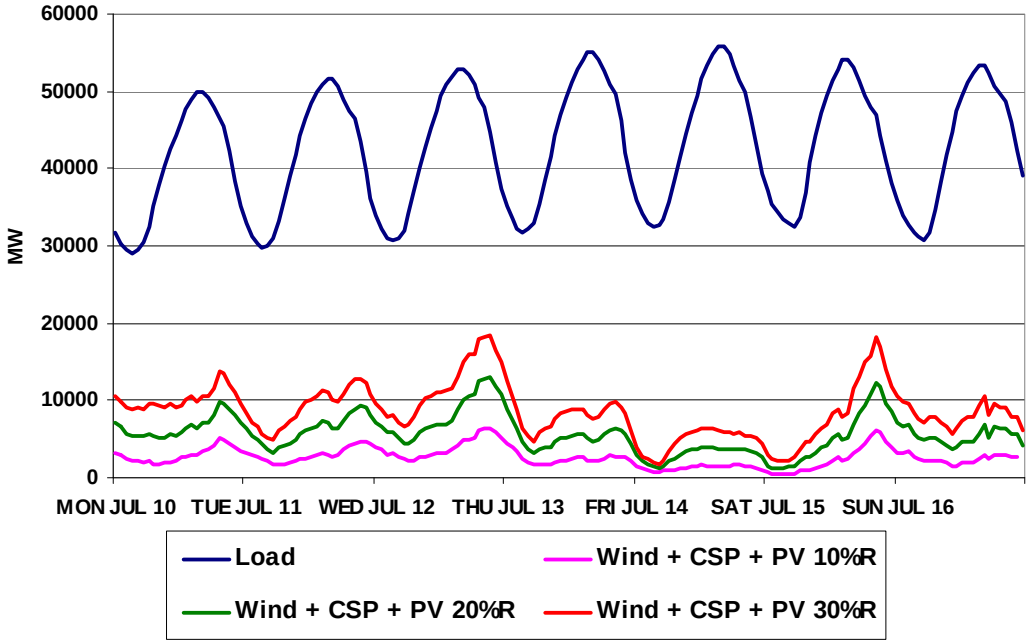


Figure 6.48 Study area - week of July 10th - renewables by penetration

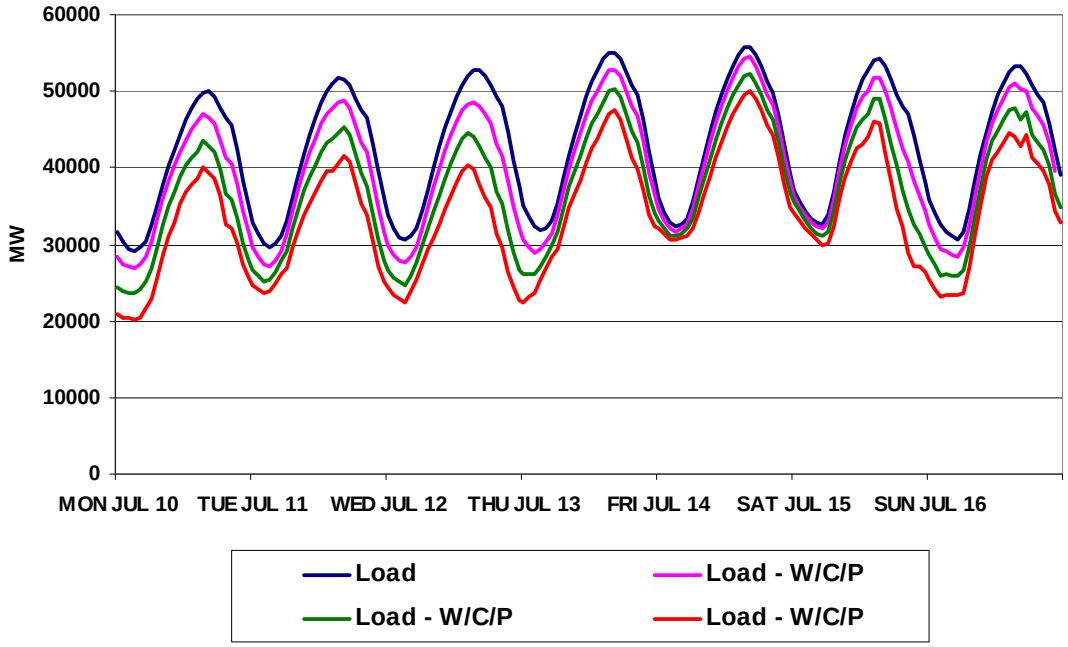


Figure 6.49 Study area - week of April 10th - net load by penetration

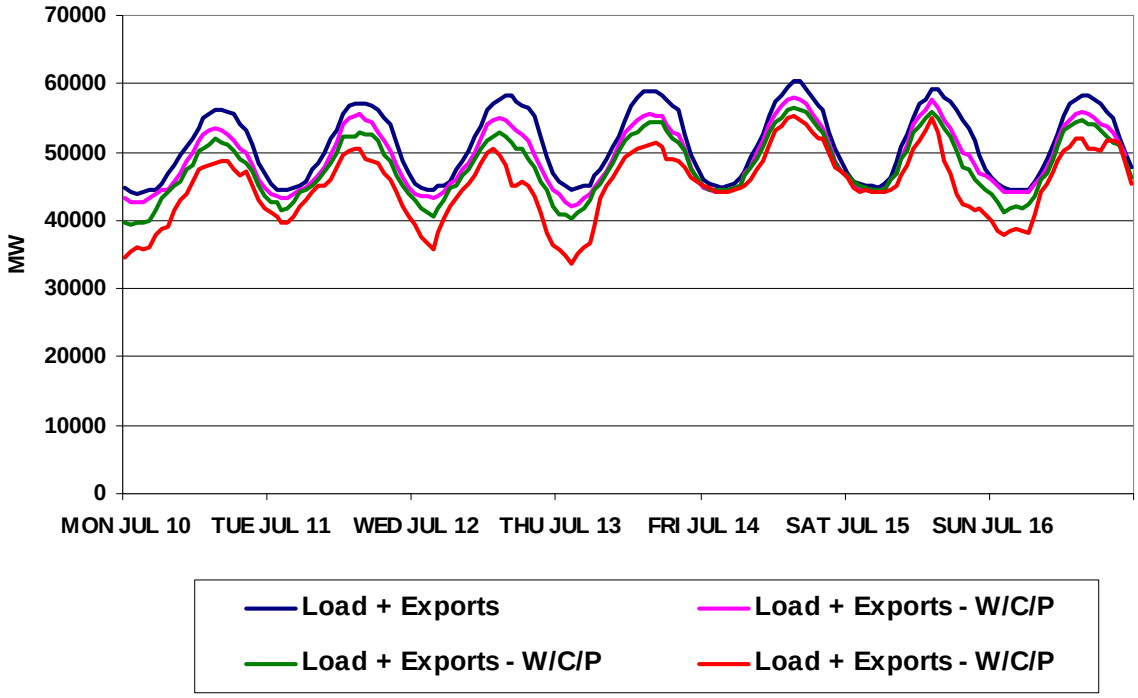


Figure 6.50 Study area - week of April 10th - net load plus exports by penetration

The graphs in Figure 6.51 through Figure 6.54 show the hourly operation by generation type for this week in July. Even at the 30% penetration scenario there is very little change in the coal plant operation. Most notable is the decrease in the gas turbine generation needed for peaking operation. It has been largely displaced by the wind and solar generation.

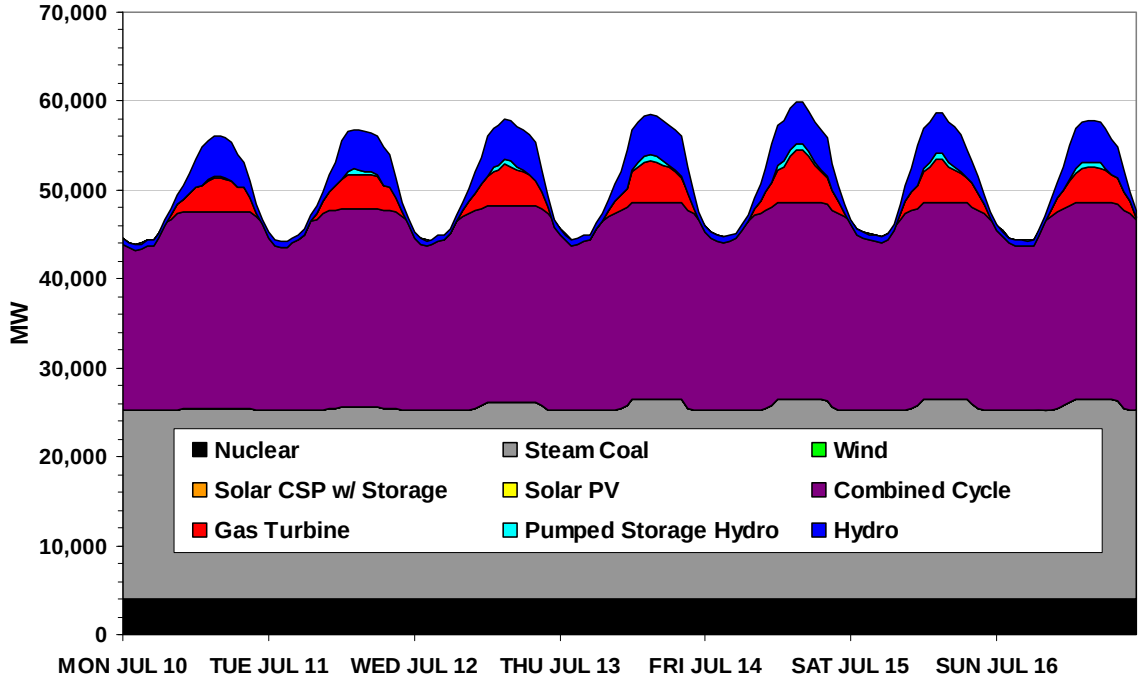


Figure 6.51 Study area dispatch - week of July 10th – no wind

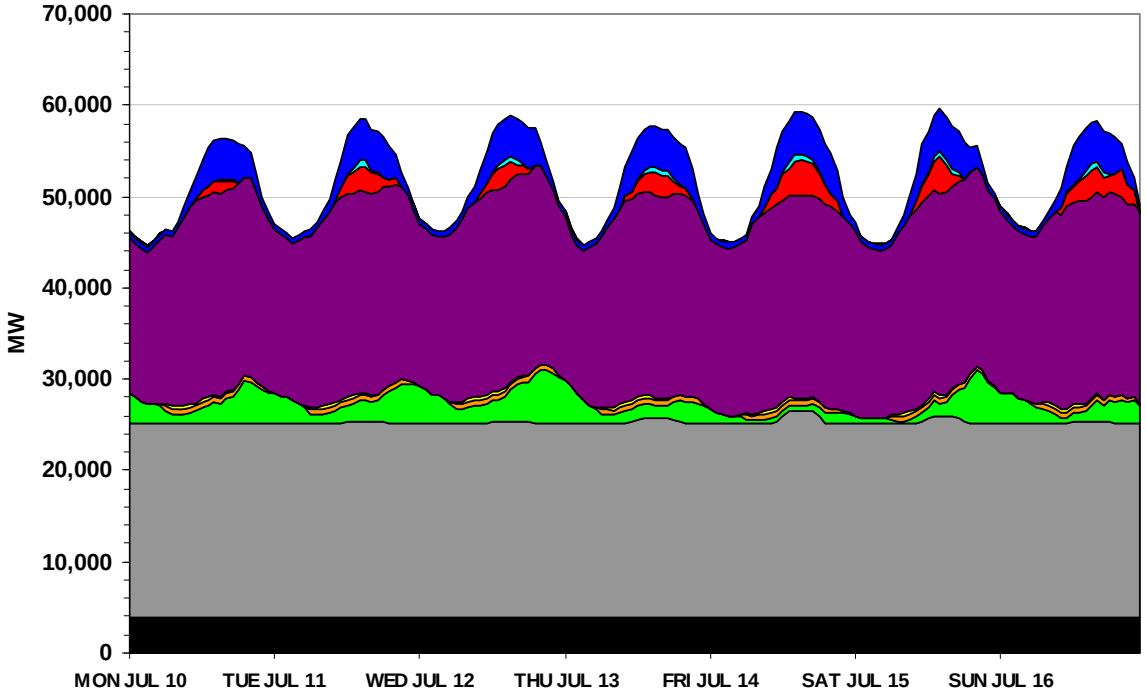


Figure 6.52 Study area dispatch - week of July 10th – 10% R scenario

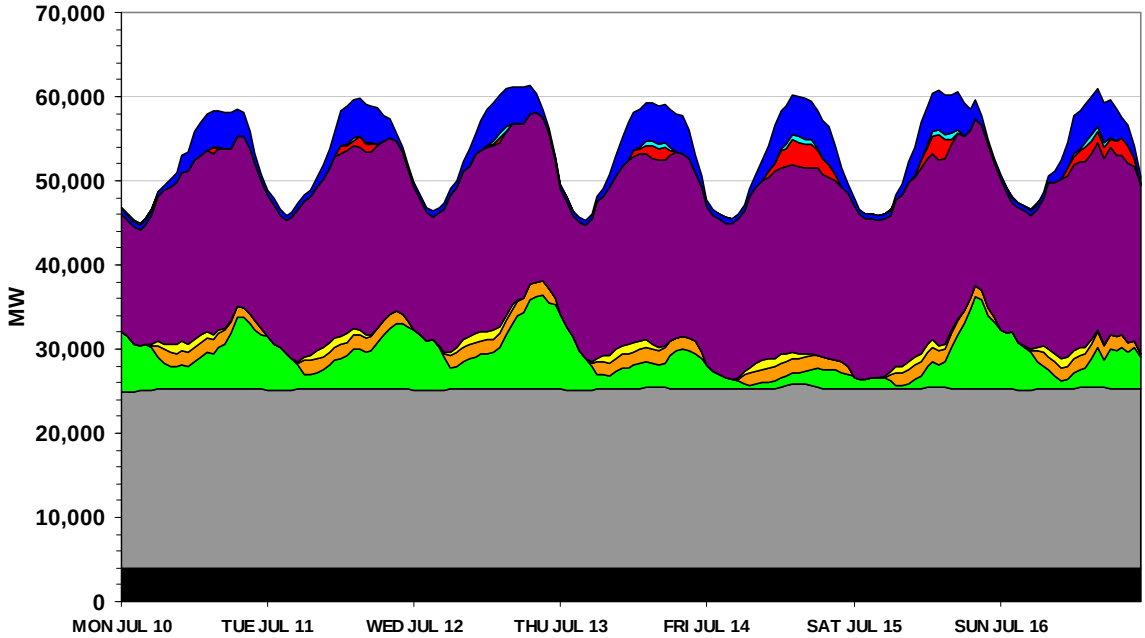


Figure 6.53 Study area dispatch - week of July 10th – 20% R scenario

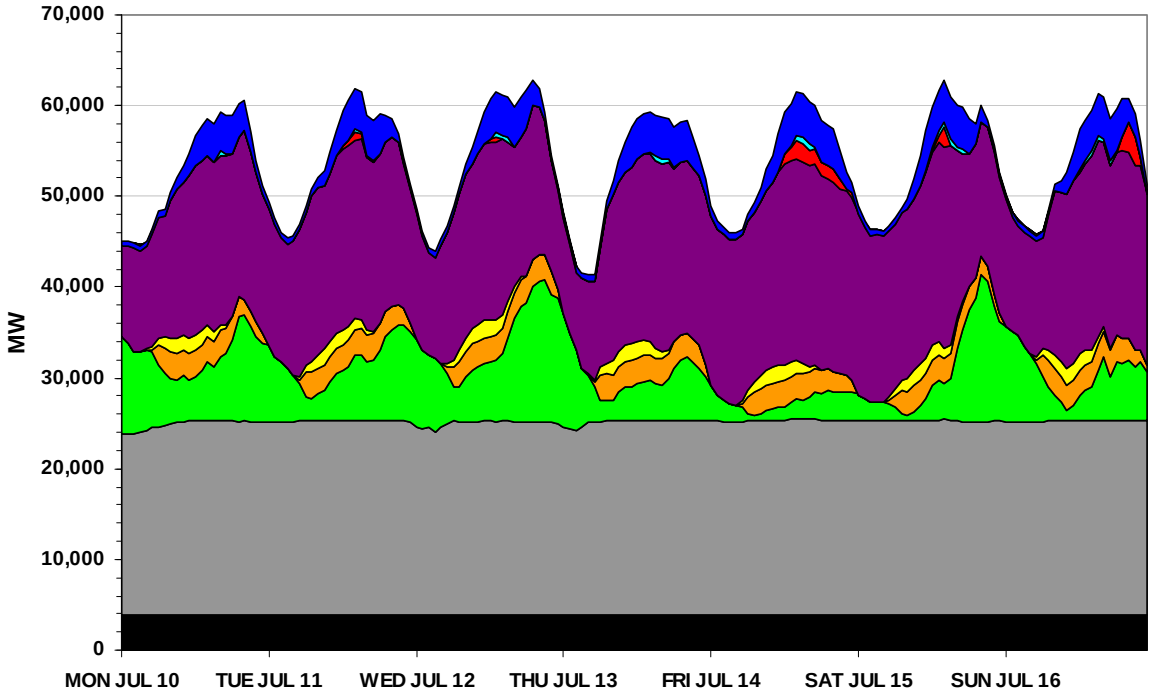


Figure 6.54 Study area dispatch - week of July 10th – 30% R scenario

Figure 6.55 highlights the shift in combined cycle and coal plant generation. The coal plant output is nearly constant and the combined cycle energy output has dropped by less than 20%. Comparing the series of figures for the April and July weeks show that while high penetration of renewables may cause significant disruptions at certain times of the year their impacts at other times will be much less severe. It may be that at low-

load/high-wind times of the year, more of the base load generation should be taken out of service to allow generators that are better able to cycle to provide the balance of the energy.

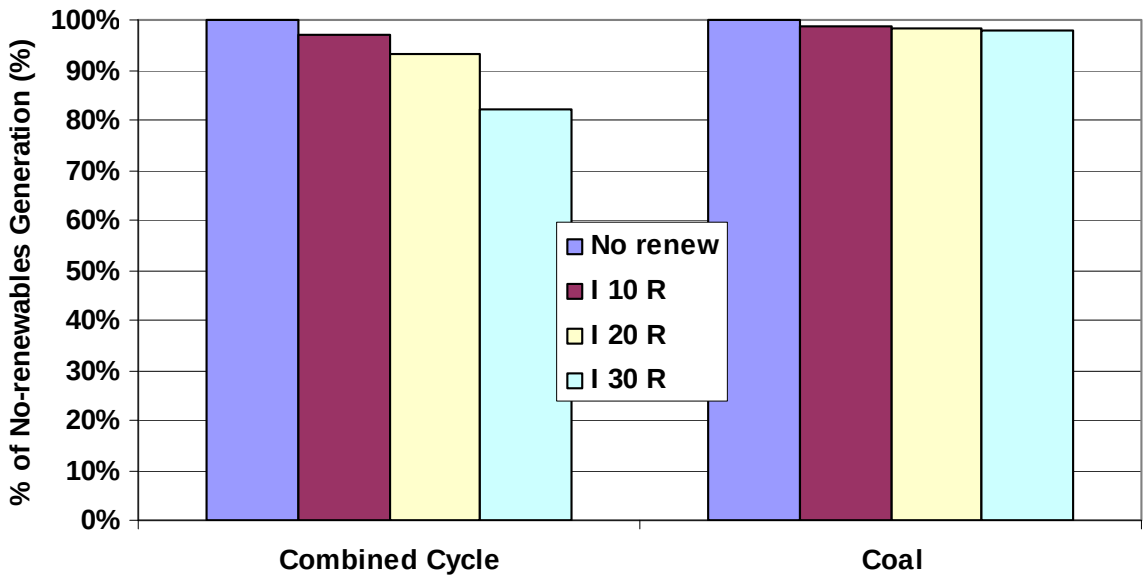


Figure 6.55 Change in operation - week of July 10th

6.4 Additional Operational Sensitivities

This section examines several additional sensitivities including variations in siting of the renewable units, sensitivity of the results to hydro and coal unit cycling capabilities, variations of the gas and coal unit priority positions and changes in the transmission and generation expansions.

6.4.1 Variations in Renewable Unit Siting

The bulk of the results shown so far were for the In-Area scenario. The various penetration levels were also examined for the Local-Priority and Mega-Project scenarios. Several comparative results will be shown over the next few pages. Only the sites within the study footprint were changed. The renewable sites in the rest of WECC were unchanged. Although the number of wind sites was changed significantly the annual energy target remained constant. The solar sites within the study footprint were mostly unchanged in the various scenarios.

Figure 6.56 shows the generation in the study area by type for the various scenarios and penetrations. Although there were some small variations the results were fairly consistent across the scenarios. This is not too surprising in light of the fact that sufficient transmission was added to allow the wind generation to be delivered to the same load areas as in the In-Area scenario.

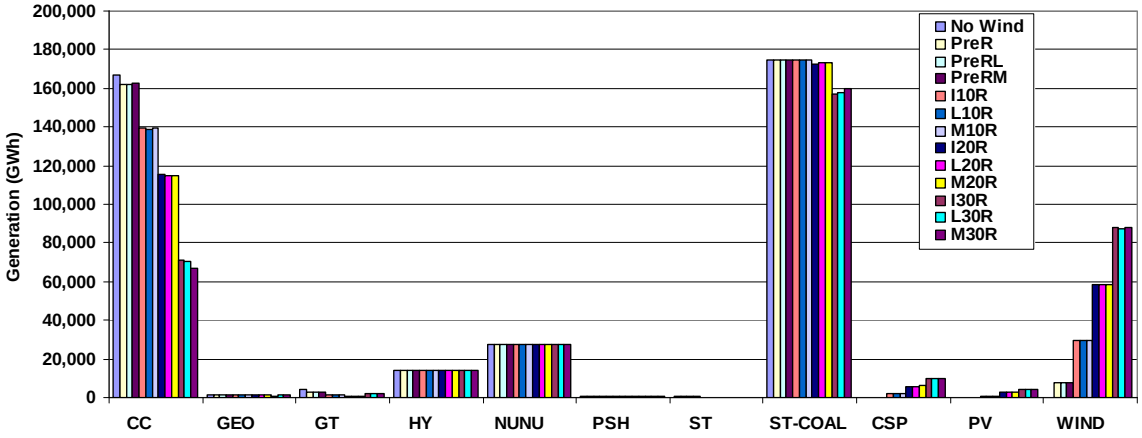


Figure 6.56 Generation by type, study area, multiple scenarios

Figure 6.57, Figure 6.58 and Figure 6.59 show the spot price duration curves by penetration level for the In-Area, Local Priority and Mega-Project scenarios respectively. The set of curves are very similar. Figure 6.60 and Figure 6.61 compare the curves across the various scenarios for the 30% penetration cases. Only slight differences exist between the three curves.

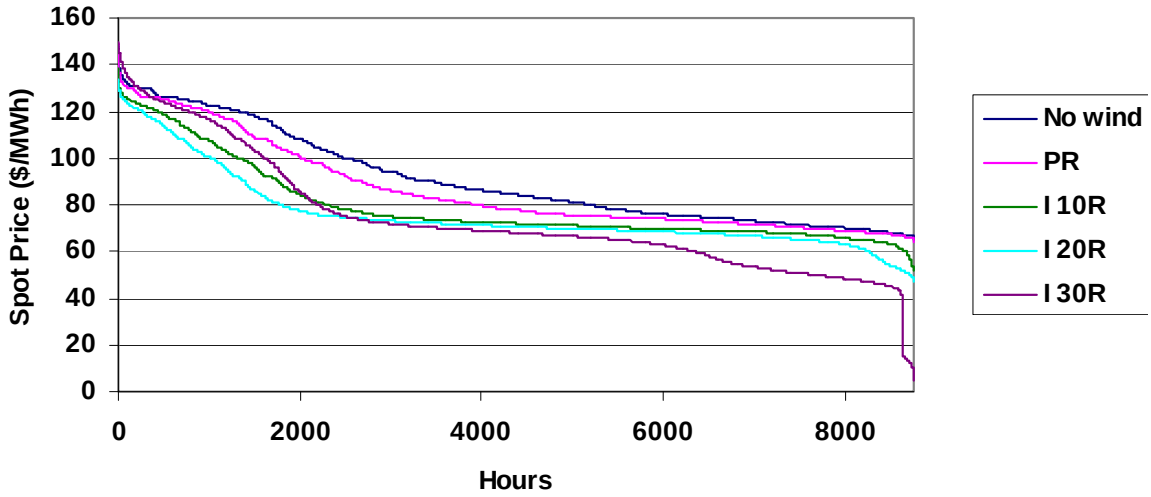


Figure 6.57 Annual spot price duration curve - S-o-A Forecast, In-Area scenario

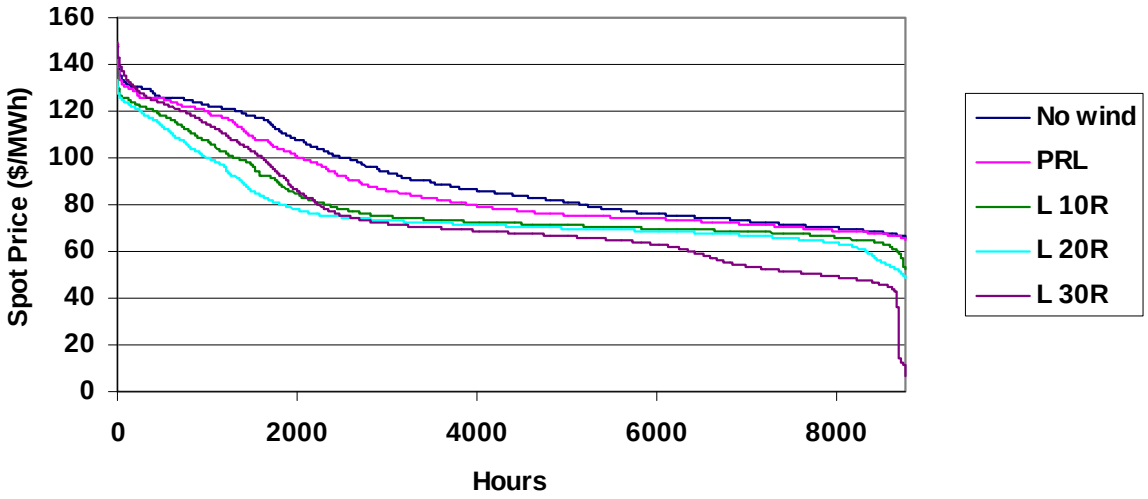


Figure 6.58 Annual spot price duration curve - S-o-A Forecast, Local Priority scenario

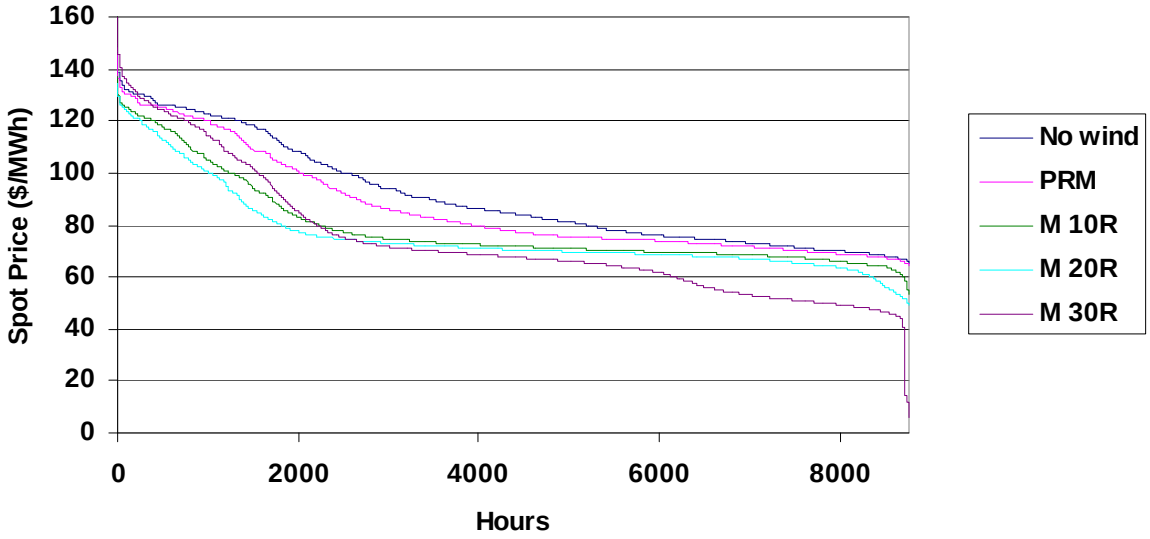


Figure 6.59Annual spot price duration curve - S-o-A Forecast, Mega-Project scenario

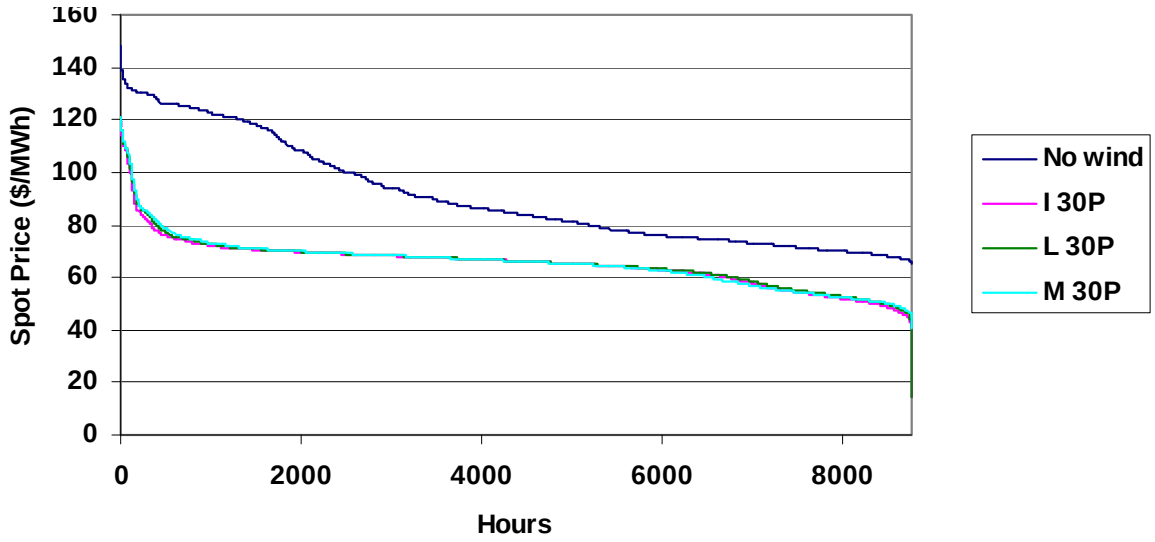


Figure 6.60 Annual spot price duration curve, perfect forecast, 30% scenarios

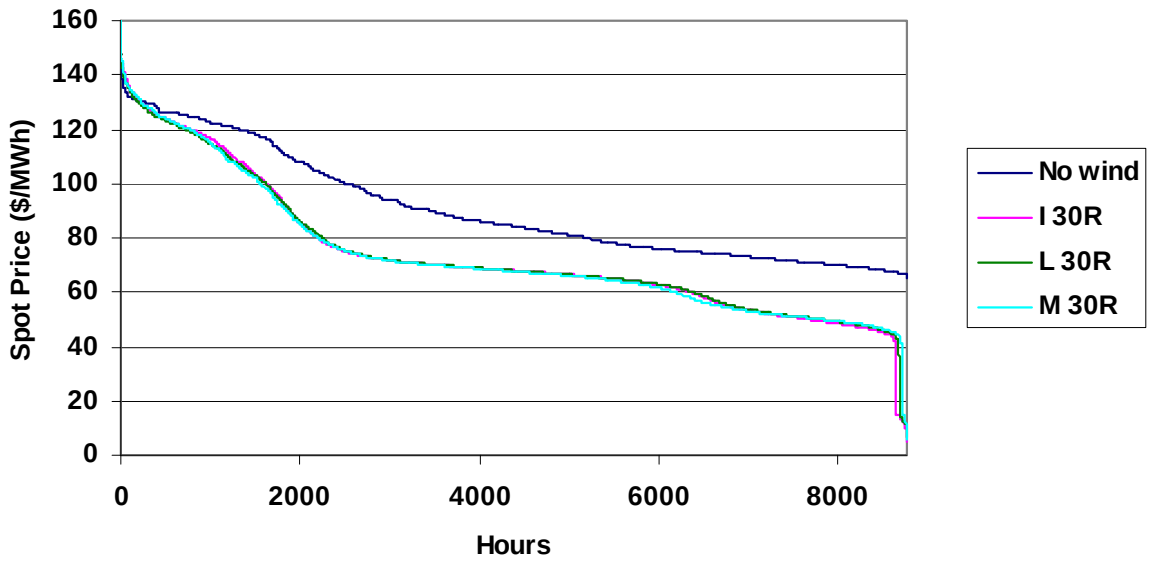


Figure 6.61 Annual spot price duration curve, S-o-A forecast, 30% scenarios

Figure 6.62 shows that the total generation in the study area is largely unchanged for a given penetration level regardless of where the wind and solar resources were located. Figure 6.63 shows the total WECC operating cost savings per MWh of renewable energy for the different cases. There was a slight increase in value as the wind plant locations were shifted to the higher capacity factor sites in the Local Priority and Mega Project Scenarios. This trend is also visible in Figure 6.64 which shows the incremental value per incremental renewable MWh.

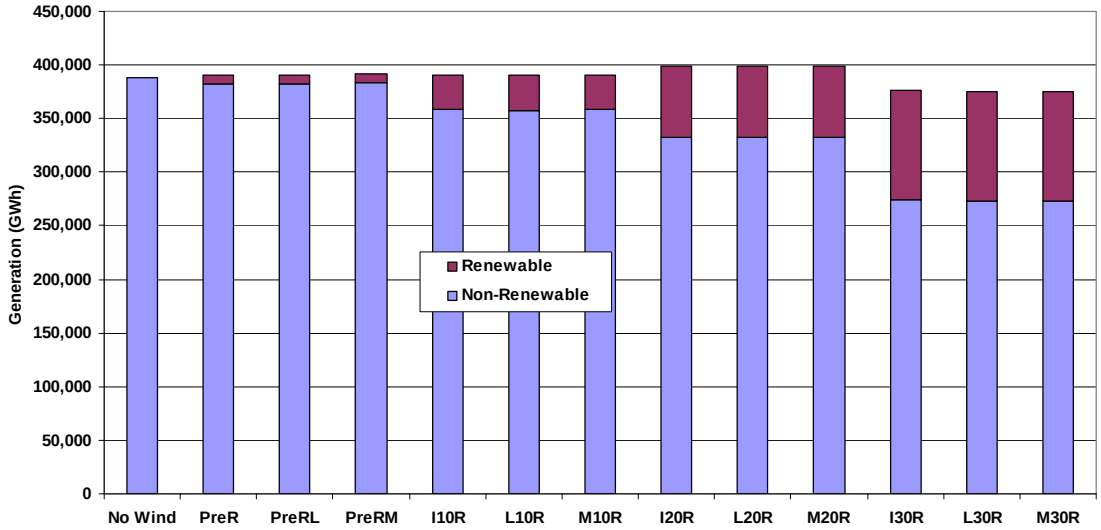


Figure 6.62 Total generation, study area, multiple scenarios

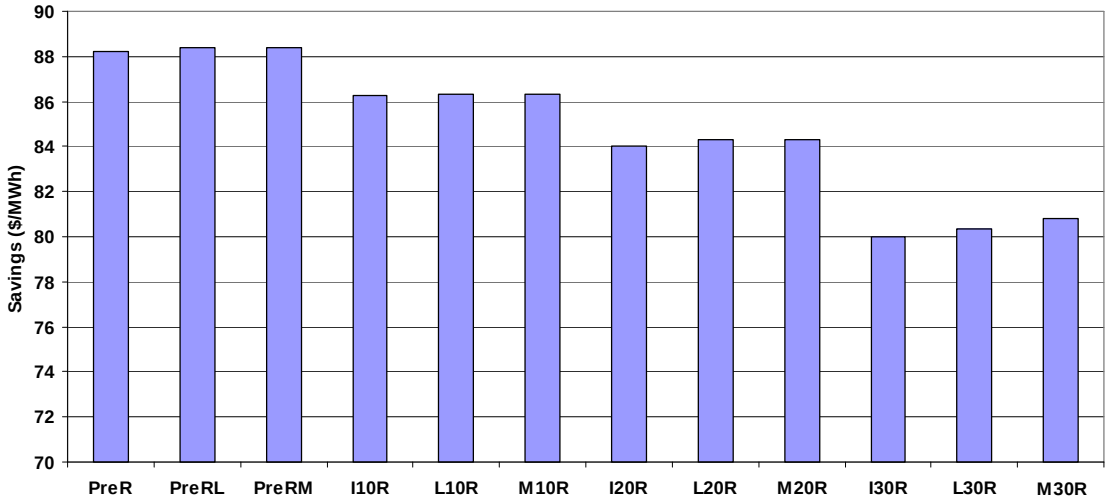


Figure 6.63 Operating cost savings per MWh of renewable energy, WECC

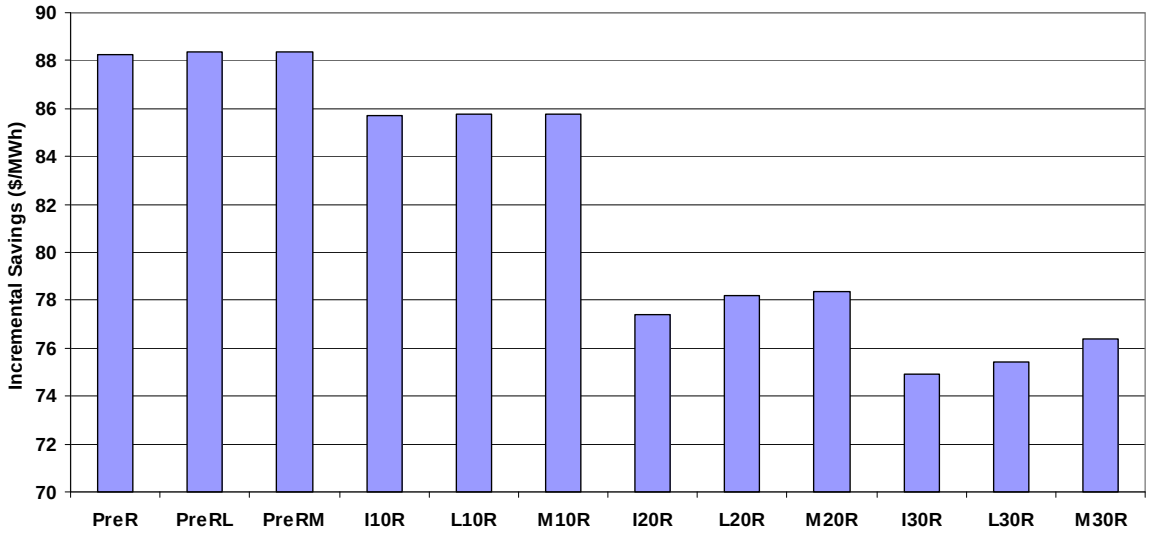


Figure 6.64 Incremental savings per incremental renewable energy, WECC

Figure 6.65, Figure 6.66 and Figure 6.67 show the incremental savings per incremental renewable MWh by penetration level for the three shape years for the three different scenarios. Although there is a slight difference between the years, the differences in incremental savings with increasing penetration are consistent with what was seen for the 2006 shapes.

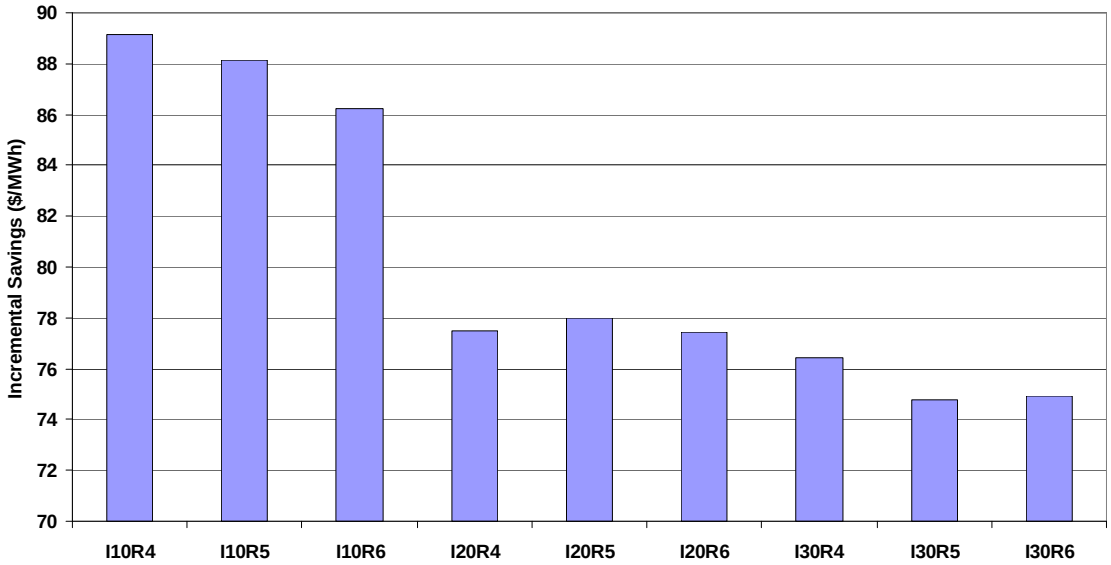


Figure 6.65 Incremental savings per incremental renewable energy, WECC, In-Area scenario

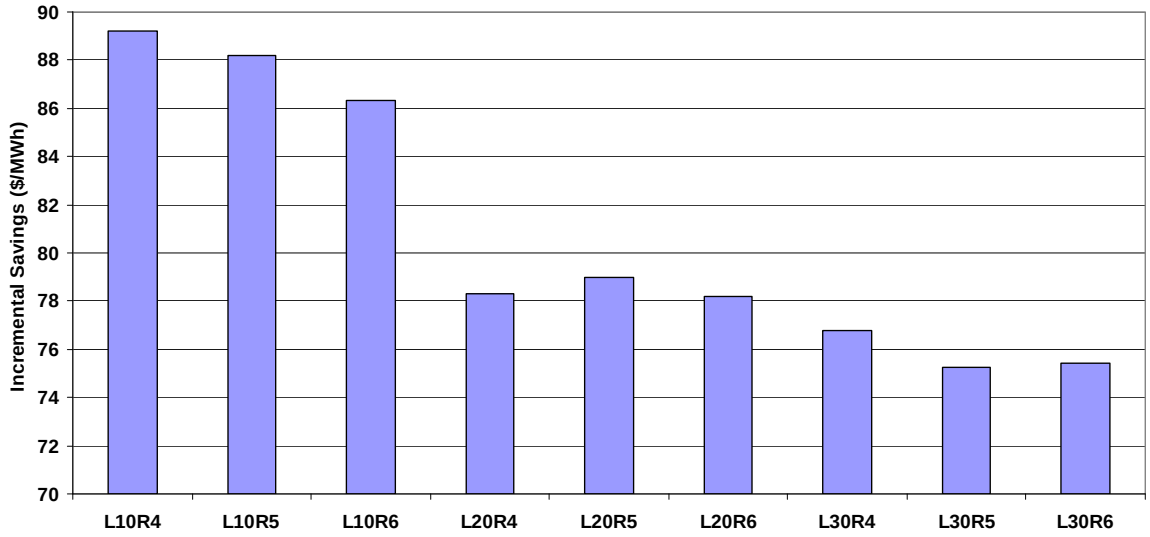


Figure 6.66 Incremental savings per incremental renewable energy, WECC, Local Priority scenario

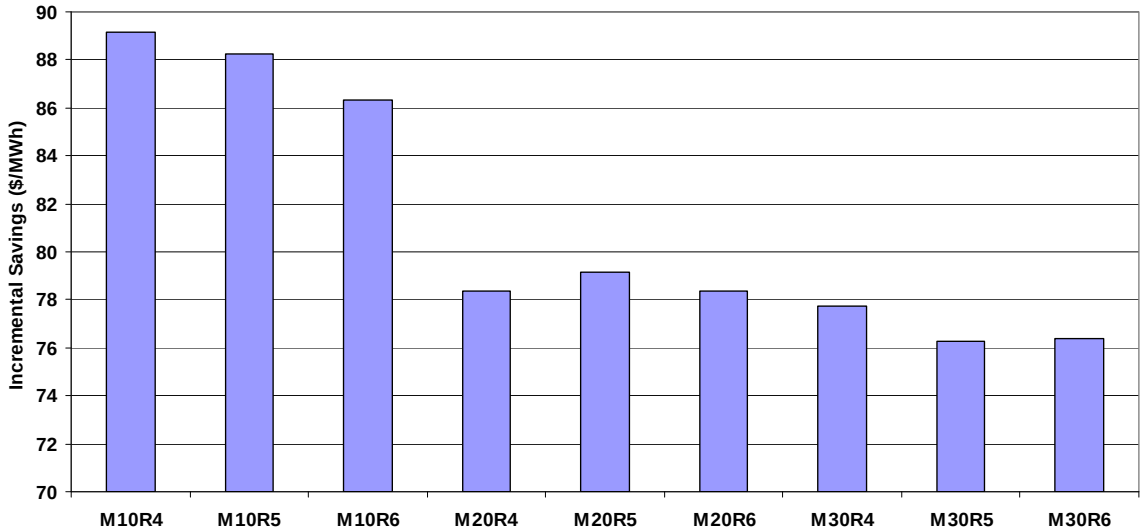


Figure 6.67 Incremental savings per incremental renewable energy, WECC, Mega-Project scenario

6.4.2 Hydro Operation

This section examines the operation of the hydro plants in the base case (no wind and solar) and how it changes with the introduction of wind and solar renewable generation. Comparisons are made to historical operation, and the impacts of restrictions on the hydro operation are examined. Figure 6.68 shows the total hourly operation of the WECC hydro plants for the week of April 10th as a function of renewable penetration. These cases assumed that the hydro was scheduled after the wind forecast. Therefore, as more wind was added the hourly schedule of the hydro changed but the total monthly energy remained constant, as well as the monthly minimum and maximum power output levels. Although the patterns shifted somewhat, there did not appear to

be major changes in the hydro operation. Figure 6.69 shows a similar comparison for a July week.

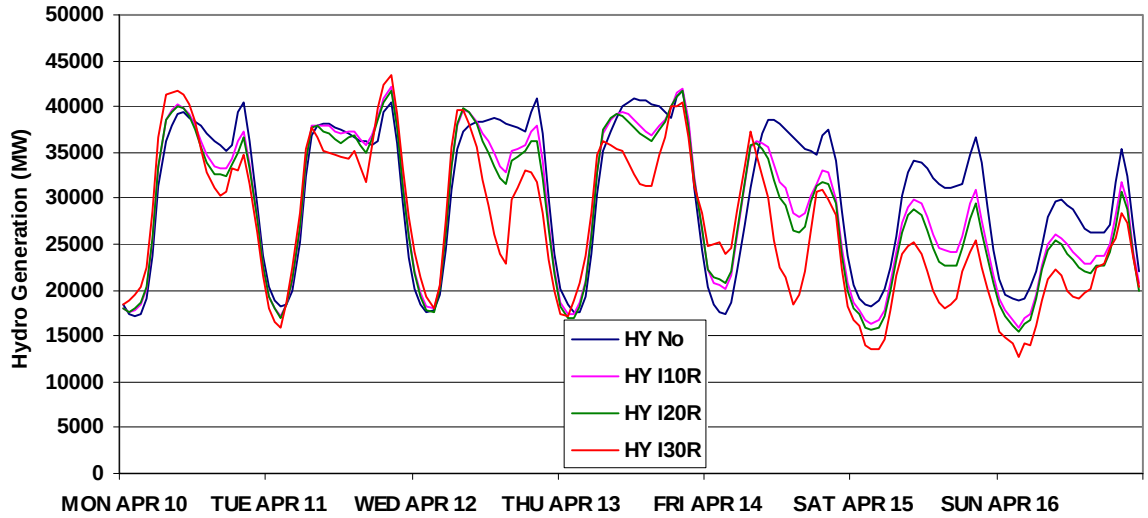


Figure 6.68 Hydro operation - week of April 10th

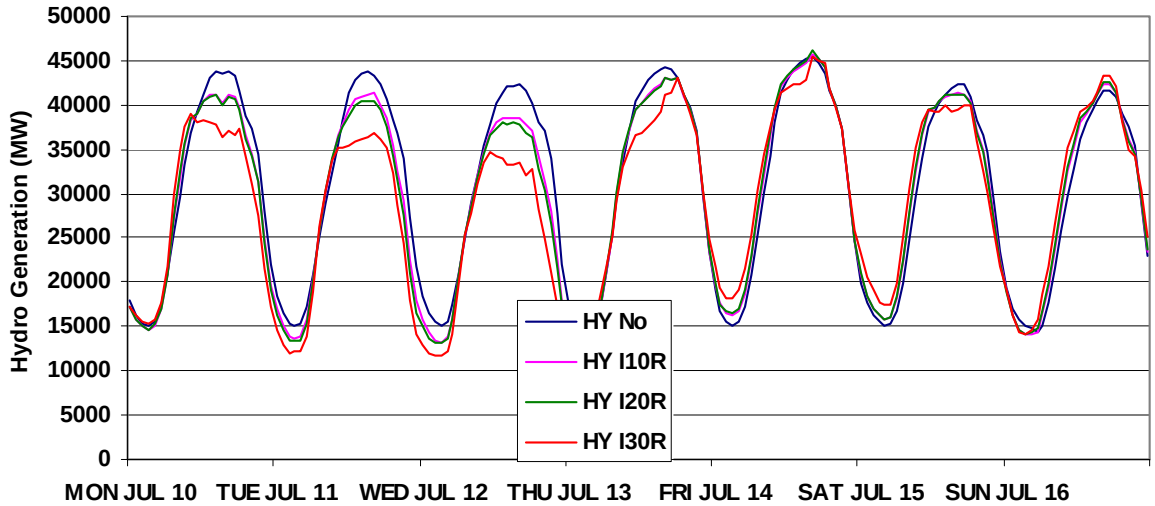


Figure 6.69 Hydro operation - week of July 10th

Figure 6.70 shows an annual duration curve for the hydro operation for the same set of scenarios. Again, from a macro level there does not appear to be any significant shifts in the operation of the hydro. Figure 6.71 shows the hourly delta for the hydro generation from the chronological curves, sorted and plotted as duration curves. It shows that the wind generation did not seem to be pushing the hydro into any significant up or down ramps that were different from the no wind scenario.

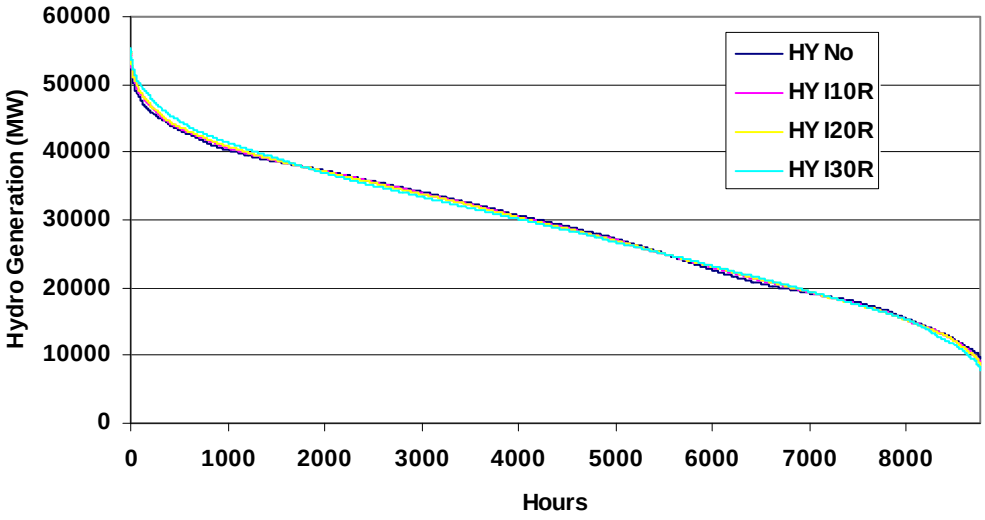


Figure 6.70 Annual hydro generation duration curve, WECC

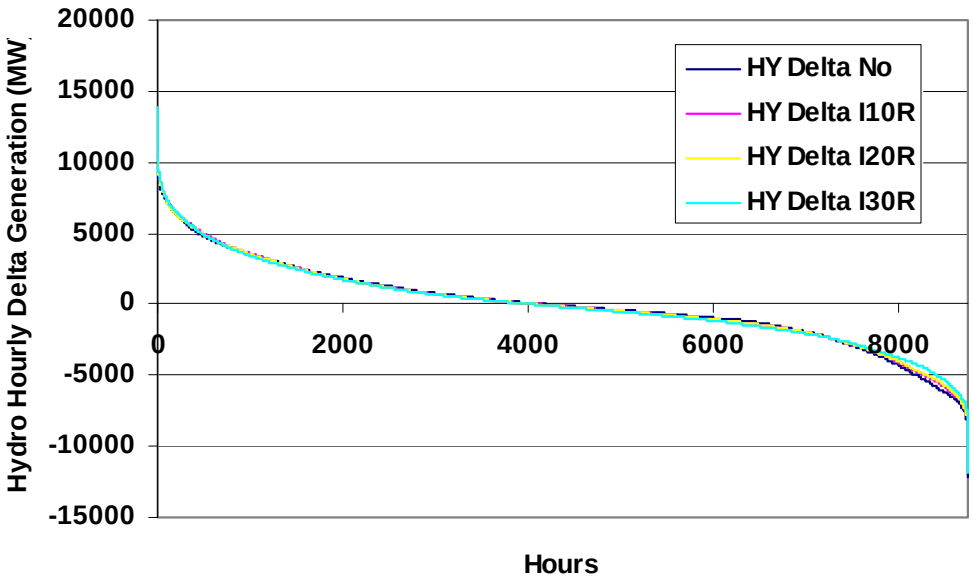


Figure 6.71 Annual hydro hourly delta duration curve, WECC

The next step was to examine the assumption that the hydro was scheduled based on the forecasted wind. Historically the hydro generation ramps up and down based on the forecasted load demand. Therefore it seemed reasonable to assume that hydro would try to follow the net load. Figure 6.72 shows spot price duration curves for the various penetrations for the base assumptions, when the hydro is scheduled on load alone(noted as "-H"). In these cases the hourly hydro generation remains unchanged

between the scenarios. As can be seen, there is not much of a shift between any pair of cases at the same penetration.

Figure 6.73 shows the operating cost increases when hydro is scheduled before the renewables rather than after. Although the values are relatively small for low renewable penetrations they exceed $200 million for the 30% scenario.

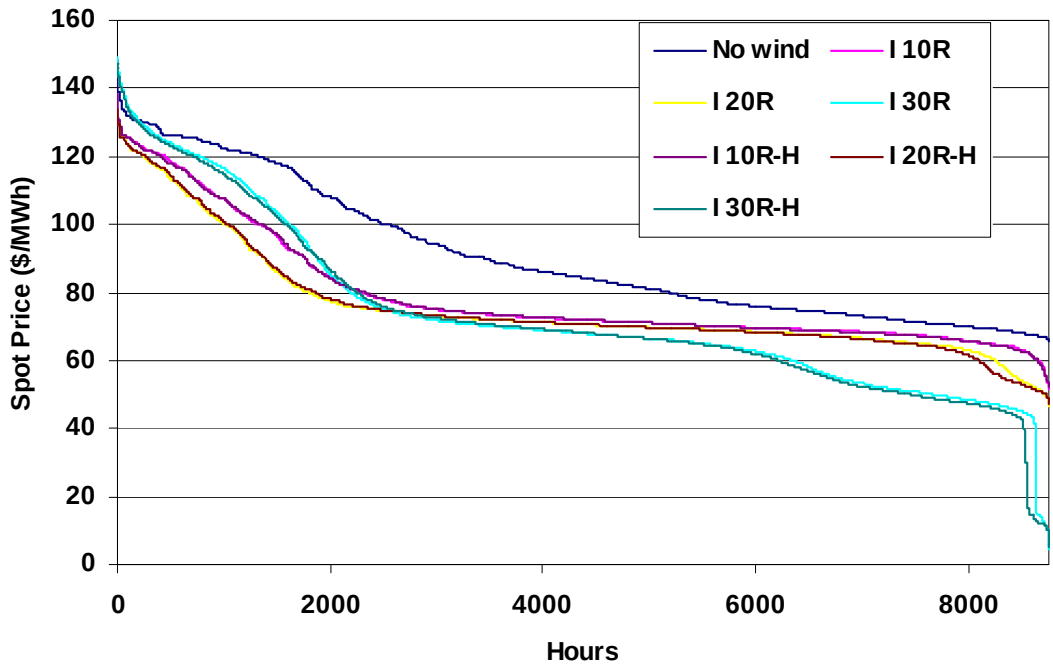


Figure 6.72 Spot price impact of hydro operation

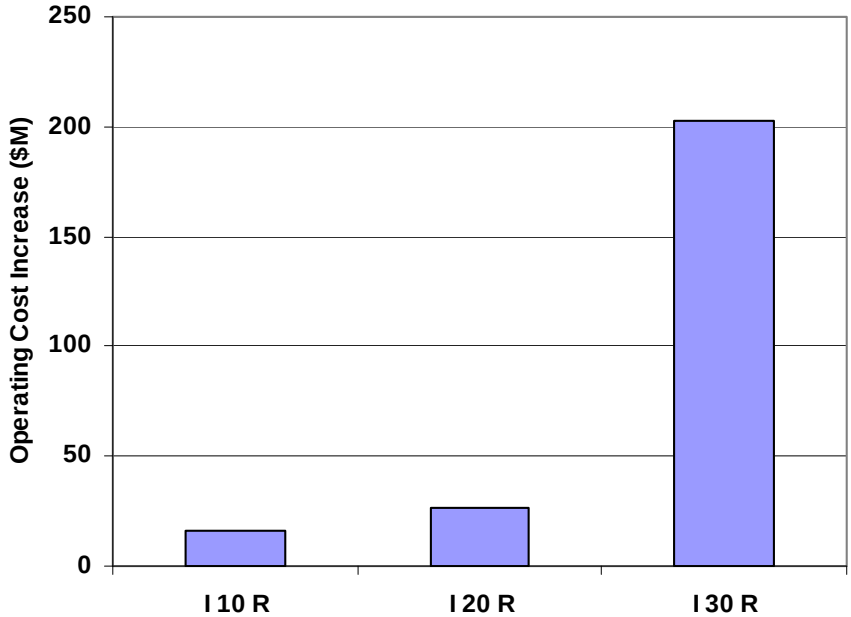


Figure 6.73 Operating cost increase for dispatching hydro on load alone versus net load, WECC

The next few charts examine the historical flexibility of hydro generation, particularly in low water periods. Figure 6.74 shows the variation in the capacity at the Glen Canyon plant as a function of the elevation of water behind the dam. When the water level drops, not only is the amount of energy that the plant is capable of producing severely limited, but the capacity at which the unit can operate is significantly reduced. Although the nameplate rating is over 1300 MW there is less than half of that capacity available at low head elevations. Figure 6.75 shows the historical water levels at Lake Powell that feeds the Glen Canyon plant. From these two charts it can be seen that available capacity over the last several years is down significantly from its maximum value. Figure 6.76 shows that the monthly generation at the plant over the past several years is less than half of the high values seen in 1996.

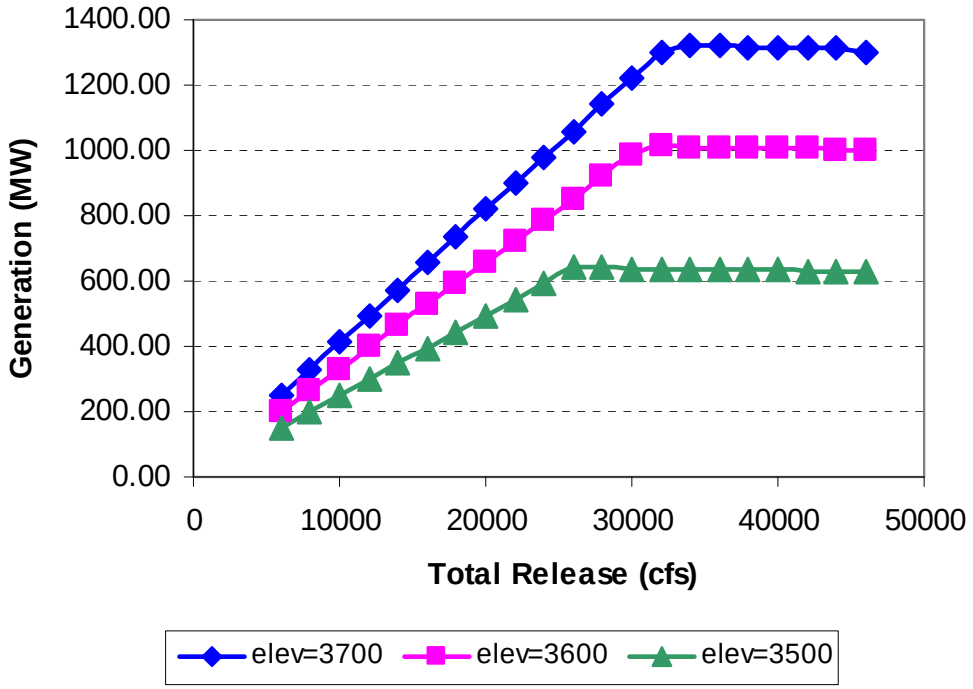


Figure 6.74 Glen Canyon capacity versus elevation

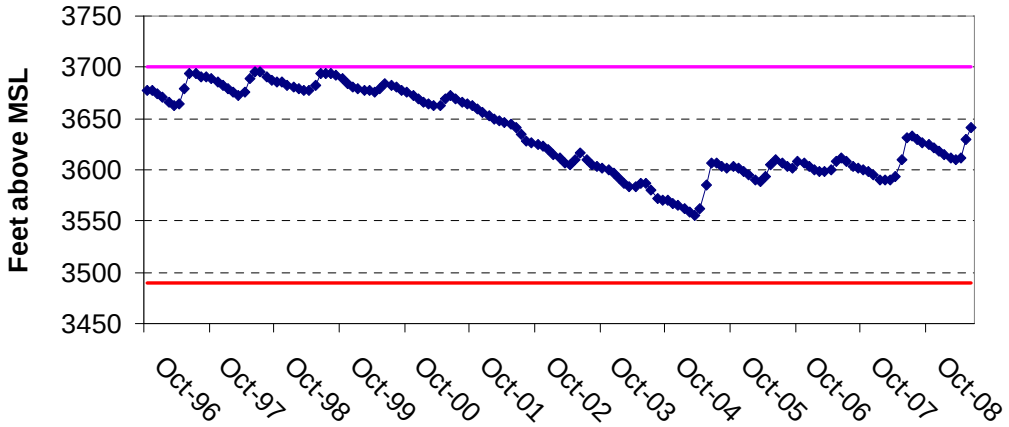


Figure 6.75 Historical elevation of Lake Powell

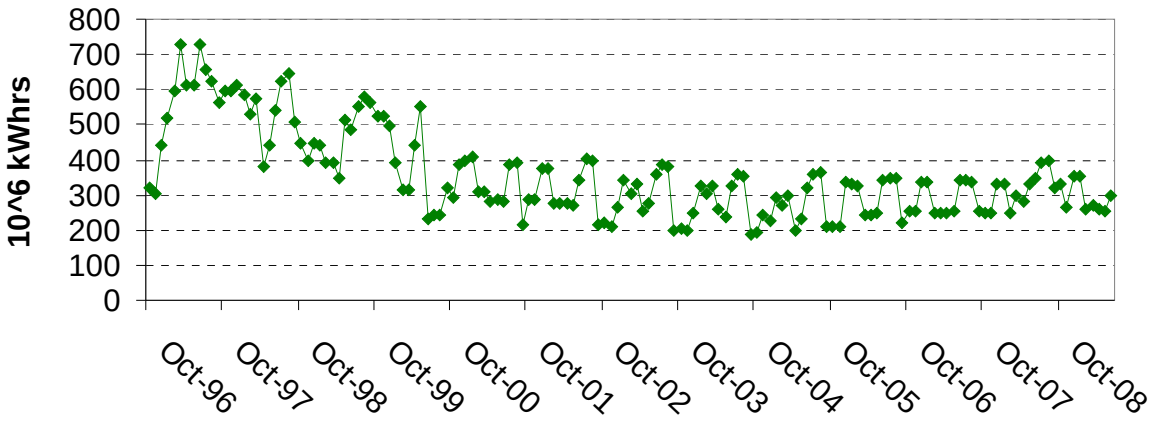


Figure 6.76 Net monthly generation at Glen Canyon

Although the energy values used in the simulation reflected the averages over the last several years the capacity values were not adjusted to reflect the drop in elevation. Figure 6.77 shows the daily maximum, minimum and average outputs from the plant. The model assumed that the plant could swing from its maximum to minimum value within 24 hours. Figure 6.78 shows the simulation values on a monthly basis. Figure 6.79 adds in the historical maximum monthly values from 2005 and 2006, which fall roughly in line with the average values used in the simulation. Figure 6.80 adds in the historical average values. Because the simulation used 10 year historical average monthly energy values for the hydro they are slightly higher than the 2005 and 2006 numbers.

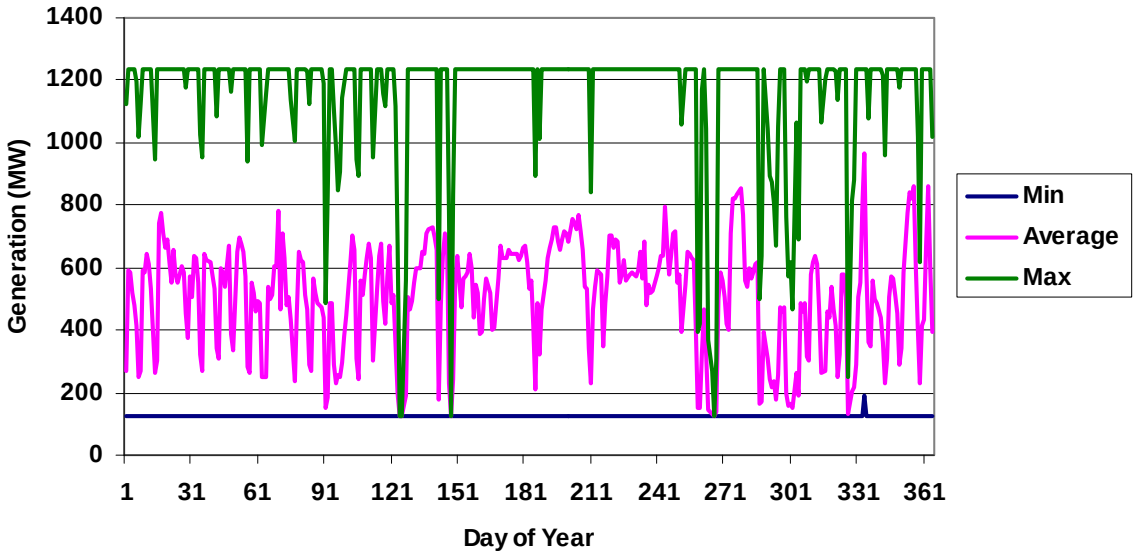


Figure 6.77 MAPS daily simulation of Glen Canyon with no wind

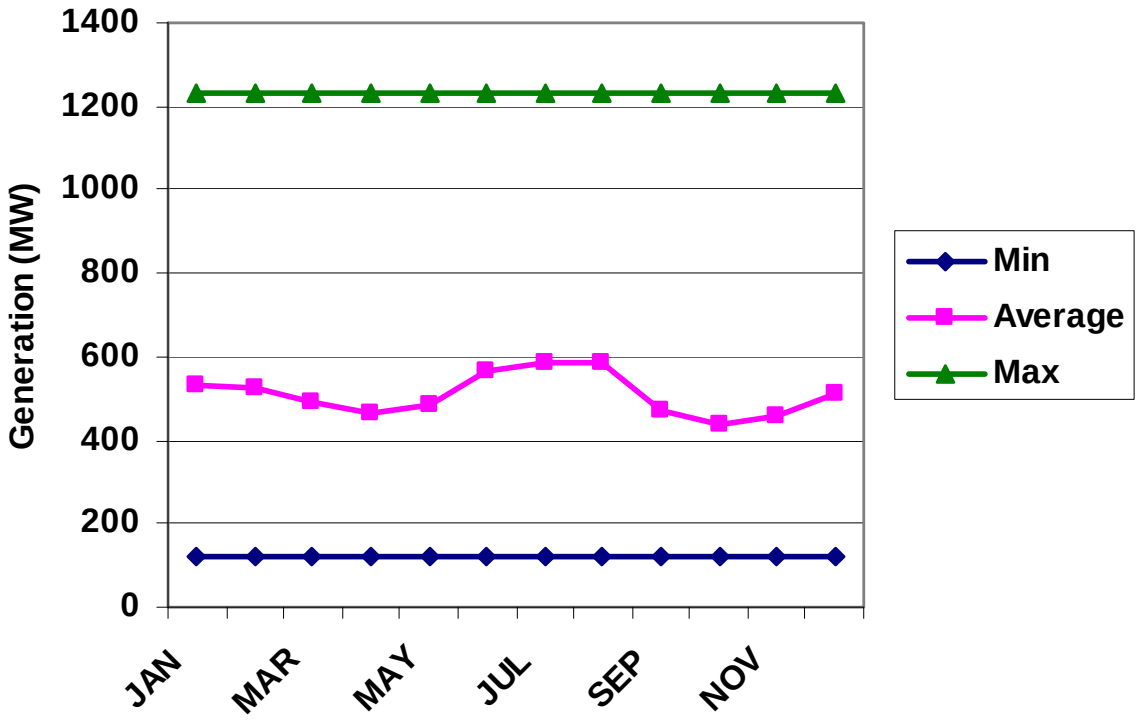


Figure 6.78 MAPS monthly simulation of Glen Canyon with no wind

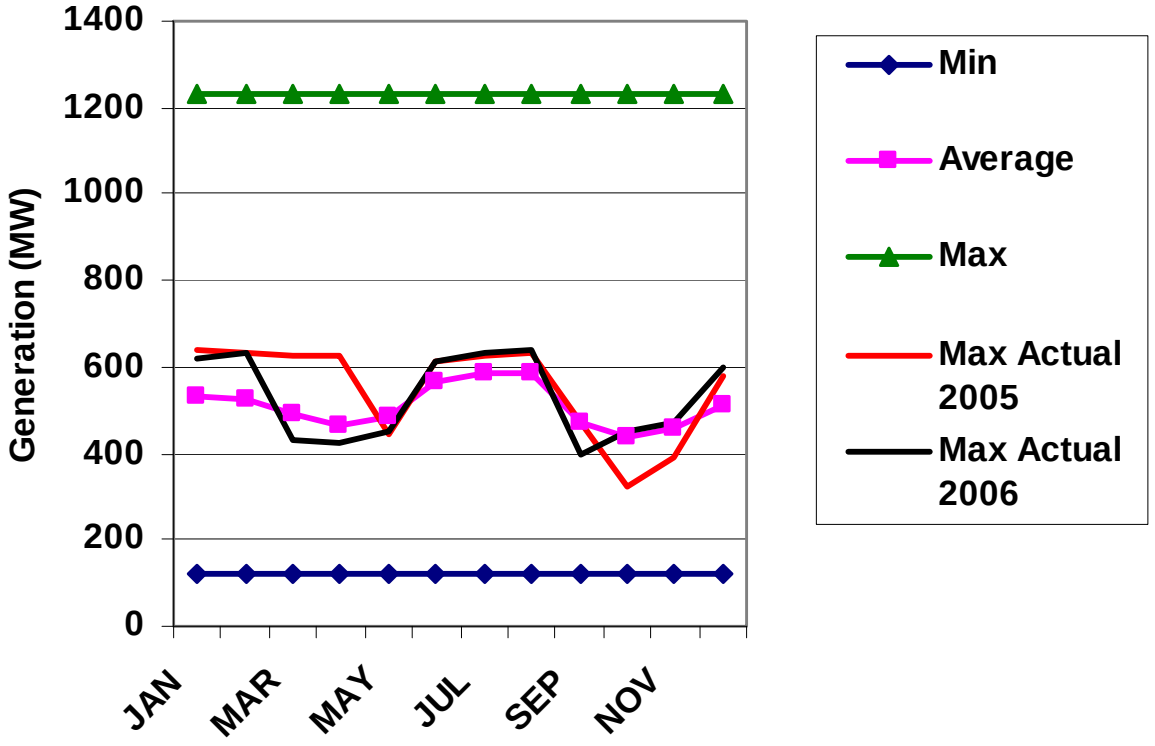


Figure 6.79 Historical maximum operation of Glen Canyon

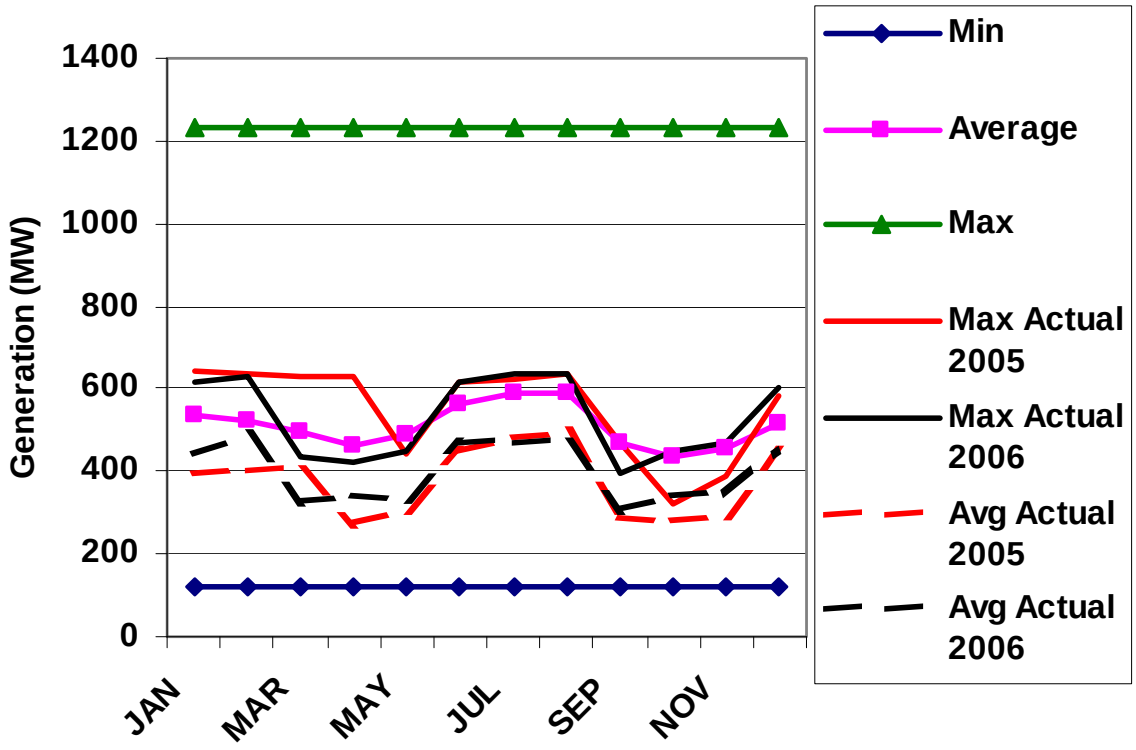


Figure 6.80 Historical maximum and average operation of Glen Canyon

In order to assess the impact of reduced capacity and flexibility, the individual hydro plants were modeled as a flat block with a constant output each month set to utilize the same monthly energy as the base case. The capacities were reduced to this average value so that the hydro plants did not provide any spinning reserve support. Figure 6.81 shows a comparison of the WECC operating costs for the various scenarios for the base assumptions and the corresponding case with flat hydro (cases ending in Hf). Figure 6.82 shows the delta impact on the WECC operating costs of the flat hydro. Restricting the hydro flexibility to fit with the reduced water levels adds $800M to $1200M to the total cost of WECC operations. In terms of its impact on the value of renewable energy restricting the flexibility of the hydro actually increases the value of the renewables by a few $/MWh. This is largely due to the fact that the no-wind case with flat hydro experiences shortages and much higher usage of the peaking units. The addition of the wind and solar generation alleviates these shortages.

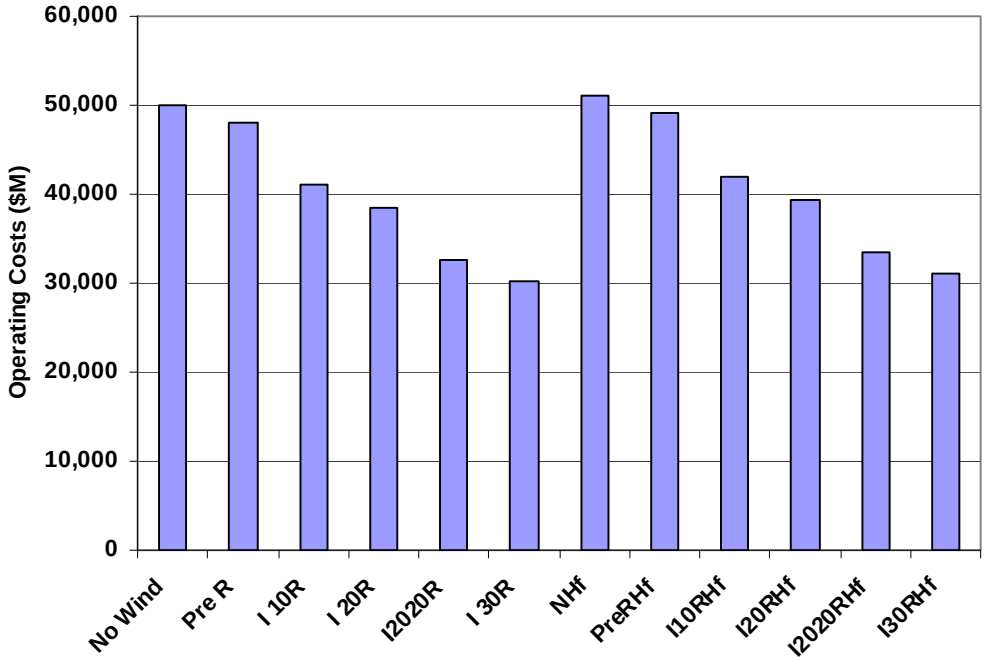


Figure 6.81 Impact of flat hydro operation on WECC operating costs

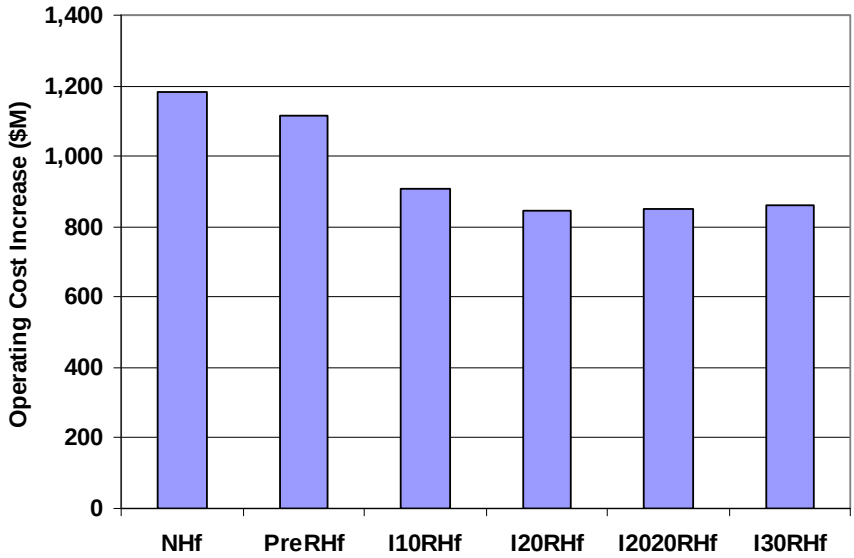


Figure 6.82 Incremental operating cost impact of flat hydro operation

Figure 6.83 compares the spot price duration curves for the no-wind and 30% scenarios for the original hydro schedules and flat hydro schedules. With no renewables the higher spot prices go up significantly since the hydro is not allowed to do any "peak shaving". The low end drops slightly due to more hydro being dispatched off peak. With the 30% penetration the high end costs are mostly unchanged while the low end cost drop slightly. Figure 6.84 shows the spot price curves for the "flat hydro" schedules for various renewable penetrations.

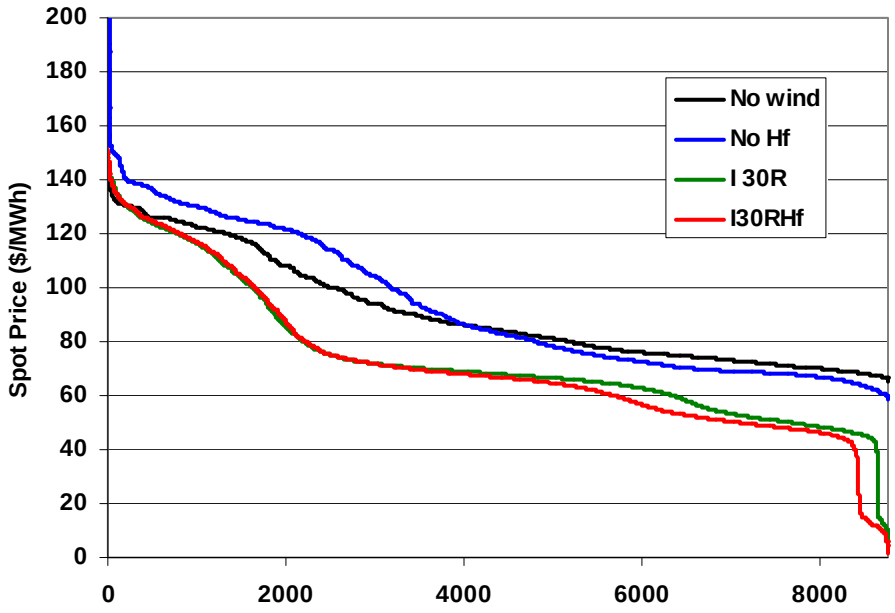


Figure 6.83 Spot price impact of flat hydro operation

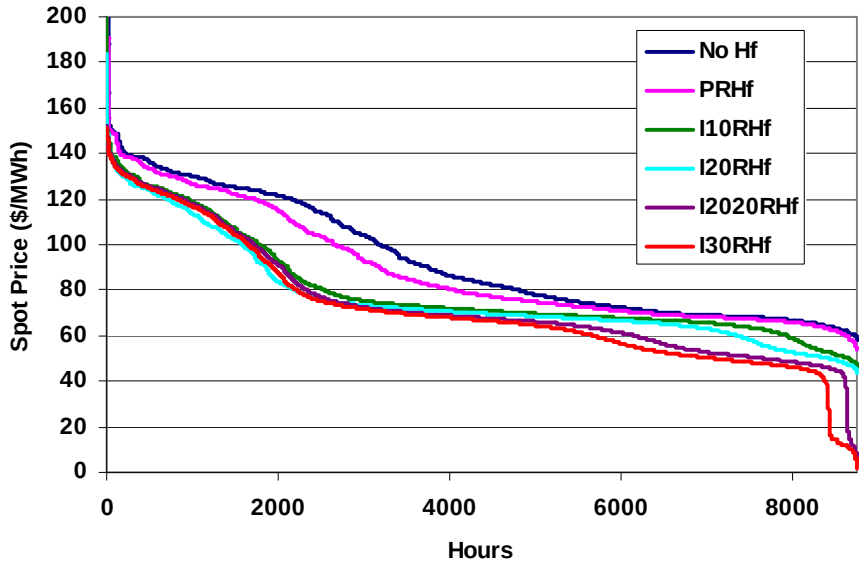
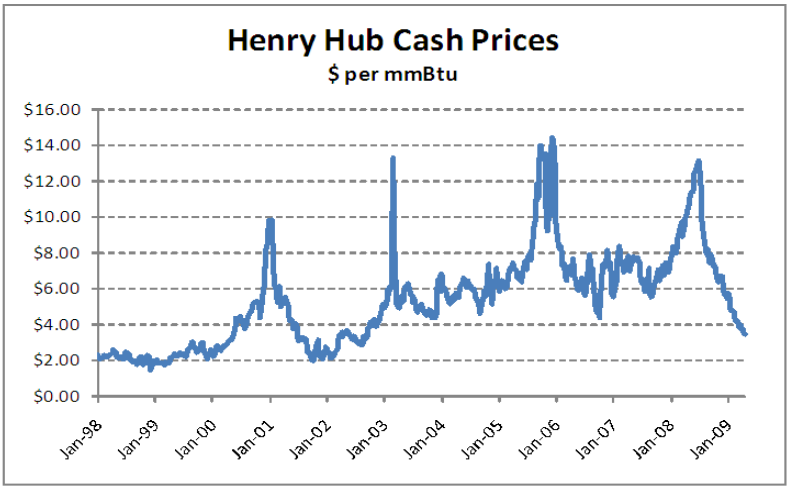


Figure 6.84 Spot price impact of flat hydro operation by penetration

6.4.3 Coal and Gas Pricing Sensitivity

As stated earlier the 2017 natural gas price assumed for this study was roughly $9.5/MBTu. However, as seen in Figure 6.85, gas prices can be volatile. Future gas prices may be high or may drop significantly. Figure 6.86 shows a comparison of the typical cost of energy from a steam coal plant and a gas fired combined cycle unit as a

function of gas price. When the gas price is low enough the combined cycle units are more economically attractive to operate than the coal units. This reversal in the priority order of these two technologies can also take place due to increases in the carbon tax. The base case assumed a $30/ton tax on CO2 emissions. Each $1/ton increase in this tax will increase the cost of coal generation by about $1/MWh but will only add $0.6/MWh to the cost of gas fired combined cycle generation.



Energy Ventures Analysis, Inc.

Figure 6.85 Historical Henry Hub natural gas prices

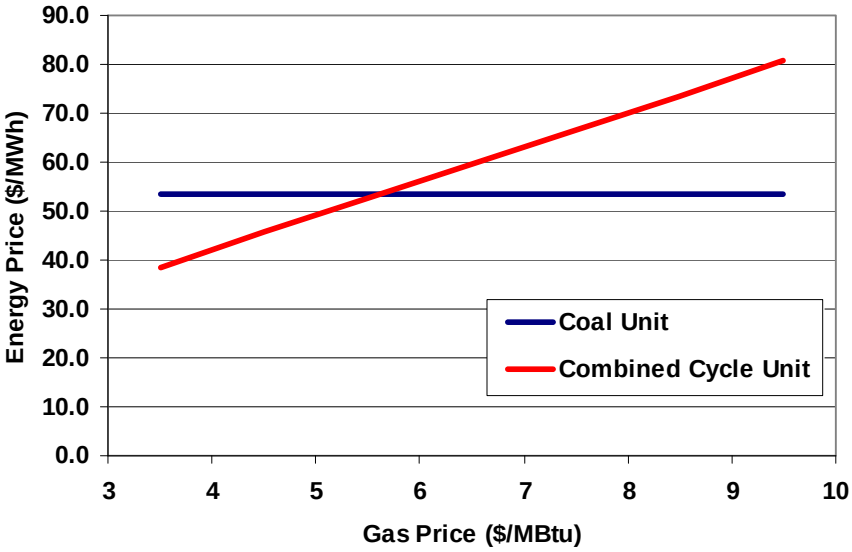


Figure 6.86 Coal vs. Combined cycle cost comparison

In order to evaluate the impact, cases were run with the carbon tax held at $30/ton but with the gas price reduced to $3.50/Mbtu, thereby making the combined cycle plants more attractive to operate than the coal plants. Figure 6.87 shows the generation by type

for the no-wind and 30% scenario for the base case assumptions and the low gas price cases. In the new "no-wind" case the combined cycle generation increases and steam coal generation drops off compared to the original case. In the new 30% case it is now the coal plants which pick up two thirds of the displacement and combined cycle units only carry about a third of the change. Figure 6.88 shows the impact on the total emissions and Figure 6.89 shows the incremental change in WECC emissions due to the reduced gas price. The emission reductions due to the renewable generation have jumped significantly now that coal plants are being displaced rather than gas plants.

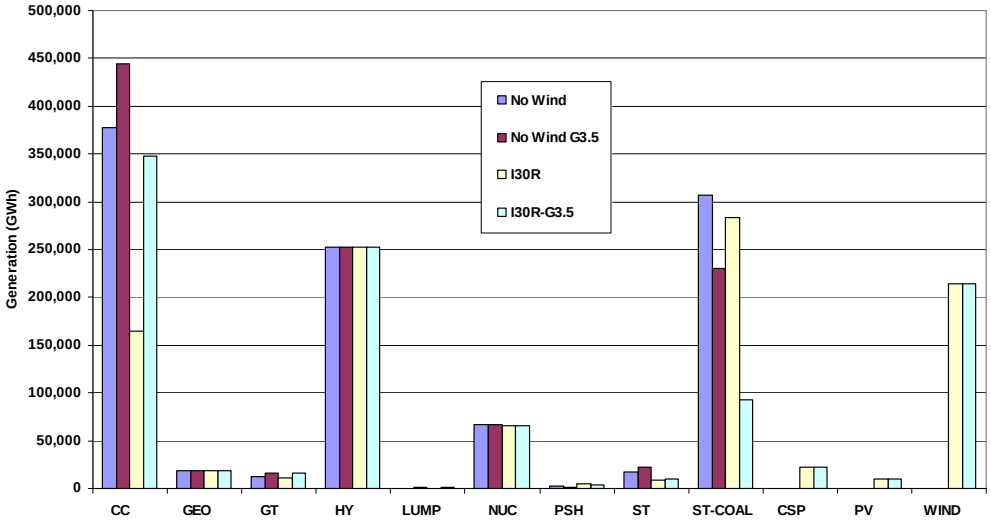


Figure 6.87 Generation by type with gas price reductions, WECC

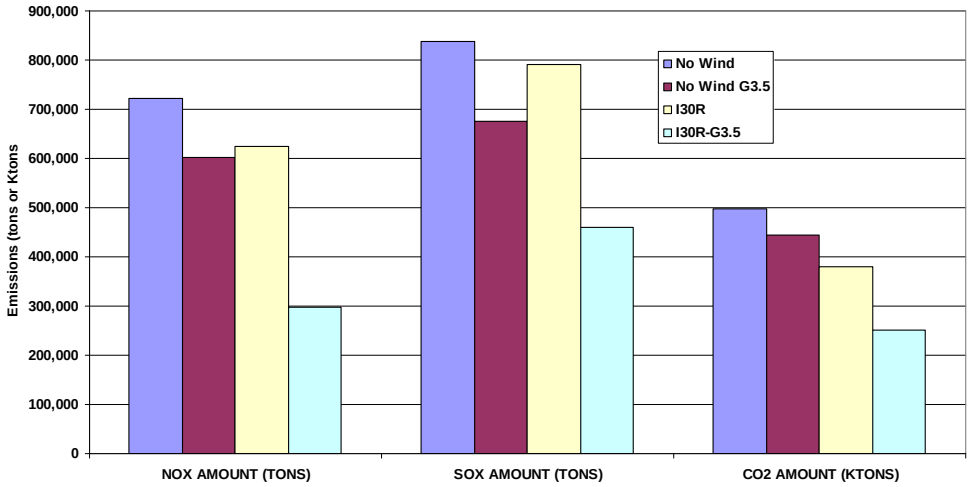


Figure 6.88 Emissions with gas price reductions, WECC

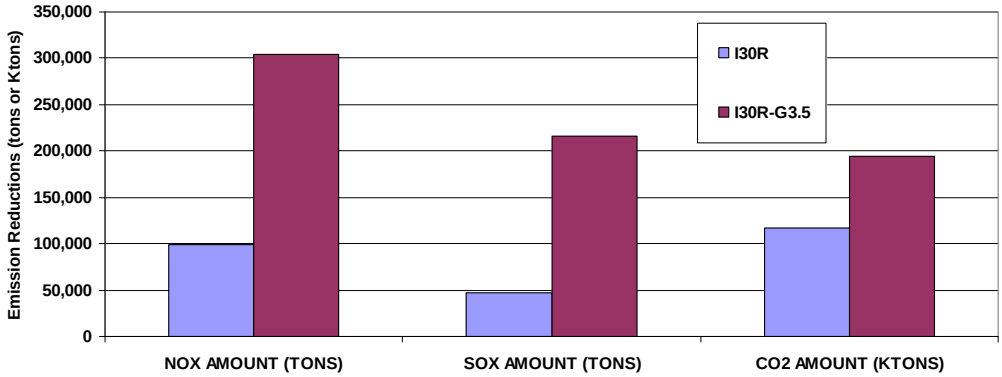


Figure 6.89 Emission reductions with gas price reductions

Figure 6.90 shows the change in savings due to the renewable generation in both millions of dollars and in dollars per megawatt hour of renewable generation. Because gas prices have dropped so much the value of the renewable generation has been almost cut in half. If the priority reversal had been accomplished by increasing the coal price or the carbon tax then the reduction in coal generation and corresponding emissions would have been achieved without dropping the value of the renewables. In fact, the value of the renewables would have increased. One significant advantage of the reduced gas price cases is that the less flexible coal generation is being turned off and the more flexible gas fired generation is remaining on line. The gas fired units are more able to respond to the variability needs of the system with high renewable penetrations.

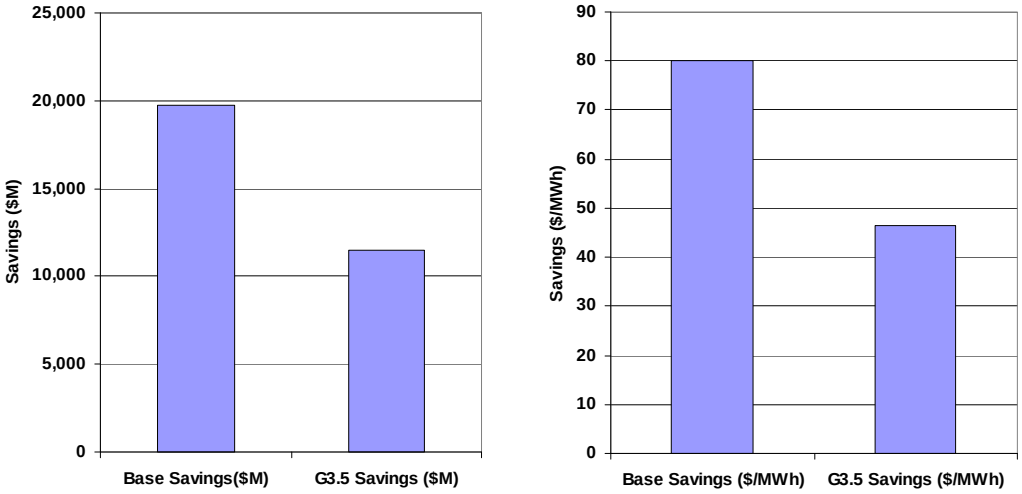


Figure 6.90 Impact of gas price reductions on operations savings, I30 scenario

6.4.4 Coal Plant Operation

One concern that has been raised is the amount of flexibility that has been assumed for the fleet of coal fired generation. The simulation assumed that coal units could cycle down to 40% of their maximum ratings when needed. Figure 6.91 shows some actual economic and emergency minimum operating points for a number of coal plants in the WECC system. While the values assumed in the simulation appear quite reasonable compared to the emergency minimums, it was pointed out by one system operator that this is not an operating point that can be achieved several times a week. The amount and depth of the cycling will vary by plant based on the unit design. For some plants, frequent cycling to emergency minimums can lead to tube leaks and increased maintenance cost on the units. The "Economic Minimum" was described as the operating point where the units could be dispatched to without significant increases in costs.

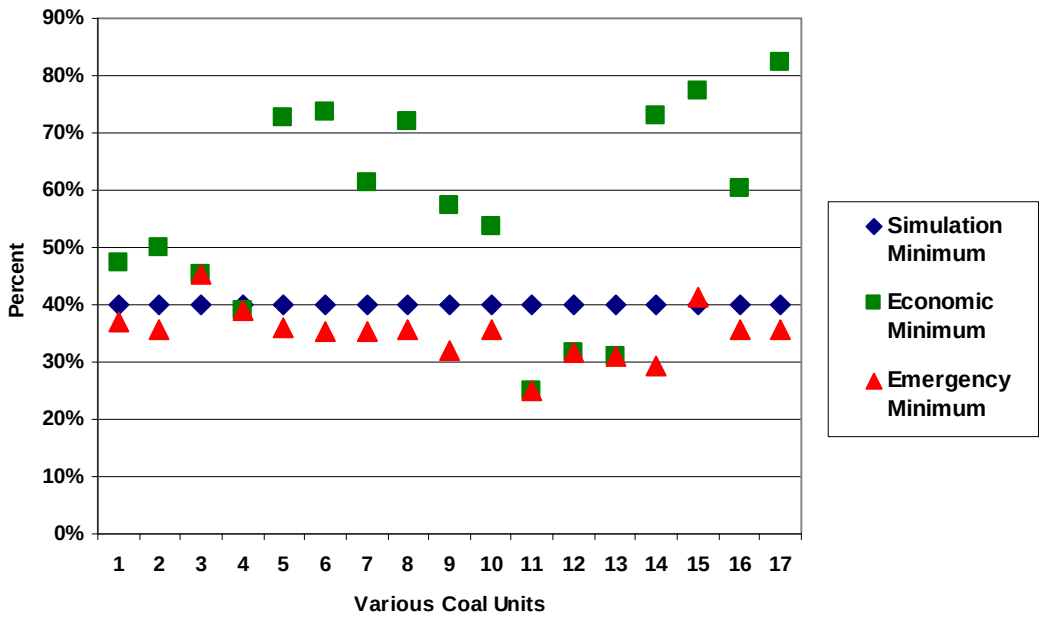


Figure 6.91 Typical minimum operating ratings of coal units as a percent of capacity

Figure 6.92 shows the number of times a certain unit was cycled below a particular operating point and then back up again in the simulated scenarios. For example, the 70% bar represents the number of times that a unit's generation dropped below 70% of its rating and then came back up above 70%. From this figure it can be seen that up to a 10% penetration of renewables resulted in essentially no cycling of the unit. The 20% scenario resulted in about 20 cycles per year below the 60% level. But most of the movement was just within the top 20% of the unit's capacity. It wasn't until the 30% scenario that significant deepcycling occurred on this unit. Figure 6.93 and Figure 6.94 show similar plots for 350 MW and 500 MW units. For the larger units minimal cycling

occurs before the 30% scenario and even then is primarily limited to the top 10 to 20%, which should be acceptable.

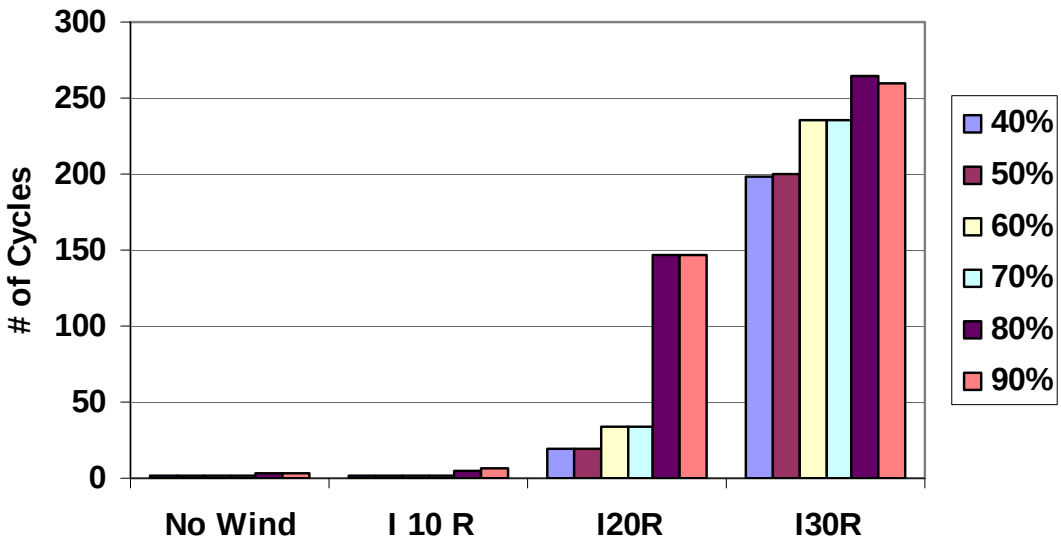


Figure 6.92 Number of cycles below operating levels – 100 MW coal unit

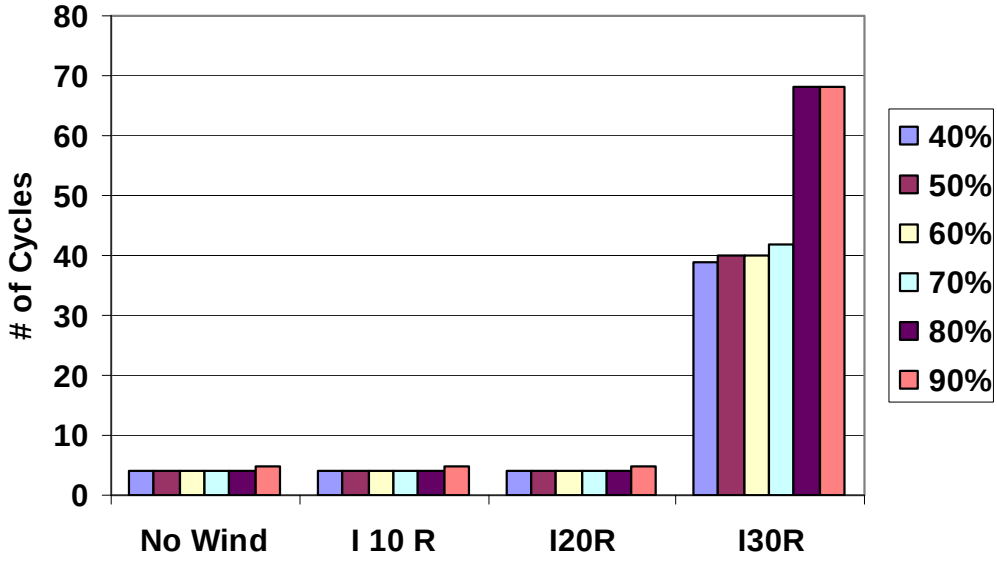


Figure 6.93 Number of cycles below operating levels – 350 MW coal unit

Figure 6.95 shows the higher level cycling, (the number of times that the unit dropped below 80% or 90% of its rating,) for the 500 MW unit on a monthly basis for the 30% scenario. The bulk of the cycling appears to occur in just a few months. Figure 6.96 shows the operation for the week of April 10th. This high-wind low-load week caused

the unit to cycle more than the operators would likely care to, but this was fairly rare even at the 30% scenario.

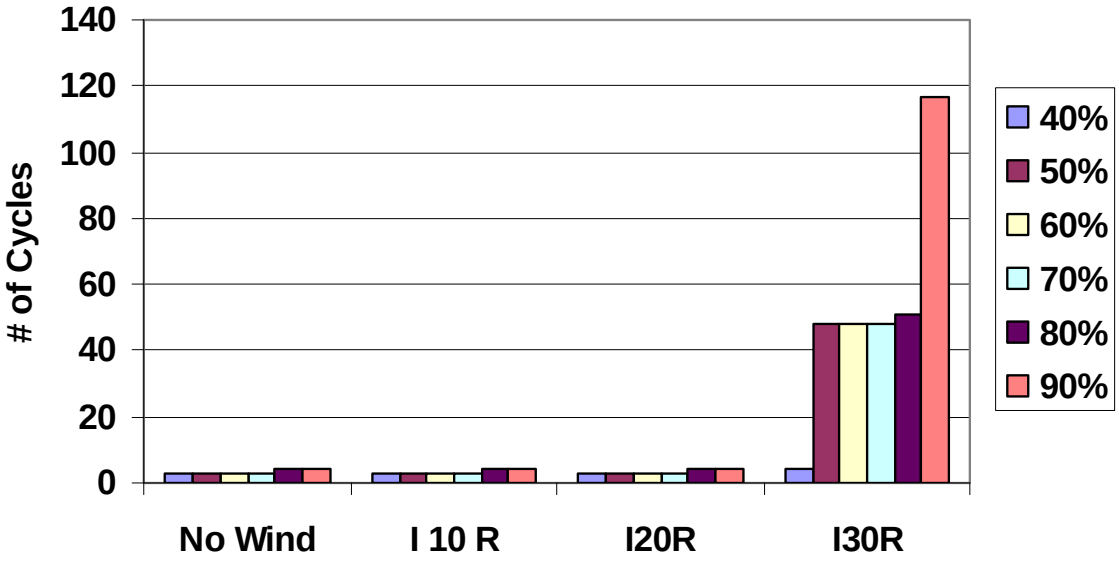


Figure 6.94 Number of cycles below operating levels – 500 MW coal unit

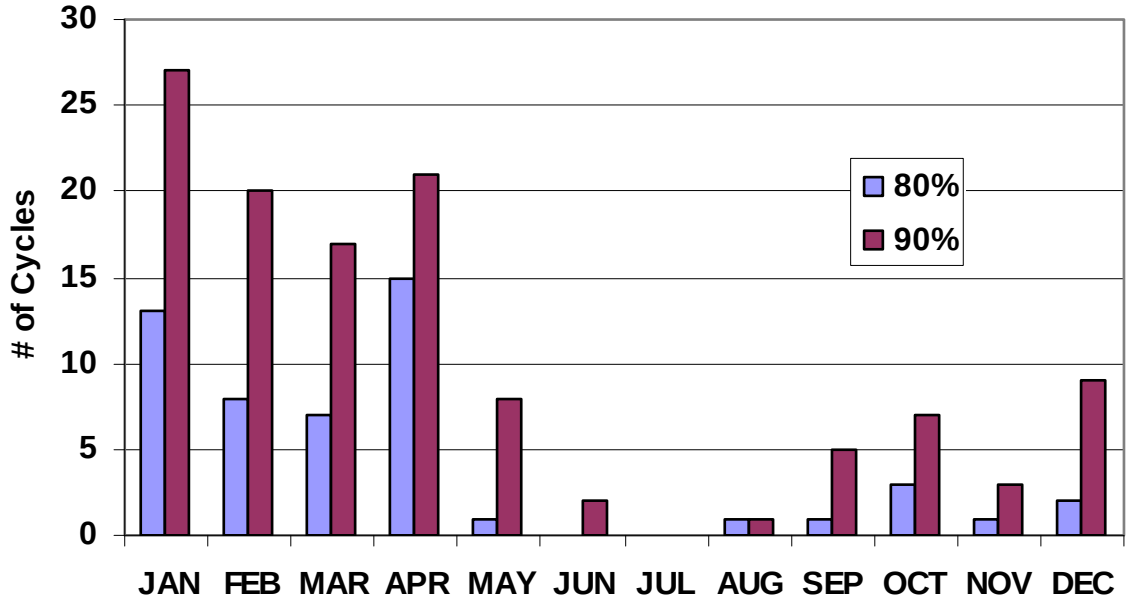


Figure 6.95 Cycles per month below 80% or 90% of rating for 500 MW coal unit at 30% penetration

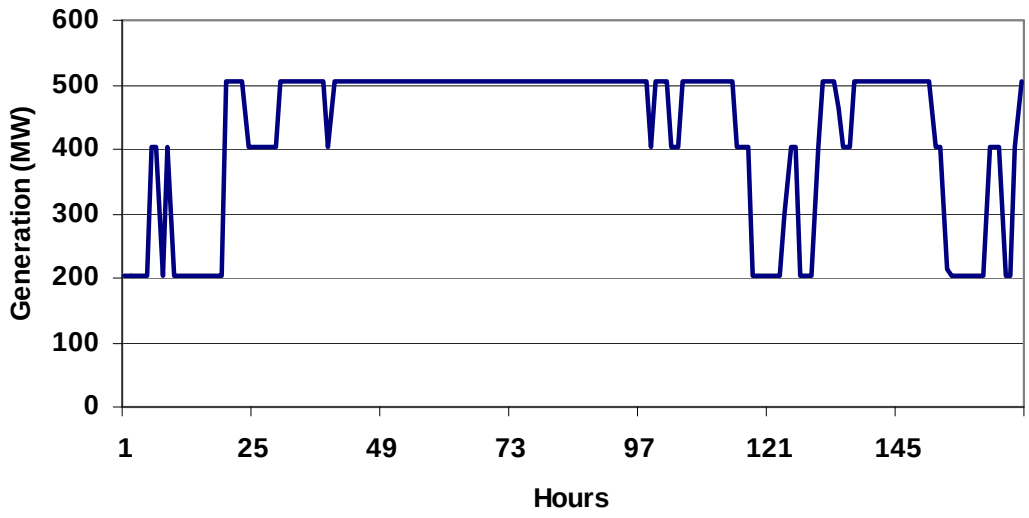


Figure 6.96 Operation of 500 MW coal unit week of April 10th at 30% penetration

Several additional scenarios were simulated with the minimum operating points of all of the coal plants in WECC restricted to 50%, 60% and 70% of the full rating. In terms of spilled energy Figure 6.97 shows that even in the 20/20 scenario with minimums at 60% there is not any significant increase in spilled energy. (In the following tables a case ending in "C60" would refer to the coal unit minimums set to 60% of their nameplate rating.) At the 30% scenario the spilled energy starts increasing at the 50% minimum level and is nearly doubled when the minimums are raised to 70% but this is still less than 1% of the total wind generation. Figure 6.98 shows that there is minimal impact on the unserved energy when the coal minimums are increased above 40%.

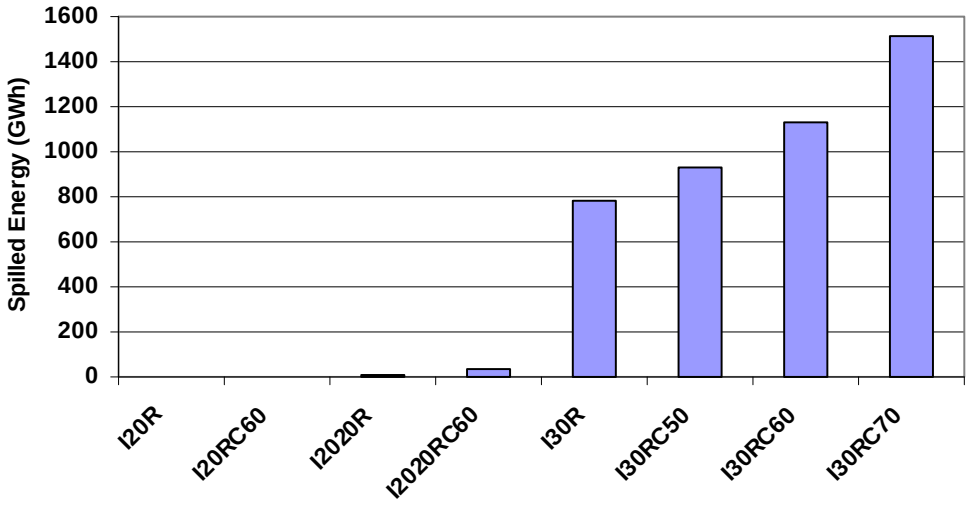


Figure 6.97 Spilled energy as a function of coal minimum operating points

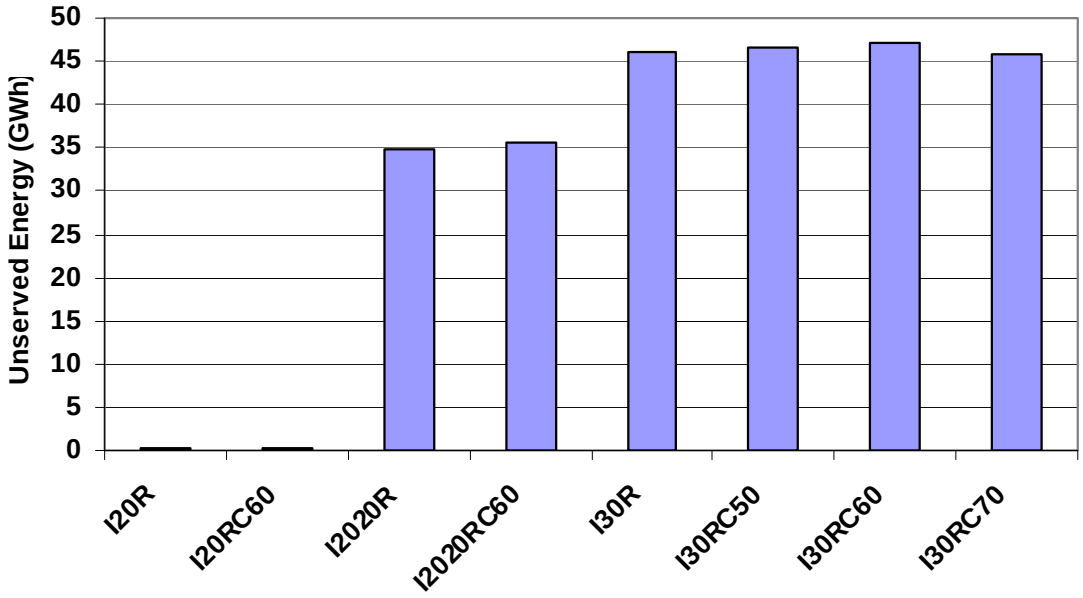


Figure 6.98 Unserved energy as a function of coal minimum operating points

Figure 6.99 shows the impact of coal minimums on the average system spot price. Reducing the flexibility of the coal plants keeps more generation on line and forces the spot prices to drop slightly.

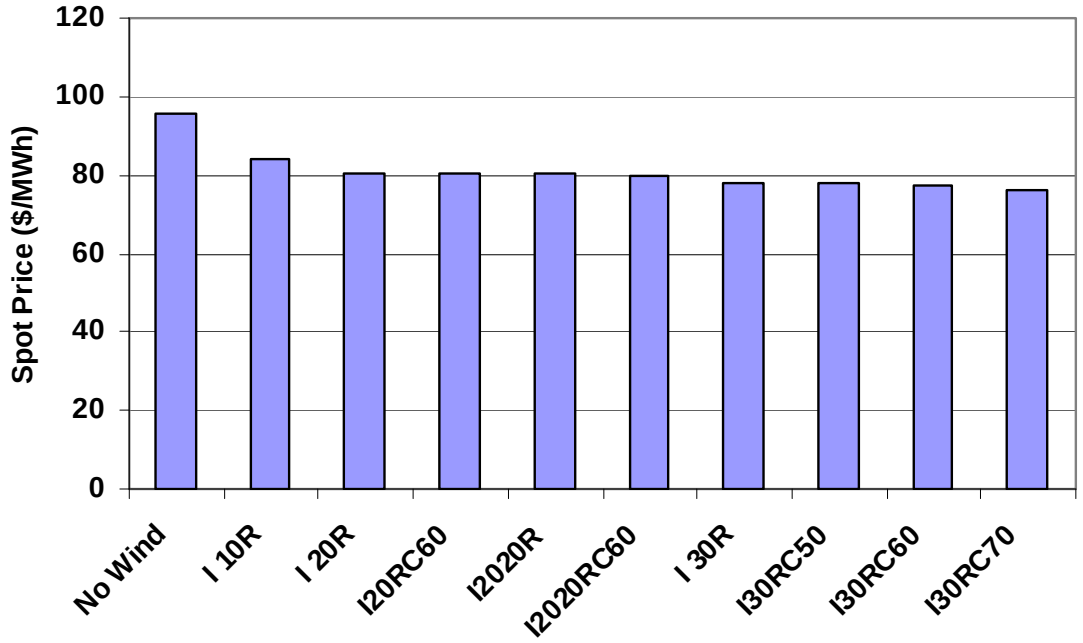


Figure 6.99 Average system spot price vs. coal minimums

The bars in Figure 6.100 show the total WECC operating costs. The differences appear fairly small. However, as Figure 6.101 demonstrates, increasing the coal minimums from 40% to 70% can increase system operating costs by almost $160 million, which is not insignificant.

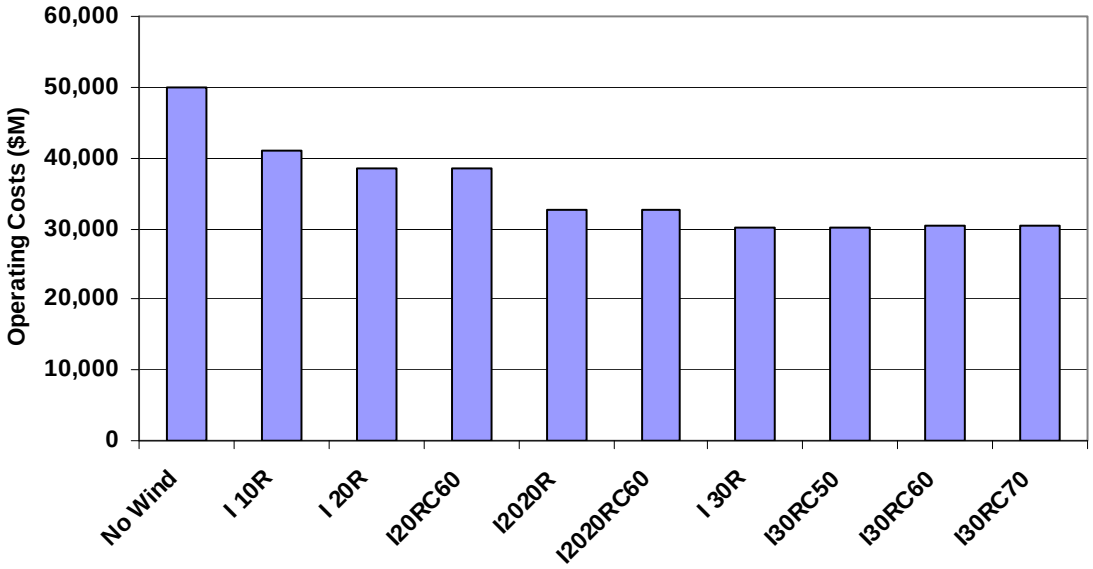


Figure 6.100 WECC operating costs vs. coal minimums

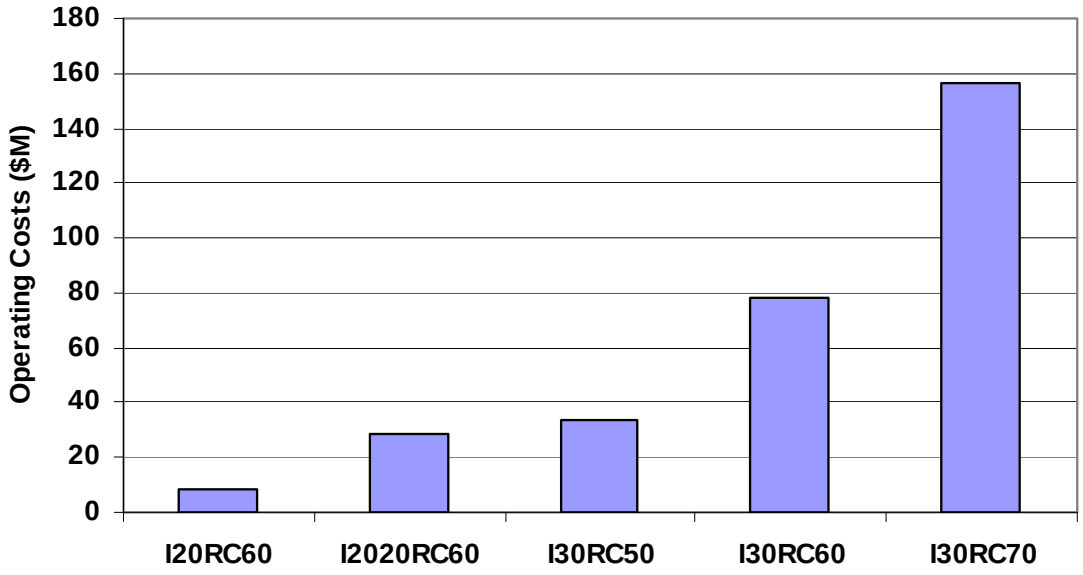


Figure 6.101 Increased WECC operating costs over coal at 40% minimum rating

Figure 6.102 shows that increasing the coal minimums increases the total emissions since the coal plants can no longer be displaced as much by the cleaner renewable energy, but the changes are slight.

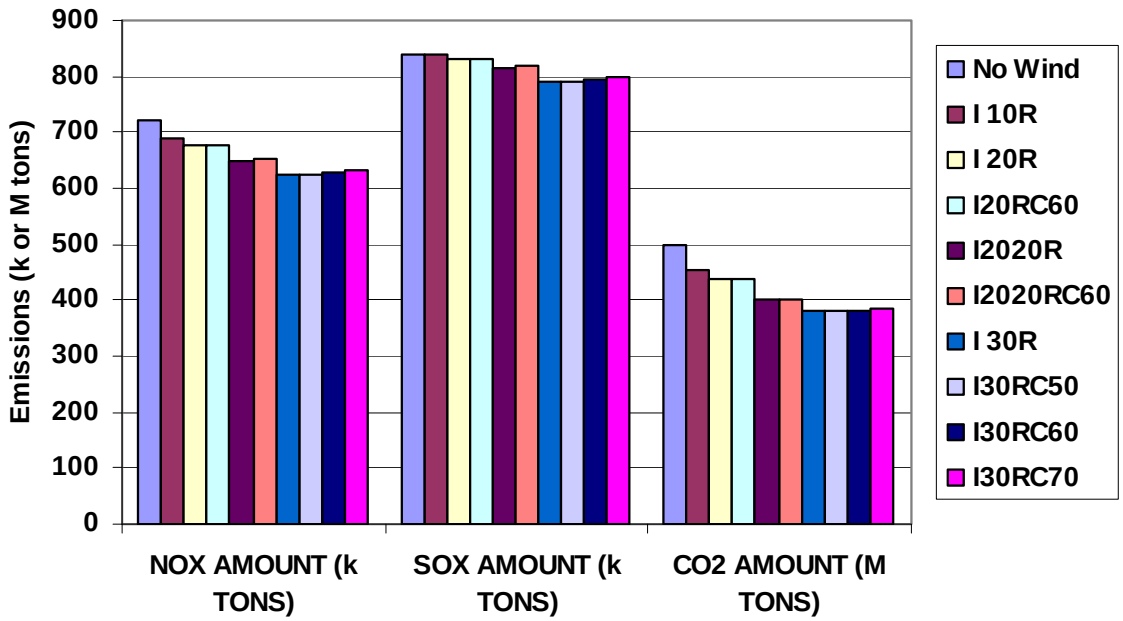


Figure 6.102 Impact of coal minimums on WECC emissions

6.4.5 Balancing Area Consolidation

The statistical analysis discussed the need for consolidation (either real or virtual) of the small balancing areas when trying to accommodate high penetrations of renewable generation. A test case was run to see the operational impact for the In-Area, 10% penetration scenario. The base case modeled spinning reserve as 3% of load on a regional basis (i.e. Arizona/New Mexico, Rocky Mountain, etc). For the change case the system still held spinning reserve at 3% of the load but on a zonal basis. For comparison WECC was divided into 5 regions but 108 zones. These zones are roughly equivalent to the existing system balancing areas. Figure 6.103 compares the annual spot price duration curve between the two 10% penetration cases and with no wind. (The case ending in ZSR refers to "zonal spinning reserves".) When the spinning reserve is held on a zonal basis it requires a lot more generation to be committed which in turn drives down the system spot prices and the value of renewable generation.

With spinning reserves determined on a zonal basis, WECC simulated operating costs were about $2 Billion higher than with the reserves shared over larger regions for the 10% in-area case. This would be expected to increase with higher penetration levels. This may be a fertile area for further investigation in another study.

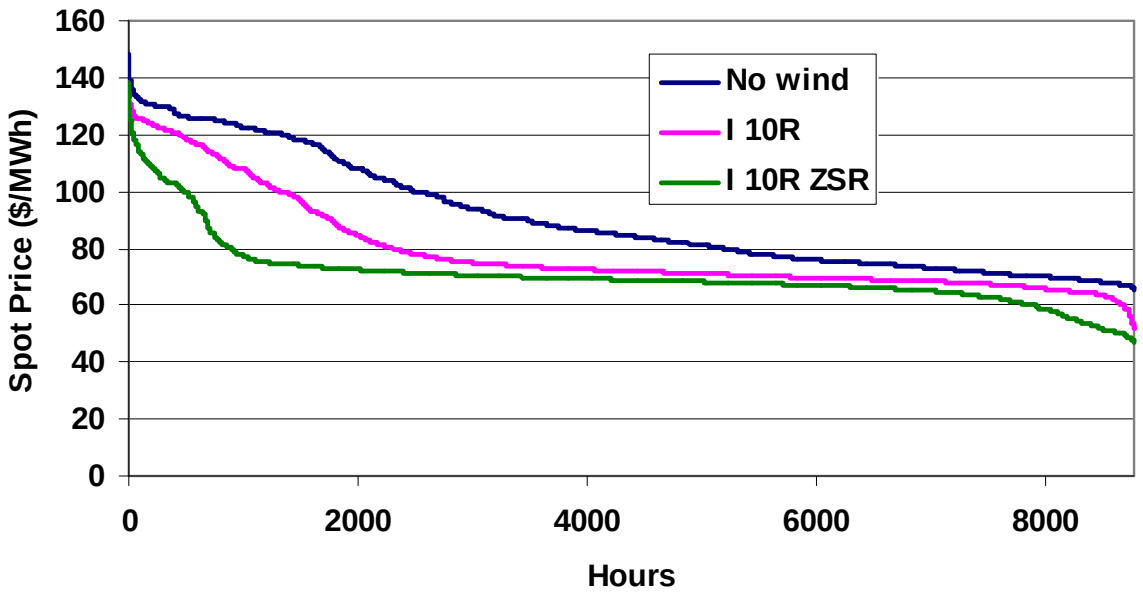


Figure 6.103 Spot price impact of balancing area consolidation, 10% penetration.

6.4.6 Transmission Expansion Sensitivity

The Local Priority and Mega-Project scenarios utilized wind sites with higher capacity factors, but consequently needed to include additional transmission facilities in order to deliver the more remote wind energy. Sensitivities were run to see the impact of building the more remote wind sites without reinforcing the transmission capability between the regions. It was assumed that all existing transmission was available to all of the generators to compete on an economic basis. Figure 6.104 shows the impact on system spilled and unserved energy. The cases ending in "t" assumed no new transmission build-out. The unserved energy did not change significantly between the scenarios, which is not surprising. If the new resources were constrained there were sufficient existing resources in the region to serve the load. Spilled energy was not evident in either scenario at the 10% penetration level. This suggests that initial expansions down these paths could be accomplished without new long distance transmission enhancements. Even at the higher penetrations the Local Priority scenario did not experience significant growth in spilled energy. Beyond the 10% level, however, the Mega-Project scenario began spilling more wind energy and by the 30% penetration level was dumping about 8% of the total WECC wind generation. Recognizing that only the study area wind sites were changed between scenarios the spilled energy in the 30% Mega-Project scenario without transmission reinforcement represents 20% of the study area total wind generation, which is clearly significant. Figure 6.105 shows the reduction in annual operating savings when the transmission expansion is ignored. Depending on the cost of capital these values are in the right ballpark to justify the construction of the additional transmission.

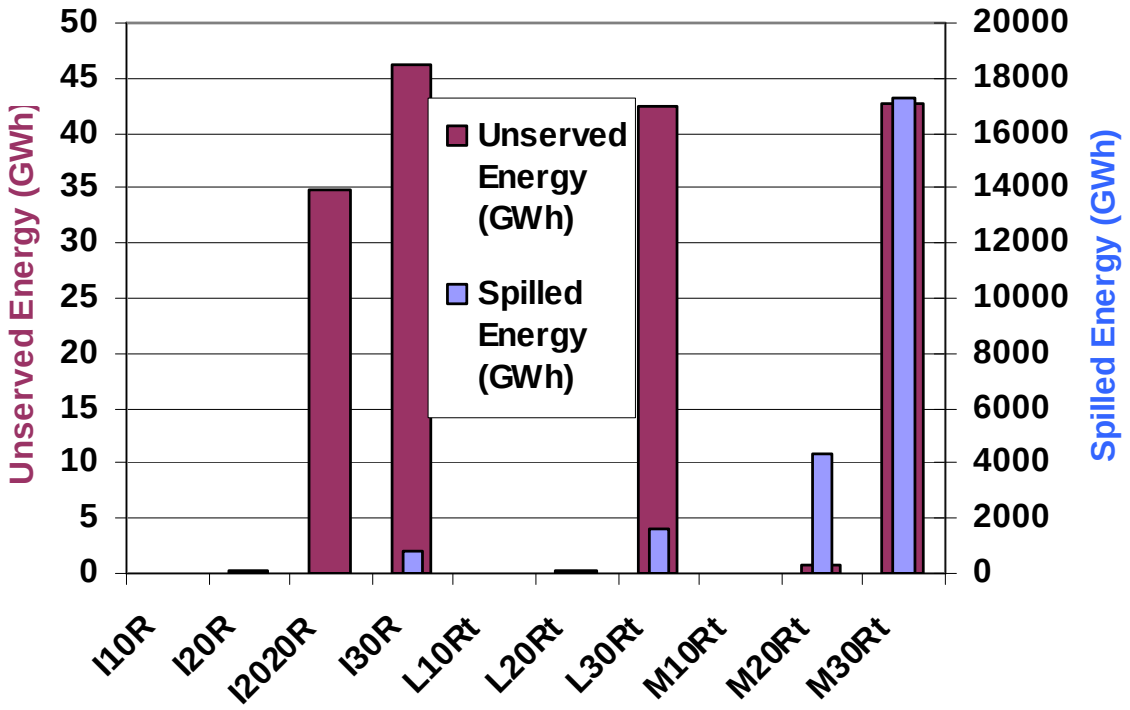


Figure 6.104 Spilled and unserved energy w/o transmission expansion

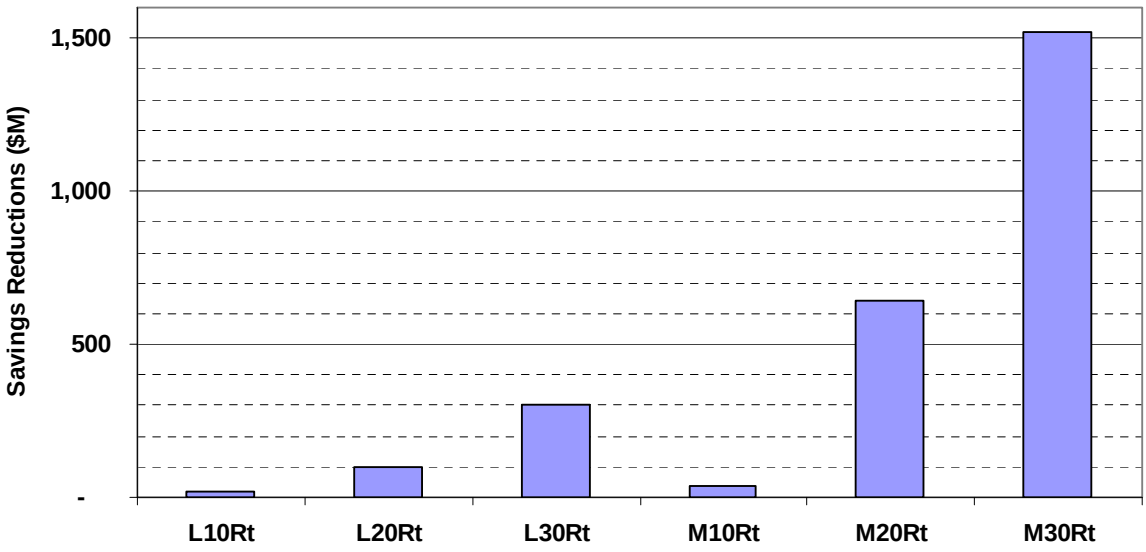


Figure 6.105 Savings reductions with no transmission expansion

6.4.7 Generation Expansion Sensitivity

The base generation expansion plan for year 2017 was developed in the absence of renewable generation. As wind and solar generation is added to the system it may be possible to delay or cancel some of this new conventional generation and still maintain required reserve margins. Based on results presented in Chapter 9, the capacity value of

the renewable generation in the study area for the 30% scenario is about 6600 MW. This is roughly equal to the 6450 MW of gas fired generation that was added after 2012 in the base expansion. A sensitivity case was run that deleted this new generation so that the reliability would be roughly equal between the systems with and without renewable generation. Figure 6.106 shows a comparison of the system emissions for the base 30% scenario and the one with the reduced capacity expansion. They are almost identical. This is due to the fact that the renewable generation reduced the need for much of the gas fired generation in the system. The new units would have been slightly more efficient than the existing generation but not enough to make a noticeable difference in the total results. Figure 6.107 shows similar results for the total variable costs and the generator revenues. There would likely have been more difference if some of the existing, older coal fired generation had been retired but that was not examined.

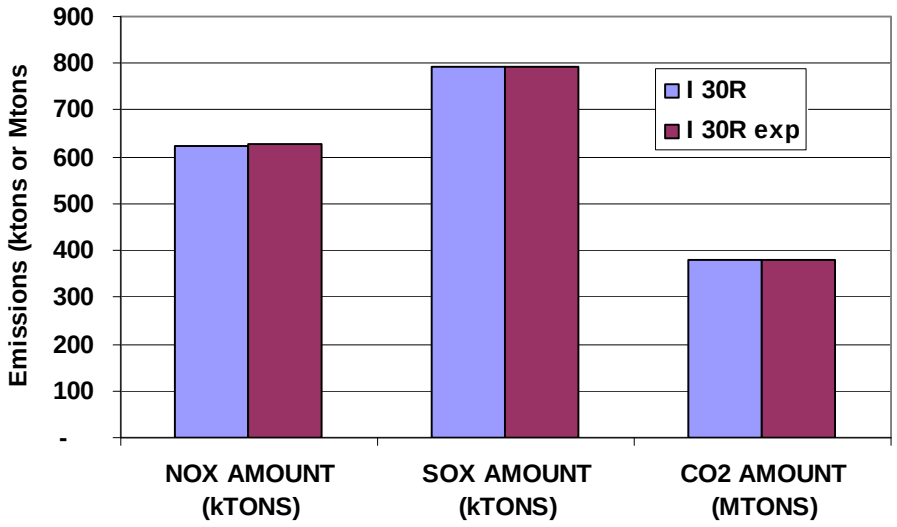


Figure 6.106 Emission impact of reduced capacity additions

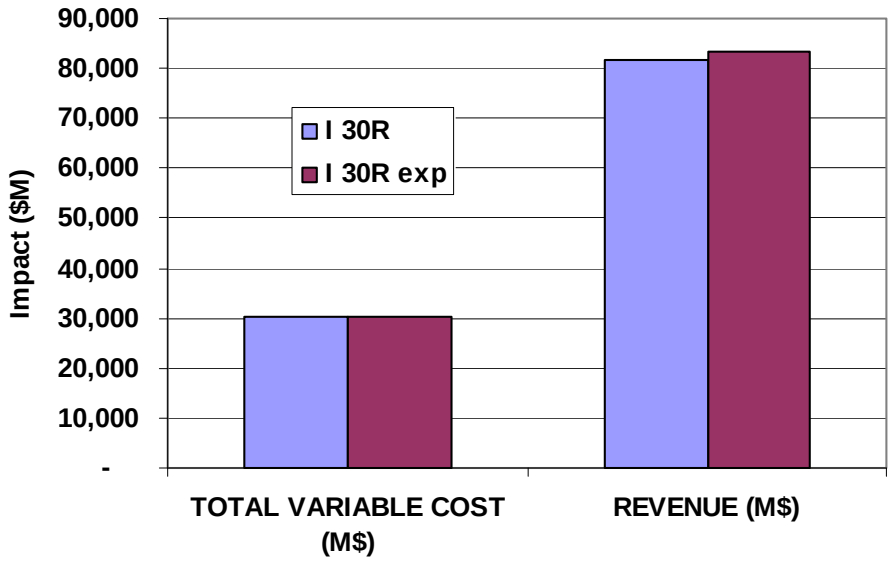


Figure 6.107 Operating cost impact of reduced capacity additions

6.5 Operational Analysis Observations and Conclusions

From an hourly operational analysis viewpoint, integration of high levels of renewables into the WestConnect and surrounding regions is feasible. The study examined up to 30% of the study area's annual energy needs being met by wind generation with another 5% supplied by solar. The balance of WECC had 20% energy from wind and 3% from solar. Variations in siting appeared to have little impact. Improved capacity factors resulted in less nameplate capacity required but generally needed new transmission to facilitate the energy transfer. The economic value of the renewable energy was roughly the same. It is likely that some amount of remote wind generation that requires minimal long distance transmission reinforcement may be attractive but major build-outs of remote wind and long distance transmission do not appear to have any significant advantages or disadvantages.

There appears to be minimal stress on system operations up to 20% wind penetration across the board. Beyond that point the system's operational flexibility is stretched. Minimum operating points on coal plants and the cycling capabilities of hydro generation become more important although neither is an absolute show stopper.

Current economic assumptions favor coal generation over gas fired units. The upshot of that is that renewable generation tends to displace gas fired generation that tends to be more operationally flexible and leaves the less flexible coal fired units still running. This makes higher penetrations of renewable generation more difficult. Decreased gas prices and/or increased carbon taxes will reverse the relative attractiveness of coal and gas generation. This would lead to more displacement of the coal generation, improved emission reductions and enhanced operational flexibility of the balance of the generation fleet. All of this would help to smooth the introduction of greater amounts of intermittent renewable generation such as wind and solar.

7 Sub-hourly Operational Analysis

This chapter focuses on multiple aspects of sub-hourly variability, specifically 10-minute variability. Section 7.1 describes the 10-minute statistical analysis, which provides a broad overview of the impact of significant wind and solar generation on system performance and sets the stage for the subsequent detailed exploration of sub-hourly behavior. In Section 7.2, the quasi-steady-state (QSS) analysis, which consists of detailed time simulations of specific 24-hour periods, is presented. It is designed to illustrate key aspects of system performance and potential mitigation measures within the broader context of the statistical and production simulation analyses. The relationship between sub-hourly variability and dynamic reserve requirements is explored in Section 7.3. The focus is primarily on understanding how much maneuvering room is required of on-line generation to handle the changes that occur within each hour, i.e., variability rather than uncertainty. Section 7.4 further examines selected MAPS and QSS simulations in the context of the requirements identified. Section 7.5 explores possible ways in which system operations could translate the reserve requirements into simple usable operating rules or guidelines. Discussion of possible demand participation and energy storage in providing these subhourly reserves is included.

7.1 Statistical Analysis

Extensive statistical analysis of hourly wind, solar and load variability was presented in Chapter 5. In this section, we present additional statistical analysis of variability that occurs in the 10-minute time frame. There are two major reasons for focusing on 10-min variability. First, we have extensive 10-minute data; all the wind data was generated at 10-minute time resolution (with the exception of selected windows used in QSS analysis, as discussed in the next section.). But equally important, 10 minutes is a good divider between running reserves and cold or standby reserves, that is, reserves that may be brought on-line quickly, but which do not contribute to managing variability until committed. The basic concept behind this analysis, and the results presented in subsequent sections of this chapter, is that the subhourly variability drives dynamic reserve requirements.

In the results presented here, we focus on the local priority scenario. Similar plots and data for the other scenarios are included in Appendix B. Results presented here have similar structure to those presented in Chapter 5. That chapter provides background and context on variability statistics and methods. Discussion here is limited to examining details of 10-minute variability that are relevant to reserves requirements.

In Table 7.1, statistics on 10-minute variability by area, study footprint and WECC are presented. This data is calculated and presented exactly the same way as the hourly variability presented in Table 5.2. Notice that at the study footprint level, the overall 10-

minute variability increase (from the load-alone case), as measured by the standard deviation of the deltas (Δσ) is relatively small, even for the 30% mega project case. The increase is on the order of +20%.

However, the extrema at the foot print level can double or triple. At area resolution, differences become more pronounced. The Arizona increase is not great. But, in Wyoming, there is an order of magnitude increase in sigma, a factor 20 increase in the maximum positive delta, and a factor of 40 increase for extreme of net load drops. Notice the difference between IA, LP and MP for Wyoming. These increases from IA to MP are consistent with the dramatic increase in installed wind between the scenarios.

Table 7.1 10 minute Net Load Variability by Area, Footprint and WECC

	Ariz			CO-E			CO-W			NM			NV			WY			In Foot Print			WECC		
	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP	IA	LP	MP
Sigma (MW)																								
Load-alone	97	97	97	61	61	61	6	6	6	25	25	25	52	52	52	15	15	15	239	239	239	731	731	731
Baseline (Existing)	97	97	97	65	65	65	6	6	6	31	31	31	52	52	52	23	23	23	240	240	240	734	734	734
10% In FP Scenario	107	105	97	69	69	69	11	10	7	33	36	43	57	56	53	24	31	49	243	245	246	717	718	719
20% In FP Scenario	128	116	100	80	81	71	19	16	7	43	46	54	68	63	55	34	56	108	259	260	268	716	718	722
30% In FP Scenario	146	128	106	98	89	72	25	20	10	54	56	70	79	69	57	46	93	157	284	286	301	728	728	734
Max Neg Delta (MW)																								
Load-alone	-348	-348	-348	-223	-223	-223	-20	-20	-20	-86	-86	-86	-200	-200	-200	-53	-53	-53	-708	-708	-708	-2239	-2239	-2239
Baseline (Existing)	-352	-352	-352	-412	-412	-412	-20	-20	-20	-260	-260	-260	-200	-200	-200	-334	-334	-334	-810	-810	-810	-2279	-2279	-2279
10% In FP Scenario	-901	-772	-406	-412	-420	-409	-134	-109	-41	-252	-240	-354	-367	-340	-250	-327	-340	-903	-843	-867	-991	-3744	-3734	-3706
20% In FP Scenario	-1367	-1052	-367	-825	-829	-490	-234	-205	-60	-394	-408	-532	-568	-565	-305	-401	-962	-1725	-1360	-1216	-1821	-3656	-3672	-3713
30% In FP Scenario	-1616	-1169	-418	-1082	-956	-559	-288	-239	-91	-516	-565	-708	-767	-633	-386	-501	-1476	-2274	-1576	-1641	-2325	-4266	-4270	-4308
Max Pos Delta (MW)																								
Load-alone	267	267	267	195	195	195	22	22	22	106	106	106	206	206	206	84	84	84	612	612	612	1786	1786	1786
Baseline (Existing)	269	269	269	306	306	306	22	22	22	147	147	147	207	207	207	228	228	228	710	710	710	1865	1865	1865
10% In FP Scenario	711	590	289	334	336	364	160	93	30	166	201	320	319	311	209	233	290	567	899	873	770	2084	2093	2118
20% In FP Scenario	917	784	887	548	555	360	211	197	51	323	358	448	455	449	233	459	630	1069	1193	1075	1219	2211	2172	2203
30% In FP Scenario	1169	1041	1207	1010	804	426	296	221	93	462	466	543	582	519	293	649	994	1805	1430	1416	1542	2728	2681	2677
No. Drops > 3* Ld Sigma																								
Load-alone	18	18	18	36	36	36	90	90	90	45	45	45	54	54	54	45	45	45	0	0	0	9	9	9
Baseline (Existing)	18	18	18	155	155	155	90	90	90	617	617	617	54	54	54	1458	1458	1458	12	12	12	9	9	9
10% In FP Scenario	203	158	21	296	323	302	2163	1367	294	822	1121	1938	219	185	59	1649	2979	6399	44	42	62	6	6	11
20% In FP Scenario	672	350	47	669	687	362	5426	4298	476	1977	2262	3188	680	464	117	3638	7836	12968	125	140	224	6	5	11
30% In FP Scenario	1172	632	159	1388	995	344	7884	6074	1415	3156	3452	5262	1317	684	156	5993	12185	15905	240	284	468	17	17	42
No. Rises > 3* Ld Sigma																								
Load-alone	0	0	0	36	36	36	72	72	72	107	107	107	27	27	27	405	405	405	0	0	0	0	0	0
Baseline (Existing)	0	0	0	66	66	66	72	72	72	449	449	449	35	35	35	1563	1563	1563	0	0	0	0	0	0
10% In FP Scenario	165	123	0	194	236	204	1956	1194	236	636	951	1940	198	138	45	1779	3144	6681	15	15	12	0	0	0
20% In FP Scenario	722	419	132	738	764	303	5663	4521	386	2043	2367	3611	714	468	74	3801	8039	13319	203	171	212	2	0	2
30% In FP Scenario	1284	782	357	1656	1209	435	7983	6146	1908	3497	3864	5850	1350	824	191	6288	12513	16353	521	476	599	63	48	50

In Table 7.2, we dig deeper into the variation of small balancing areas. The blue cells in this table are for the 7 zones that make up the Wyoming area in our analysis. Some of these zones, TRSTWYOA, for example, show a 50 fold increase in net load 10-minute Δσ. The single most extreme net load rise in 10 minutes is 100 times as great as with load alone. Clearly managing incremental variability due to additional wind power is utterly infeasible for these small, high wind balancing areas.

Table 7.2 Summary Statistics for 10-Minute Delta for Wyoming

	BEPCWA	BHPLA	WYCENA	WYNWA	WYSWA	TRSTWYOA	WACMA	WY	In FootPrint	WECC
Sigma (MW)										
Load-alone	2	2	2	3	3	1	2	15	239	731
Baseline (Existing)	2	2	8	3	17	2	2	23	240	734
10% In FP Scenario	2	2	15	4	17	3	14	31	245	718
20% In FP Scenario	2	2	33	8	17	18	27	56	260	718
30% In FP Scenario	2	2	47	9	18	53	36	93	286	728
Max Neg Delta (MW)										
Load-alone	-7	-8	-10	-10	-11	-3	-8	-53	-708	-2239
Baseline (Existing)	-7	-8	-91	-10	-335	-29	-8	-334	-810	-2279
10% In FP Scenario	-7	-8	-162	-56	-335	-35	-369	-340	-867	-3734
20% In FP Scenario	-7	-8	-409	-170	-335	-439	-860	-962	-1216	-3672
30% In FP Scenario	-7	-8	-590	-170	-308	-809	-1128	-1476	-1641	-4270
Max Pos Delta (MW)										
Load-alone	11	13	16	17	19	6	7	84	612	1786
Baseline (Existing)	11	13	90	17	227	27	7	228	710	1865
10% In FP Scenario	11	13	168	50	227	31	264	290	873	2093
20% In FP Scenario	11	13	443	134	227	276	548	630	1075	2172
30% In FP Scenario	11	13	618	134	227	620	716	994	1416	2681

The temporal coincidence of load and wind changes is shown in Figure 7.1. These plots are similar to those presented in Figure 5.2. The results have a broadly similar character to the hourly variability. However, there is some increase in the relative amplitude of extreme wind changes compared to load. This is most noticeable in the summer data. Interestingly, the outlier wind changes do not coincide with load change outliers (which may be slightly because of linearization of one hour data).

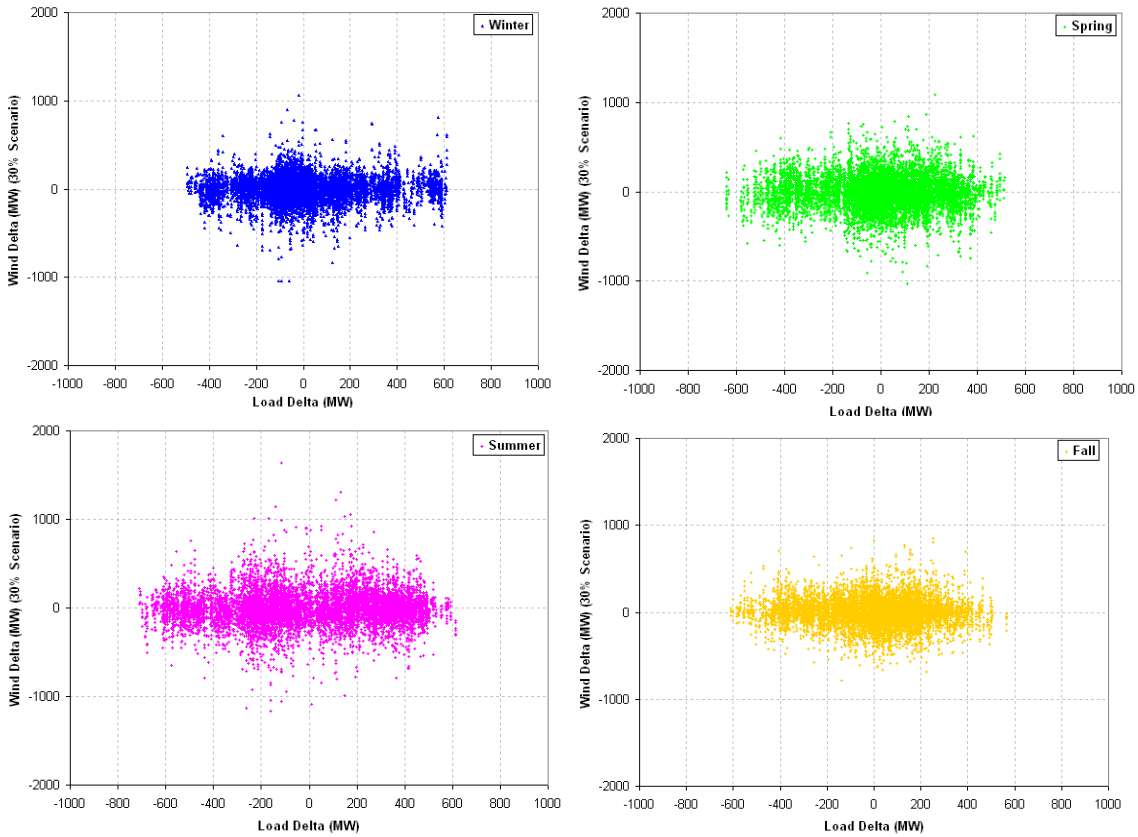


Figure 7.1 Wind Deltas vs. Load Deltas by Season for Study Area (2006, 30%, LP Scenario)

The timing of extreme 10-minute net load increases is shown in Figure 7.2. This figure presents the same type of information as presented in Figure 5.10 through Figure 5.13. They look quite different because there are 6 times as many 10 minute periods in a day as hours, so the plots are stretched horizontally. As expected, periods of rapid net load rise tend to occur in the summer mornings and early evenings, and winter late evening. The increases in the evenings from October to April are substantial.

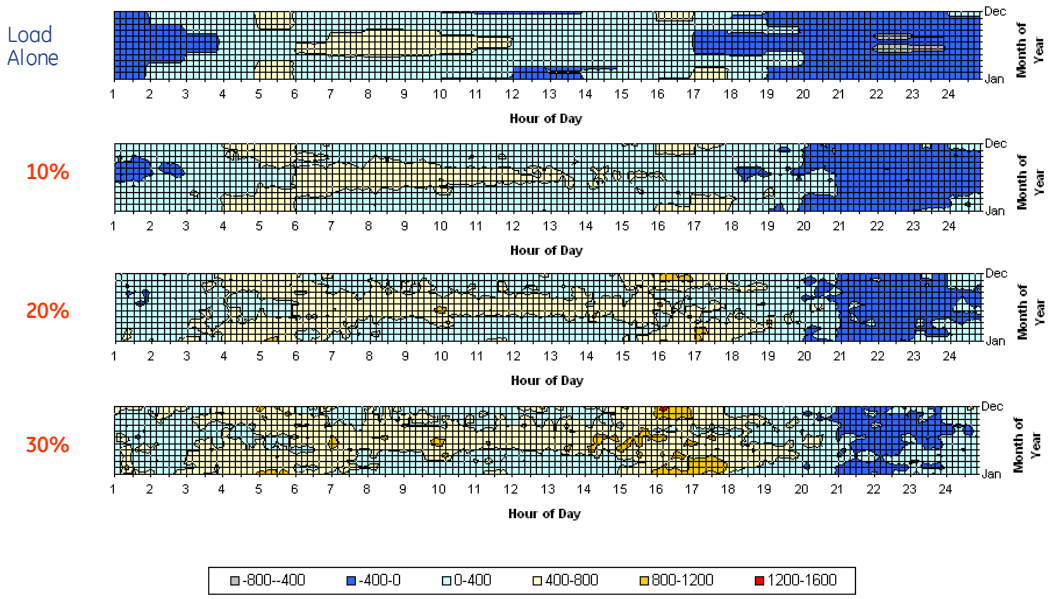


Figure 7.2 Timing of Maximum Daily 10-Min Positive Deltas for Study Area (2006, LP Scenario)

Figure 7.3 shows the timing of extreme net load drops. Just as in Figure 5.14, the biggest net load drops occur in the early night.

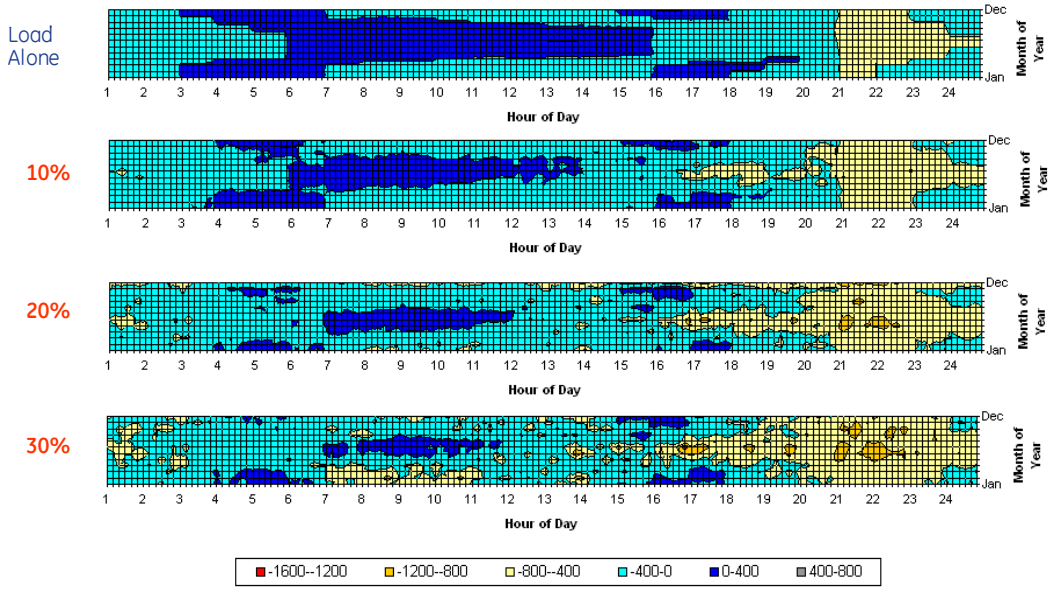


Figure 7.3 Timing of Maximum Daily 10-Min Negative Deltas for Study Area (2006, LP Scenario)

A histogram of the footprint (study area) 10-minute net load changes is shown in Figure 7.4. As with Figure 5.15, the distribution widens and appears to become slightly less normal with increasing renewable penetration. The bottom part of the figure shows that there are occasions of substantial net load rise (and drop) that exceed the maximum observed with load alone.

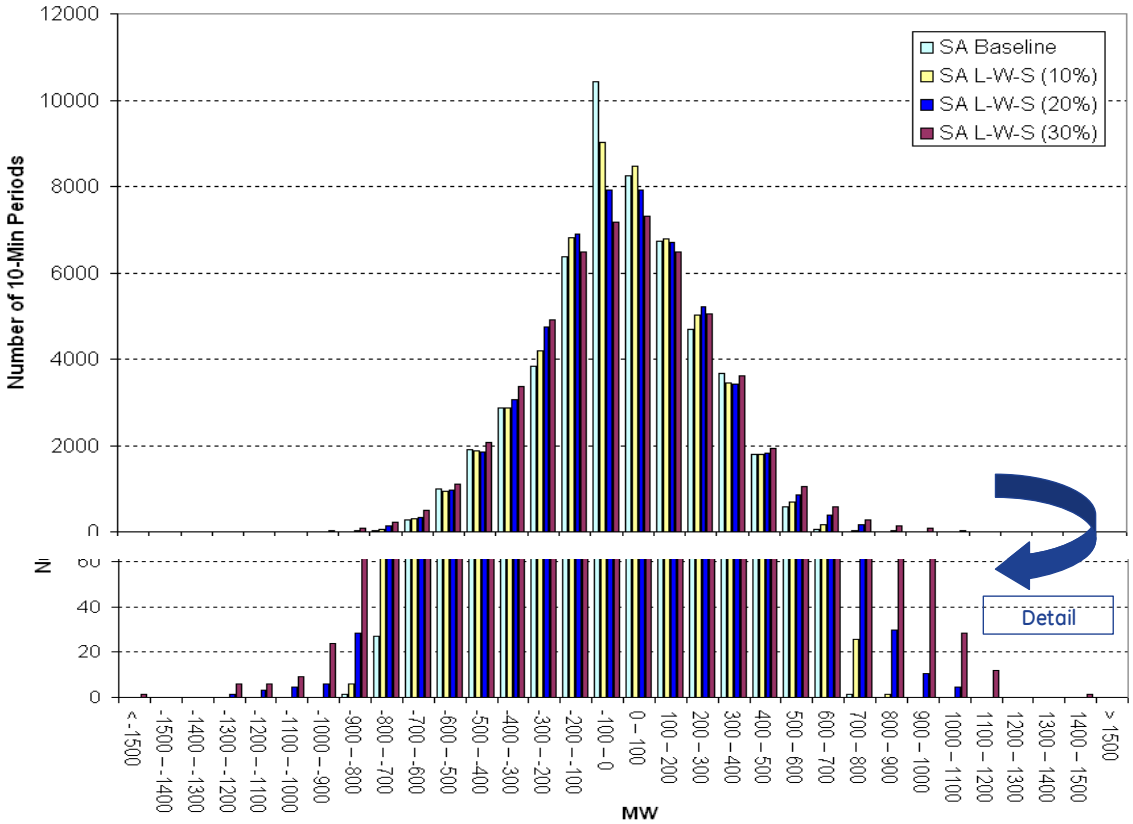


Figure 7.4 Distribution of Net Load Deltas for Study Area (2006, LP Scenario)

The extremes of net load rise and drop are shown in a cumulative fashion in Figure 7.5. Again, this figure contains similar information to that presented in Figure 5.16. The tails of these distributions are consistent with the extreme summarized in Section 5.4.

Overall, at footprint and area level, the increases in 10-minute variability are incremental, not monumental, with the addition of wind and solar generation. Strategies for addressing these increases, as developed through the balance of this chapter, are also incremental.

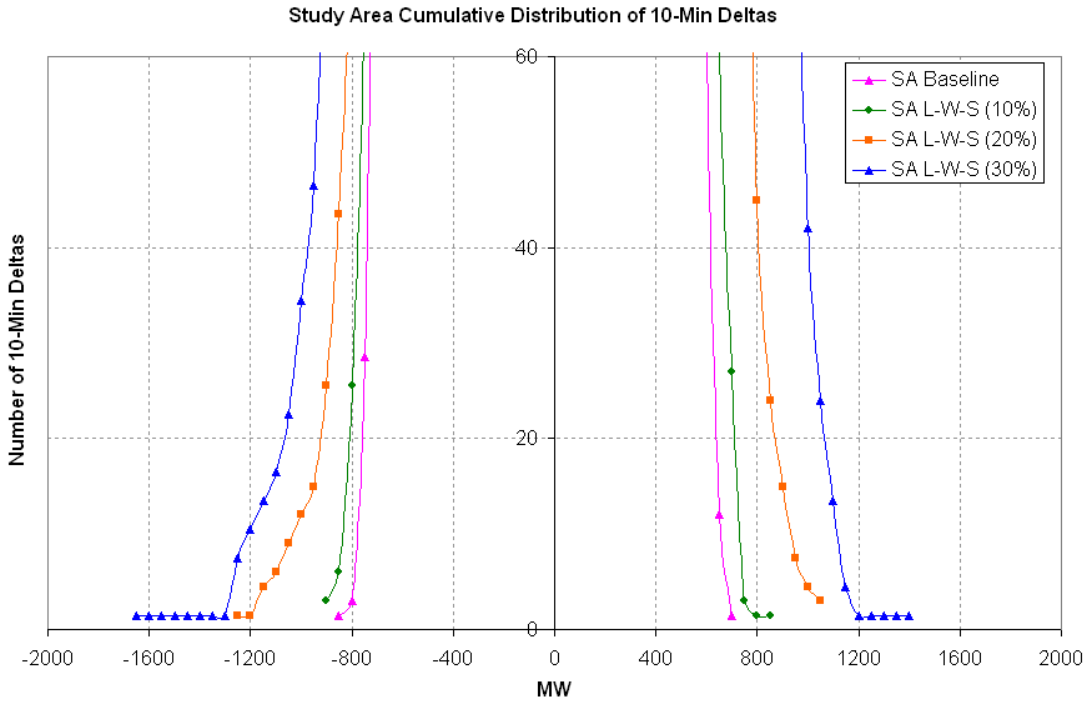


Figure 7.5 Distribution of Extreme Hourly Wind Deltas for 2006 (2006, LP Scenario)

7.2 Quasi-Steady State (QSS) Analysis

The statistical and production simulation analyses provided a broad view of the impact of significant wind and solar generation on system performance. They covered a range of time scales, from sub-hourly to hourly as well as daily, seasonal and annual. In contrast, the quasi-steady-state (QSS) analysis consists of detailed time simulations of specific 24-hour periods. It is designed to illustrate key aspects of system performance and potential mitigation measures within the broader context of the statistical and production simulation analyses. As such, the QSS analysis is tightly linked to both of these analyses. For example, the QSS study scenarios were selected on the basis of the statistical analysis, and the QSS boundary conditions were set by the production simulation analysis.

The data, methods, assumptions, study scenarios and results for the QSS analysis are described in the following sections. All QSS analysis was performed using MATLAB.

7.2.1 Overview of Algorithm

The primary objectives of the QSS analysis were to evaluate the impact of significant wind and solar generation on load following (5-minute time scale) and regulation (1-minute time scale) requirements within the study footprint.

The study footprint was represented by seven, separate transmission areas - Arizona, New Mexico, Colorado East, Colorado West, Wyoming, Northern Nevada, and Southern Nevada. Each area was represented by aggregate profiles of all the individual loads, generation sources, and inter-area transmission path flows (i.e., exports). One profile represented all loads in a given area and another profile represented the total export schedule from a given area. However, generation profiles were aggregated by type. Thus, there was one profile for wind; one profile for solar, one for hydro, one for combined cycle, etc.

Up to four types of generating units (e.g., hydro, combined cycle, steam, gas turbine) were identified as participants in load following via the 5-minute economic dispatch function. Each unit type was assigned a priority number. If the priority #1 unit type exhausted its capability, the priority #2 unit type made up the difference. If priority #2 unit type reached its limit, the priority #3 unit type began to participate. When the net load and therefore, economic dispatch commands reversed direction, the lowest priority unit type reversed direction first. Thus, the priority #3 unit type would return to its nominal dispatch, followed by the priority #2 unit type, leaving the primary load following responsibility to the priority #1 unit type. Maxima, minima and ramp rate limits were respected for each unit type.

Up to four types of generating units were also identified as providers of regulation. Each unit type was assigned both a priority number and a specific amount of regulation (e.g., + and/or – MW) capability. Each unit type's participation in regulation followed a similar priority procedure as described above for the economic dispatch unit types. The maxima and minima of the assigned regulation capability are respected. Regulation units were assumed to have sufficient ramp rate capability, so no ramp rate limits were applied.

The remaining generating unit types were treated as un-dispatchable generation subject only to an hourly schedule.

The load, wind, and solar profiles varied on a minute-by-minute basis. The export and balance of portfolio (BOP) generation schedules changed on an hourly basis in accordance with the production simulation results. The hourly schedule changes were implemented as a ramp +/- 10 minutes around the hour, unless otherwise noted.

The difference between total generation and load plus exports was calculated at 1-minute intervals, and assigned to the regulation units. At 5-minute intervals, a simplified economic dispatch was performed to redistribute the power from the regulation units onto the designated load following units over the next 5 minutes. Ramp rate limits (MW/minute) and absolute power limits (maximum and minimum MW) were respected on each unit type.

If the economic dispatch units in a particular transmission area lacked sufficient capability, the regulation units picked up the excess load following. If the regulation units lacked sufficient capability, an area control error (ACE) signal was generated, and the export to other transmission areas was affected. The ACE signal was compared to an approximate L10 limit to identify potential Control Performance Standard 2 (CPS2) violations [7.1].

Additional details on the study periods and input data, as well as regulation and economic dispatch unit selection from the boundary conditions are presented in Sections 7.2.2 through 7.2.4.

The results of selected 24-hour QSS simulations are described in Sections 7.2.5 and 7.2.6.

7.2.2 Input Data

Several types of data were used in the QSS analysis: wind generation profiles, solar generation profiles, load profiles, unit type ramp rate capabilities, transmission area regulation requirements, and L10 limits for CPS2.

NREL provided 1-minute wind generation profiles for all wind plants included in a given scenario (e.g., Local Priority) for each QSS study period. These profiles were then aggregated by transmission area. Limited high resolution solar and load data were available. Therefore, the necessary 1-minute solar profiles were created with a cubic spline interpolation of the 10-min data. The necessary 1-minute load profiles were created with a cubic spline interpolation of the 1-hour data. Additional information on the data used in this study is provided in Chapter 2.

Generic ramp rate data (MW/minute) were used for each unit type. These data were drawn from the CEC Intermittency Analysis Project [7.2], and is shown in Table 7.3.

Table 7.3. Generic Ramp Rate Data by Unit Type.

	Ramp Rate (%/Minute)
Combined Cycle	3.8
Combustion Turbine	13.5
Hydroelectric	22.3
Steam	3.1

The regulation requirement for each transmission area was estimated as 1% of peak load for both positive and negative regulation. This assumption is consistent with the actual regulation requirements observed in other studies. The regulation requirement for each transmission area is shown in Table 7.4.

Table 7.4. Regulation Requirement by Transmission Area.

	Regulation (+/- MW)
Arizona	231
Colorado – East	116
Colorado – West	15
Northern Nevada	29
Southern Nevada	97
New Mexico	53
Wyoming	40
In Footprint	581
Out of Footprint	1200

CPS2 requires that the average ACE for each of the six ten-minute periods during an hour must be within specific limits. These limits are called L10, and vary with each operating area. Approximate L10 values were used in the QSS analysis to identify potential CPS2 violations. These values were based on the NERC "2007 CPS2 Bounds Report," aggregated to match the transmission areas under study, and shown in Table 7.5. The L10 limits were constant across all scenarios and all penetration levels.

Table 7.5 Approximate CPS2 L10 Limits by Transmission Area.

	L10 (MW)
Arizona	187
Colorado – East	83
Colorado – West	15
Northern Nevada	25
Southern Nevada	85
New Mexico	63
Wyoming	48

7.2.3 Boundary Conditions

The export schedule for each transmission area changed on an hourly basis in accordance with the production simulation results. These schedules were based on the dispatch, not the day-ahead commitment with its imperfect renewable generation forecast, and as such have taken the forecast error into account.

The production simulation results were also used to identify up to four types of generating units (e.g., hydro, combined cycle, steam, gas turbine) as participants in load following via the 5-minute economic dispatch function. The unit types that moved the most across the study period were selected as participants with an appropriate priority number. For example, if the MAPS analysis showed the combined cycle dispatch moved between 1,000 MW and 2,500 MW across a study period, and the hydro dispatch moved between 50 MW and 200 MW, then the QSS economic dispatch priority would be combined cycle #1 and hydro #2.

The production simulation results were also used to identify up to four types of generating units as providers of regulation. First, a priority number was assigned to each regulation unit type – similar to that described above for the economic dispatch unit types. Next, the available up range (unit type maximum minus unit type dispatch) or down range (unit type dispatch minus unit type minimum) was used to assign a specific percentage of the desired regulation capability to each unit type. For example, if both the combined cycle and hydro units had significant available up range, then about 91% (i.e., [1,500/(1,500 + 150)]*100) of the required up regulation capability would be assigned to the combined cycle units and about 9% of the required regulation capability would be assigned to the hydro units. For situations with limited available range on one particular unit type, the required regulation would be assigned to a unit type with available range.

The maximum and minimum limits of the unit types on economic dispatch were adjusted (i.e., decreased and increased, respectively) to accommodate the desired regulation capability.

The remaining generating unit types were treated as un-dispatchable generation subject only to the hourly schedule from the production simulation results.

Changes in commitment observed in the MAPS results were implemented in the QSS algorithm as hourly changes to the maximum and/or minimum of each unit type. The ability to incorporate such commitment changes allowed for a longer (i.e., 24-hour) QSS study period than that used in previous studies (i.e., 3-hour) [7.2].

7.2.4 Study Periods

The QSS study periods were selected based upon the hourly statistical analysis. The primary objective was to identify challenging, but credible, system conditions. Therefore, the hourly statistical analysis was used to identify study periods with any of the following characteristics:

- Large 1-hour, 3-hour and 6-hour changes in net footprint load (e.g., load minus wind minus solar)
- High levels of wind and solar penetration

- Low load levels
- High wind forecast errors

Two primary study periods were chosen – an April day with low load and high wind penetration, and an October day with a high wind forecast error. The focus of the analysis was on the Local Priority scenario with 30% wind penetration. Selected other scenarios and penetrations were analyzed as needed.

An overview of the hourly system characteristics for the April QSS period with 30% wind penetration in the Local Priority scenario is shown in Figure 7.6. The total load in the study footprint is shown in dark blue, total wind generation in green, total PV generation in red, total CSP with storage generation in gold and net load in light blue. Note that net load is negative during the nighttime minimum load period: it is the hour with the most negative load in the study footprint in 3 years of data. This period is also discussed in Chapters 4 and 6.

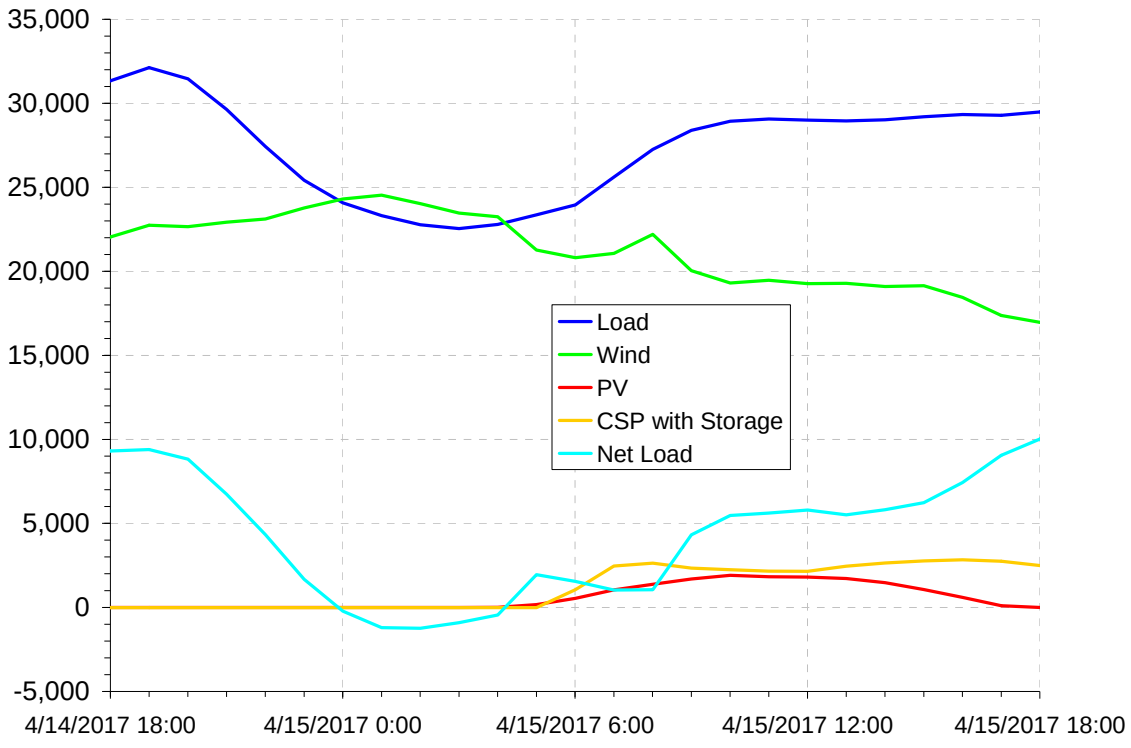


Figure 7.6 Study Footprint Characteristics for April QSS Period, Local Priority, 30% Wind Penetration.

An overview of the hourly system characteristics for the October day is shown in Figure 7.7. The same color coding is used for the traces, with one addition. The dark green line represents the total wind forecast for the study footprint. Note that the maximum forecast error (i.e., forecast minus actual for a given hour) in the study footprint reached almost 12,000 MW, the single worst forecast error in 2006. The maximum forecast error

in each transmission area was about 2,600 MW in Arizona, 3,500 MW in Colorado East, 300 MW in Colorado West, 700 MW in Nevada, 2,000 MW in New Mexico, and 4,700 MW in Wyoming. Due to geographic diversity, the total study footprint forecast error is less than the sum of the individual transmission area forecast errors.

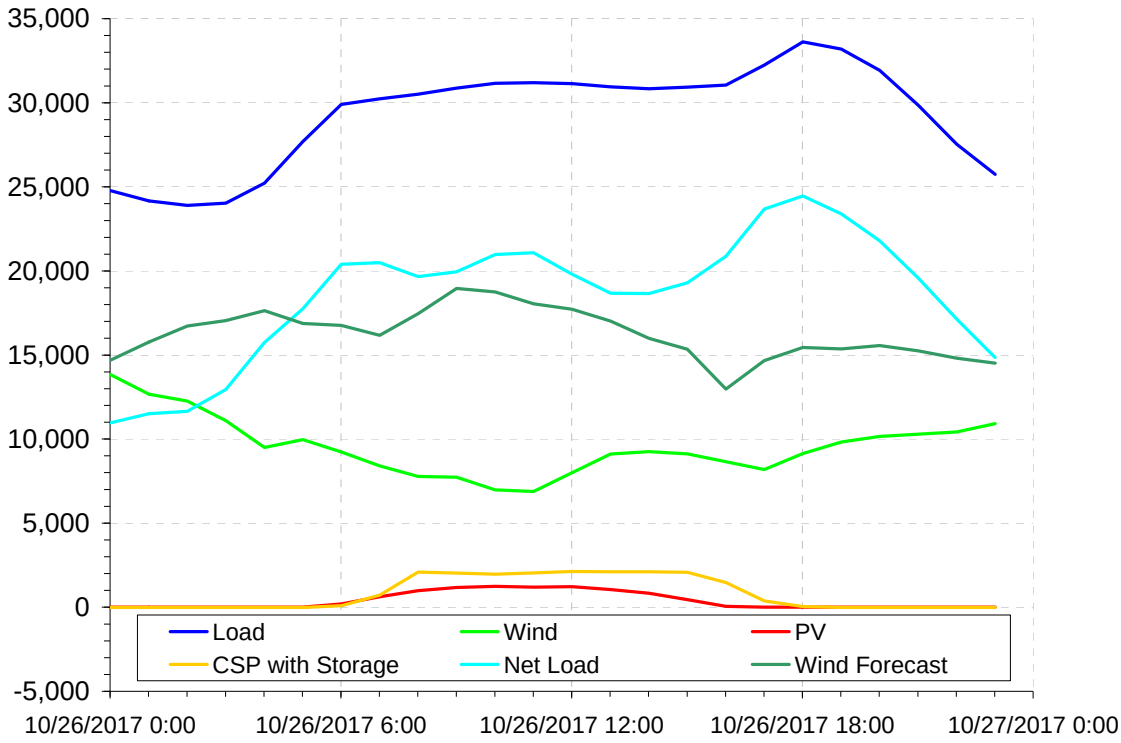


Figure 7.7 Study Footprint Characteristics for October QSS Period, Local Priority, 30% Wind Penetration.

7.2.5 April 15, 2006 Example

The QSS simulation results for the April day with low load and high wind penetration are presented in this section. The Local Priority scenario was analyzed for four penetration levels – 10%, 20%, 20/20%, and 30%. See Chapter 3 for additional description of the scenario development and site selection. The focus is on the Arizona transmission area, with other areas brought in for comparison and contrast as needed. Additional QSS results are provided in Appendix F.

The Arizona wind and load 1-minute input profiles are shown in Figure 7.8. The gray line represents the total Arizona load, the pink line represents the total wind plant output with 30% energy penetration, the green line represents the total wind plant output with 20% penetration, and the dark blue line represents the total wind plant output with 10% penetration.

As shown in Chapter 3, 2,850 MW of wind projects were installed to achieved 10% penetration. For 20% penetration, 5,250 MW of wind projects were installed, and for

30% penetration, 7,710 MW of wind project were installed. At the beginning of this April study period, the wind projects are at almost 100% rated output. At about 4 a.m., the wind output for the 30% penetration level exceeds the load.

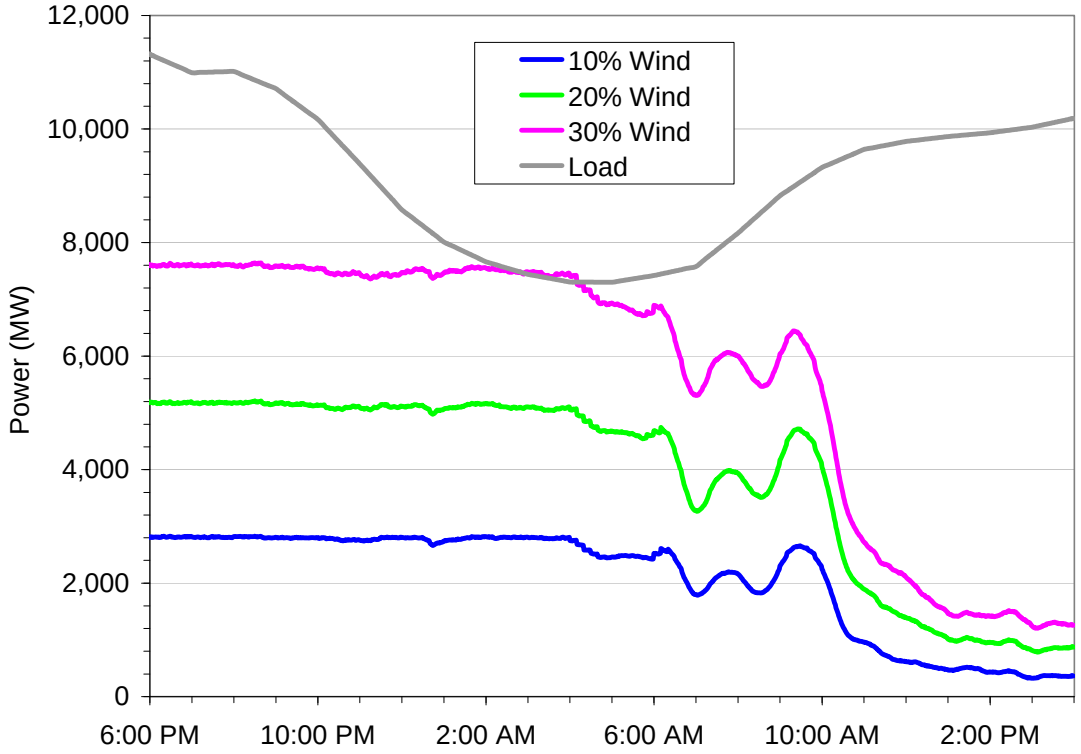


Figure 7.8. Arizona Input Profiles, Local Priority, April QSS Study Period.

The boundary conditions from the production simulation analysis are shown in Figure 7.9 and Figure 7.10. Figure 7.9 shows the hourly schedule for the BOP generation at 10%, 20%, 20/20%, and 30% wind penetration. As the amount of wind generation increases, the amount of conventional generation decreases.

Figure 7.10 shows the hourly export schedule at 10%, 20%, 20/20%, and 30% wind penetration. As the amount of wind generation increases from 10% to 20/20%, the Arizona exports decrease. This indicates that Arizona conventional generation is displaced by wind generation both inside and outside Arizona as penetration increases. As the wind penetration increases from 20/20% to 30%, the export schedule increases. This indicates that the additional Arizona wind is displacing conventional generation outside Arizona.

The difference between the 20% and 20/20% cases (dark blue and light blue, respectively) is entirely due to additional renewable generation outside the study footprint. The generation mix of the rest of WECC has a significant impact on the performance of the study footprint.

The generation boundary conditions were separated into unit types and used to identify the participants in load following via the 5-minute economic dispatch function, and the providers of regulation. The economic dispatch unit types, and their priority, are shown in Table 7.6 for each penetration level. The regulation unit types, their priority and capability, are shown in Table 7.7.

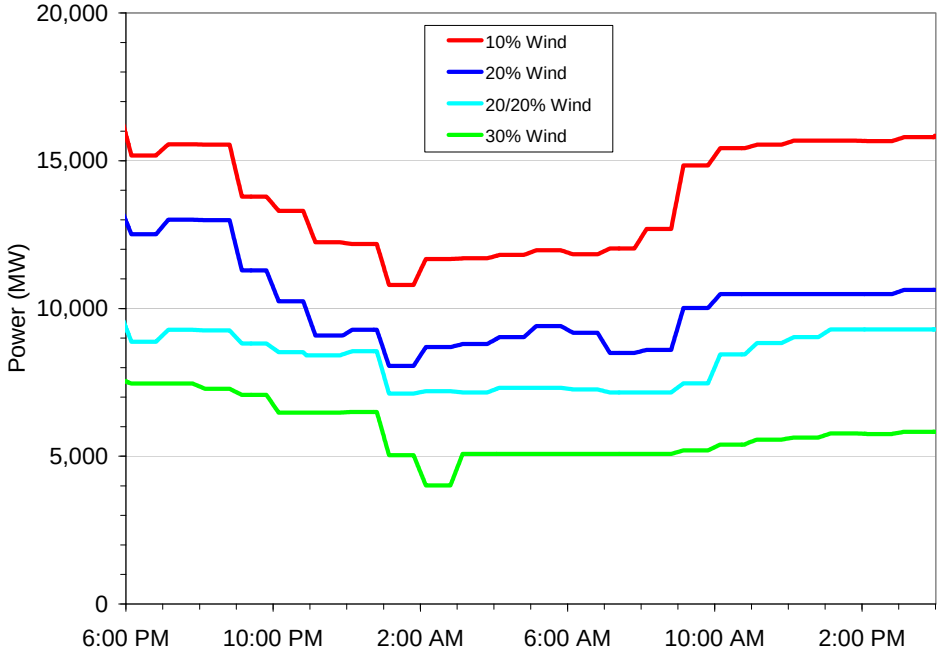


Figure 7.9 Arizona Conventional Generation Hourly Schedule, Local Priority, April QSS Study Period.

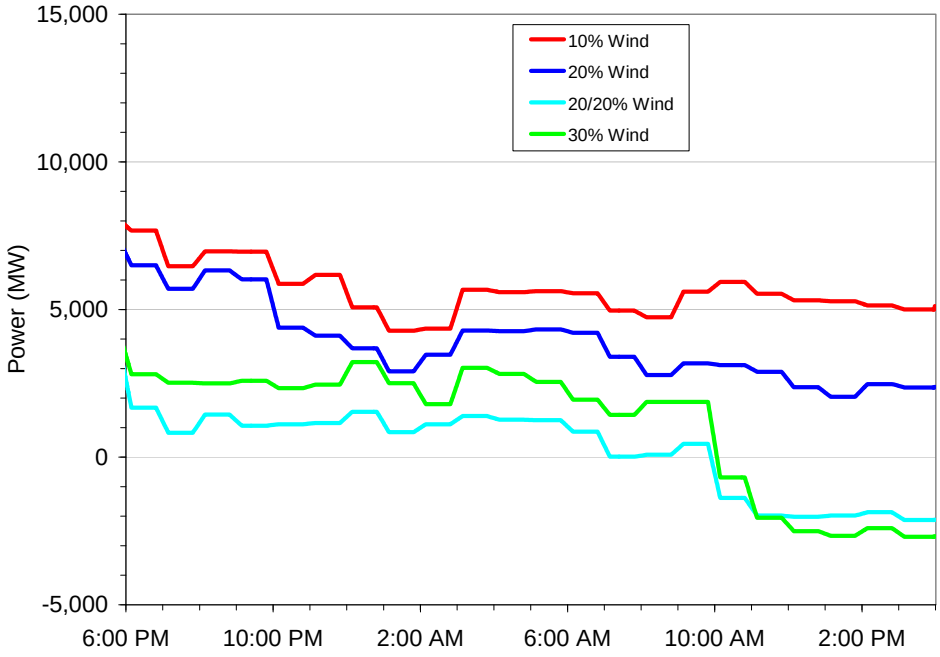


Figure 7.10 Arizona Export Schedule, Local Priority, April QSS Study Period.

Table 7.6 Economic Dispatch Priority for Arizona during April QSS Study Period.

	10% Wind	20% Wind	20/20% Wind	30% Wind
Hydro	3	3	4	3
Combined Cycle	1	1	3	4
Gas Turbine	4	4	2	2
Steam	2	2	1	1

Table 7.7 Regulation Priority and Capability for Arizona during April QSS Study Period.

	10% Wind			20% Wind			20/20% Wind			30% Wind		
	Priority	+ MW	- MW	Priority	+ MW	- MW	Priority	+ MW	- MW	Priority	+ MW	- MW
Hydro	3	48	-6	3	11	0	4	229	0	3	0	0
Combined Cycle	1	182	-174	1	219	-70	3	1	-2	4	0	0
Gas Turbine	4	0	0	4	0	0	2	0	0	2	0	0
Steam	2	0	-52	2	0	-161	1	1	-229	1	231	-231

The results of the April QSS analysis with the above input data and boundary conditions are presented in Figure 7.11 through Figure 7.24.

The Arizona dispatch with 10% wind penetration for the Local Priority scenario is shown in Figure 7.11. As shown in Table 7.6, the economic dispatch priority for this case is combined cycle (green), steam (light blue), hydro (dark blue), and gas turbine (pink). The heavyweight lines represent the unit type power output, and the lightweight lines represent the maxima and minima of the committed units. Changes in commitment can be observed in the changes to the maxima and minima.

Over the course of this simulation, the top three unit types (e.g., combined cycle, steam, and hydro) respond to the economic dispatch system and follow load down and then up again. The bulk of the load following is performed by the combined cycle units, with these units operating at minimum for several hours over night when the load is at its lowest level.

The amount of regulation provided is shown in Figure 7.12, as the dark blue line. The conventional generation hourly schedule (pink) and the hourly export schedule (gold) are also shown. The right vertical scale applies to regulation; the left vertical scale applies to the hourly schedules.

As shown in Table 7.4, +/- 231 MW of regulation capability is available in Arizona during the simulation. The regulation that is actually provided is largely driven by the hourly schedule changes, not by the wind and solar variability. Each time the provided

regulation hits a capability limit (i.e., +/- 231 MW), it is due to an hourly schedule change.

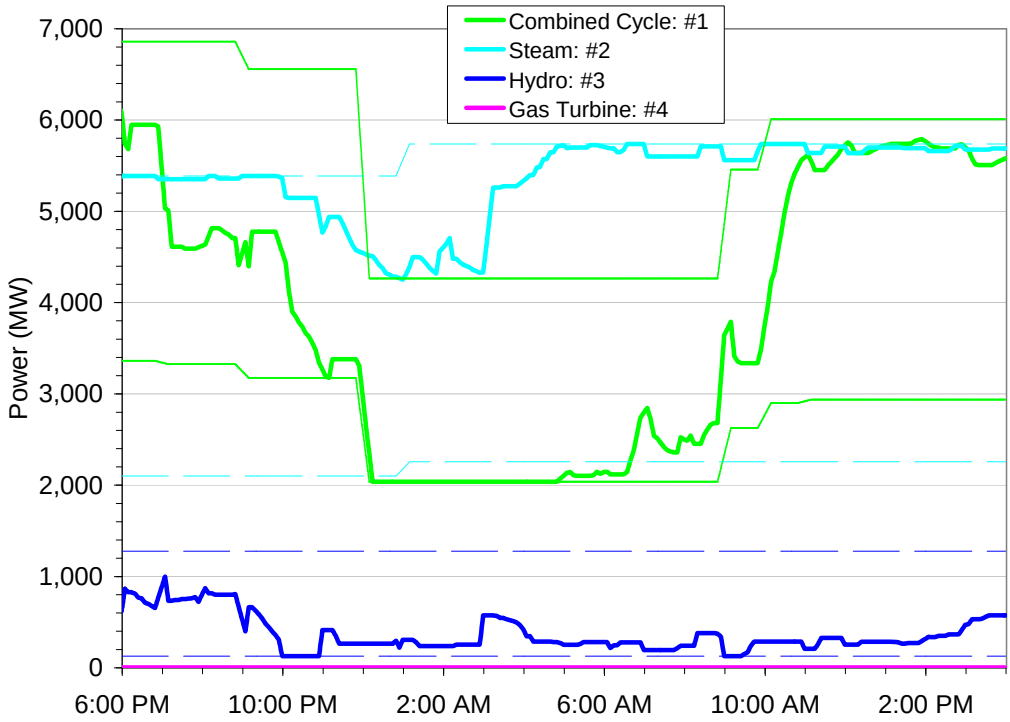


Figure 7.11 Arizona Dispatch, 10% Wind, Local Priority, April QSS Study Period.

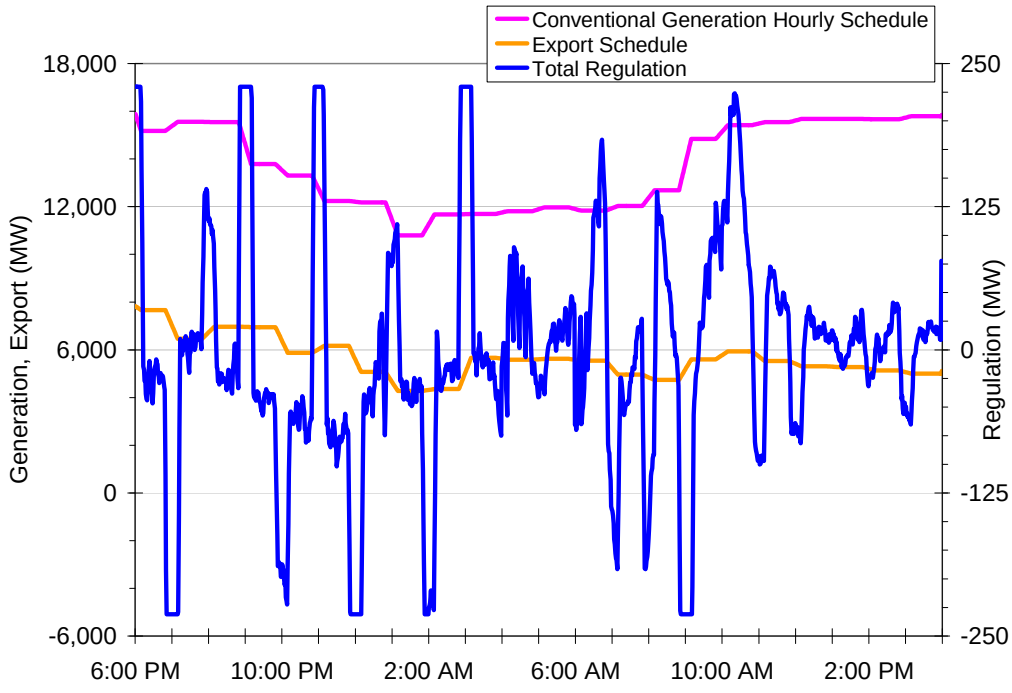


Figure 7.12. Arizona Regulation, 10% Wind, Local Priority, April QSS Study Period.

The overall performance of the Arizona system with 10% wind penetration is shown in Figure 7.13. The dark blue line represents the Total Generation, or all generation in the Arizona transmission area including wind and solar. The pink line represents the Conventional Generation Hourly Schedule or the hourly boundary conditions from the production simulation analysis. The gray line (generally hidden behind the light blue line) represents the Conventional Generation Total, which includes all generation responding to economic dispatch, regulation, and hourly schedules – effectively, all generation except wind and solar. The light blue line represents the Load-Wind-Solar+Export or load minus wind minus solar plus the hourly export schedule. The green line represents Load-Wind-Solar or load minus wind minus solar, and the gold line represents the hourly Export Schedule. Both the Conventional Generation Hourly Schedule and the Export Schedule contain hourly information only. The other traces change minute-by-minute.

The key comparison in this plot is between the light blue line (Load-Wind-Solar+Export) and the gray line (Conventional Generation Total). When the Arizona generation and net load are in balance, then these two traces will be indistinguishable. When the generation-load balance is not maintained, then the gray line (Conventional Generation Total) will no longer be hidden by the light blue line (Load-Wind-Solar+Export). Several small generation-load imbalances occur, with the most obvious at about 9 a.m. At this time, the units on economic dispatch and the units providing regulation have insufficient capability to meet the net changes in load, wind, solar, and hourly export.

This will result in an ACE, as shown by the red line in Figure 7.14. The amount of regulation provided is represented by the blue line, and matches that shown in Figure 7.12. A positive ACE signal means that generation exceeds net load, and the actual export will exceed the export schedule. A negative ACE signal means that net load exceeds generation, and the actual export will fail to meet the export schedule. The two black lines represent the approximate L10 limits that indicate a potential CPS2 violation. As with the regulation itself, the ACE is largely driven by the hourly generation and export schedule changes, not by the wind and solar variability.

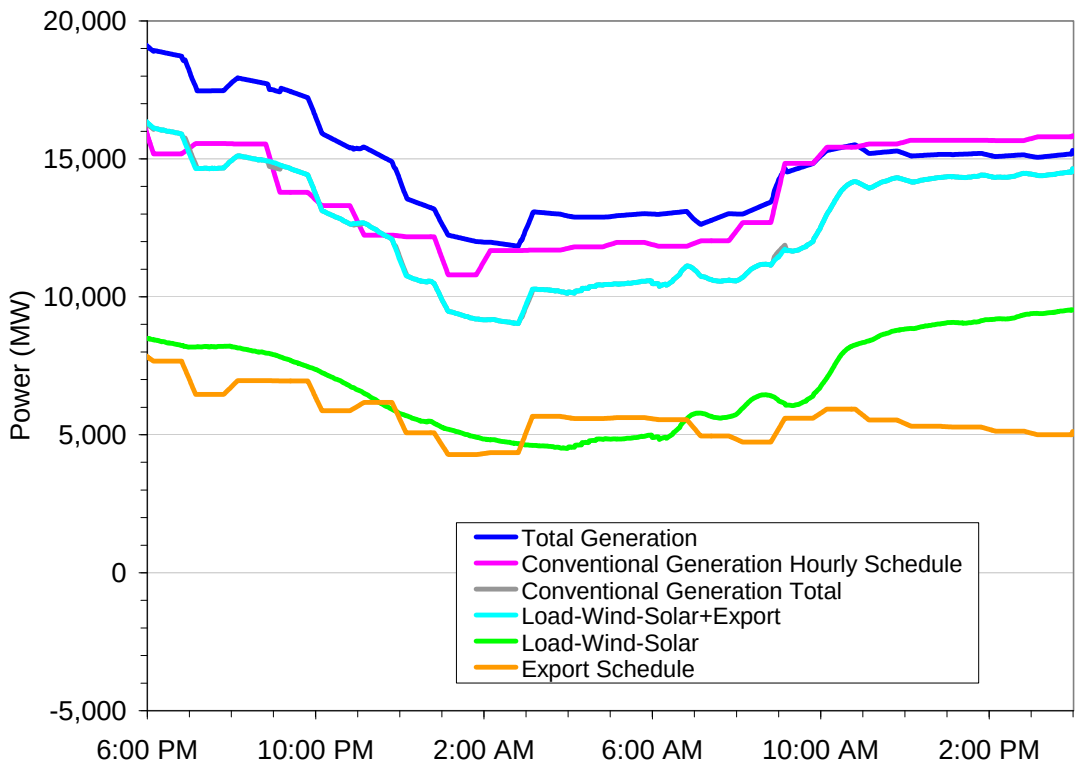


Figure 7.13 Arizona Totals, 10% Wind, Local Priority, April QSS Study Period.

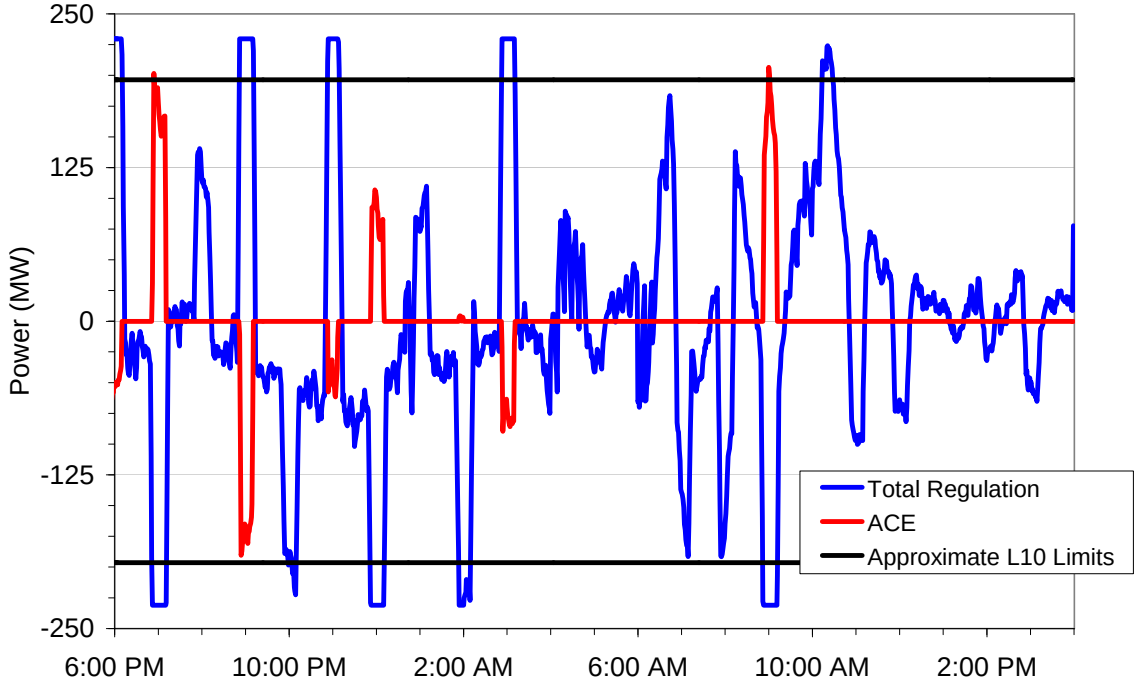


Figure 7.14 Arizona Regulation and ACE, 10% Wind, Local Priority, April QSS Study Period.

The impact of increasing levels of wind and solar penetration, and the associated increased variability, were also evaluated.

Figure 7.15 to Figure 7.17 show the Arizona dispatch for the Local Priority scenario with 20%, 20/20%, and 30% wind penetration. As described in Chapter 3, the 20/20% case has the same wind penetration within Arizona as the 20% case. However, the penetration outside the study footprint has increased from 10% to 20%.

Several effects were observed as penetration increased from the 10% penetration level shown in Figure 7.11. First, the combined cycle commitment was significantly reduced. This is consistent with the results reported in Chapter 6, which showed that wind generation displaces the conventional generation with the highest marginal cost. Second, the economic dispatch priority order changed. At 10% penetration, the priority was combined cycle, steam, hydro, and gas turbine. At 30% penetration, the priority was steam, gas turbine, hydro, and combined cycle. This reflects the changing BOP generation mix as wind and solar displace combined cycle units. Finally, the amount of wind and solar generation in neighboring systems had a significant impact. At 20% penetration, the bulk of the Arizona load following was performed by combined cycle and steam units. With the increased wind and solar penetration outside the study footprint in the 20/20% case, no combined cycle units were committed and the bulk of the load following was performed by steam units. The additional out-of-footprint wind and solar effectively reduced the opportunity for Arizona to export power.

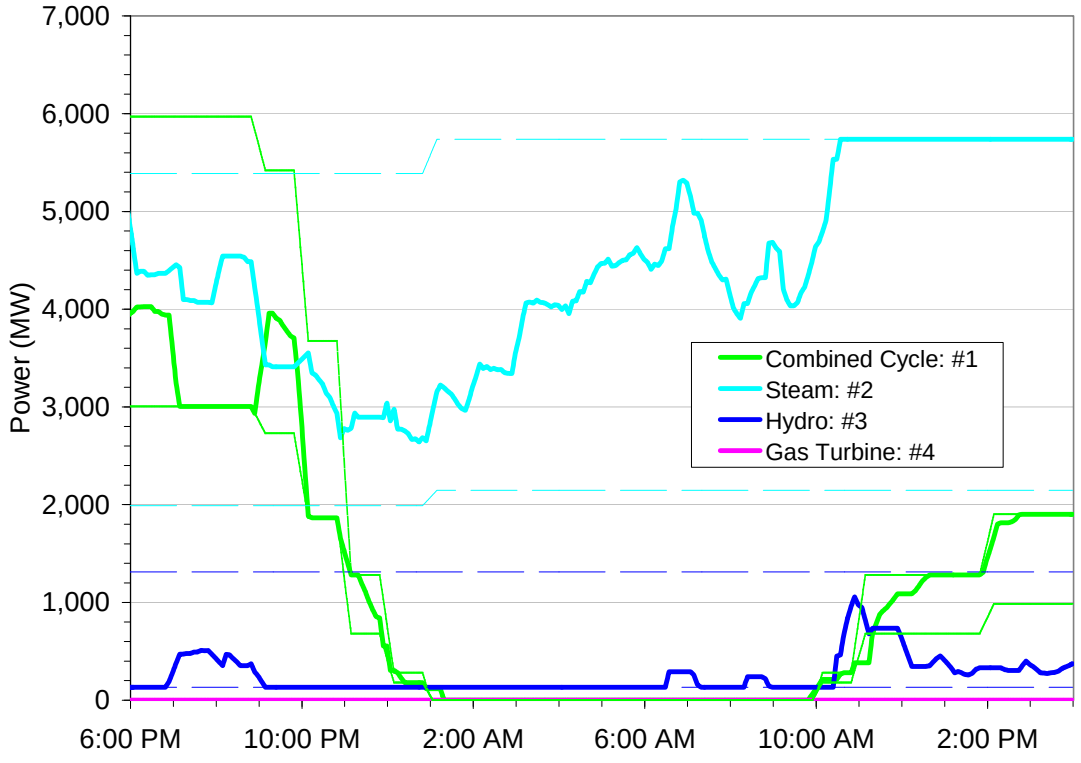


Figure 7.15 Arizona Dispatch, 20% Wind, Local Priority, April QSS Study Period.

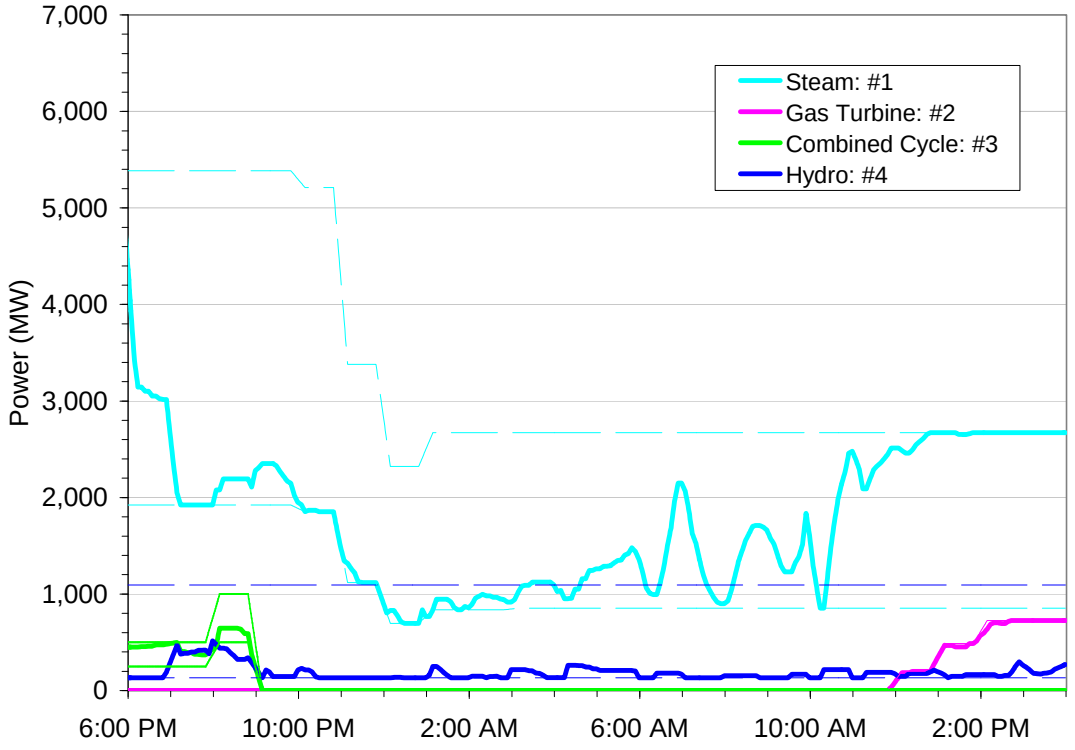


Figure 7.16 Arizona Dispatch, 20/20% Wind, Local Priority, April QSS Study Period.

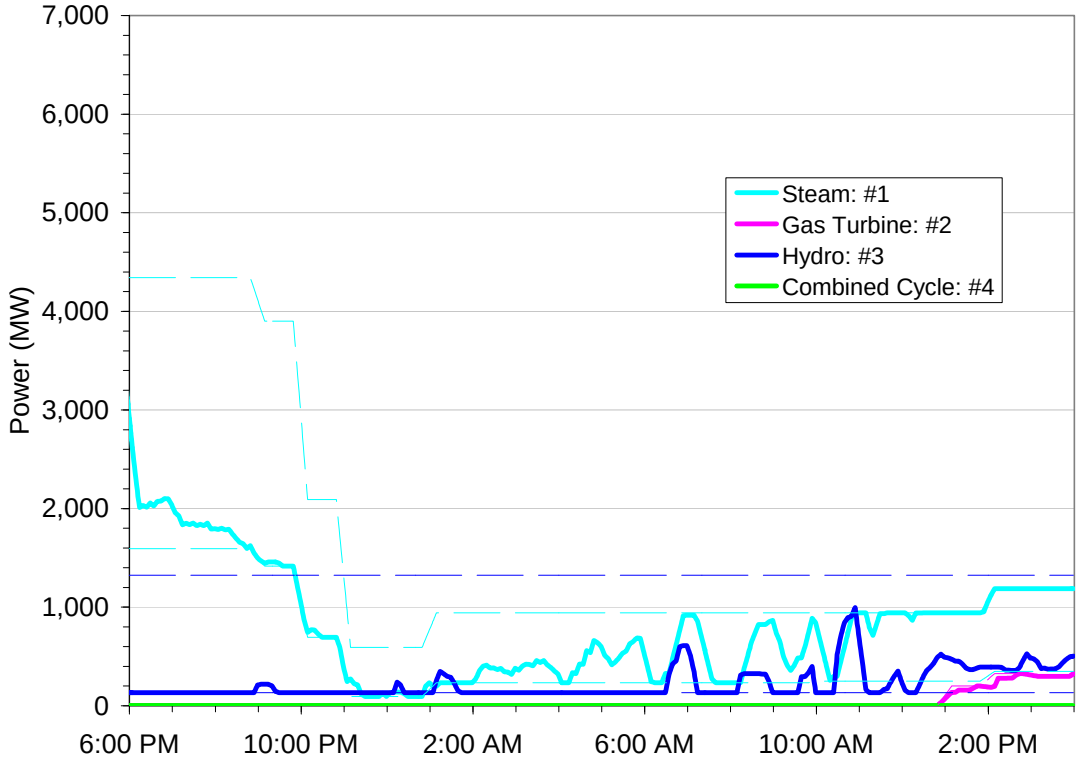


Figure 7.17 Arizona Dispatch, 30% Wind, Local Priority, April QSS Study Period.

Figure 7.18 to Figure 7.20 show the Arizona regulation and hourly schedules for the Local Priority scenario with 20%, 20/20%, and 30% wind penetration.

The export schedule decreased significantly as penetration increased from the 10% penetration level shown in Figure 7.12. At 10% and 20% penetration, the Arizona system begins with an export schedule in the range of 7,000 to 8,000 MW, and it is always exporting. With the increased wind and solar penetration outside the study footprint in the 20/20% case, the initial export schedule is reduced to about 2,000 MW and the system ends up as an importer. A similar pattern is observed for the 30% case.

As the penetration increased, the impact of wind and solar variability on regulation increased. However, the largest regulation swings were still driven by the hourly schedule changes, not by the variability.

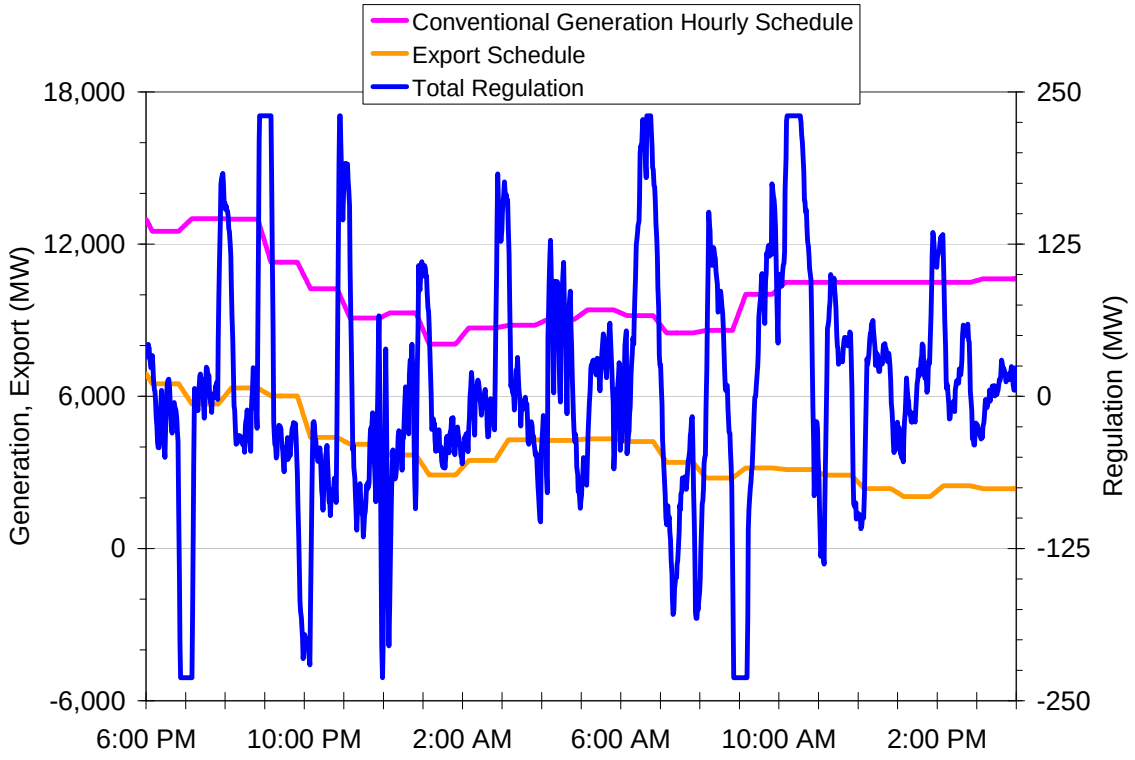


Figure 7.18 Arizona Regulation, 20% Wind, Local Priority, April QSS Study Period.

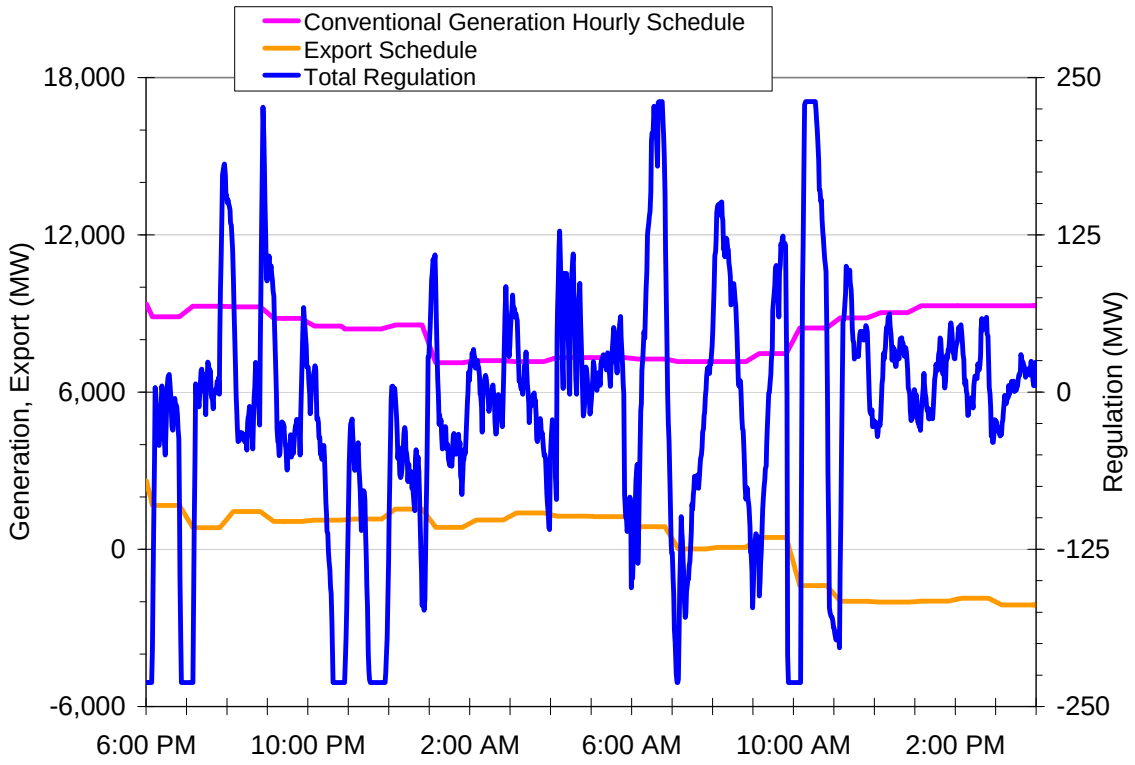


Figure 7.19 Arizona Regulation, 20/20% Wind, Local Priority, April QSS Study Period.

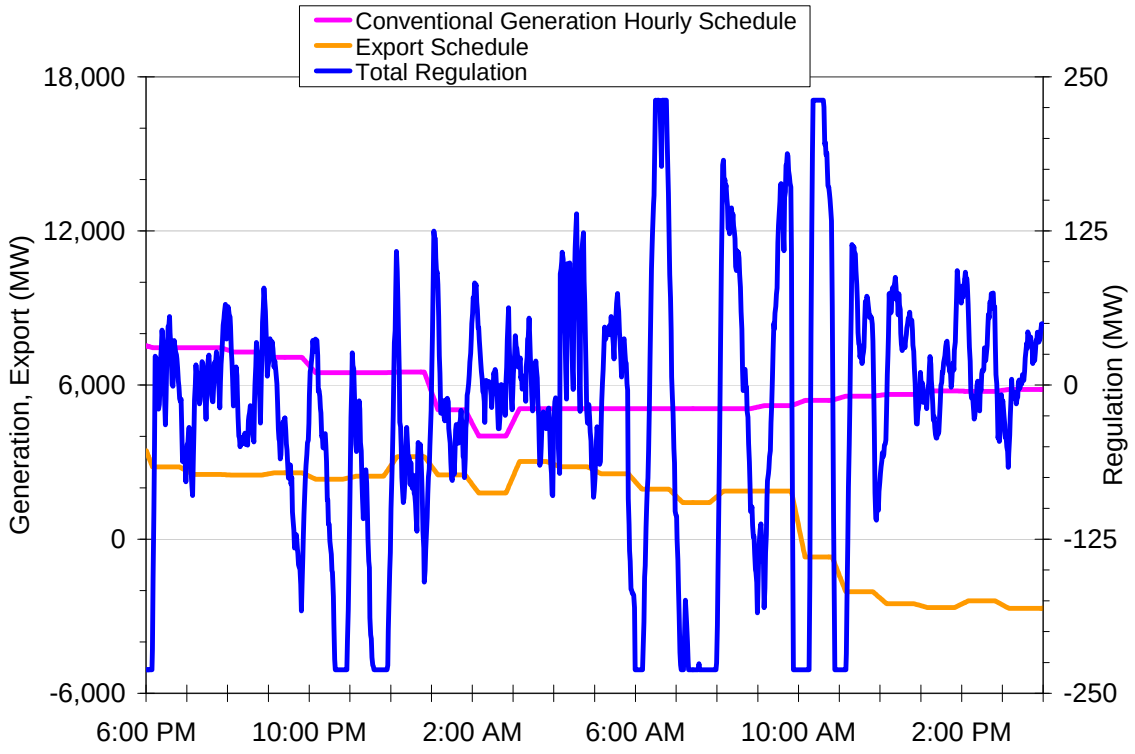


Figure 7.20 Arizona Regulation, 30% Wind, Local Priority, April QSS Study Period.

An ACE will occur when there is insufficient regulating capability to meet the net changes in load, wind, solar, and hourly schedules. Figure 7.21 shows the Arizona ACE for the Local Priority scenario with various levels of wind penetration. The red line represents 10% wind penetration, the green line represents 20% wind, the light blue line represents 20/20% wind, the dark blue line represents 30% wind, and the black lines represent the approximate L10 limits. These L10 values were used to identify potential CPS2 violations.

Several effects are observed as wind penetration increased. First, the Arizona ACE increased. Second, the performance of the 10% and 20% cases were similar, and the performance of the 20/20% and 30% cases were similar. The breakpoint between the 20% case and the 20/20% case illustrates that the amount of wind and solar generation in neighboring systems has a significant impact on the performance of the study footprint. Third, the 20/20% and 30% cases exceed the approximate L10 values around 10 a.m., suggesting that a CPS2 violation occurred. As noted above, the largest regulation requirements and ACEs occur with large changes in the hourly generation and/or export schedules.

It is of some interest to note that at 4 a.m., when Arizona has more than 100% of its load served by wind power (30% case), the system behaves well. The biggest challenge on this day was associated with the rapid decline of wind power in mid-morning.

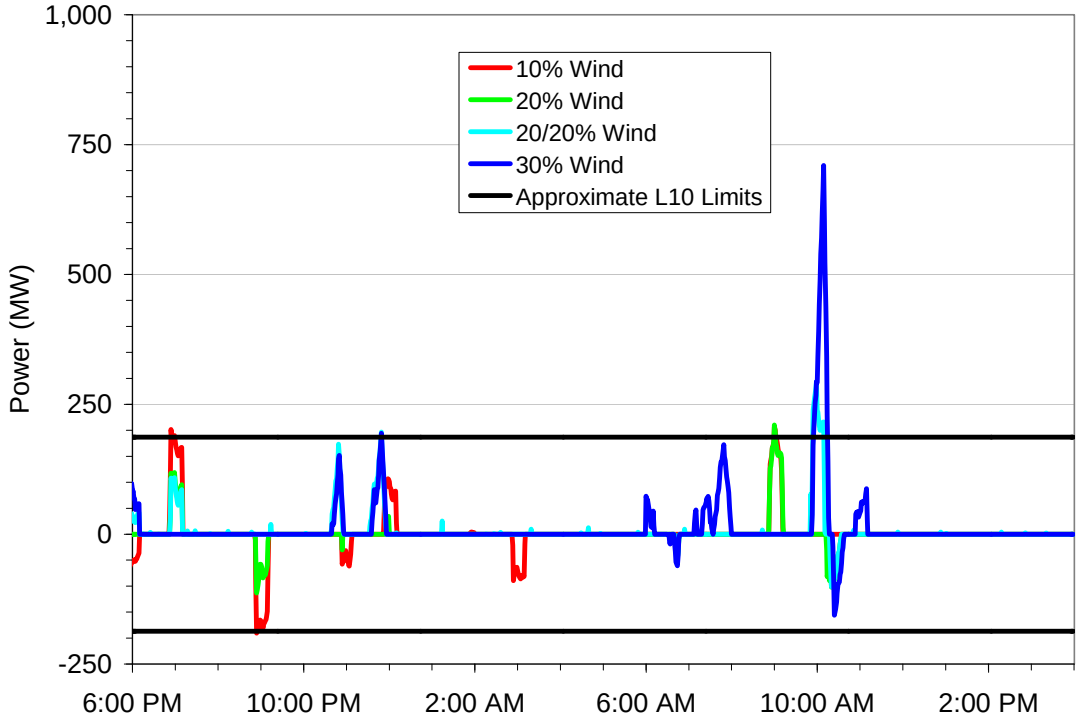


Figure 7.21 Arizona ACE, All Penetration Levels, Local Priority, April QSS Study Period.

Figure 7.22 through Figure 7.24 show the impact of consolidating balancing areas on area control errors for the Local Priority scenario with 30% wind penetration.

Figure 7.22 illustrates the consolidation of Arizona and New Mexico. The dark blue line represents the Arizona ACE, the light blue line represents the New Mexico ACE, and the red line represents the sum of the two ACEs. However, if Arizona and New Mexico are operated as a single area, the total ACE is reduced to that shown by the green line. At 10 a.m., the total ACE is reduced by about 50% with area consolidation.

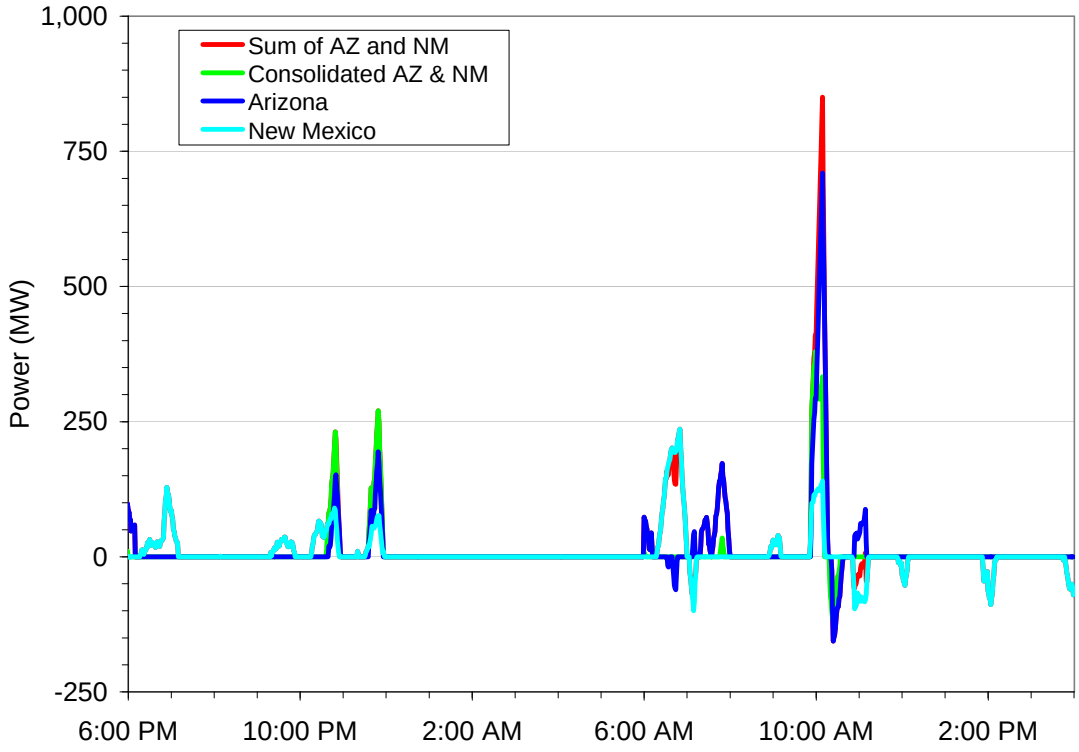


Figure 7.22 Arizona and New Mexico ACEs, 30% Wind, Local Priority, April QSS Study Period.

Figure 7.23 and Figure 7.24 illustrate the consolidation of the entire study footprint.

Figure 7.23 shows the individual ACEs for each transmission area in the study footprint. Figure 7.24 shows the entire study footprint ACE with and without consolidation. The dark blue line is the sum of the individual ACEs shown in Figure 7.23, or the footprint ACE without consolidation. The green line represents the ACE when all seven transmission areas are consolidated and operated as one. Under many conditions, the ACE has been eliminated. Between 11 p.m. and midnight, the ACE is unchanged. At 10 a.m., the ACE is reduced by about 30% with area consolidation.

This time period was chosen because of the low load overnight. However, the challenging period of operation turned out to be during the morning load rise.

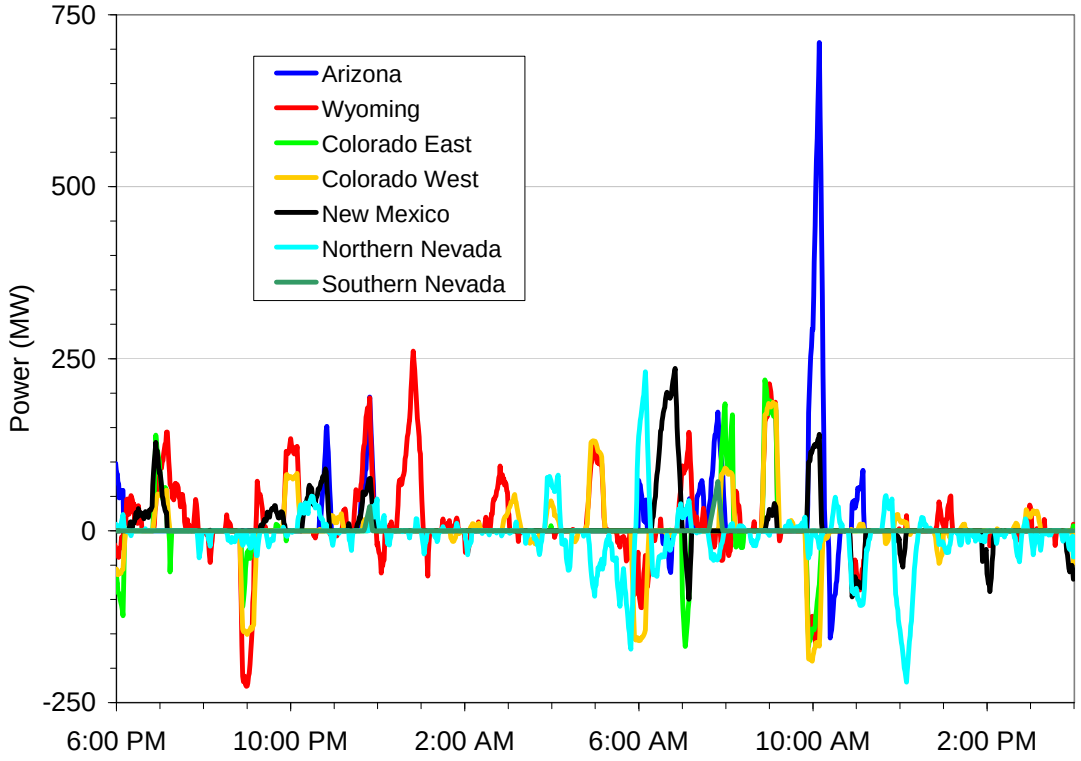


Figure 7.23 Transmission Area ACEs, 30% Wind, Local Priority, April QSS Study Period.

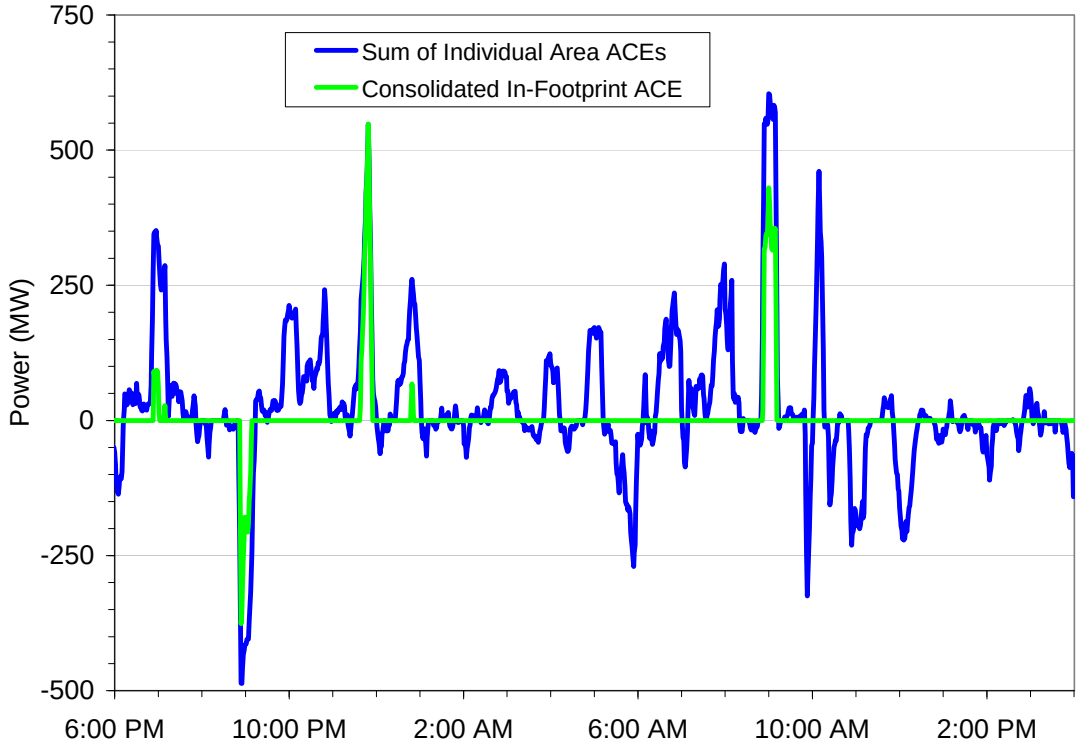


Figure 7.24 Footprint ACEs with and without Consolidation, 30% Wind, Local Priority, April QSS Study Period.

7.2.6 October 26, 2006 Example

The QSS simulation results for the October day with a high wind forecast error are presented in this section. The Local Priority scenario was analyzed for four penetration levels – 10%, 20%, 20/20%, and 30%. See Chapter 3 for additional description of the scenario development and site selection. The focus is on the Colorado East transmission area, with other areas brought in for comparison and contrast as needed. Additional QSS results are provided in Appendix F.

The Colorado East wind and load input profiles are shown in Figure 7.25. The gray line represents the total Colorado East load, the solid pink line represents the total wind plant output with 30% energy penetration, and the dashed pink line represents the 30% wind forecast. Similarly, the green lines represent the total wind plant output (solid) and forecast (dashed) with 20% penetration, and the dark blue lines represent the total wind plant output (solid) and forecast (dashed) with 10% penetration.

As shown in Chapter 3, 2,190 MW of wind projects were installed to achieved 10% penetration. For 20% penetration, 3,870 MW of wind projects were installed, and for 30% penetration, 4,650 MW of wind project were installed. During this October study period, the maximum output for all penetration levels is about 45% of rated. As discussed in Chapter 4, the maximum forecast error, about 3,500 MW, occurred near 10 a.m. with 30% wind penetration.

The boundary conditions from the production simulation analysis are shown in Figure 7.26 and Figure 7.27. Figure 7.26 shows the hourly schedule for the BOP generation at 10%, 20%, 20/20%, and 30% wind penetration. Figure 7.27 shows the hourly export schedule at each wind penetration level. As the amount of wind generation increases, the amount of conventional generation decreases. Similarly, as the amount of wind generation increases, the Colorado East exports decrease.

The generation boundary conditions were separated into unit types and used to identify the participants in load following via the 5-minute economic dispatch function, and the providers of regulation. The economic dispatch unit types, and their priority, are shown in Table 7.8 for each penetration level. The regulation unit types, their priority and capability, are shown in Table 7.9.

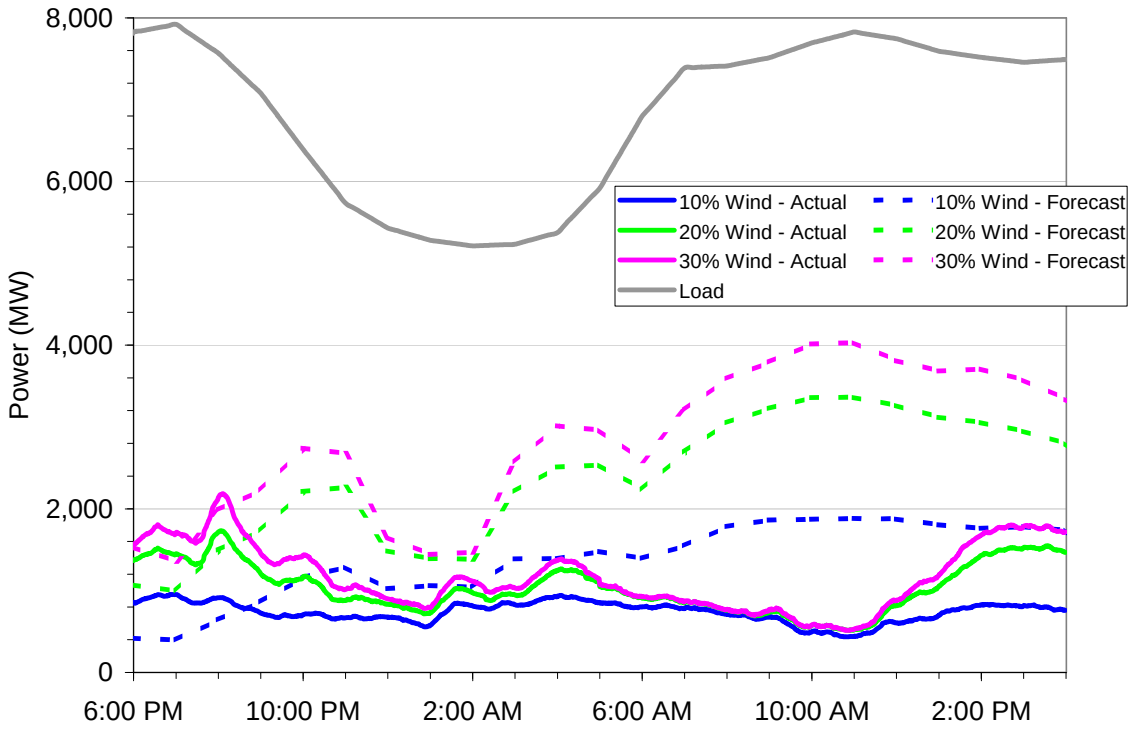


Figure 7.25 Colorado East Input Profiles, Local Priority, October QSS Study Period.

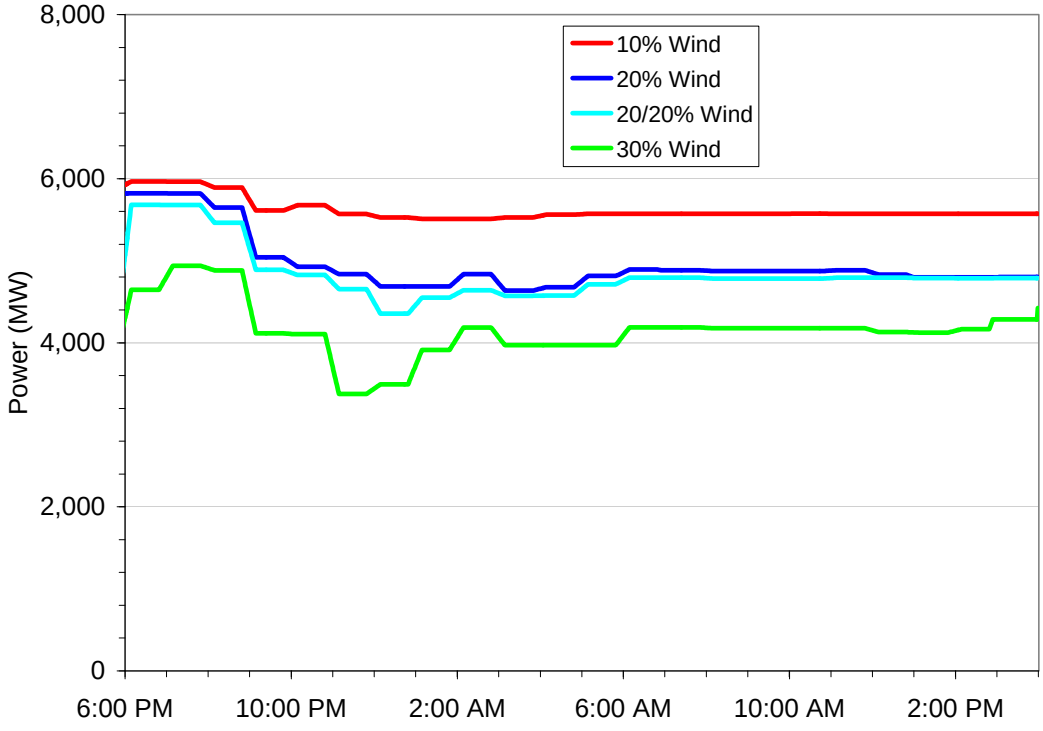


Figure 7.26 Colorado East Conventional Generation Hourly Schedule, Local Priority, October QSS Study Period.

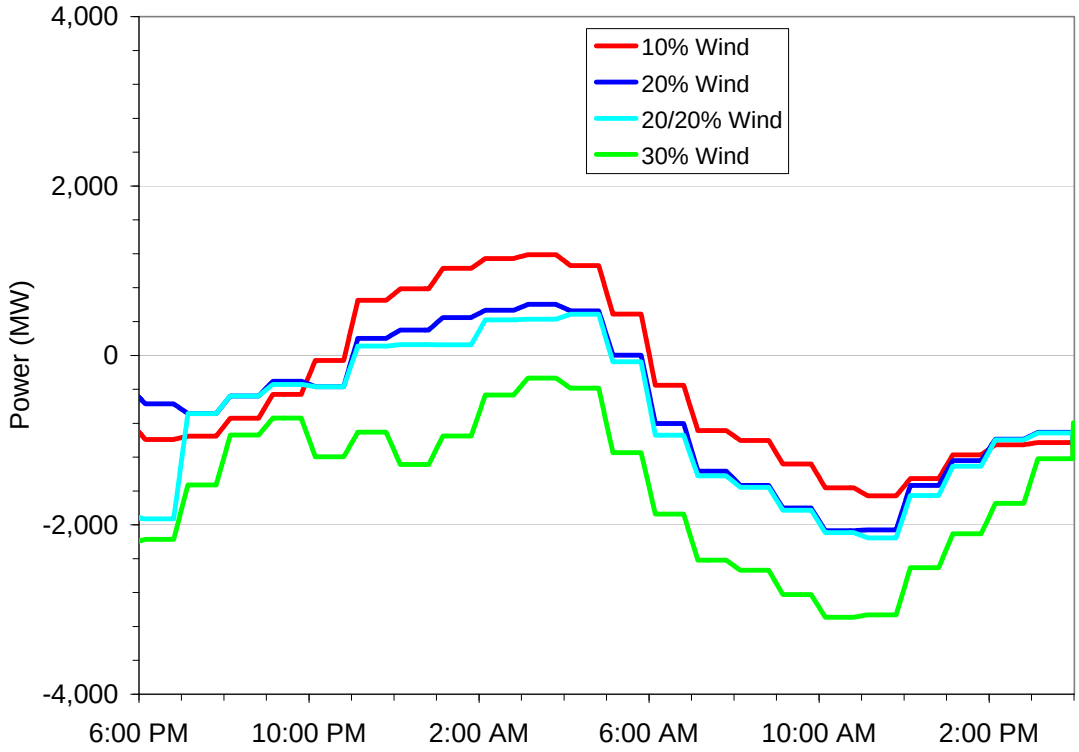


Figure 7.27 Colorado East Export Schedule, Local Priority, October QSS Study Period.

Table 7.8 Economic Dispatch Priority for Colorado East during October QSS Study Period.

	10% Wind	20% Wind	20/20% Wind	30% Wind
Hydro	2	2	3	3
Combined Cycle	1	1	1	1
Gas Turbine	4	4	4	4
Steam	3	3	2	2

Table 7.9 Regulation Priority and Capability for Colorado East during October QSS Study Period.

	10% Wind			20% Wind			20/20% Wind			30% Wind		
	Priority	+ MW	- MW	Priority	+ MW	- MW	Priority	+ MW	- MW	Priority	+ MW	- MW
Hydro	2	15	0	2	2	0	3	0	0	3	0	0
Combined Cycle	1	101	-115	1	114	-115	1	116	0	1	114	0
Gas Turbine	4	0	0	4	0	0	4	0	0	4	0	0
Steam	3	0	-1	3	0	-1	2	0	-116	2	2	-116

The results of the October QSS analysis with the above input data and boundary conditions are presented in Figure 7.28 through Figure 7.43.

Figure 7.28 to Figure 7.31 show the Colorado East dispatch for the Local Priority scenario with 10%, 20%, 20/20%, and 30% wind penetration, respectively. As shown in Table 7.8, the economic dispatch priority for this case is combined cycle (green), hydro (dark blue), steam (light blue), and gas turbine (pink). The heavyweight lines represent the unit type power output, and the lightweight lines represent the maxima and minima of the committed units. Changes in commitment can be observed in the changes to the maxima and minima.

Over the course of this simulation, the top three unit types (e.g., combined cycle, steam, and hydro) respond to the economic dispatch system and follow load down and then up again. The bulk of the load following is performed by the combined cycle units. During the morning load rise, all units spend a significant amount of time at their maxima.

As penetration increases, the combined cycle commitment was significantly reduced. This is consistent with the results reported in Chapter 6, which showed that wind generation displaces the conventional generation with the highest marginal cost. In addition, the economic dispatch priority order changed. As the combined cycle generation was reduced, the steam generation moved up from third to second priority for the 20/20% wind penetration case.

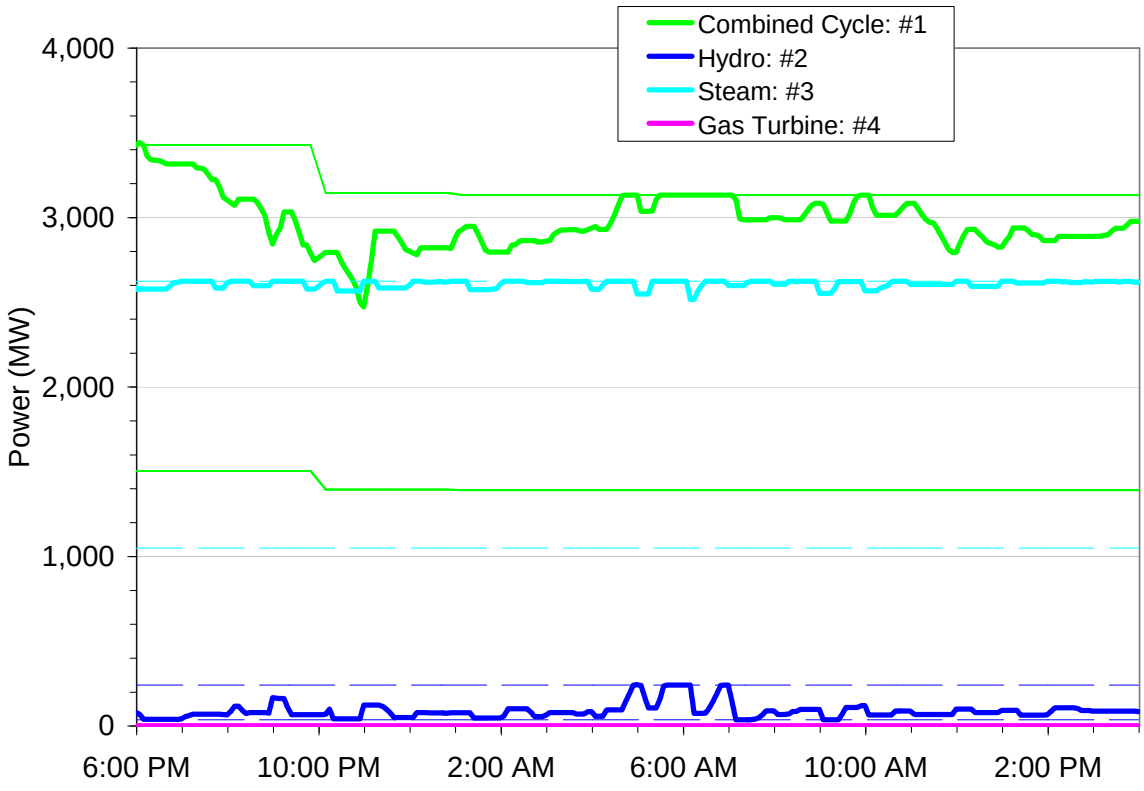


Figure 7.28 Colorado East Dispatch, 10% Wind, Local Priority, October QSS Study Period.

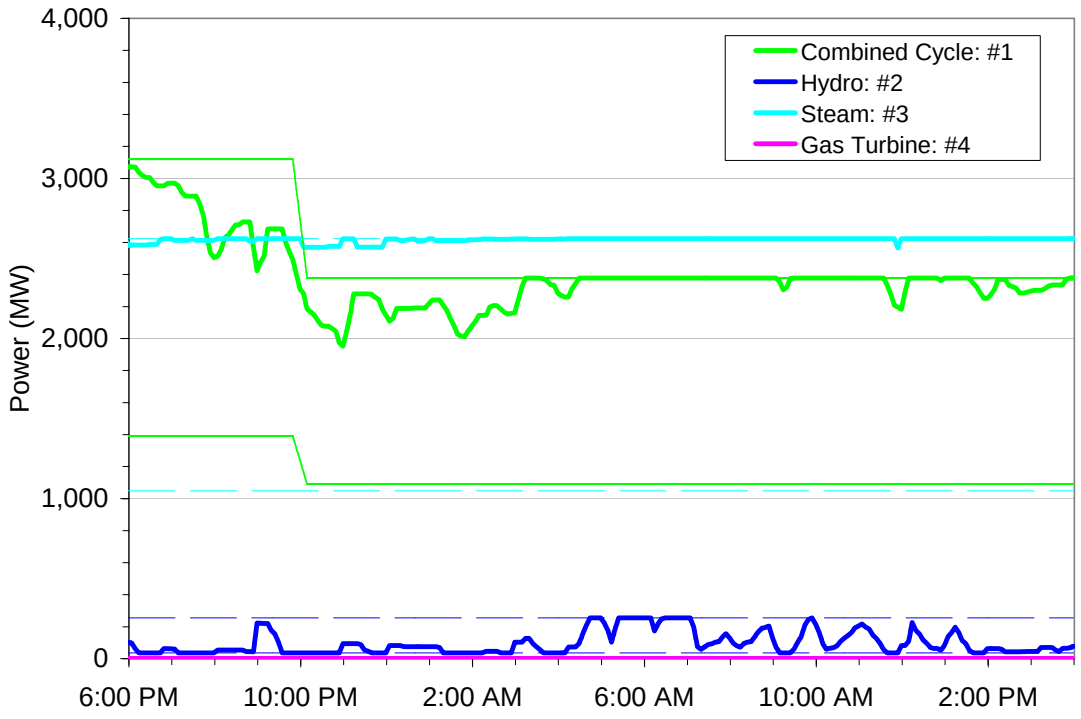


Figure 7.29 Colorado East Dispatch, 20% Wind, Local Priority, October QSS Study Period.

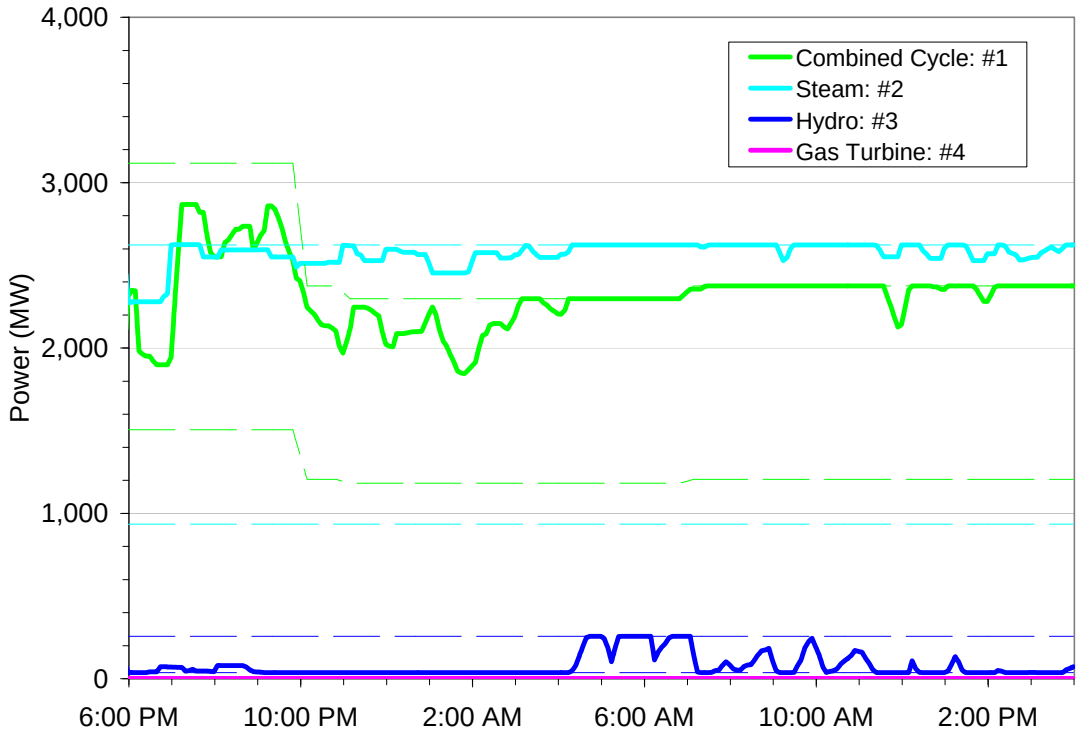


Figure 7.30. Colorado East Dispatch, 20/20% Wind, Local Priority, October QSS Study Period.

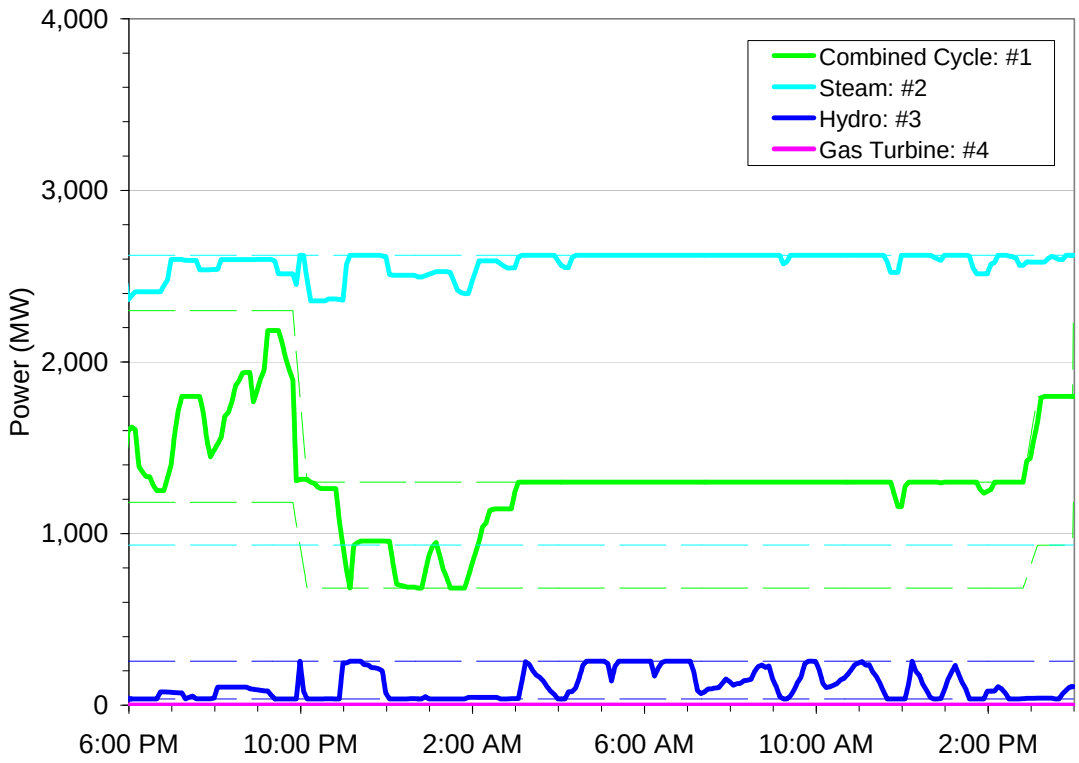


Figure 7.31 Colorado East Dispatch, 30% Wind, Local Priority, October QSS Study Period.

The amount of regulation provided for each penetration level is shown in Figure 7.32 to Figure 7.35. In each figure, regulation is the dark blue line. The conventional generation hourly schedule (pink) and the hourly export schedule (gold) are also shown. The right vertical scale applies to regulation; the left vertical scale applies to the hourly schedules.

As shown in Table 7.4, +/- 116 MW of regulation capability is available in Colorado East during the simulation. For all penetration levels, the regulation that is actually provided is largely driven by the schedule changes, not by the wind and solar variability. As the penetration increases, the schedule changes tend to increase as more flexibility is required of fewer units. Each time the provided regulation hits a capability limit (i.e., +/- 116 MW), it is due to an hourly schedule change.

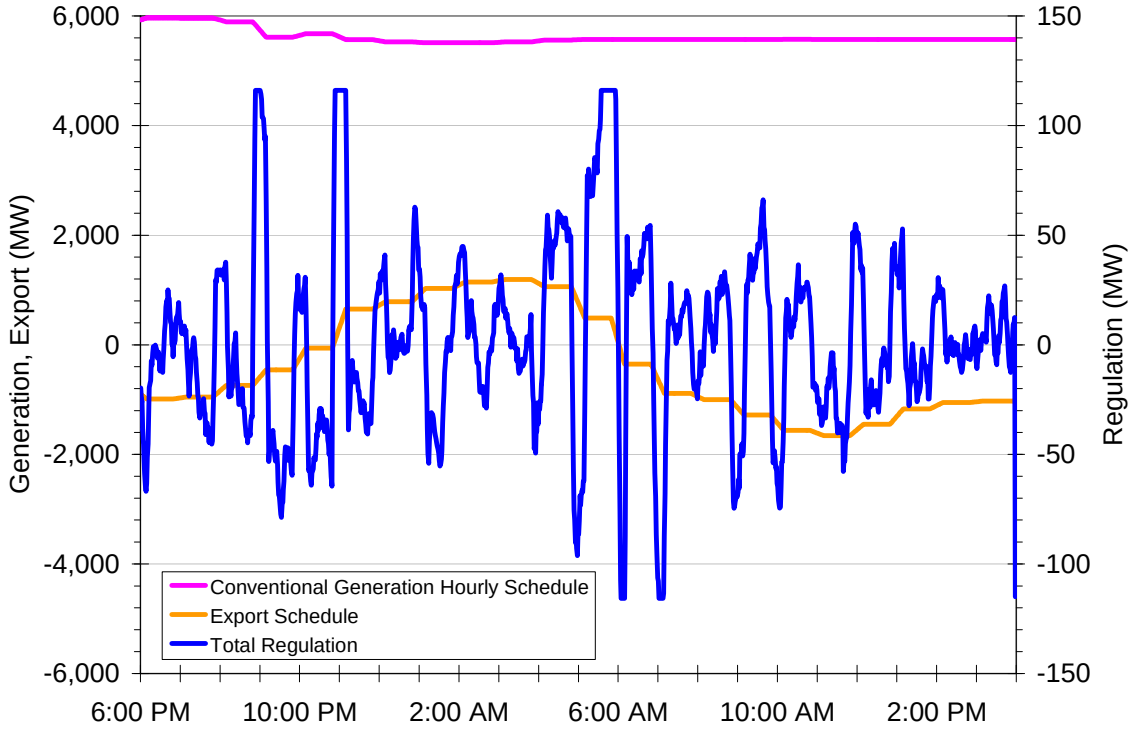


Figure 7.32 Colorado East Regulation, 10% Wind, Local Priority, October QSS Study Period.

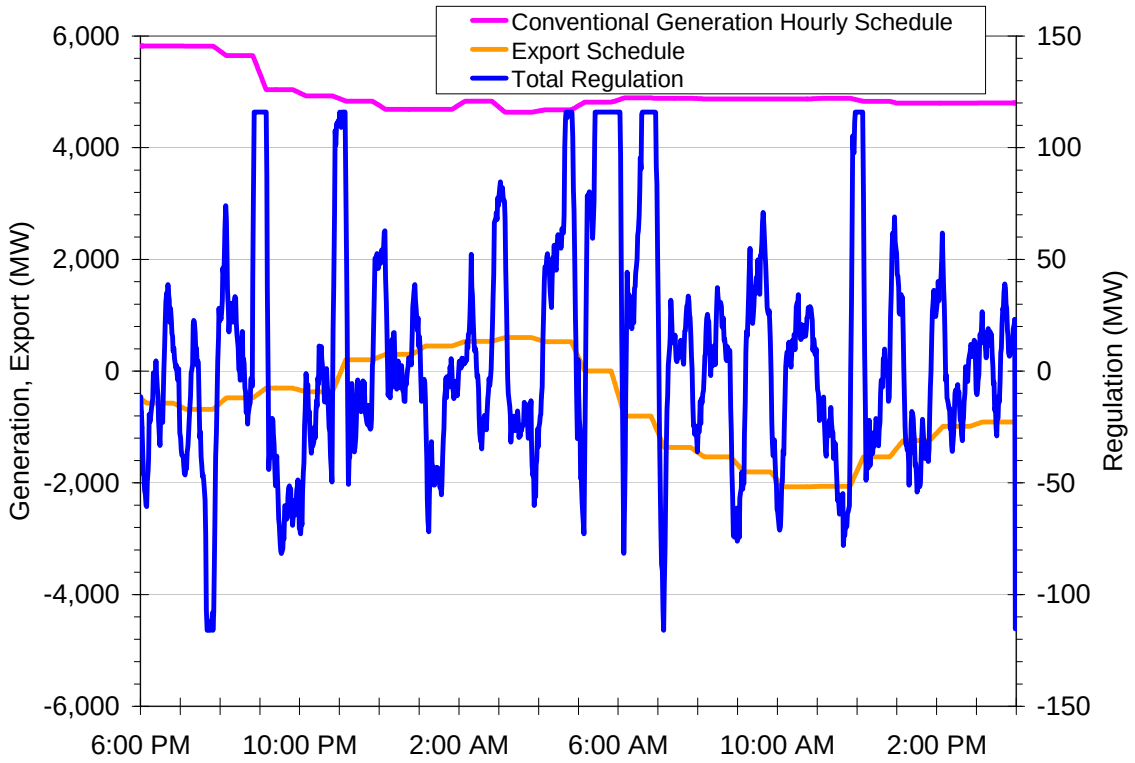


Figure 7.33 Colorado East Regulation, 20% Wind, Local Priority, October QSS Study Period.

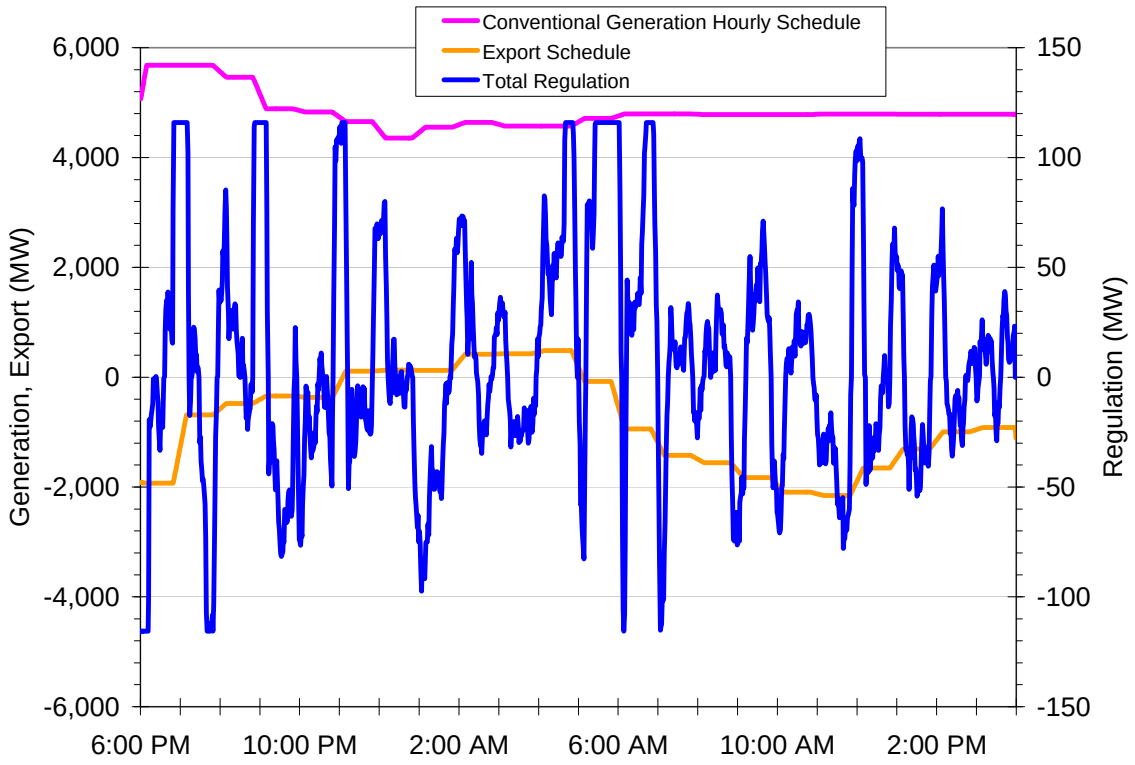


Figure 7.34. Colorado East Regulation, 20/20% Wind, Local Priority, October QSS Study Period.

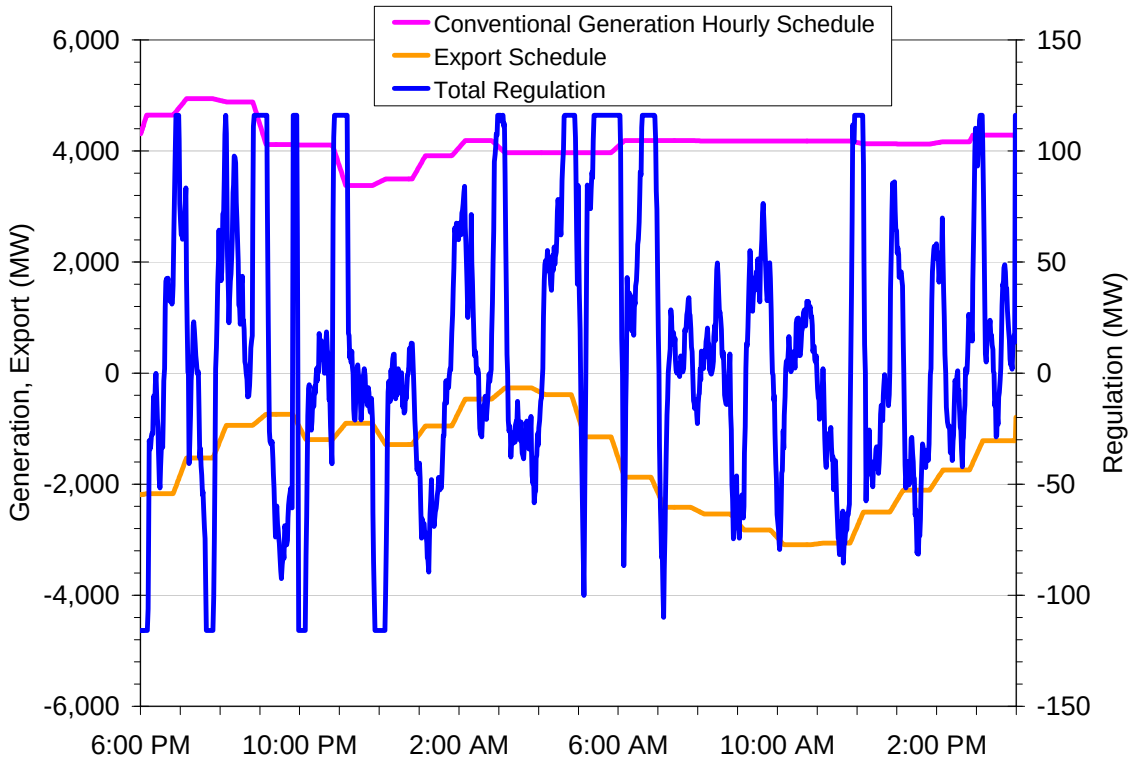


Figure 7.35 Colorado East Regulation, 30% Wind, Local Priority, October QSS Study Period.

The number of minutes that the Colorado East regulation is at its maximum or minimum is shown in Table 7.10. As penetration increases, the amount of time at the maximum or minimum increases.

Some of these events result in ACEs, as shown in Figure 7.36. This figure shows the Colorado East ACE for the Local Priority scenario with various levels of wind penetration. The red line represents 10% wind penetration, the green line represents 20% wind, the light blue line represents 20/20% wind, the dark blue line represents 30% wind, and the black lines represent the approximate L10 limits. These L10 values were used to identify potential CPS2 violations.

A positive ACE signal means that generation exceeds net load, and the actual export will exceed the export schedule. A negative ACE signal means that net load exceeds generation, and the actual export will fail to meet the export schedule. The two black lines represent the approximate L10 limits (Table 7.5) that indicate a potential CPS2 violation. As with the regulation itself, the ACE is largely driven by the hourly generation and export schedule changes, not by the wind and solar variability.

Table 7.10. Colorado East Regulation at Capability Limits.

	Minutes at Maximum	Minutes at Minimum
10% Wind	53	13
20% Wind	111	8
20/20% Wind	109	30
30% Wind	155	57

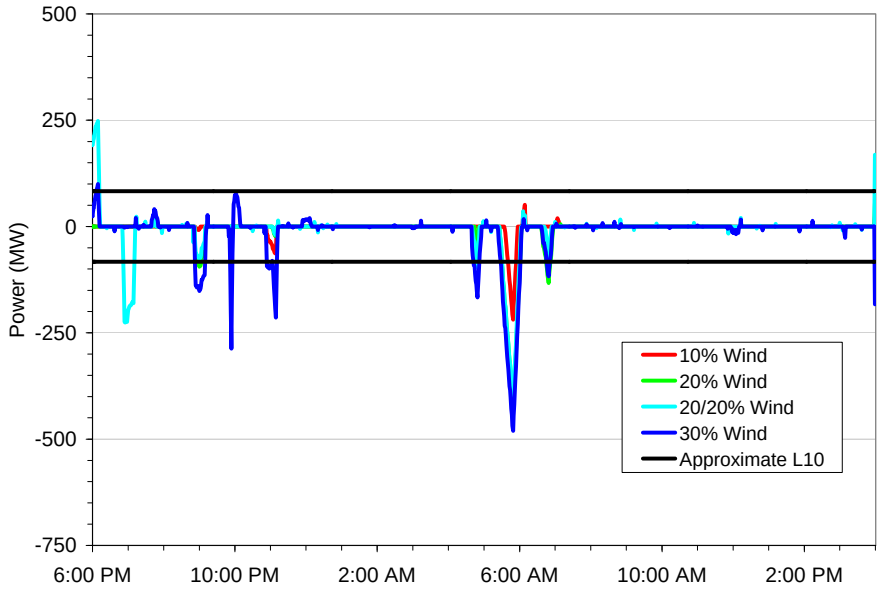


Figure 7.36 Colorado East ACE, All Penetration Levels, Local Priority, October QSS Study Period.

The impact of an imperfect wind forecast and the hourly schedule on both the duty imposed on the economic dispatch units and the required regulation was also investigated.

Two additional QSS simulations were performed, both with 30% wind penetration and the Local Priority scenario. The first QSS simulation implemented the hourly generation and export schedules using a +/- 30 minute ramp around the hour. These smoother schedules approximate a continuous schedule. Note that discontinuities remain at 30 minutes after the hour.

All of the QSS simulations described above used the MAPS boundary conditions for cases with the state of the art (SOA) forecast (e.g., L30R). The second, exploratory QSS simulation used the MAPS boundary conditions from the perfect forecast, or L30P, production simulation case of Chapter 6.

Figure 7.37 shows the Colorado East dispatch with the continuous generation and export schedules, and 30% wind penetration. In comparison to Figure 7.31, the continuous schedule requires less movement from the economic dispatch units. Since it is only approximate, some of the discontinuities at 30 minutes past the hour can be observed. The most noticeable occurs at 9:30 a.m.

Figure 7.38 shows the Colorado East regulation with a continuous schedule, and 30% wind penetration. In comparison to Figure 7.35, the regulation requirement on the hour is significantly reduced.

Figure 7.39 shows the Colorado East dispatch with the perfect forecast, and 30% wind penetration. Since the actual wind was much less than the forecasted wind, the perfect forecast resulted in more combined cycle units committed across the board in comparison to Figure 7.31.

Figure 7.40 shows the Colorado East regulation with the perfect forecast, and 30% wind penetration. In comparison to Figure 7.35, the regulation requirement on the hour is again reduced

The number of minutes that the Colorado East regulation is at its maximum or minimum for the two sensitivity cases, as well as the original 30% wind penetration case, are shown in Table 7.11. Both a perfect forecast and a continuous schedule reduce the duty on the regulation units.

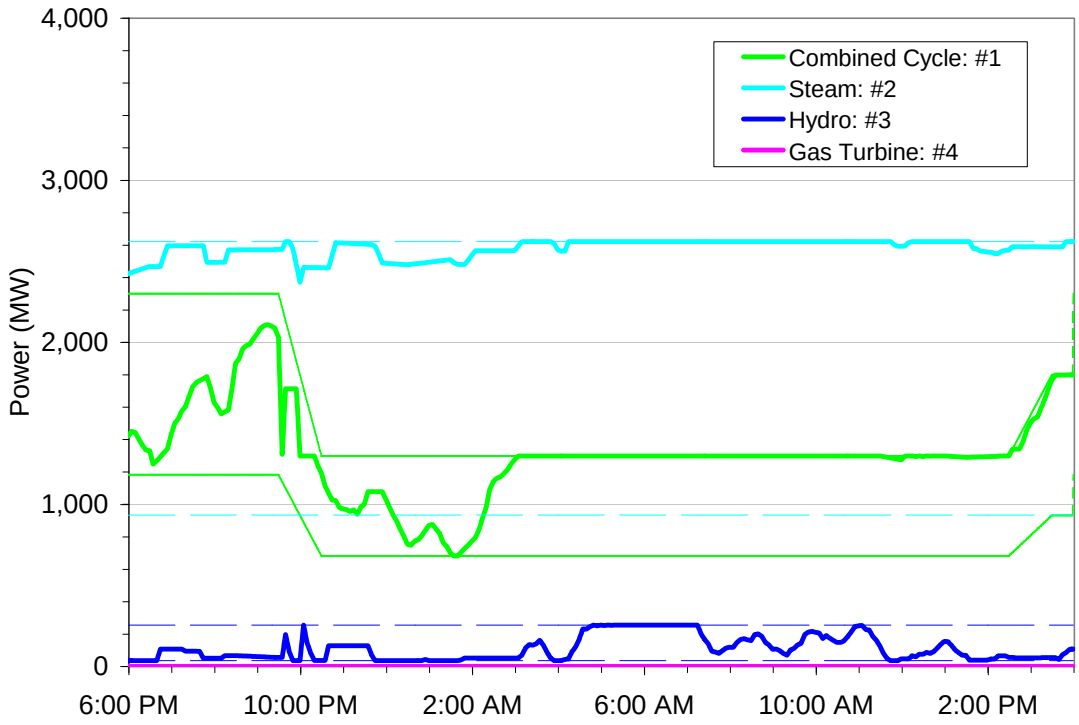


Figure 7.37 Colorado East Dispatch, Continuous Schedule, 30% Wind, Local Priority, October QSS Study Period.

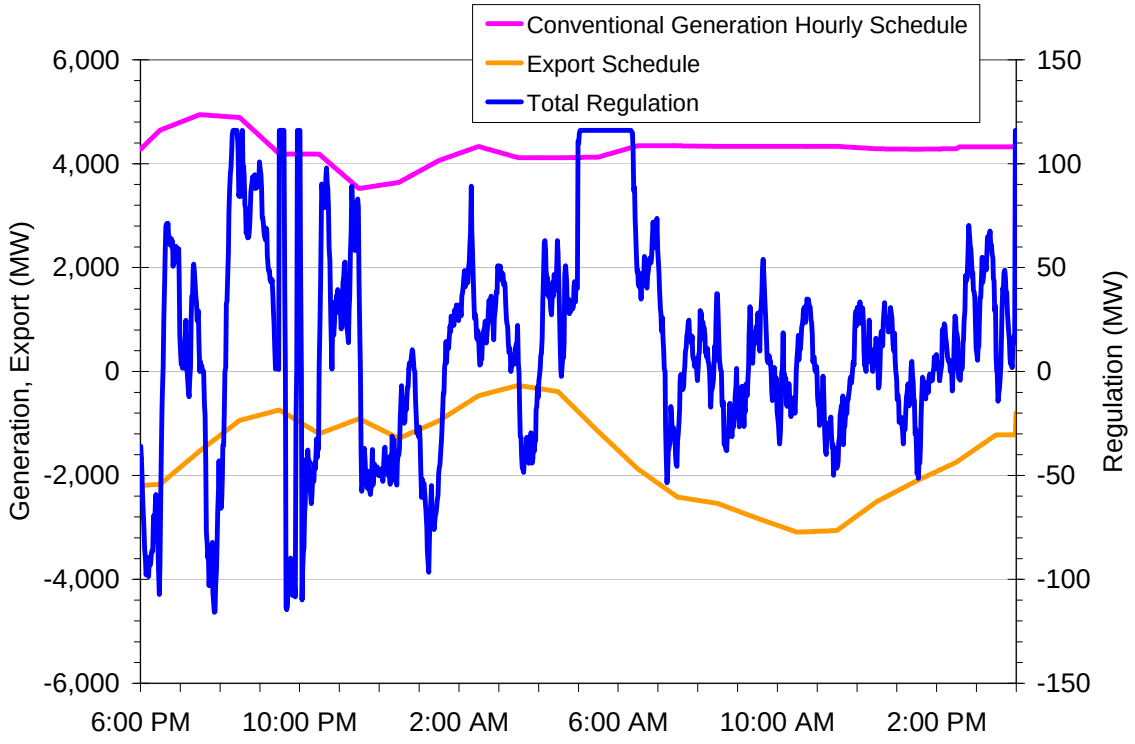


Figure 7.38 Colorado East Regulation, Continuous Schedule, 30% Wind, Local Priority, October QSS Study Period.

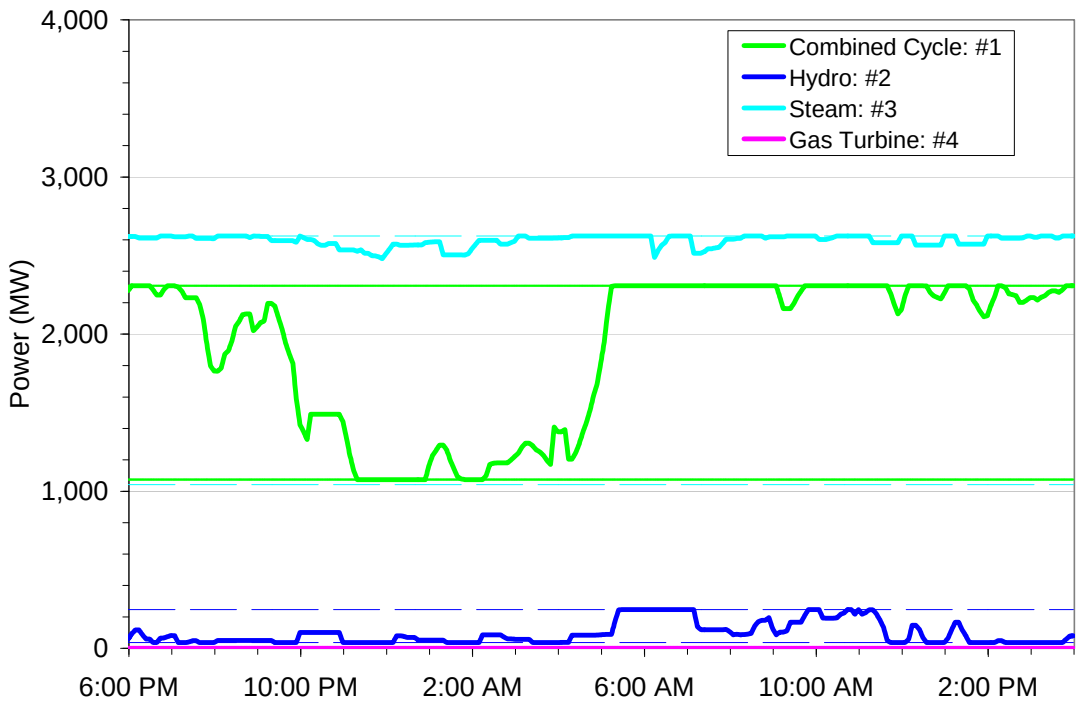


Figure 7.39. Colorado East Dispatch, Perfect Forecast, 30% Wind, Local Priority, October QSS Study Period.

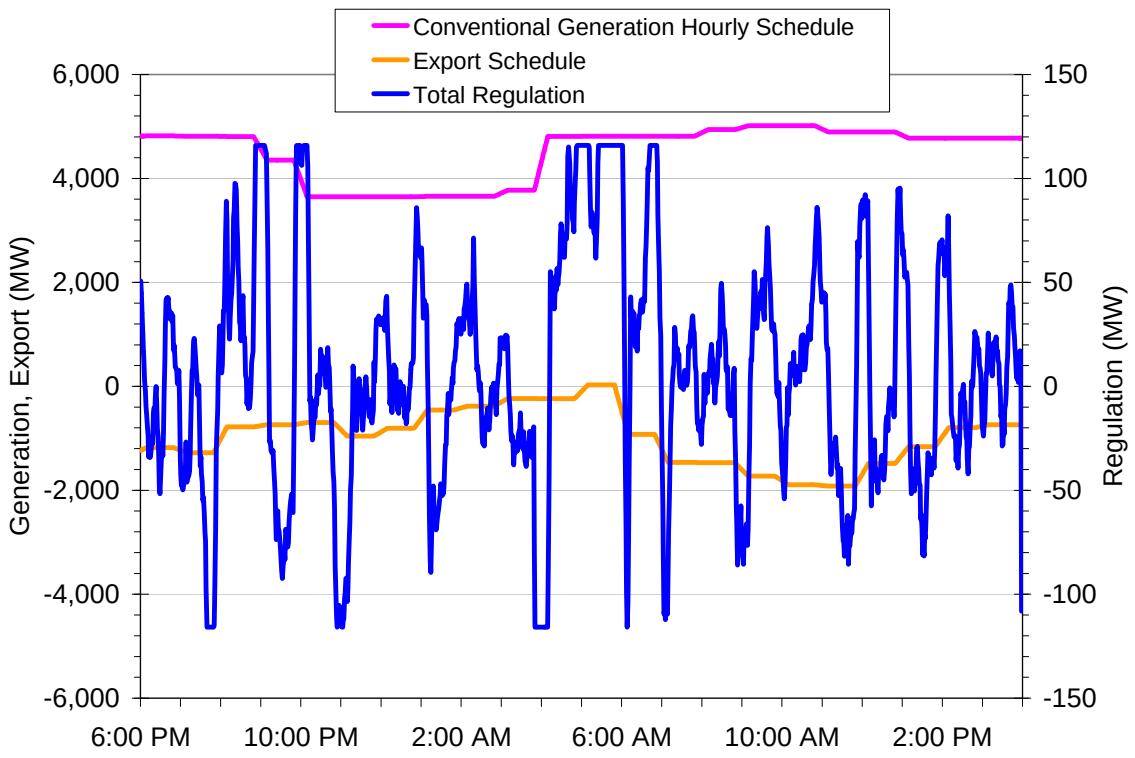


Figure 7.40. Colorado East Regulation, Perfect Forecast, 30% Wind, Local Priority, October QSS Study Period.

Table 7.11. Colorado East Regulation at Capability Limits for Sensitivity Cases.

	Minutes at Maximum	Minutes at Minimum
30% Wind, SOA Forecast, Hourly Schedule	155	57
30% Wind, Perfect Forecast, Hourly Schedule	97	35
30% Wind, SOA Forecast, Continuous Schedule	105	1

The duty applied to the economic dispatch units under various scenarios was also explored. Figure 7.41 shows the combined cycle unit output (dark blue line) on economic dispatch for the 30% wind penetration, Local Priority scenario with the SOA forecast. The red line represents a 1-hour rolling average of the combined cycle generation. The difference between the actual output and the rolling average output is represented by the green line. This difference is a measure of the amount of the sub-hourly duty, MW, applied to the combined cycle units. However, the same sub-hourly duty applied to a lot of units is less challenging than when it is applied to a few units. In this simulation, the combined cycle commitment decreased by about 1,000 MW between 6 p.m. and midnight, but the sub-hourly MW duty remained about the same. Therefore, this duty is per unitized on the committed range (i.e., maximum output minus minimum output) for the subsequent figures.

Figure 7.42 shows this per unit usage metric for all penetration levels, with the SOA forecast. The dark blue line represents 10% wind, the red line represents 20% wind, the light blue line represents 20/20% wind, and the green line represents 30% wind. As penetration increases, the duty required of the BOP generation increases.

Figure 7.43 shows this per unit usage metric for the two sensitivity cases, as well as the original 30% wind penetration case. The green line represents the original 30% wind penetration case with the SOA forecast and hourly schedule changes. The dark blue line represents the sensitivity case with the perfect forecast, and the red line represents the sensitivity case with the continuous schedule. Both sensitivity cases apply less duty to the economic dispatch units.

This time period was chosen because of the high wind forecast error at mid morning. However, as observed above, the challenging period of operation turned out to be several hours earlier in the morning load rise.

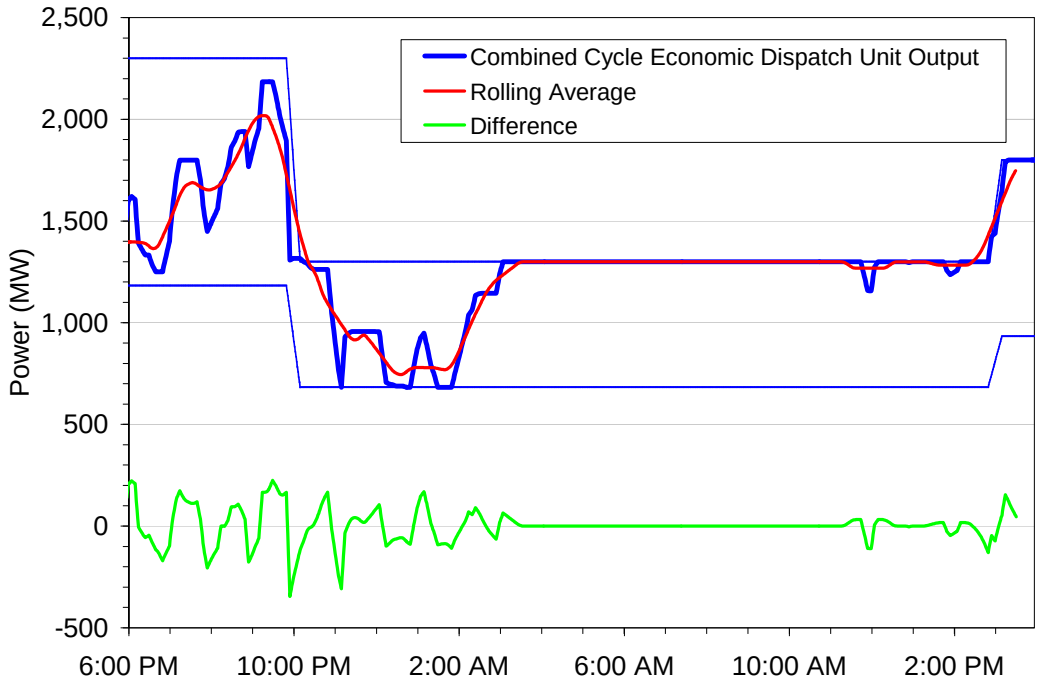


Figure 7.41. Colorado East Combined Cycle Usage, 30% Wind, Local Priority, October QSS Study Period.

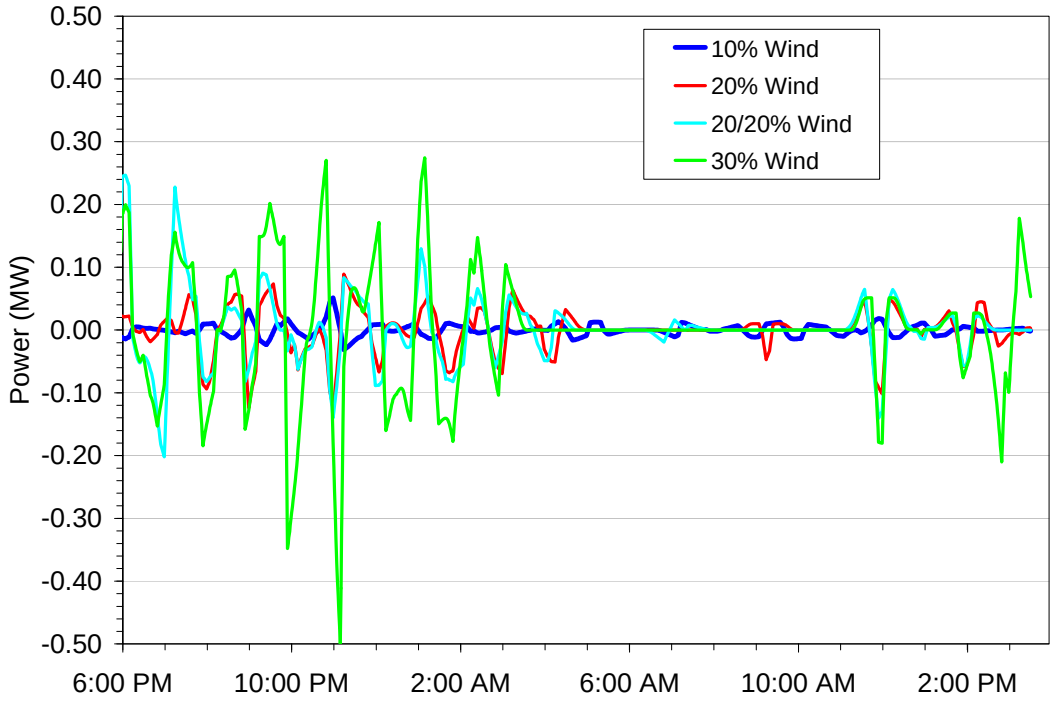


Figure 7.42Colorado East Combined Cycle Usage, All Penetration Levels, Local Priority, October QSS Study Period.

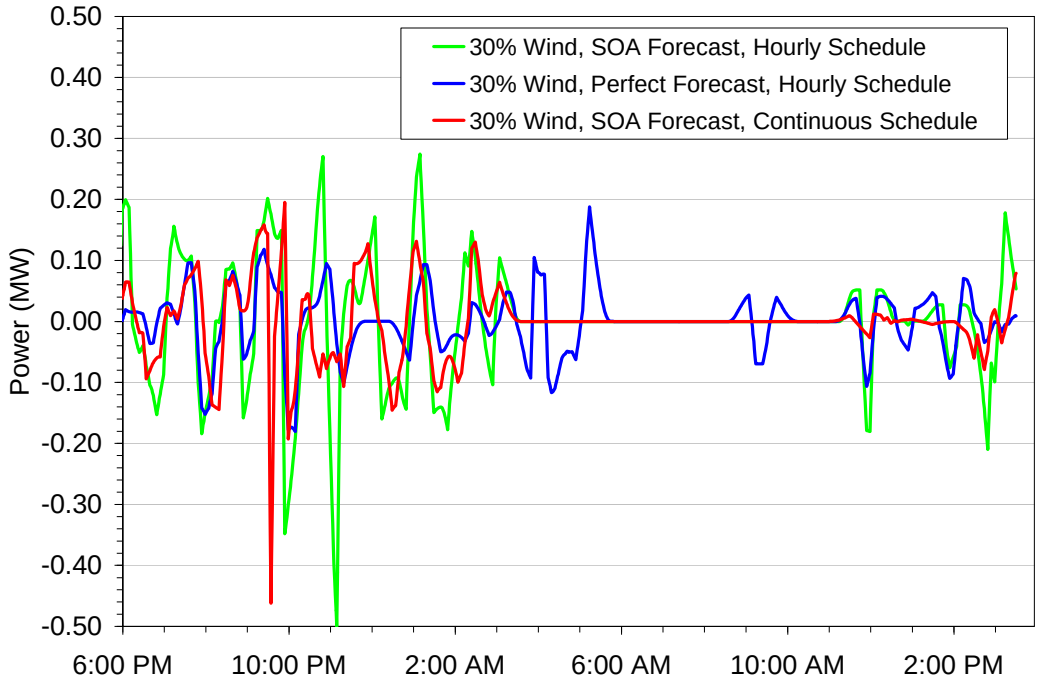


Figure 7.43. Colorado East Combined Cycle Usage, Forecast and Schedule Variations, 30% Wind, Local Priority, October QSS Study Period.

7.2.7 Mitigation

The QSS simulations showed varying ACE levels, some of which exceeded the approximate L10 limits and indicated a potential CPS2 violation. Mitigation of the ACE could be achieved by a combination of wind energy curtailment and load participation (or demand side management, DSM). Wind curtailment can be an effective response to a positive ACE signal, which occurs when generation is greater than load and results in the actual export exceeding the scheduled export. Curtailment of wind generation in response to an AGC command makes wind generation a contributor to system down reserve. Load participation addresses a negative ACE signal, which occurs when load exceeds generation and results in the actual export failing to meet the export schedule.

The amount of wind curtailment required to reduce the positive Arizona ACE to zero was calculated for the April QSS cases with 10%, 20%, 20/20% and 30% wind penetration (Local Priority scenario, SOA wind forecast, hourly schedule changes). This defines the maximum wind curtailment for the given study period. It was calculated as the energy, in MWh, under the positive ACE signal. In addition, the maximum ramp down required was calculated as the largest 1-minute change in ACE. The maximum ramp down capability of the wind plants was assumed to be 10%/minute on the MW rating. These results are summarized in Table 7.12.

The wind curtailment for this single worst event in 3 years of data constituted far less than 1% of Arizona's annual wind energy production for all penetration levels. The maximum ramp down required was within the wind plants' capability.

Table 7.12. Maximum Arizona Wind Curtailment for Various Penetration Levels, Local Priority, April QSS Study Period.

	10%	20%	20/20%	30%
Arizona Wind Energy Curtailed, MWh	123	75	162	294
Annual Arizona Wind Energy, GWh	8,048	14,569	14,569	21,138
Maximum Wind Curtailment Ramp Down, MW/min	89	80	131	134
Total Arizona Wind Plant Rating, MW	2,850	5,250	5,250	7,710
Maximum Ramp Down Capability, MW/min	285	525	525	771

The amount of load participation required to bring the negative Arizona ACE to zero was calculated for the October QSS cases with 10%, 20%, 20/20% and 30% wind penetration (Local Priority scenario, SOA wind forecast, hourly schedule changes). This defines the maximum load participation for the given study period. It was calculated as the energy, in MWh, under the negative ACE signal. These results are summarized in Table 7.13. In contrast to curtailment of wind generation, response of load to an AGC command makes the load response a contributor to system up reserve.

The load participation for the single worst forecast error in 2006 constituted far less than 1% of Colorado East's annual load energy for all penetration levels.

Table 7.13 Maximum Colorado East Load Participation for Various Penetration Levels, Local Priority, October QSS Study Period.

	10%	20%	20/20%	30%
Colorado East Load Energy Participation, MWh	59	198	239	322
Annual Colorado East Load Energy, GWh	61,372	61,372	61,372	61,372

7.2.8 Summary

The QSS results showed no significant sub-hourly system performance concerns, and no hourly performance concerns at all. Thus, the production simulation results which identified an acceptable hour to hour generation dispatch also identified a dispatch capable of responding successfully to sub-hourly variations.

In general, the 10% and 20% wind penetration cases exhibit similar characteristics, and the 20/20% and 30% wind penetration cases exhibit similar characteristics. Thus, the impact of increasing wind penetration has two aspects – wind penetration in the study

footprint, and wind penetration outside the study footprint. With low levels of wind and solar penetration outside the study footprint, exports from the study footprint could increase. With higher levels of penetration outside the footprint, exports were constrained.

The hourly generation and export schedules drive the regulation requirements and AGC performance violations more than the wind and solar variability. As penetration increases, the magnitude and frequency of the hourly schedule changes also increases. Therefore, the regulation requirements will increase at higher levels of penetration. However, a more frequent or even continuous generation and export schedule would improve performance for units on both regulation and economic dispatch.

Control area consolidation, or cooperation between areas, significantly improves the system's ability to respond to hourly schedule changes and sub-hourly variability. As a result, high levels of wind and solar penetration have less impact on larger control areas.

Uncertainty due to forecast error has an impact on both commitment and dispatch. As such, improved forecasting can reduce the maneuvering required of the balance of portfolio generation to follow net load and to provide regulation.

Mitigation of the area control errors can be achieved with a combination of wind curtailment when generation exceeds load, and load participation when load exceeds generation. This approach makes both wind and load contributors to system reserves. Neither appears to have significant technical or economic hurdles.

7.3 Variability Impacts on Reserves

In the following four sections, we will examine the relationship between variability of load and wind, and how that variability affects system reserve requirements. The discussion here is aimed primarily at understanding how much maneuvering room is required of on-line generation to handle the changes that occur within each hour. The discussion is therefore focused on variability, rather than uncertainty. However, to some extent these two concerns are interrelated aspects of incorporating variable renewables. Specifically, day-ahead forecast error is the major contributor to uncertainty. Day-ahead forecasts are included in unit commitment decisions. The discussion of Section 6.2.1 is devoted to exploring strategies for managing uncertainty, as manifested in wind forecast errors. Ultimately, the difference between forecasted and actual wind and load, and the unit commitment strategies used to deal with those differences will have a major impact on the resources available in real-time to respond to variability. This section is dedicated to building understanding of the requirements for sub-hourly reserves and to developing useable rules for operation.

Initially, we will examine load and wind variability in the 10-minute time frame, and show how that relates to the existing practice of carrying 3% of system load for spinning reserve. We will show statistically that the 3% of load reserve rule makes sense in the context of load variability, and that extensions of that rule to consider wind variability are reasonable. We will show that in broad, study area terms, the 3% rule is roughly adequate to handle wind and load variability, but that enhancements are desirable. We will show that that a fraction of the reserves, amounting to about 1 standard deviation of the expected 10-minute variability, should be allocated to the fastest acting reserves: regulation.

In the next section, we will revisit the MAPS simulations of Chapter 6, and QSS time simulations presented in Sections 7.2.5 and 7.2.6 in the context of reserves. Finally, we will explore means to take wind variability into account in allocation of system reserves during operation. This will result in rules that are simple enough to be practical in the operating environment. The work will show that simple rules, for example carrying 3% of load PLUS 5% of wind production (*not* installed MW), result in generally satisfactory performance.

7.3.1 Load and Net Load Variability

In Section 7.1, 10-minute load and net load variations were presented. Since existing reserve rules (the 3% of load rule) are based on load level, it is useful to examine system variability in that light. In Figure 7.44 the variability of wind power in the study footprint is shown as a function of wind power. The three traces in the figure each include ten data points. The data for each of these points are from statistical analyses of 1/10th of the wind data for the year – 876 hours (5256 data points). Consequently, each point is the standard deviation of the 10-minute deltas for all the hours in that bucket (y value) plotted versus the average wind power of all the wind data in that bucket (x value). The callout on the plot indicates one example. The data are not, therefore, equidistant on the x axis. Further, individual 10-minute samples of wind power less than the left-most point, or greater than the right-most point exist, and are reflected in the average data for their respective decile points. Superimposed on the curve are dotted orange lines that roughly capture the 30% wind variability curve in two piecewise continuous linear segments. The slope of the first part shows an increase in variability with wind of about 3.3% per unit wind. The second flat section is from about 8000 MW, or about 30% of nominal maximum wind. This piecewise curve fit will be revisited later in this chapter.

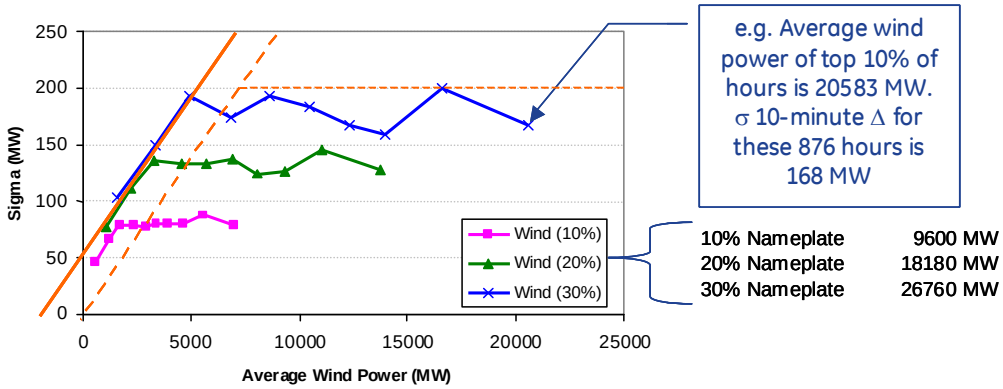


Figure 7.44 Local Priority Case – Wind Variability for 2006

While this result is of interest to understanding system needs, the variability of wind power is only part of the problem. Preceding sections have shown that the challenge for the system is to operate with the net load. Figure 7.45 shows the net load[3] variability of the study area for the three local priority scenarios. The figure also includes the variability of the load alone (the orange trace with circular symbols). As with Figure 7.44, the data are analyzed in 10 buckets of 876 (1/10th of the year) hours. Thus, for example, the average net load power of the 2nd to top 10% of hours (arrow in figure) for the L30 case is 34,821 MW. The standard deviation, σ, of the 10-minute delta for these 876 hours is 374 MW.

As expected, the variability increases with increased penetration. In particular, periods of low net load tend to have considerably more variability. These, of course tend to coincide with periods of higher wind. Indeed, for the 30% case, roughly half of the year has net load less than the system minimum load (as indicated with the vertical orange line). This is consistent with load duration curve of Figure 4.17.

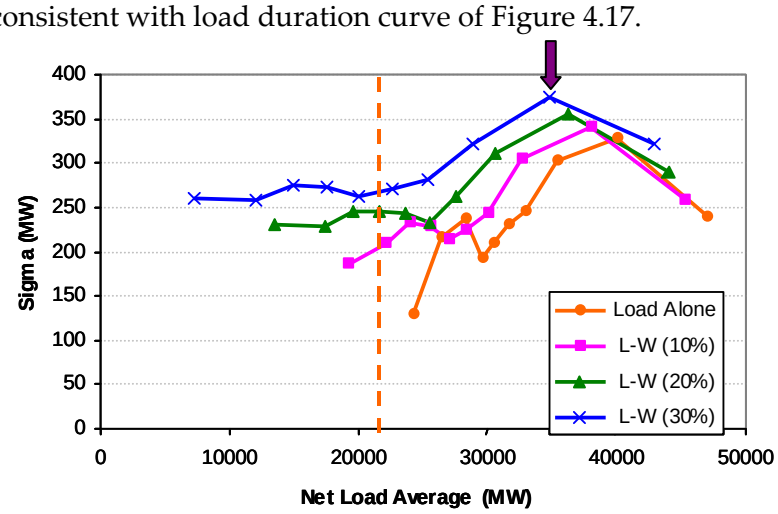


Figure 7.45 Local Priority Net Load Variability for 2006

[3] Throughout the balance of this section, we have neglected the contribution of solar to variability. Net load here refers to load minus wind power. The concepts presented conceptually extend to variability from solar and other variable generation resources.

These traces provide a better sense of how variable the system will tend to be compared to the total non-renewable generation that needs to be on-line to serve system net load. Clearly variability at low levels of net load are noticeably greater than the variability at just low system load.

The sensitivity of net load variability and wind variability to scenarios is shown in Figure 7.46. In this figure, the wind variability shapes vary with spatial diversity. This is most evident in the wind variability for the Mega Project scenario. The Mega Project profile, with clear relative maxima at mid power range, is similar to that observed in a single plant.

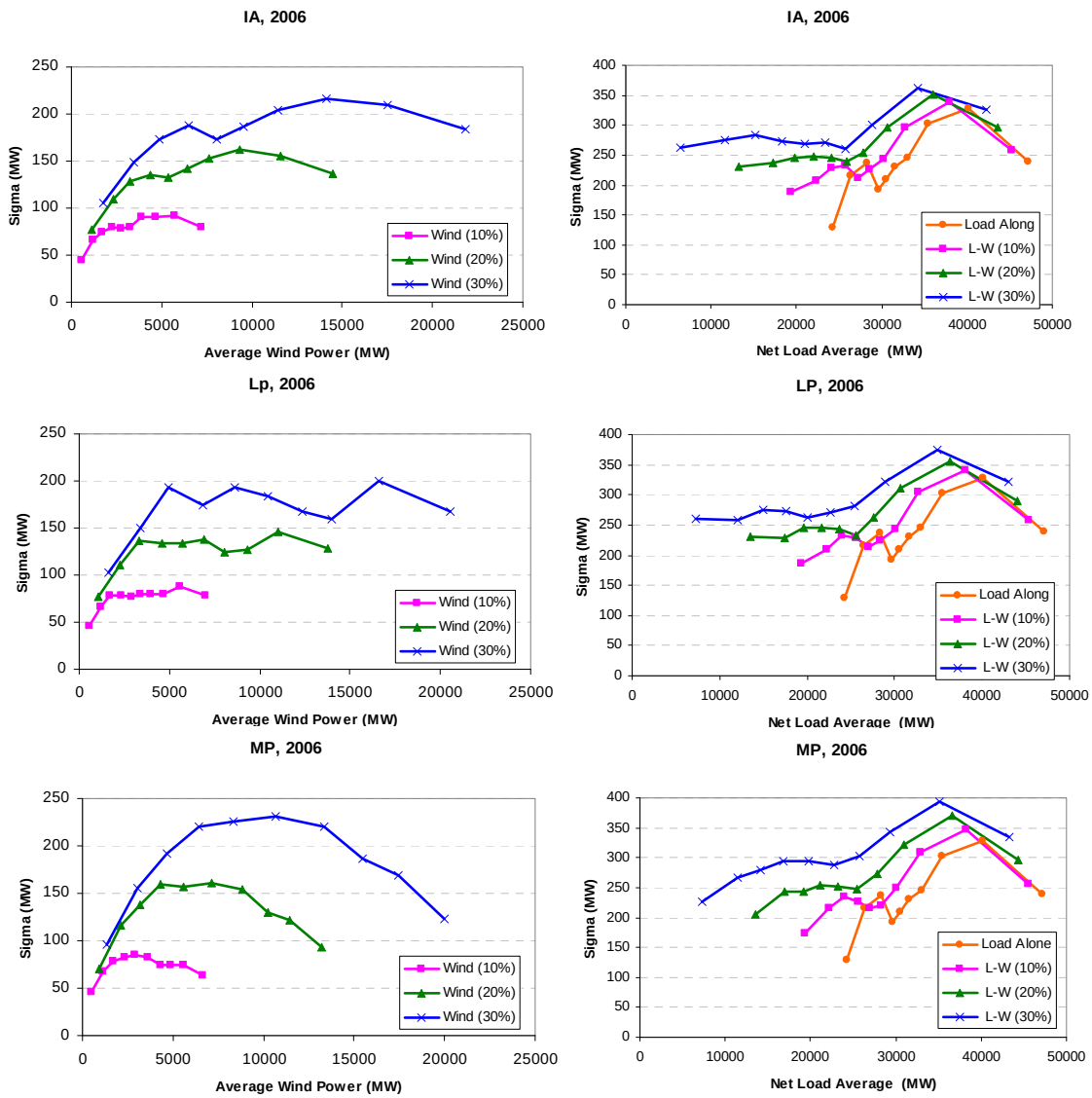


Figure 7.46 10-minute Variability: Wind and Net Load - 3 Scenarios

Figure 7.47 shows the same information as the left side of the preceding figure. But on the right hand side, the variability, Δσ, is normalized by the installed nameplate MW of wind, which is summarized in the embedded table with each plot. It is interesting to note that, for the in-area and local priority scenarios, the normalized variability drops with increased penetration. This is a consequence of increased spatial diversity as more wind plants are added. This effect is least observable in the mega project scenarios, because the wind generation additions progressing from 10% to 20% to 30% tend to be added in essentially the same relatively tight geographic area. So broadly, these curves show that (a) at higher penetration there is less wind variability in a normalized sense, and (b) for wider spatial distribution, the overall wind variability is less dependent on wind level (i.e. the curves get flatter).

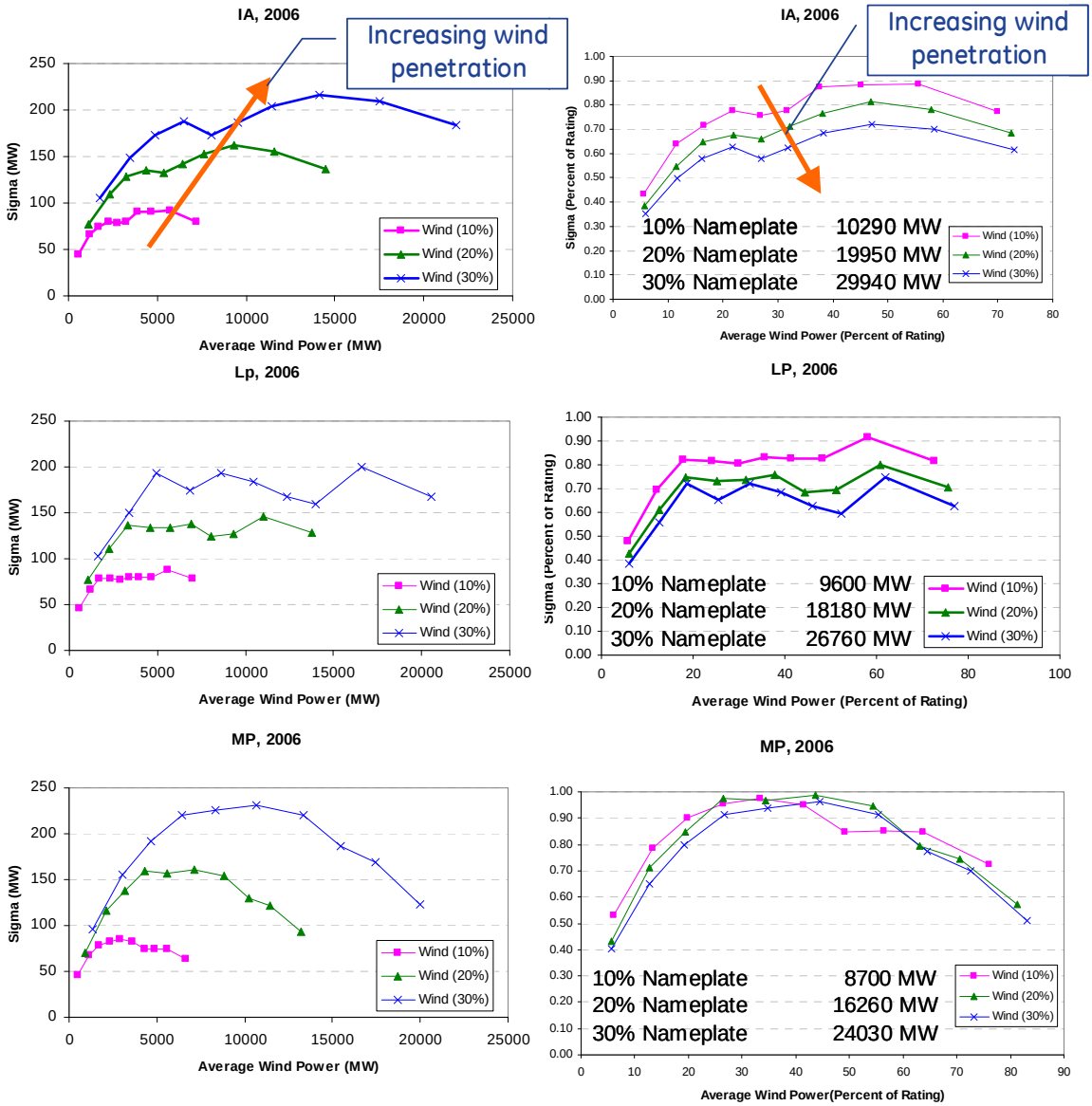


Figure 7.47 Wind Variability: Normalized to Installed Rating to Installed Rating

The behaviors become more interesting as individual areas are examined. The wind and net load variability of Arizona and Wyoming are shown in Figure 7.48. Consistent with observations from hourly analysis, at the area (or state) level, wind impact is more observable. In a very high wind system like Wyoming, wind dominates. This is apparent in that the net load variability curves are essentially mirrored and shifted from the wind curves.

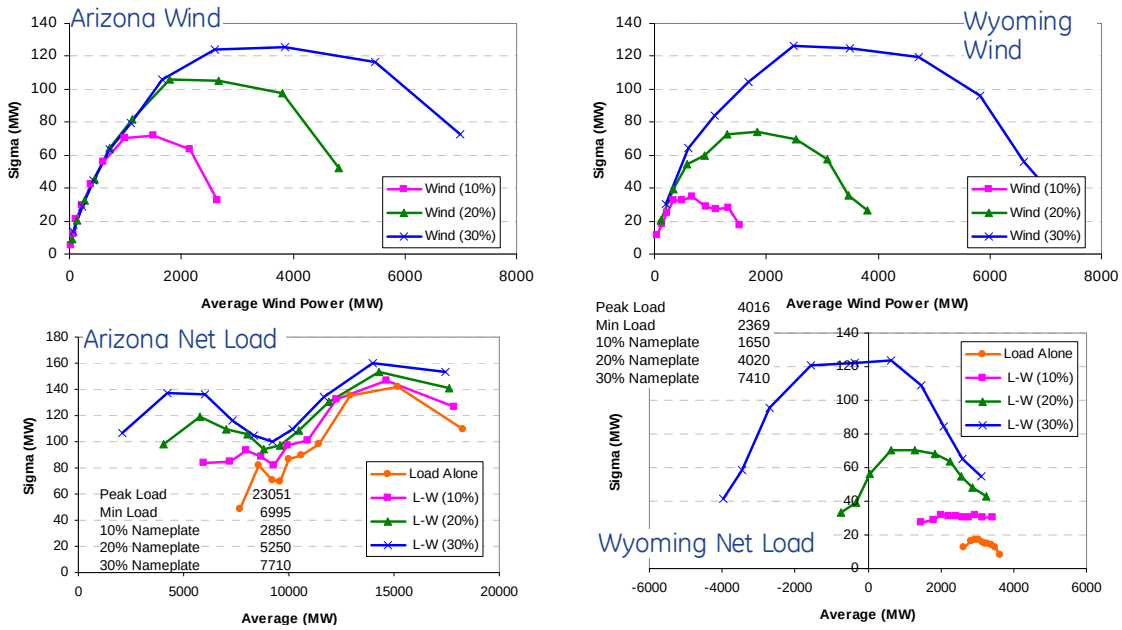


Figure 7.48 Arizona and Wyoming: Average (MW) vs. Sigma of 10-min Delta (MW)

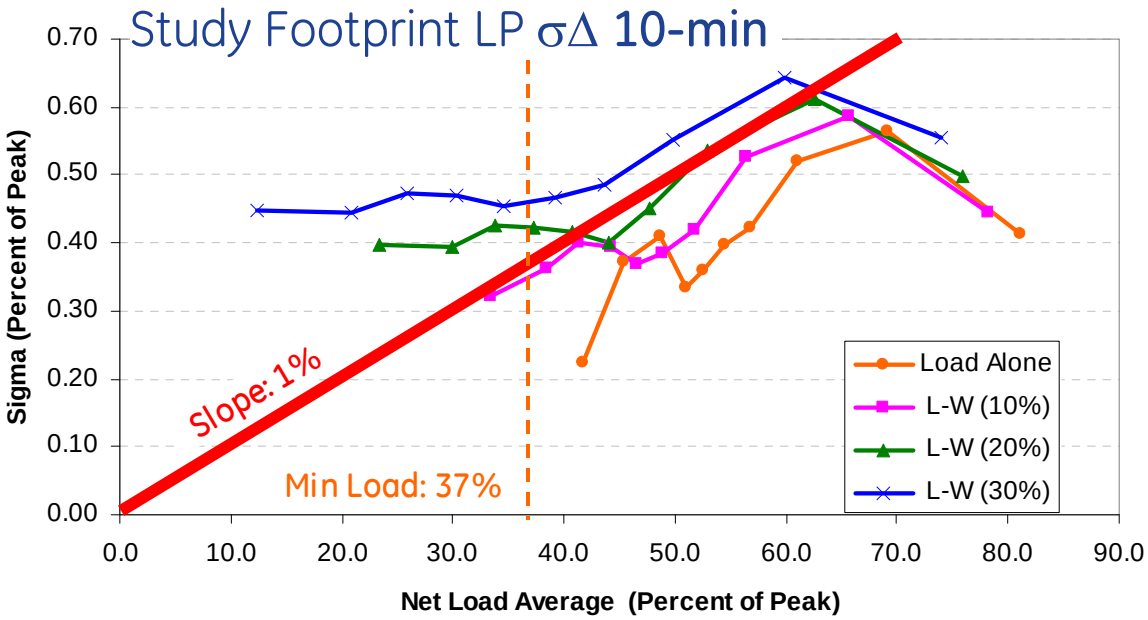
7.3.2 Relationship to Existing Reserve Rules

The fact that system variability increases with load is no surprise to system operators. The development of reserve rules that are a function of system load is partially a reflection of that knowledge.

In Figure 7.45 the increase in system variability, as measured by the 10-minute $\Delta\sigma$ is apparent in the "Load Alone" trace. On closer inspection, for most load levels in the figure, the relationship between variability and load is roughly linear. The exception is at and near system peak loads (on the right hand side of the curve). In Figure 7.49, a simple straight line has been overlaid on the load-alone trace for the study footprint and Arizona. Note that the slope of that line is about 1%. That means that *the statistical expectation of load variability that needs to be met by increased generation maneuvering, is about 1% of load*. Of course, as the curve (and the other analysis leading to this curve) shows, load variability is statistical. The variability is roughly normal. A rule that covers most variability is needed. There is precedence for using 3 standard deviations to cover the majority (99.7%) of expected variability. Interestingly, this means that 3σ of the 10-minute Δ is approximately 3% of load. In short, the traditional 3% of load dispatched for spinning reserve, as discussed in Section 6.1 and used throughout the MAPS runs, is

consistent with the concept of managing expected variability with subhourly reserves. The 3% of load rule for dispatch of spinning reserves makes perfect sense in this light.

In the next sections, we will build on the fundamental notion that sub-hourly reserves have historically been allocated to cover expected variation within this time frame.



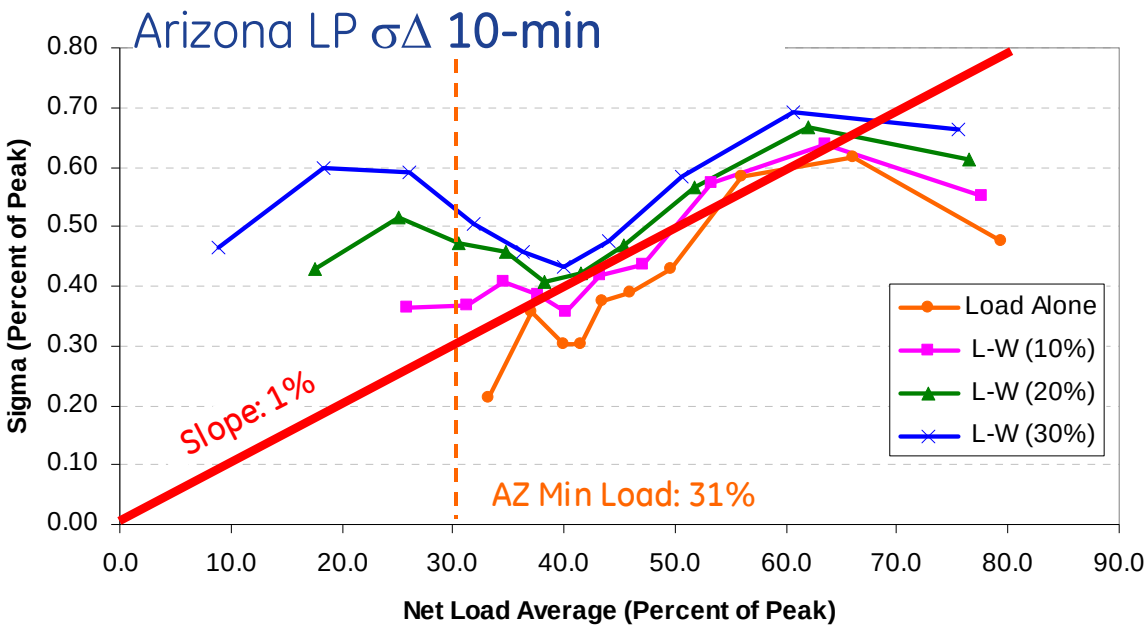


Figure 7.49 Variability and 3% Spinning Reserve Rule

7.3.3 Net Load Variability Relationship to Load and Wind Levels

With the addition of wind (and solar) generation, system variability is driven by two separate, but not necessarily independent phenomena. As shown repeatedly in Chapter 6, system reserves must be provided by resources available under each load and wind condition.

Earlier, the figures of Section 7.3.1 pointed out the change in variability with net load. Here we examine ways to separate the impact of load and wind on that net load variability. In order to do so, some simple relationships between load and wind need to be established.

In Figure 7.50, a load and wind space is presented. The x-axis corresponds to system load. Load varies between a minimum and maximum. At the foot print level, the minimum load is 21,249 MW and the maximum is 58,087 MW (as noted on the figure). Similarly, the wind power varies between zero and a maximum. The maximum for the local priority 30% scenario used throughout the balance of this exercise is 26,760 MW – the total installed nameplate of wind generation in the footprint. The range of load and wind are each divided into 10 equal sized buckets. Consequently, there are 100 combinations of load and wind. The colors indicate net load level, i.e. load minus wind, as listed in the legend. The value (color) at each intersection is the net load for that combination.

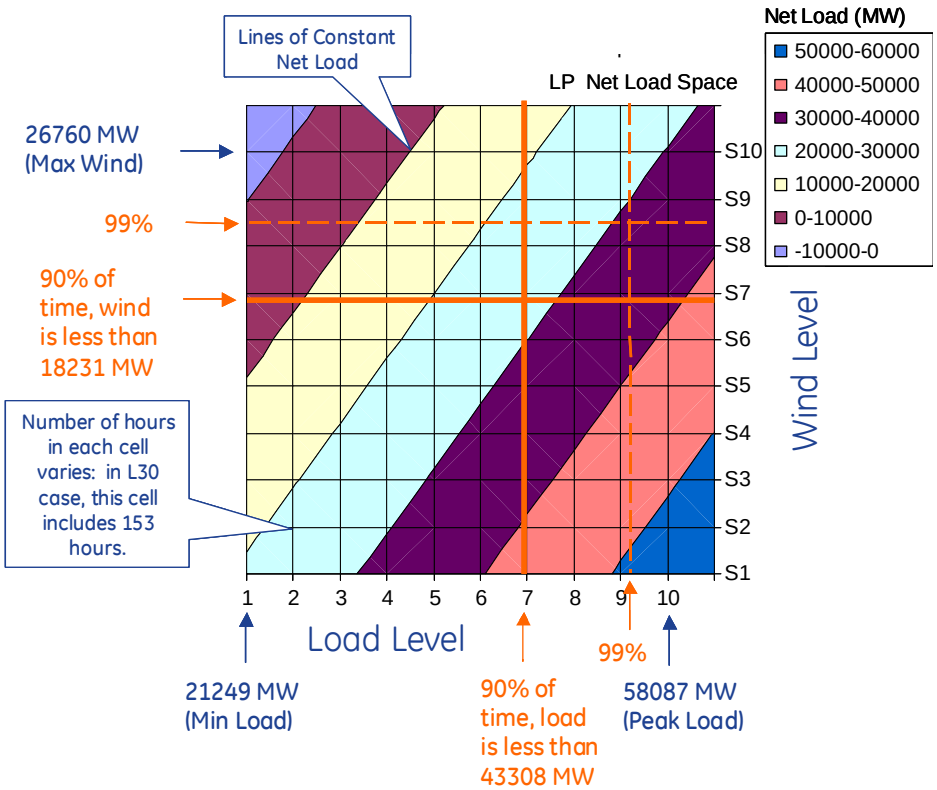


Figure 7.50 Load - Wind - Net Load Relationship for L30 System

This space represents 100 evenly distributed load and wind "cells." They are evenly distributed, in that load and wind levels are divided into 10 equal sized groups from minimum to maximum. It is critical to recognize however, that the system does not reside in each of the 100 cells for the same amount of time. Indeed some cells corresponding to coincident high wind and high load conditions (upper right hand corner) are *never* met (on an hourly basis at least). Thus, it is useful to examine the orange lines on the figure. The solid orange lines represent the 90% upper boundaries for load and wind. That is, the system load and wind are to the left of and below, respectively, these lines 90% of the time. Similarly, the dotted lines are the 99% boundaries. These results are, at first glance, surprising. The reasons for this become more obvious by examining the familiar net load duration curves presented in Figure 7.51. In this net load duration curve, from Figure 4.16, heavy weight lines showing the minimum and maximum system load are drawn. It is this load range that is divided into 10 equal parts for the X axis in the load and wind space of Figure 7.50. The lighter orange lines show that system load is greater than 70% of the *range* from min to max about 10% of the time. This is consistent with the solid vertical orange line in the preceding figure.

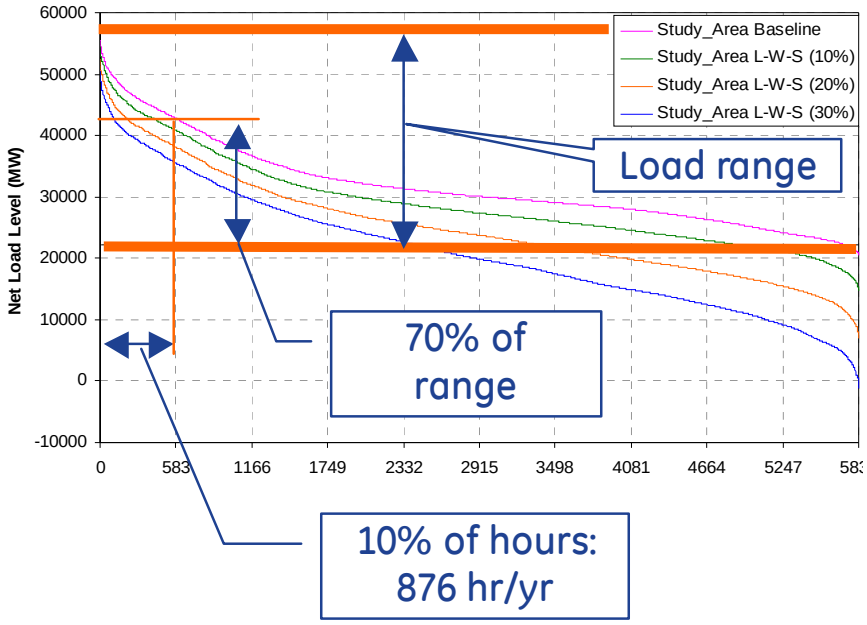


Figure 7.51 Relationship between Load Duration and Load Range for LP Scenario

The total time spent in each cell, in hours per year, for each load and wind combination is shown in Figure 7.52. The 8760 hours (and 52560 10-minute periods) in a year are distributed, non-uniformly, across the surface. The blue "never" cells are wind and load combinations that never occur. The figure shows that the system spends the majority of time at moderate load and wind levels in the neighborhood of 20 to 40% of nameplate. This is consistent with wind generation of 30-40% capacity factors.

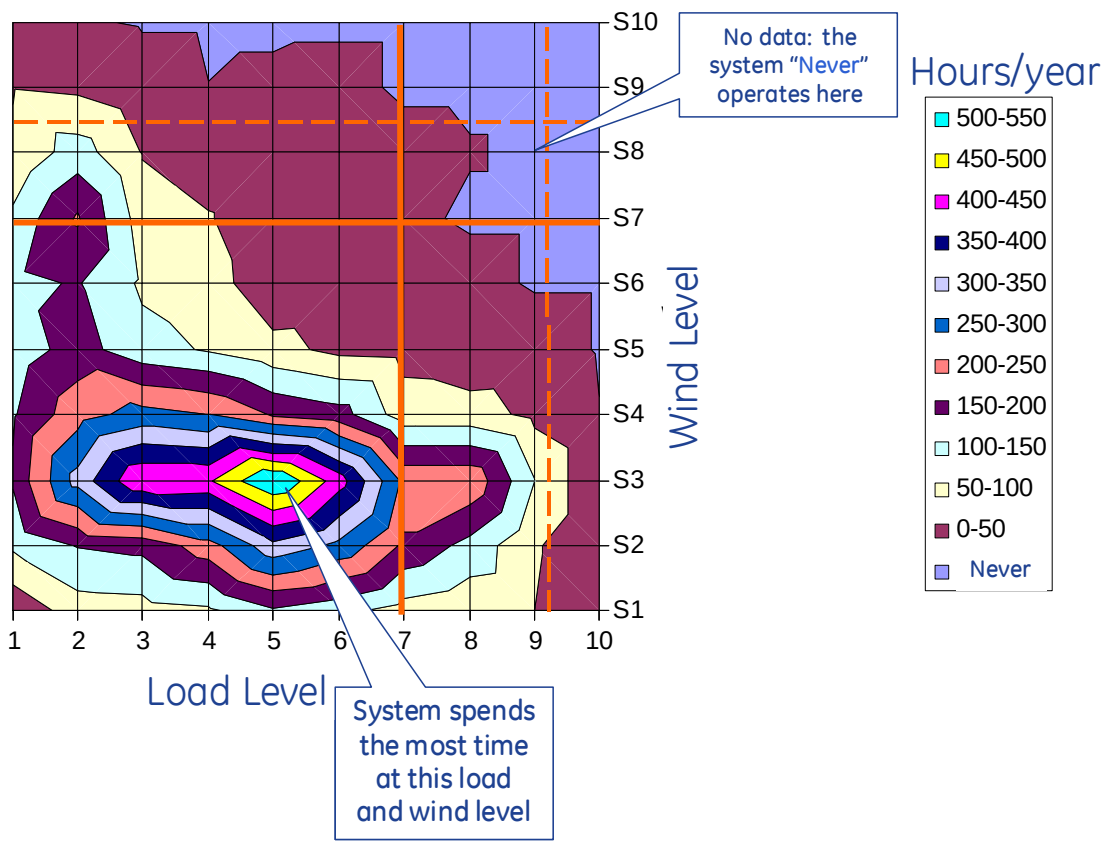


Figure 7.52 Operations L30: Hours of Load and Wind Combinations

Now we investigate wind, load and net load variation in this load and wind space. In Figure 7.53, the variability of wind is shown. The value associated with each cell corresponds to the standard deviation of the 10-minute wind deltas for all of the data samples associated with that cell. Some cells have a large number of data samples, and some have very few or none ("never"). Note that these figures have additional cells around the outer maxima to facilitate plotting the edges. All the surfaces presented in this section show steep gradients at the edges abutting "never" cells. This is an artifact of gradient between actual non-zero data and zero values associated with "never" cells, which are empty of data.

There are two trends observable in this surface. First, as expected, wind variability increases with increasing wind up to roughly the mid-range of wind power. This is observable by moving from bottom to top on the surface. What is less obvious, and something of a surprise at first, is that there is a significant correlation between load level and wind variability. Moving from left to right across the surface, it is clear that the wind is more variable at higher system load levels. This apparent incongruity is, we believe, due to the fact that the atmospheric conditions during the day, around times of high load, are more variable than at night. Thus, the wind is more variable during periods of high load.

Figure 7.54 shows the variability of load in this load and wind space. As expected, and consistent with the orange trace in Figure 7.45, load variability tends to increase with load to moderately high levels of load, and then it drops off again near peak load. The load variability is dominated by the diurnal cycles.

Figure 7.55 shows the variability of net load. Notice that, in general, the values of sigma are somewhat higher across the entire space. Further, on close inspection, the presence of two areas of relative maxima become apparent: one at mid-load (around 5) and moderate wind (around 2 or 3), and another at high load (around 9) and moderate wind (around 3). This surface is roughly the convolution (but not the arithmetic sum) of the wind and load variability surfaces. The bimodal character is consistent with the blue (30%) trace in Figure 7.45.

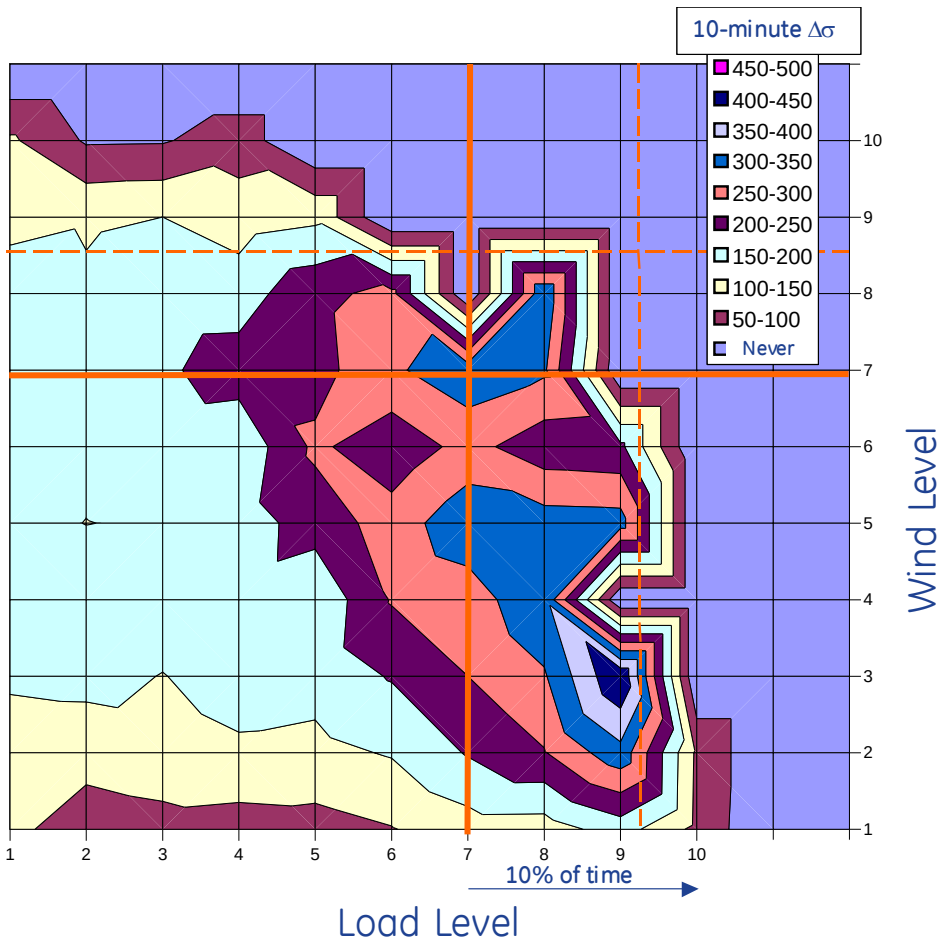


Figure 7.53 Wind Only Variability L30

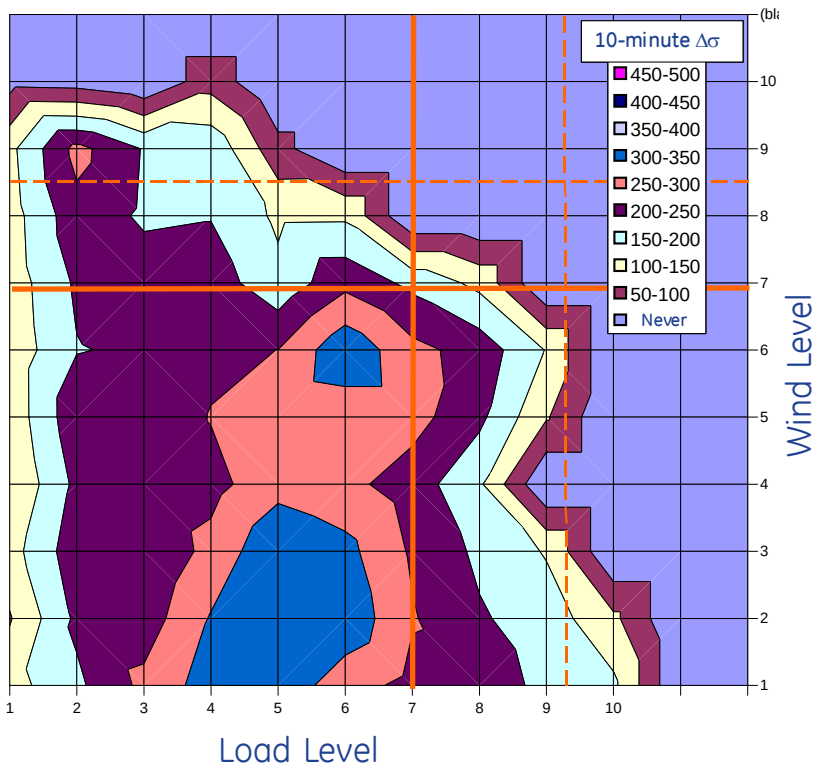


Figure 7.54 Load Only Variability L30

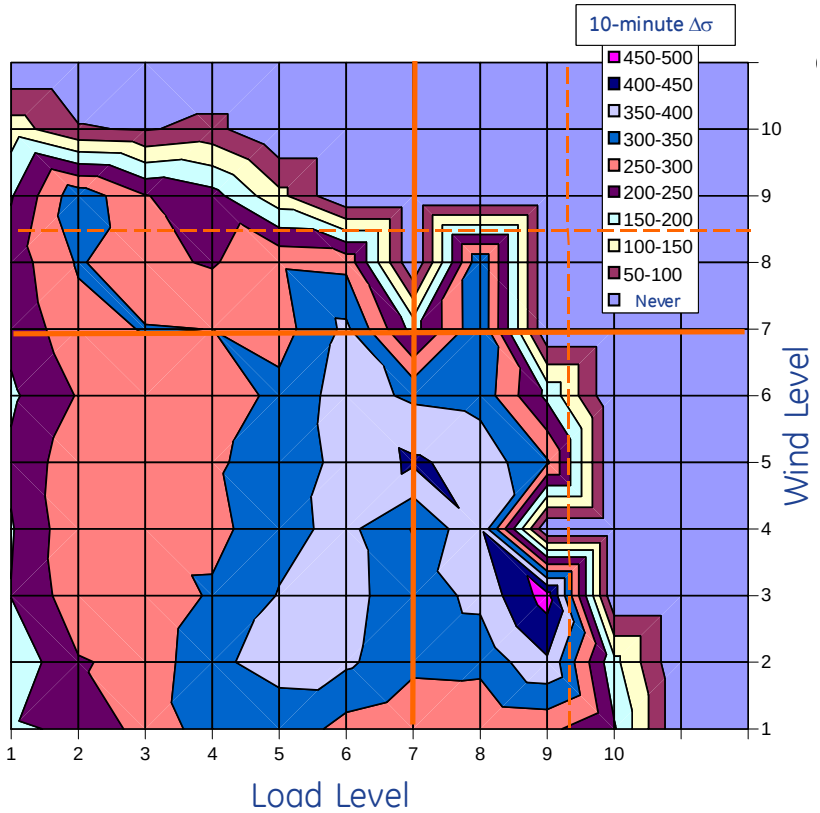


Figure 7.55 Net Load Variability L30

In total, we can see that the net load variability increases with wind and load, reaching maxima somewhat below peak load and peak wind levels. Here we return to the concept introduced in the preceding section, that a logical extension of the present practice for reserves is to require 3 times the standard deviation of expected 10-minute variability. Thus, for this load and wind space, the implied reserve requirement is $3\Delta\sigma$. The requirement is a function of both load level and wind level.

This sequence of figures provides some useful insights into the variability of the entire study foot print. The variability with each individual area is important to understanding the requirements and allocation of reserves across the system. We next, examine the concept of net load variability in load and wind space by area.

The Arizona system has a peak load of 23,051 MW, a minimum load of 21,249 MW, and 7710 MW of wind generation installed in this scenario. Therefore the boundaries of the Arizona load and wind space are adjusted accordingly. Figure 7.56 shows the load alone variability for Arizona. The Arizona load variability is relatively unaffected by wind level, and reaches a relative maximum at moderate levels of load.

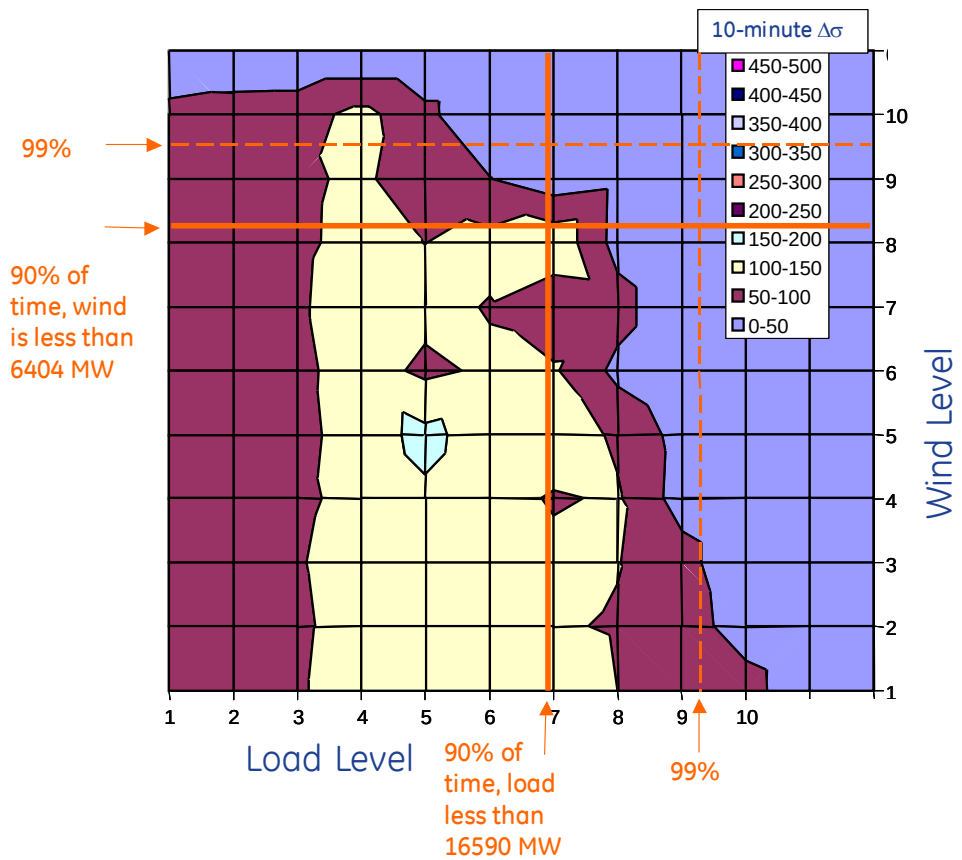


Figure 7.56 Arizona L30R Load Variability

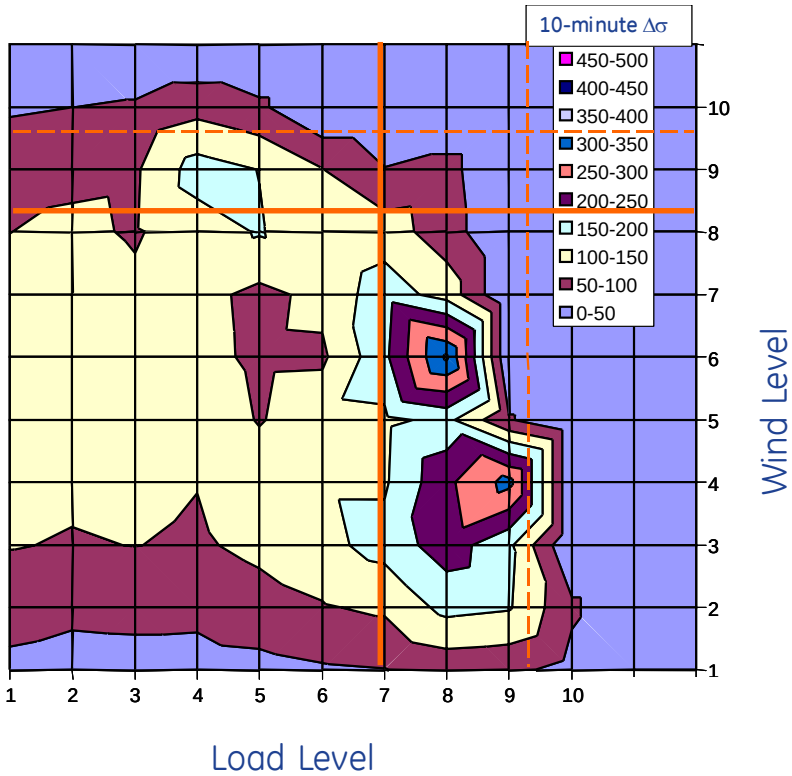


Figure 7.57 Arizona L30R Wind Variability

In contrast, the Arizona wind variability, as shown in Figure 7.57 above, is highly correlated to load level: Again, the wind is clearly more variable during the day, i.e. coincident with high load levels.

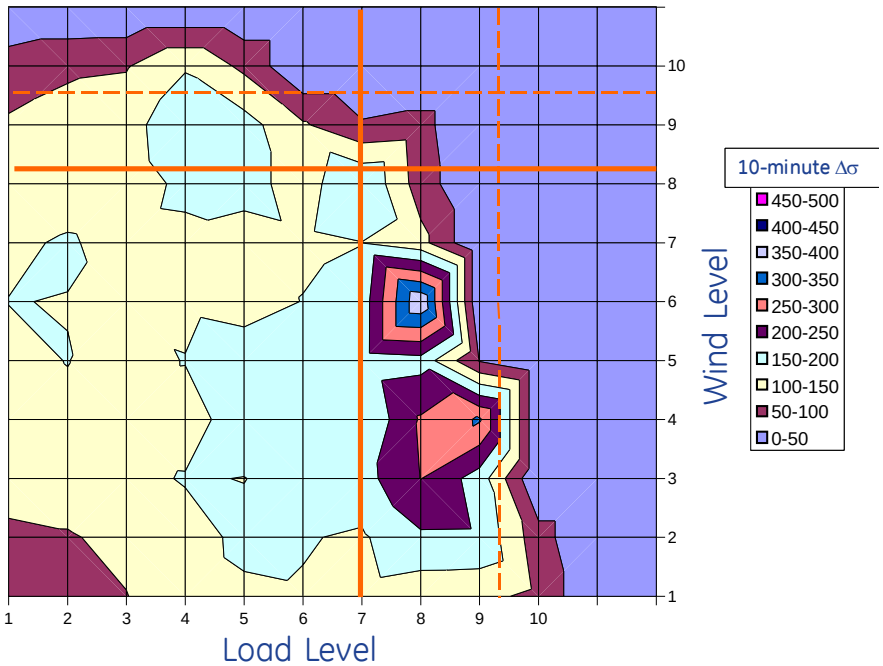


Figure 7.58 Arizona L30R Net Load Variability

The Arizona net load variability, as shown in Figure 7.58, is a mix of wind and load impacts, consistent with the traces on the left side of Figure 7.48.

Now we move to Wyoming, which has a peak load of 4016 MW, a minimum load of 2360 MW, and 7410 MW of wind generation installed in this scenario. The wind power penetration for Wyoming in this scenario is 185%. Figure 7.59 shows wind only variability for Wyoming. Again the, wind variability shows a slight dependency on load level – except at very high loads. There is a very small sample of points for the data at very high load and moderate wind. Consequently, the high variability shown may not be statistically significant. Overall, the high variability at middle of wind power range is an expected characteristic.

Figure 7.60 shows load only variability. Load variability is basically insignificant compared to wind variability. Note the scale in the figure: load $\Delta\sigma$ is an order of magnitude smaller than wind variability.

Finally, Figure 7.61 shows net load variability. As might be expected, the net load variability is totally dominated by wind variability, which is consistent with the right side traces of Figure 7.48.

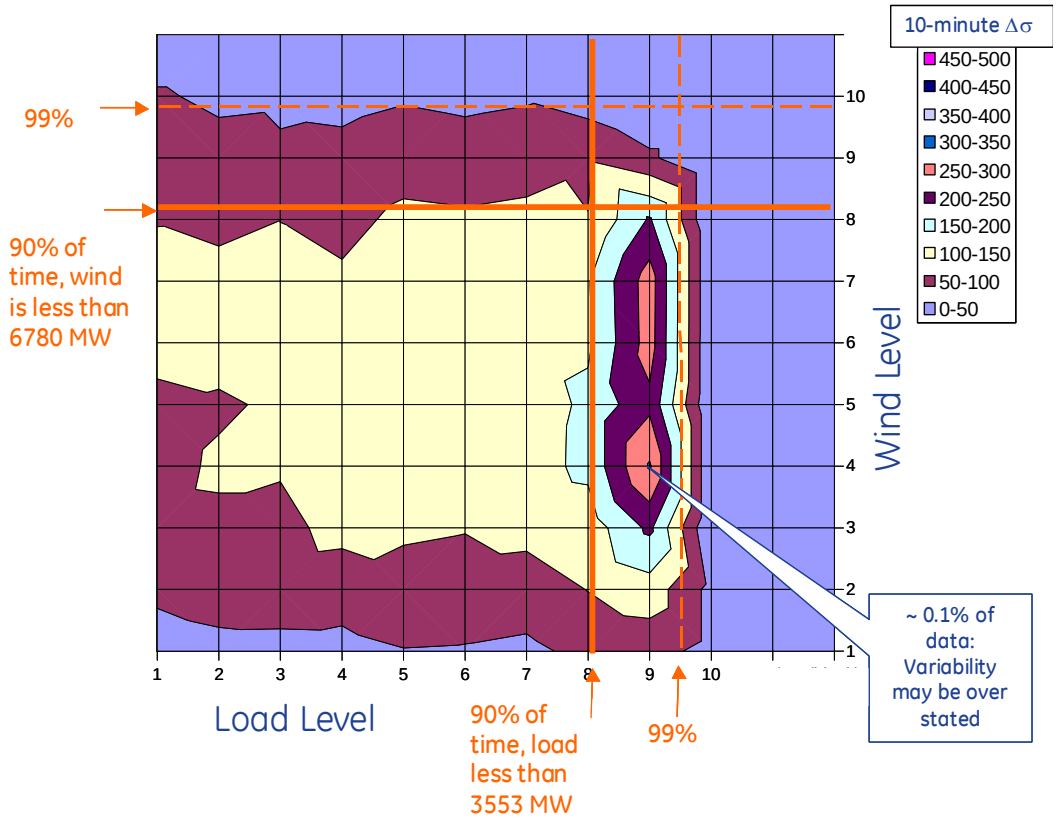


Figure 7.59 Wyoming L30R Wind Variability

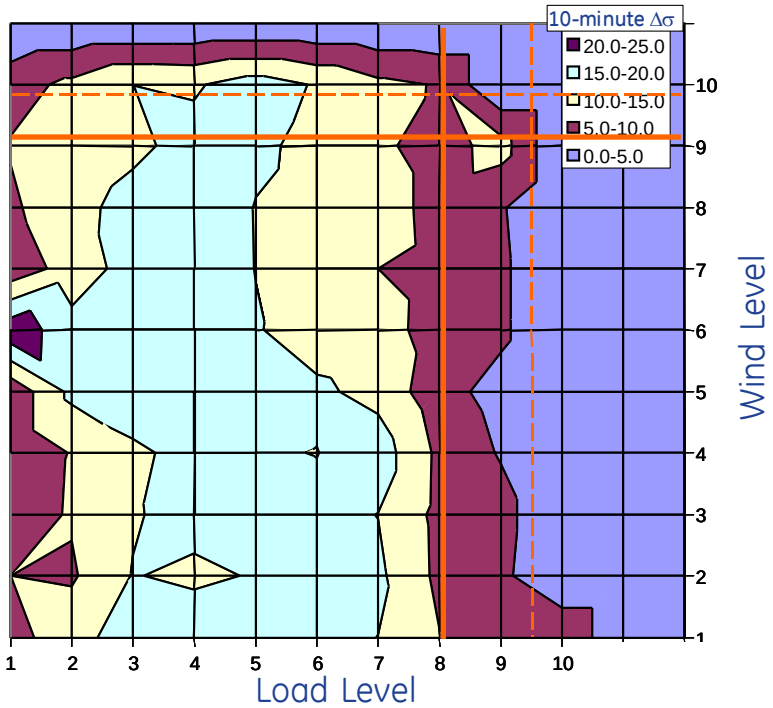


Figure 7.60 Wyoming L30R Load Variability

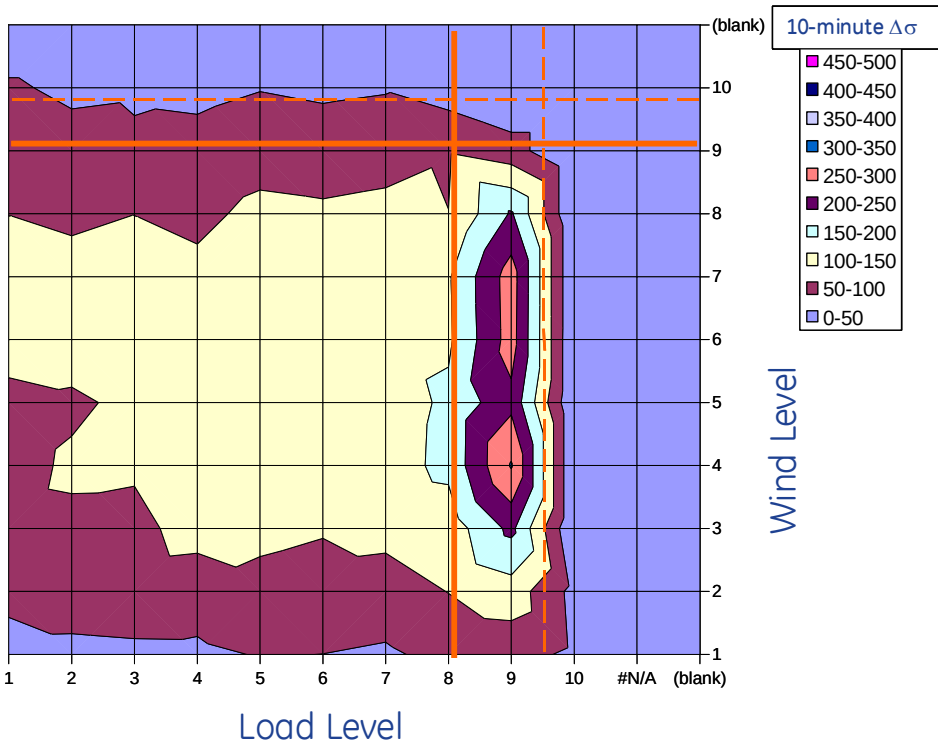


Figure 7.61 Wyoming L30R Net Load Variability

The time that the Wyoming system spends in the various cells provides some interesting insights on the wind resource there. In Figure 7.62, it is clear that Wyoming wind is bi-modal: it has relatively light wind or relatively strong wind. (This can also be seen in the deviation curves of Figure 4.12 and Figure 4.13.) Figure 7.61 shows that periods of highest implied reserve requirements occur at high load and moderate wind. From Figure 7.62 it is clear that these conditions are relatively uncommon.

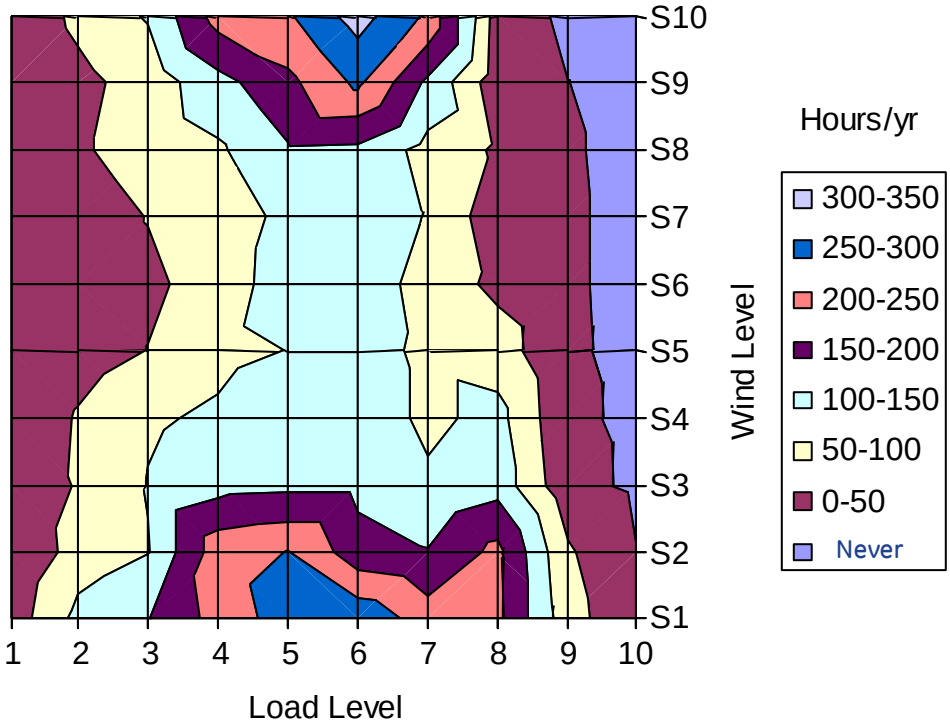


Figure 7.62 Wyoming L30R Time Space

The dominance of wind in the Wyoming system raises some interesting questions. For calculation of reserves, is it reasonable to consider *all* net load variations? The primary concern for reserves is for *rises* in net load. Down reserves, as will be examined more in the next section, are of less concern. Figure 7.63 shows the results of an exercise in which only the frequency and amplitude of increases in net load (dominated by drops in wind) are considered. The lower figure is the mean value of all net load rises, μ, plus three times the standard deviation of the distribution of rises, $3\Delta\sigma$-rise. The upper plot shows the $3\Delta\sigma$ implied reserve.

This result is consistent with other wind variability statistics. Over the majority of operating conditions, the expectation of wind variability is quite symmetric. Adding distinction between up and down to assessment of the required reserve does not appear to significantly improve the information.

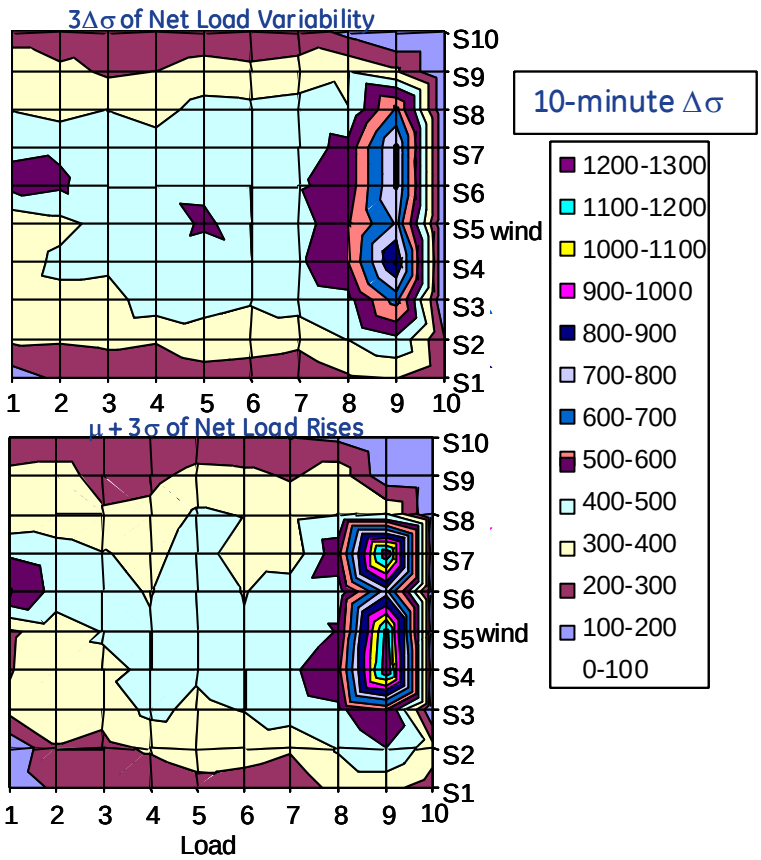


Figure 7.63 Wyoming L30R Net Load Variability: 3Δσ vs. μ + 3Δσ-rise

Figures for all the individual areas present a somewhat confusing picture of the reserve requirements. However, when viewed together, the trends become more understandable. A summary of the implied 3Δσ requirements is shown in Figure 7.64. All the points in this figure are for average values over the year. The average reserve required to meet 3Δσ of load only is indicated with blue diamonds. The averages for net load are shown as circles, and the average following the 3% of load rule are shown as red triangles. The insert gives the footprint wide *summation* of the averages: 979 MW, 730 MW and 1393 MW, for 3% rule, load only and net load, respectively. The 1392 MW average requirement represents a 90% increase over 730 MW, and a 42% increase over 979 MW. Thus, in order to meet performance objectives (based on 3Δσ) with reserves carried by area, the reserve requirement increases about 42% from that carried today for load variability. Alternatively, one could conclude that the reserves carried today are excessive *for load variability* and could, in the absence of wind build out, be reduced by 25% (in this metric to 730MW from 979MW). With this view, the requirement with 30% wind energy nearly doubles, with an increase of 90%.

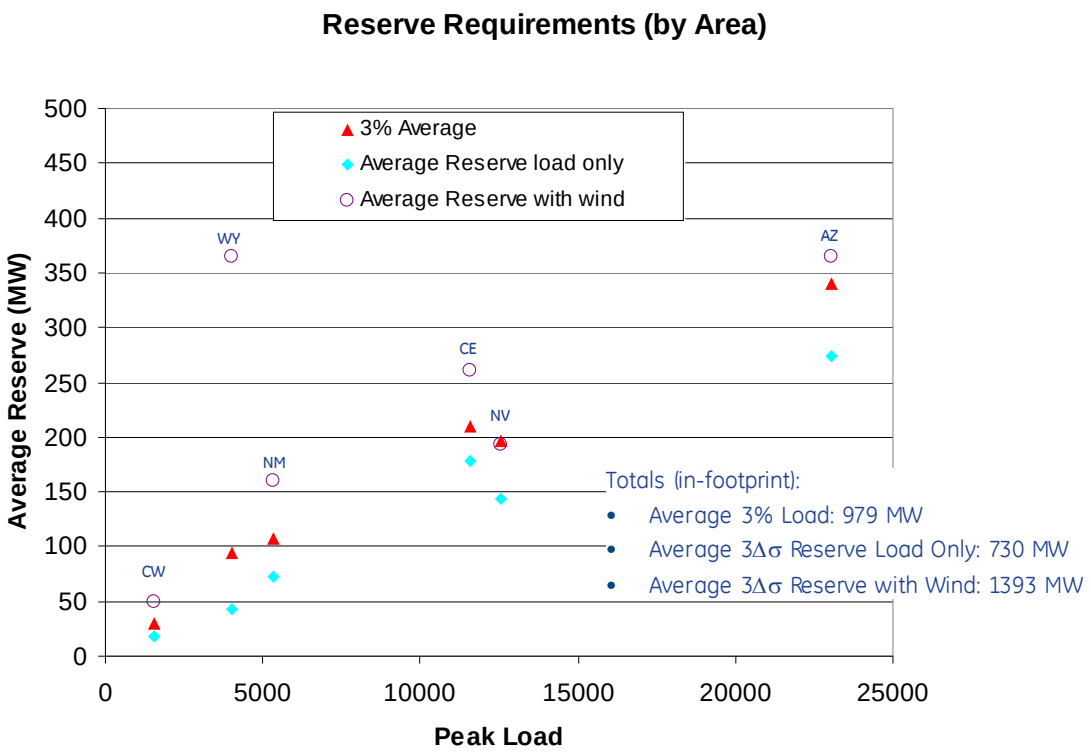


Figure 7.64 Average Reserve Requirements

7.3.4 Reserve Time Frames and Other Reserve Drivers

The statistical analysis presented so far in the section is focused on 10-minute variability. As noted, the availability of sub-hourly reserves is driven in significant part by the unit commitment strategies employed in the day ahead. The hour-to-hour changes, examined in Section 5, impact the system dispatch.

For successful operation of the system, some resources must be allocated that can respond rapidly to signals from system AGC. These regulation reserves are, for the purpose of the analysis presented here, a subset of the sub-hourly reserves. Since the regulating reserves are the primary mechanism by which the system maintains balance in the 5 minute intervals between economic redispatch, there must be enough regulating reserves to cover most changes that occur within those 5 minutes.

Five-minute data was unavailable for this study, but past experience with system variability in other system studies shows common characteristics. Figure 7.65 shows trend lines for a number statistical analyses performed by GE on data from other regions of North America. The variability of net load over 5 minutes is statistically about ½ that for 10 minutes.

This provides some guidance for allocating regulation reserves. Since regulating reserves are backed up by longer time-frame on-line reserves, the need for perfect balancing in the sub-economic dispatch time frame is less critical. The operational expectation that balancing within the 10-minute time frame will not always be perfect is also reflected in the NERC rules governing CPS2. The expectation is that systems will be within L10, i.e. will be successful in balancing in the regulation time frame, at least 90% of the time.

Since the 5-minute variability is about ½ of the 10-minute variability, and there is an expectation of at least 90% success (implied by CPS2 rules), allocation of one 10-minute $\Delta\sigma$ to regulation results in approximately 2σ, or 95%, of 5-minute variability being covered by regulation. This relative simple rule then fits nicely with the $3\Delta\sigma$ rule for overall subhourly on-line reserves.

This relates well to the 1% of peak load regulation rule used in the QSS simulations as broadly representative of utility practice. In Figure 7.66, the 1% of peak load rule (red triangles) is compared with the average requirement resulting from the $1\Delta\sigma$ of 10-minute variability rule suggested here. The results are on the same order of magnitude.

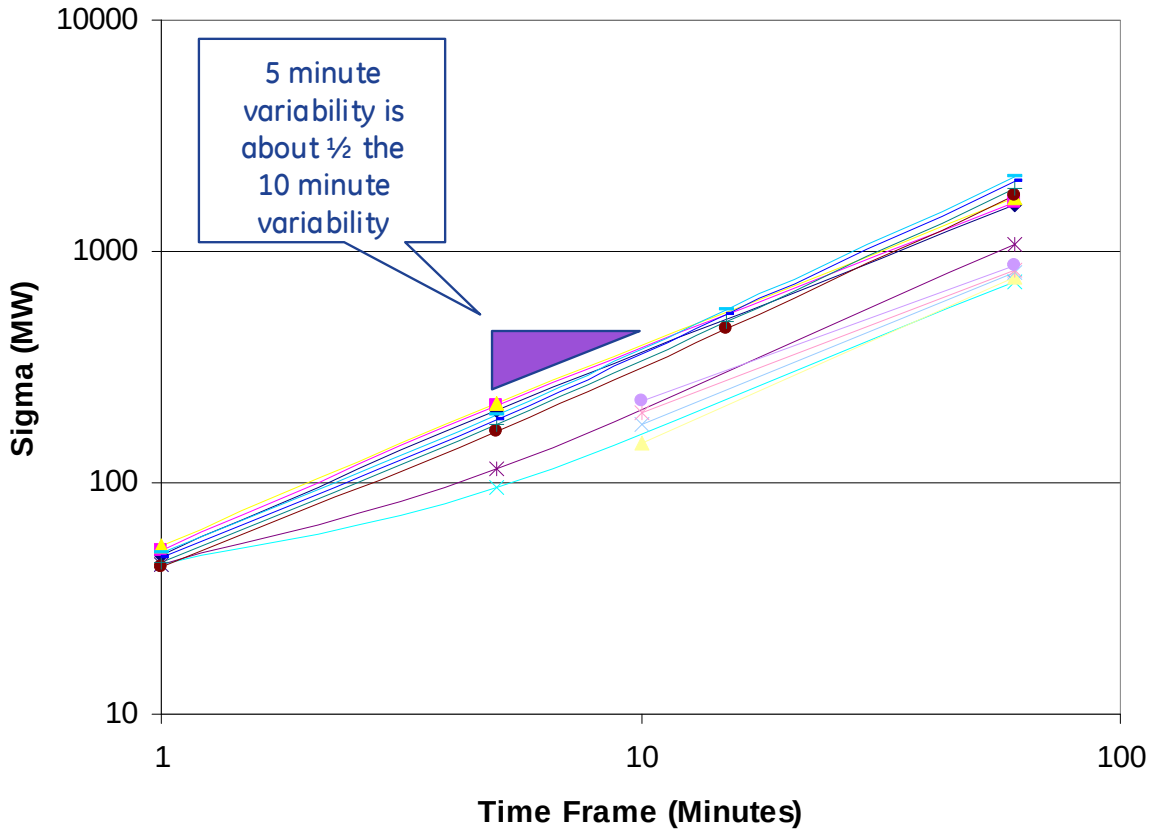


Figure 7.65 Net Load Variability in Different Time Frames – Various GE Studies.

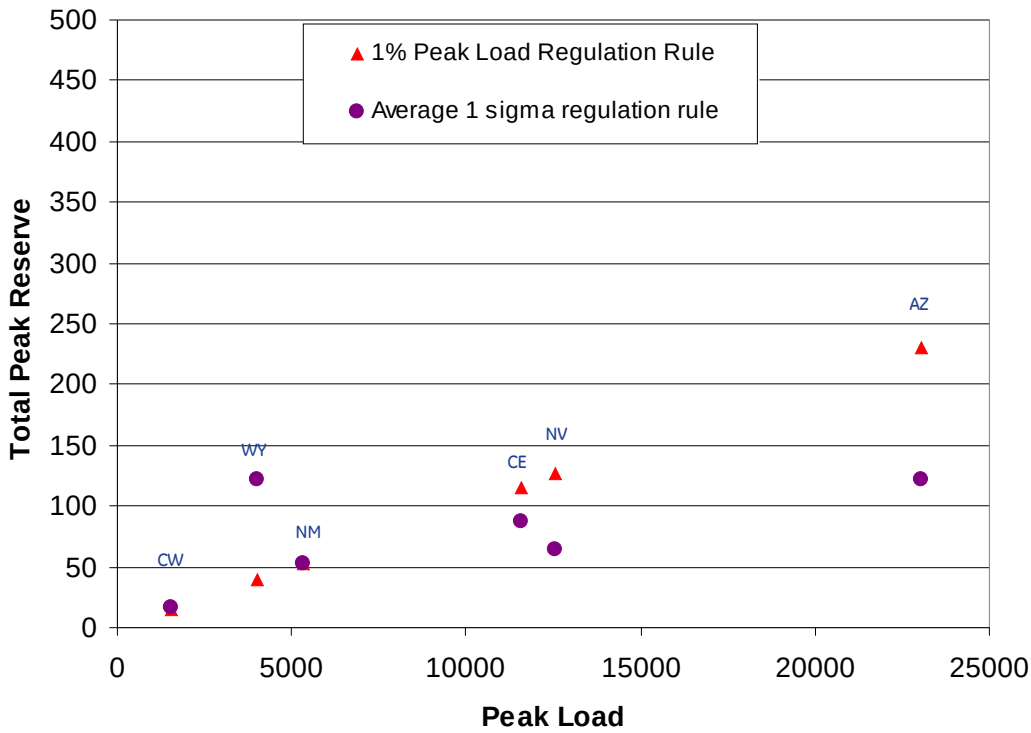


Figure 7.66 Regulation Reserve Requirements (by Area)

There are other considerations that drive system reserves beyond variability. Most notably, systems typically carry on-line reserves to handle unbalances dictated by the worst single system contingency (e.g. loss of the biggest plant). Thus industry practice is actually for 3% of load or for 50% of the worst contingency (or ½ of the total MW at risk). Regardless, of the details for each system, these reserves are generally not additive. That is, extra reserves are not typically carried to handle substantial load variation *and* contingency events. Continuation of this practice is implicit in the results and recommendations provided here. The implied reserve requirements shown in this section, and explored further below, do not consider the worst contingency aspect. Therefore, the incremental requirements identified to handle wind and solar variability will tend to be overstated for areas where the worst contingency criteria exceeds the 3% of load criteria for significant periods of time.

7.4 Reserve Performance

This section will show selected examples from MAPS and QSS simulations to illustrate the relationship between the concepts reported in the previous section and the behavior of the system as simulated.

7.4.1 Hourly Reserves at Dispatch

In this section the behavior of the system in the MAPS runs will be compared to the requirements implied by the 3Δσ reserve rules. The reserve requirements implied by the

surfaces shown in Section 7.3.3 are not explicitly recognized in the MAPS simulations presented in Chapter 6. However, the day-ahead unit commitment and the real-time (hourly) dispatch result in system dispatches that have some level of reserve in each hour simulated. These on-line reserves will, in general, be greater than or equal to the 3% of load requirement across the MAPS regions.

In this section, the on-line reserves resultant from the system dispatch in the selected L30R MAPS simulation, are compared to the implied reserve requirements. In the plots presented below, the hourly load and wind are segregated in exactly the same fashion as described in Section 7.3.1. For each hour resident in a load and wind cell, the actual dispatch is compared to the available up range for the committed units. This is the total sub-hourly reserve for that hour.

In Figure 7.67, the average system reserves for the study foot print are shown in the load and wind space. Reserves here mean the difference between maximum power and dispatched power of committed units. Overall, the system has substantial reserves. Two trends are obvious: system reserves tend to be lower at higher load levels, and system reserves tend to be higher at higher wind levels. Both of these trends make physical sense, since higher load levels will tend to load up committed generation, and higher wind levels will tend to unload committed generation.

Of course, average performance is only a broad measure of behavior. The system needs to be secure at each hour. In Figure 7.68, the implied reserves based on the $3\Delta\sigma$ rule are compared to each hour. This means the reserves (from MAPS) minus the implied reserves, i.e. 3 times the values from Figure 7.55, are reported. Negative values are violations, i.e. the MAPS simulation ended up with fewer reserves than the $3\Delta\sigma$ rule implies are necessary. The upper plot in Figure 7.68 shows the amplitude of the single worst violation of implied reserves for each cell in the load-wind space. The color key is that green areas represent load-wind combinations that do not ever have reserve violations. The blue "never" cells are, again, load-wind combinations that never occur. The lower plot is the count of hours with any violations. The total count of violations in the year is 132, about 1.5% of all hours. This suggests that the rules used with the MAPS runs are largely correct in that they produce adequate reserves. However, these results also suggest that some refinement in the reserve rules would be beneficial.

Violations tend to occur at relatively high load and low wind power. It is of interest to note that the increased reserve requirement associated with modest amounts of wind combines with the high load levels to make deficiencies in reserve most acute at high load and low, but not very low, wind. This is also a reflection of the impact of forecast error. When wind is under-forecasted, the committed units use up-range to serve load, depleting reserve margins. Scarcity of reserves at very high load is aggravated by increased reserve requirement due to wind variability. A violation means that the hour has insufficient reserves to meet the implied requirement. *Load is still served*.

The deficiency of up reserves at low wind power has some correspondence to hours for which the wind forecast was higher than the actual wind. In Figure 7.69, the actual reserves are plotted against the wind forecast error for the full year of the L30R case. There is some trend towards lower reserves with higher forecast error, but clearly there are other factors involved as well. In Figure 7.70 details of three cells, selected from Figure 7.68, (and marked in that figure with color coded dots) are plotted. The color coded lines correspond to $3\Delta\sigma$, from Figure 7.55, for the respective cells. Overall the up-range or reserves for the two cells (green triangle and blue diamond) that showed violations tend to be much lower. Again, there is some correlation to wind forecast error, but other factors contribute to the availability of reserves as well.

For down reserves, the issue is less troublesome. As shown in Section 7.2.7, wind can contribute to down reserves when necessary. The pair of plots in Figure 7.71 conveys similar information to Figure 7.68, except for down reserves. Not surprisingly, at high load and low wind levels, down reserves are abundant and there are no violations. Conversely, at high wind and low load, there are eight hours during which down reserves are below the implied requirements. These results suggest that down reserves are unlikely to be a limiting or substantial economic consideration.

The performance for individual areas is more complex. In Figure 7.72, the up reserve violations for Arizona are shown. The two plots convey the same information as Figure 7.68, but for Arizona only. In Arizona, with 7710 MW of wind and a peak load of 23 GW, the system has a total of 757 hours of violations – about 9% of hours. There is a tendency to be short of reserves at low wind conditions, with the worst violations occurring at high load and moderately low wind. Again, the shortage of wind generation tends to deplete the available up range.

The behavior of Wyoming as shown in Figure 7.73 is much worse, and consistent with the results shown in Figure 7.62. As the tables presented in Section 7.3.3 and Figure 7.64 show, the 3% of load rule will tend to ask for significantly less reserves than the implied reserve rules for Wyoming. With a wind power penetration of nearly 200%, rules that only consider load are expected to be short. In the figure, 2075 hours, about ¼ of the year, are in violation. The implication is that either Wyoming must carry substantially more reserves, or the neighboring (i.e. importing) systems must contribute to the reserve requirements. The implications of these trade-offs will be explored further in the next section.

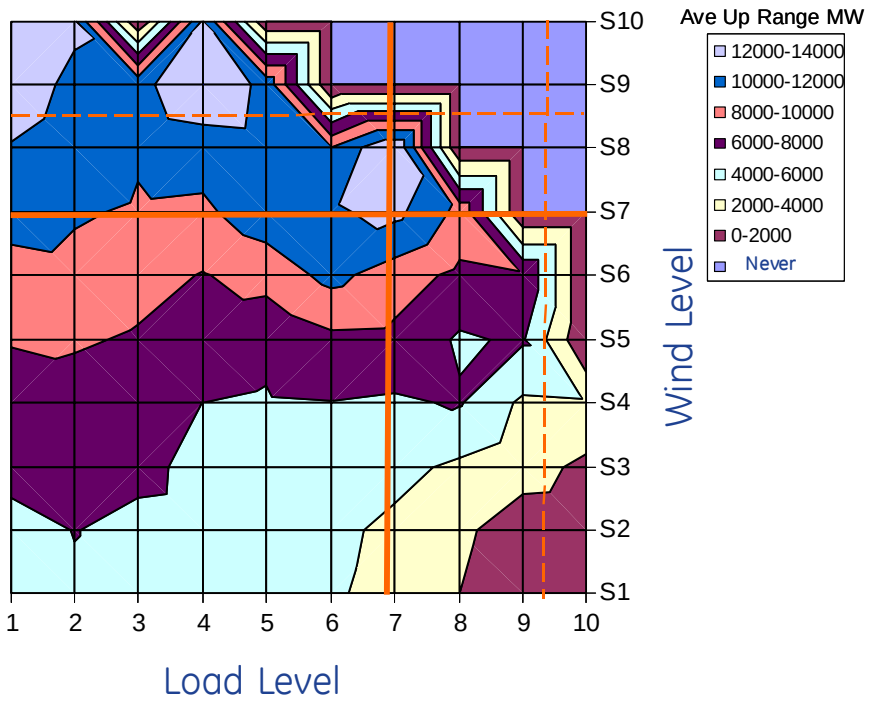


Figure 7.67 Average Up Range L30R Scenario

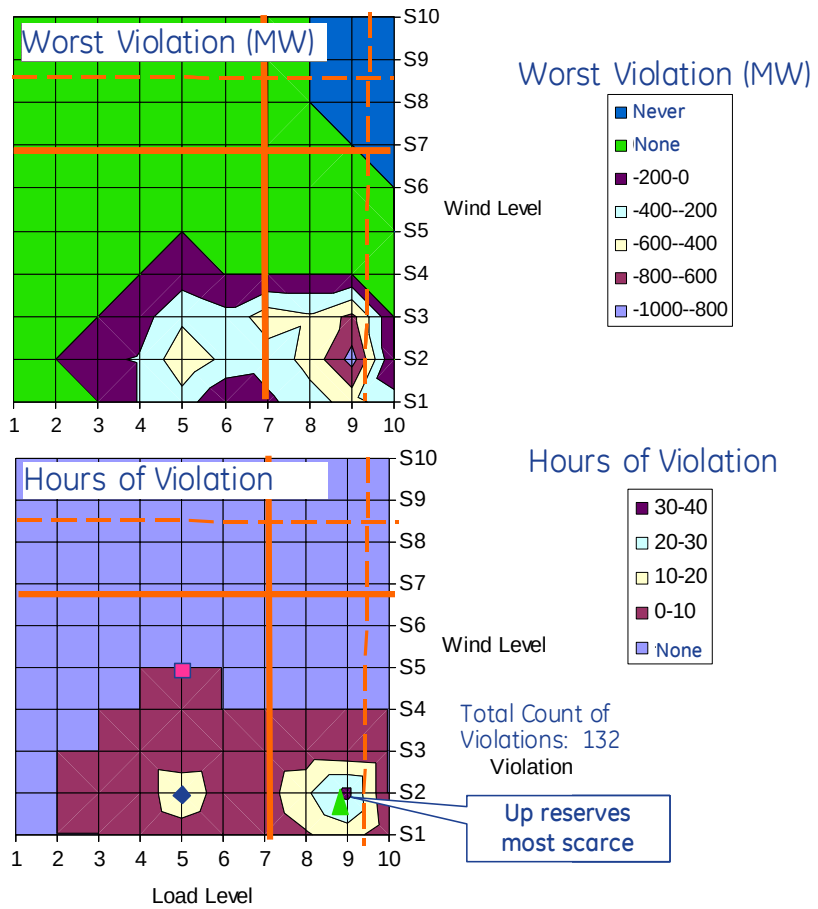


Figure 7.68 L30R Scenario Up Reserve Violations

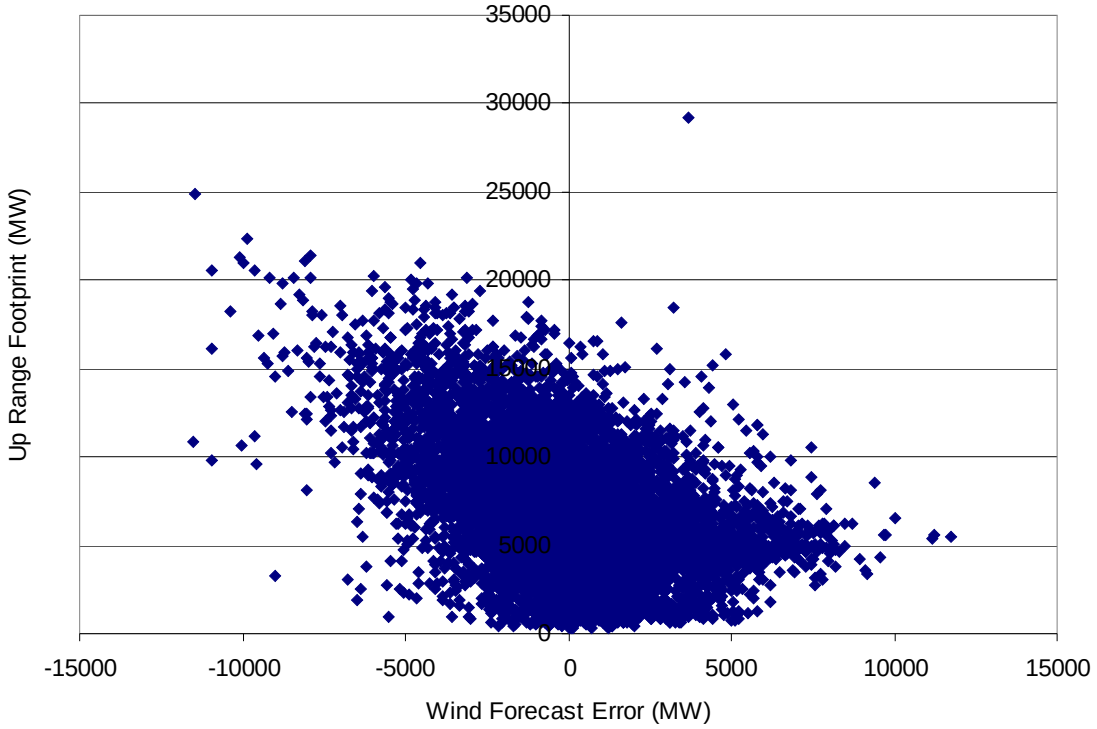


Figure 7.69 Up Reserves vs. Forecast Error (Full Year)

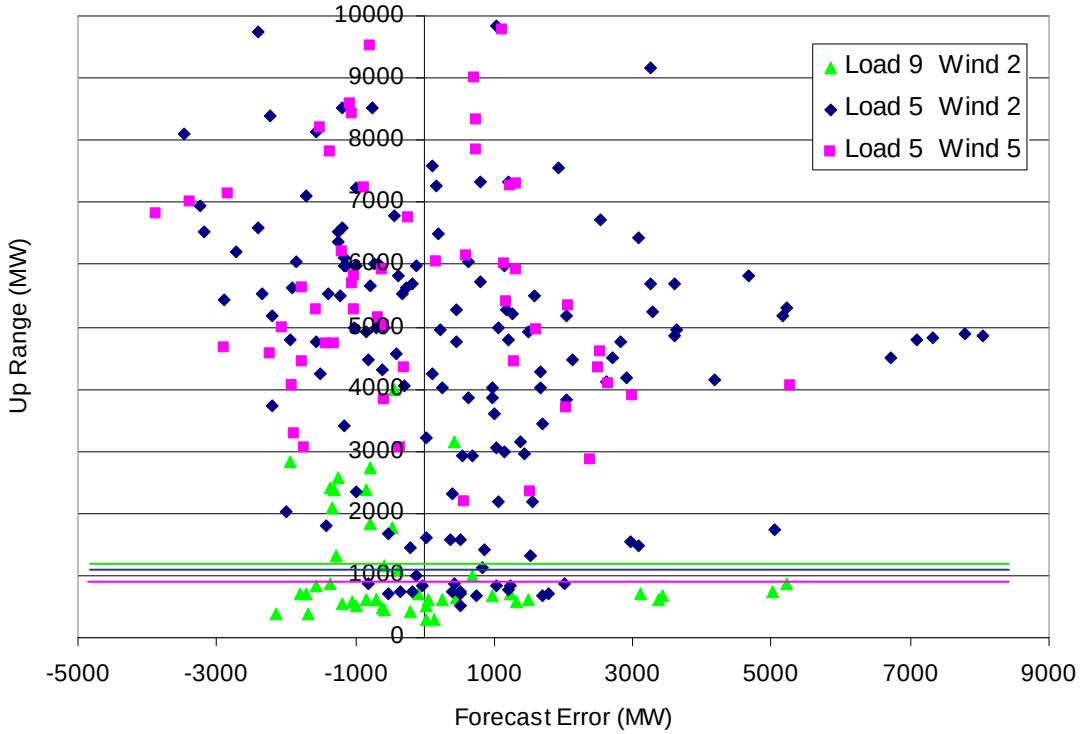
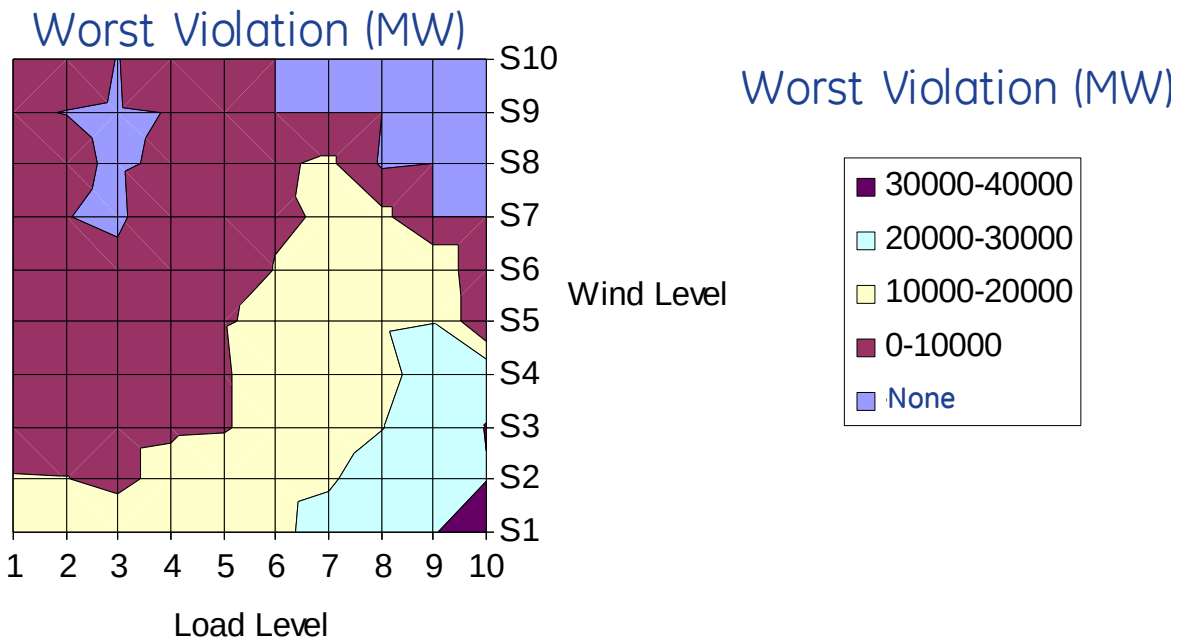


Figure 7.70 Up Reserves vs. Wind Forecast Error (Selected Load – Wind Pairs)



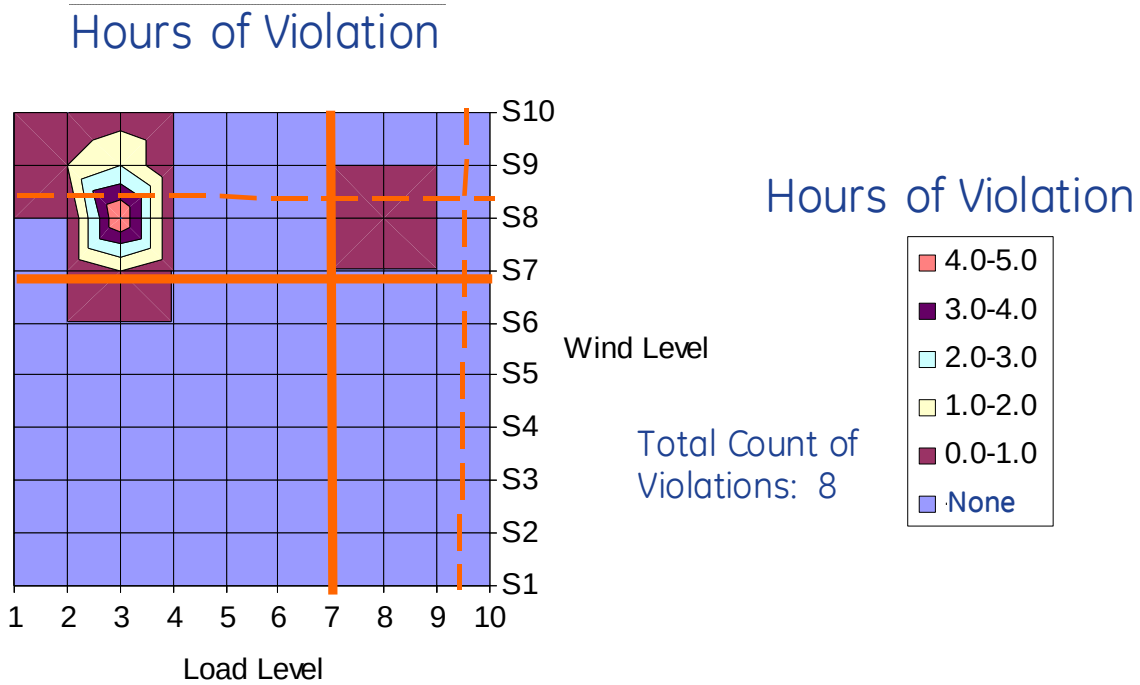


Figure 7.71 L30R Scenario Down Reserve Violations

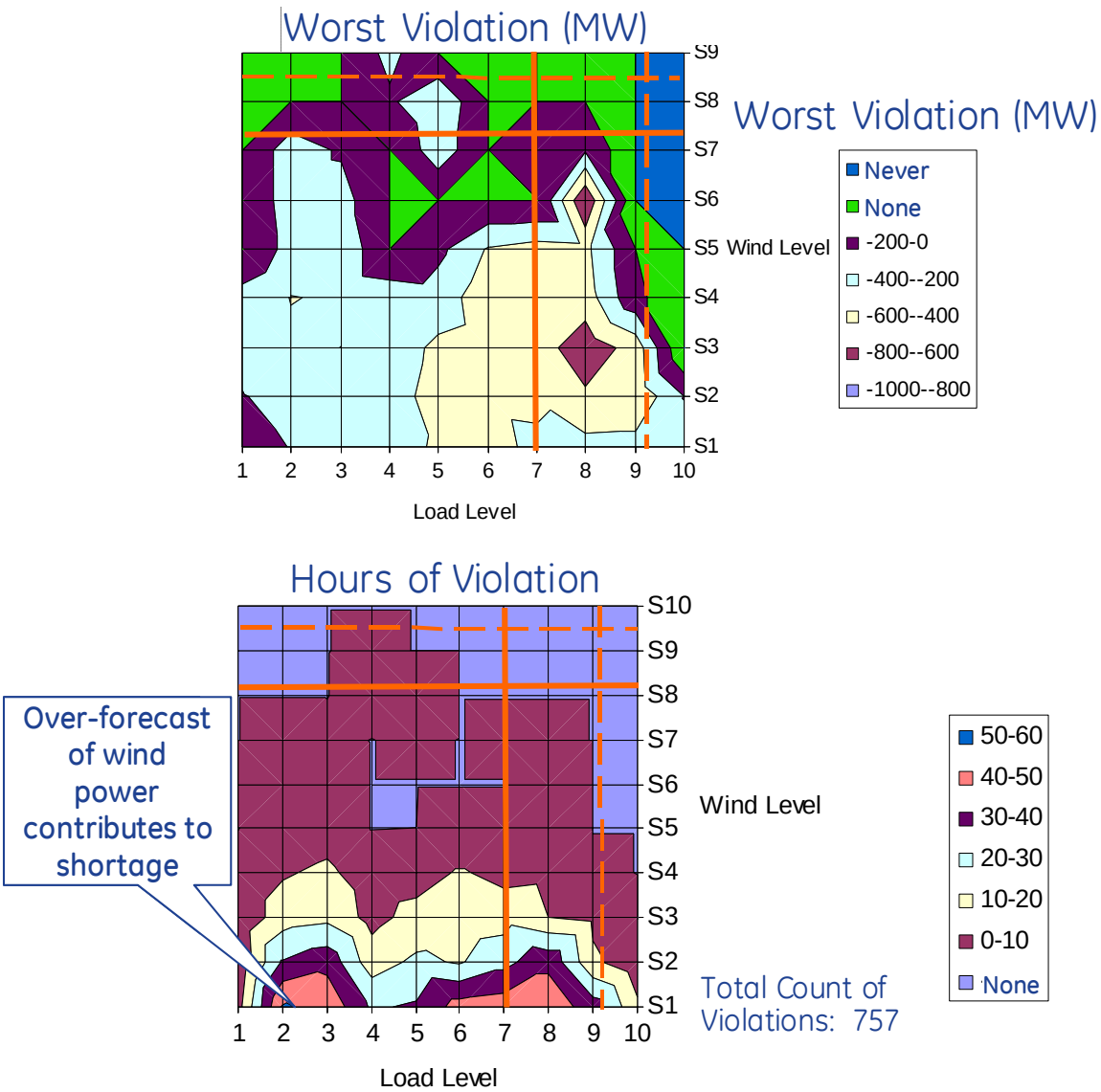


Figure 7.72 Arizona L30R Scenario Reserve Violations

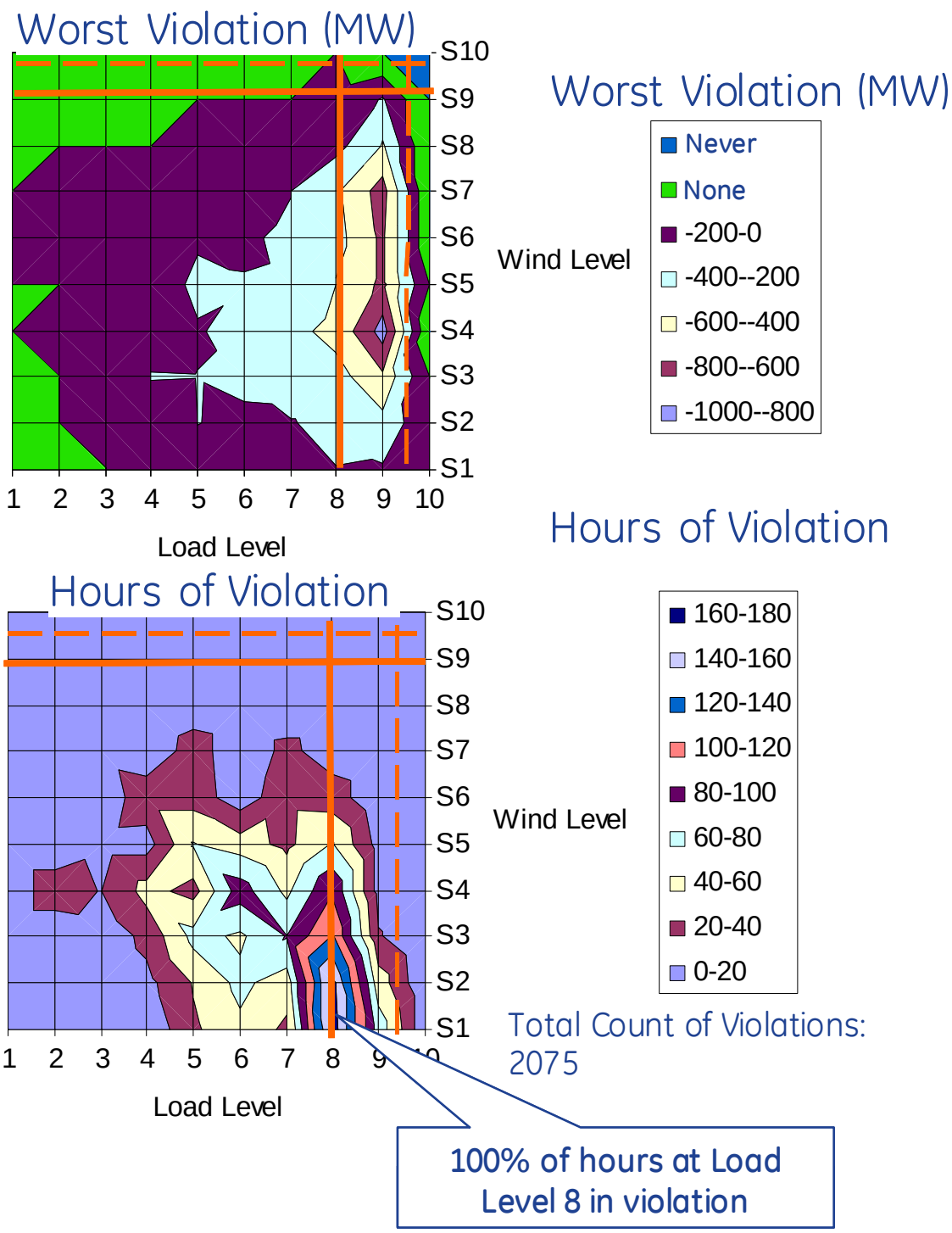


Figure 7.73 Wyoming L30R Scenario up Reserve Violations

7.4.2 Intrahour Performance

This section re-examines the QSS simulations presented in Sections 7.2.5 and 7.2.6 with the intent of exploring the dynamic balance of the system, including intrahour behavior against the concepts of 3Δσ reserve rules.

In Figure 7.74, the Arizona L30R Δσ surface is reproduced from Figure 7.58. Overlaid on that surface is the load-wind trajectory of the April 15, 2006 QSS simulation presented in Figure 7.13. The minute-by-minute trajectory is shown in blue, with dots added at one hour intervals. The arrow shows the direction of the progression in time. This particular day was chosen because of the simultaneous very high wind, low load conditions. Recall that at one point in this particular day, the instantaneous wind penetration exceeded 100% for the entire study footprint. In the figure, it is apparent that the reserve requirements are, as expected, varying but modest, with Δσ in the range of 50 to 150 MW, compared to Δσ at high load and moderate wind.

In Figure 7.75, the actual and implied reserves for the day are plotted against time. As committed generation that is available for maneuvering is economically re-dispatched, the available reserves constantly change. Early in the simulation (6 – 10 pm), there is a considerable amount of reserve. In the middle of the night, units are decommitted and the reserve level drops. The blue curve with pink dots is the 3Δσ reserve requirement approximately read from the trajectory on Figure 7.74. Note that the factor of 3 (in 3Δσ) is taken into account in this trace. The regulation deficiency from the QSS simulation is shown in green. Non-zero points correspond to times when the regulation (not economic dispatch) was unable to keep up with the net load and schedule changes. As was shown in Section 7.2, hourly schedule changes tend to dominate ACE. There is a rough correlation between the drops in range and reserve depletion. The depletions tend to lead the relative minima of range. This is an indication that the capability of the units dedicated to regulation has been exceeded, but not that the overall reserves are deficient.

In Figure 7.76, the behavior of Arizona for the October 26, 2006 day is shown on the Arizona L30R Δσ surface. Again there is substantial wind, but then as the day progresses, the wind power drops. This drop was poorly forecast, and so system reserves, as can be see in Figure 7.77, around 6 a.m. are relatively low. Nevertheless, the actual reserves still meet the implied 3Δσ reserve requirements, and the only regulation deficits are associated with hourly schedule changes.

The behavior of the Wyoming system is, as suggested by the results presented in the previous section, substantially different. The April 15, 2006 trajectory is shown in Figure 7.78. The wind rises to very high levels during low load conditions. As was presented in Figure 7.72, the proportionately high variability of the wind tends to drive a significant number of regulation reserve deficits. However, the trend in Wyoming is for

the other generation (including a significant coal fleet) to stay on-line even at light load and high wind. Thus, the total up reserve is proportionally quite large. In Figure 7.79, the upper left hand plot shows that up reserves are on the order of 2000MW for most of the day, with implied reserve requirements being in the neighborhood of 200-400 MW. Nevertheless, the detail on the lower left shows frequent regulating-reserve deficiencies.

The 1% of peak load regulation rule for Wyoming only places about 40MW of generation on regulation. With wind power penetration of nearly 200%, this is inadequate. The pair of plots on the right are for exactly the same commitment and dispatch rules, but with 100MW of the available reserves dedicated to regulation. As discussed in Section 7.3.4, Figure 7.66, this level of regulation corresponds approximately to 1 $\Delta\sigma$ of the 10-minute variability. The regulation performance is greatly improved. Overall, this case reinforces the conclusion that the roughly 1/3 of the minimum implied subhourly reserves should be allocated to regulation. For most of the study system, this represents on average roughly the 1% of peak load rule, but for this very high wind penetration system, the required regulation is about 2½ times as great.

The October 26, 2009 case for Wyoming, as shown in Figure 7.80, is interesting in that poor wind forecast results in the thermal generation in Wyoming being heavily dispatched to cover the shortfall in wind. The resultant sub-hourly reserve is much less than was shown in the April 15 case. On this day, the trend in sub-hourly reserve is roughly coincident with the implied requirements. The substantial hourly schedule changes cause fluctuation around that trend line. Deficits in regulation, as shown in Figure 7.81 are coincident with periods during which reserves are being drawn down rapidly. Again this is partly due to an insufficient portion of the reserves being allocated to regulation, but is also due to the generally lower levels of reserves due to large wind forecast error.

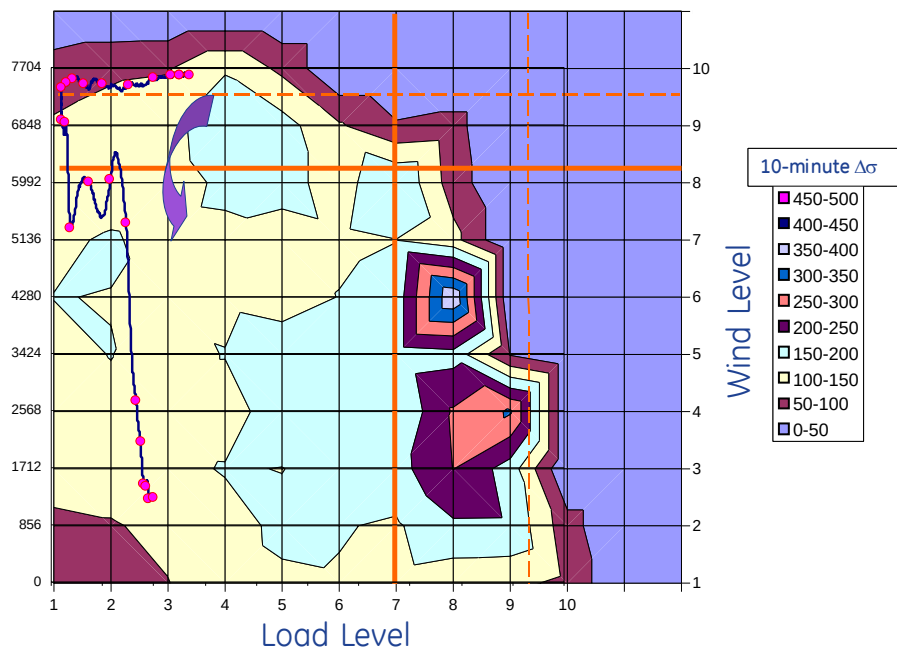


Figure 7.74 Arizona L30R Scenario April 15, 2009 Trajectory

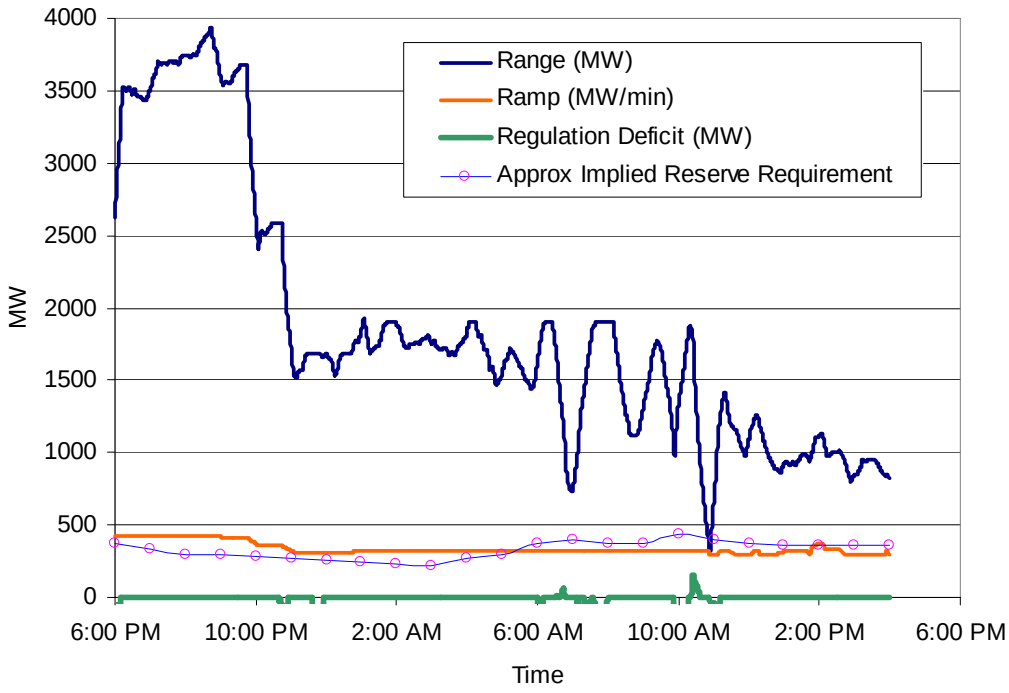


Figure 7.75 Arizona L30R Scenario Results April 15 2006

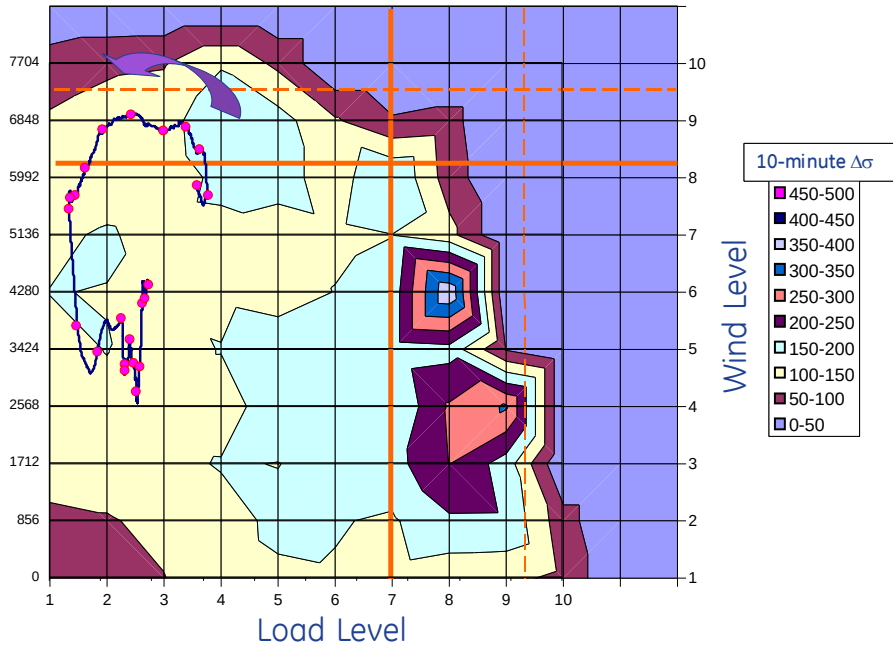


Figure 7.76 Arizona L30R Scenario October 26 2006 Trajectory

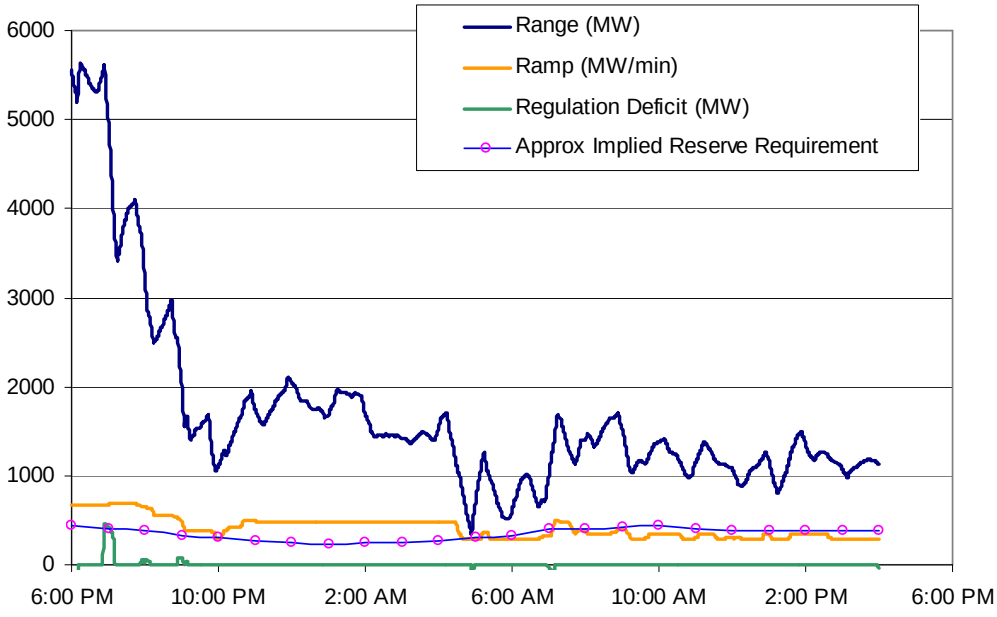


Figure 7.77 Arizona L30R Scenario Results October 26 2006

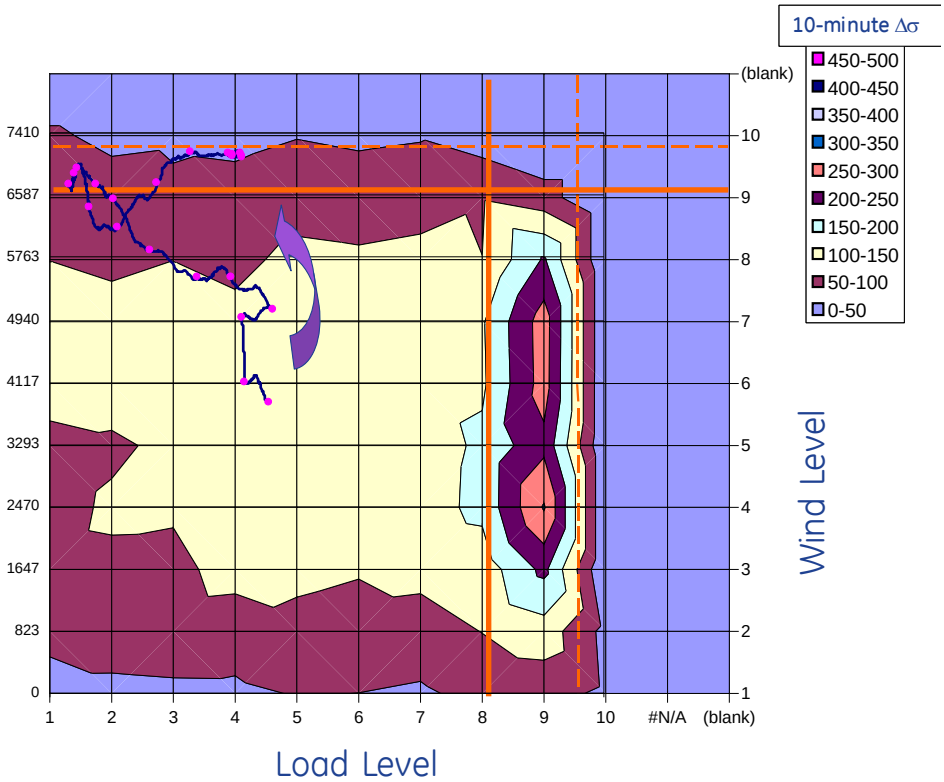


Figure 7.78 Wyoming L30R Scenario April 15, 2006 Trajectory

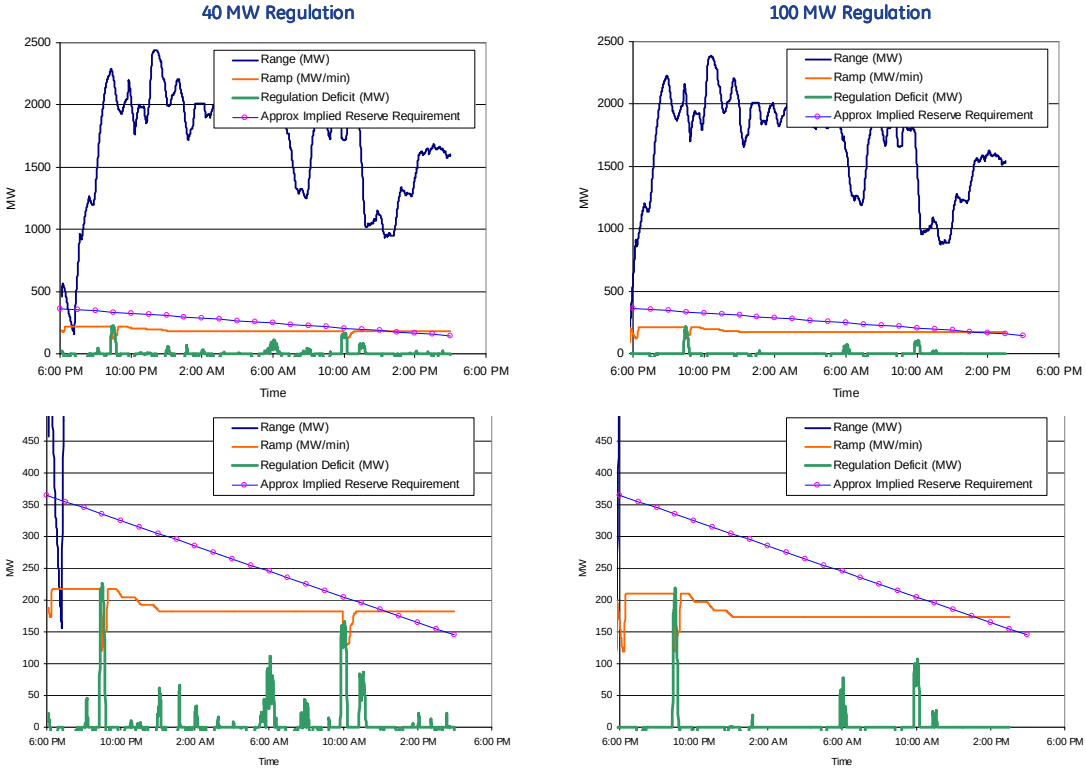


Figure 7.79 Wyoming L30R Scenario – Regulation Allocation Detail – April 15 Results

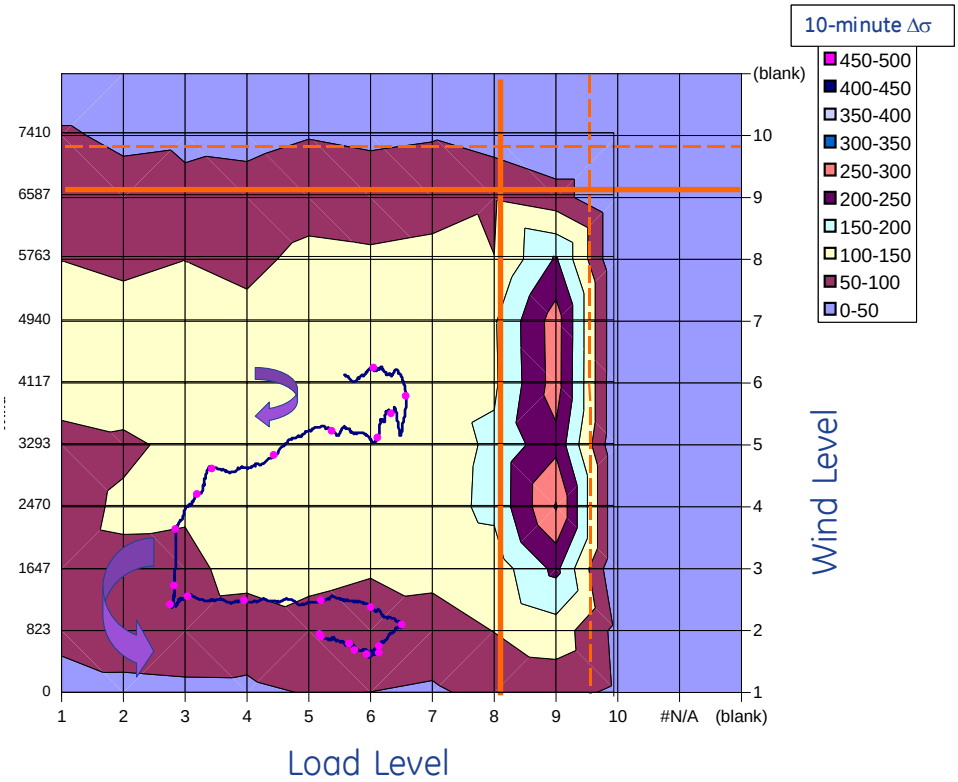


Figure 7.80 Wyoming L30R Net Load Variability October 26 2006 Trajectory

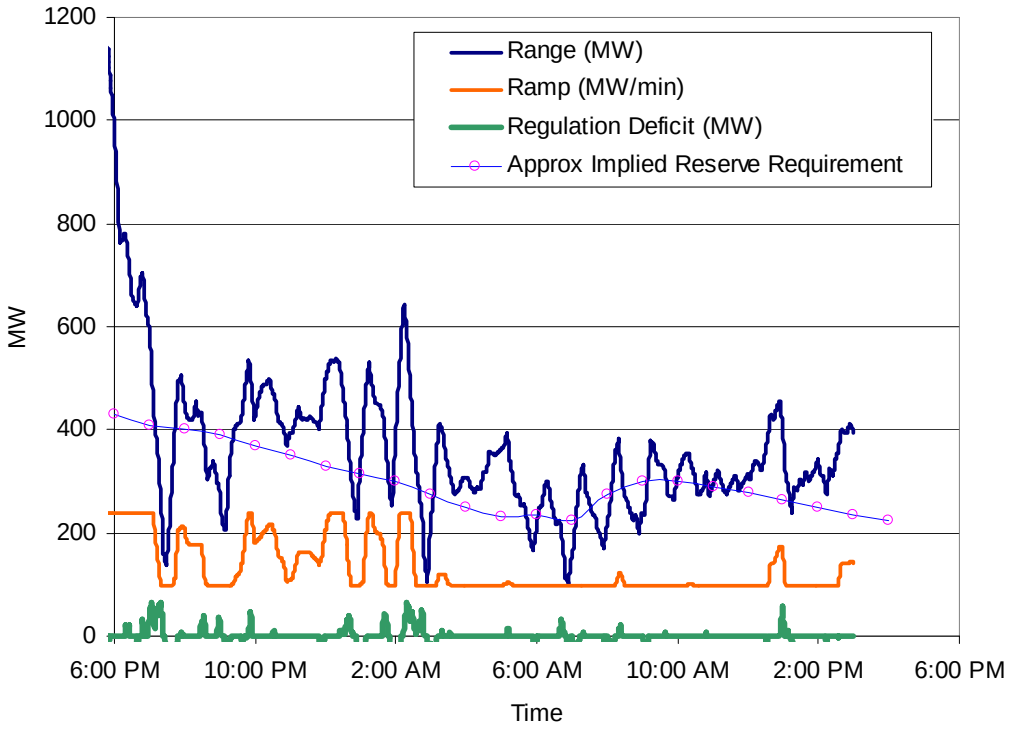


Figure 7.81 Wyoming L30R Scenario October 26, 2006 Results

7.5 Concepts for Simple Reserve Rules

The requirements for reserves, as they relate to system variability, have been presented in the preceding two sections. The relatively complex variability surfaces reflect the needs of the system. However, these surfaces in themselves do not present particularly usable information for system operations.

This section will explore concepts for reserve rules that could be used by system operators to allocate the reserves necessary to handle variability. These rules must be relatively simple and understandable; they should be based on the physical reality of the system, and they should be reasonably accurate.

7.5.1 Load and Wind Level Based Rules

In the following subsections we will present different concepts and how they relate to the different areas. Area results are reported in the sequence Arizona, Wyoming, Colorado East, Nevada, New Mexico, and Colorado West. This is the descending order of installed wind power in the six areas for the local priority 30% case.

7.5.2 3+5 Rule

In this section, we start with a simple and somewhat conservative heuristic rule: carry 3% of load (the existing rule) *plus* 5% of the wind. Note that this is 5% of actual or short-term forecasted wind, and *not* 5% of installed nameplate MW. This is the "3+5 rule" that governs the *commitment* for the 5% wind reserve runs discussed in Section 6.2.2.

Figure 7.82 shows the 3+5 rule for the study footprint. The figure, and subsequent ones for each area, presents three surfaces. The top surface is the implied 3Δσ of net load rule for the footprint. This is exactly the same information presented in Figure 7.55, except that variability has been multiplied by three to get the 3Δσ rule. The middle surface is the 3+5 rule. This is the amount of reserves that would be carried to meet the rule. The bottom surface is the margin between the 3+5 rule and the reserve requirement from the 3Δσ rule. That is, this is the difference between the 3Δσ requirement and the reserves carried by the 3+5 rule. Violations occur when this margin is negative. For the entire footprint, there are no cells, and therefore no conditions, for which the 3+5 rule results in insufficient reserves to meet the implied 3Δσ requirement for net load variability.

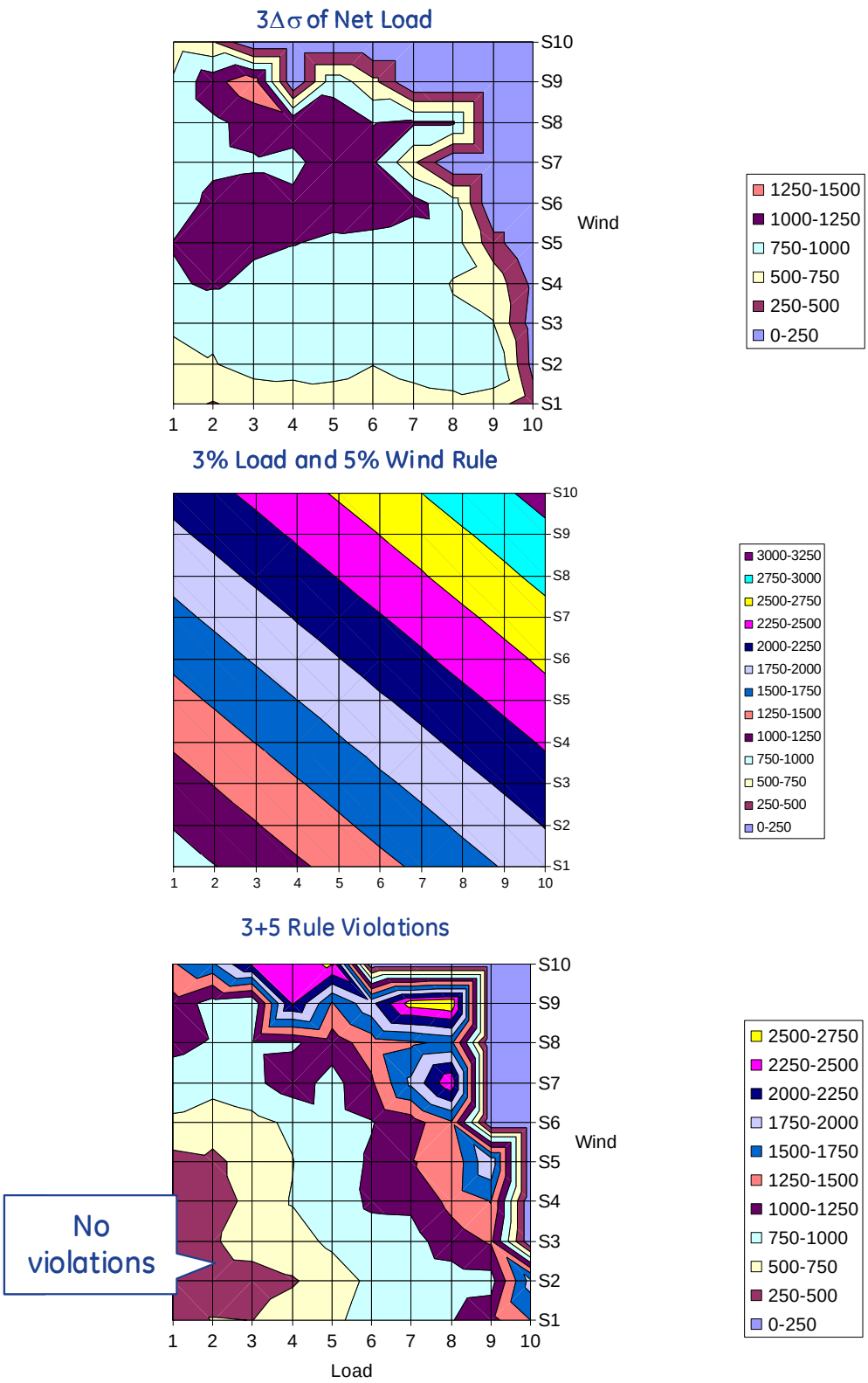


Figure 7.82 In Footprint L30R 3% Load plus 5% Wind Rule

As we examine the individual areas, the details vary considerably.

Arizona - The 3+5 rule performance for Arizona is shown in Figure 7.83. There are generally positive margins, although are some rare periods of high load and moderate wind (load 9 and wind 4) where there are pockets of violations.

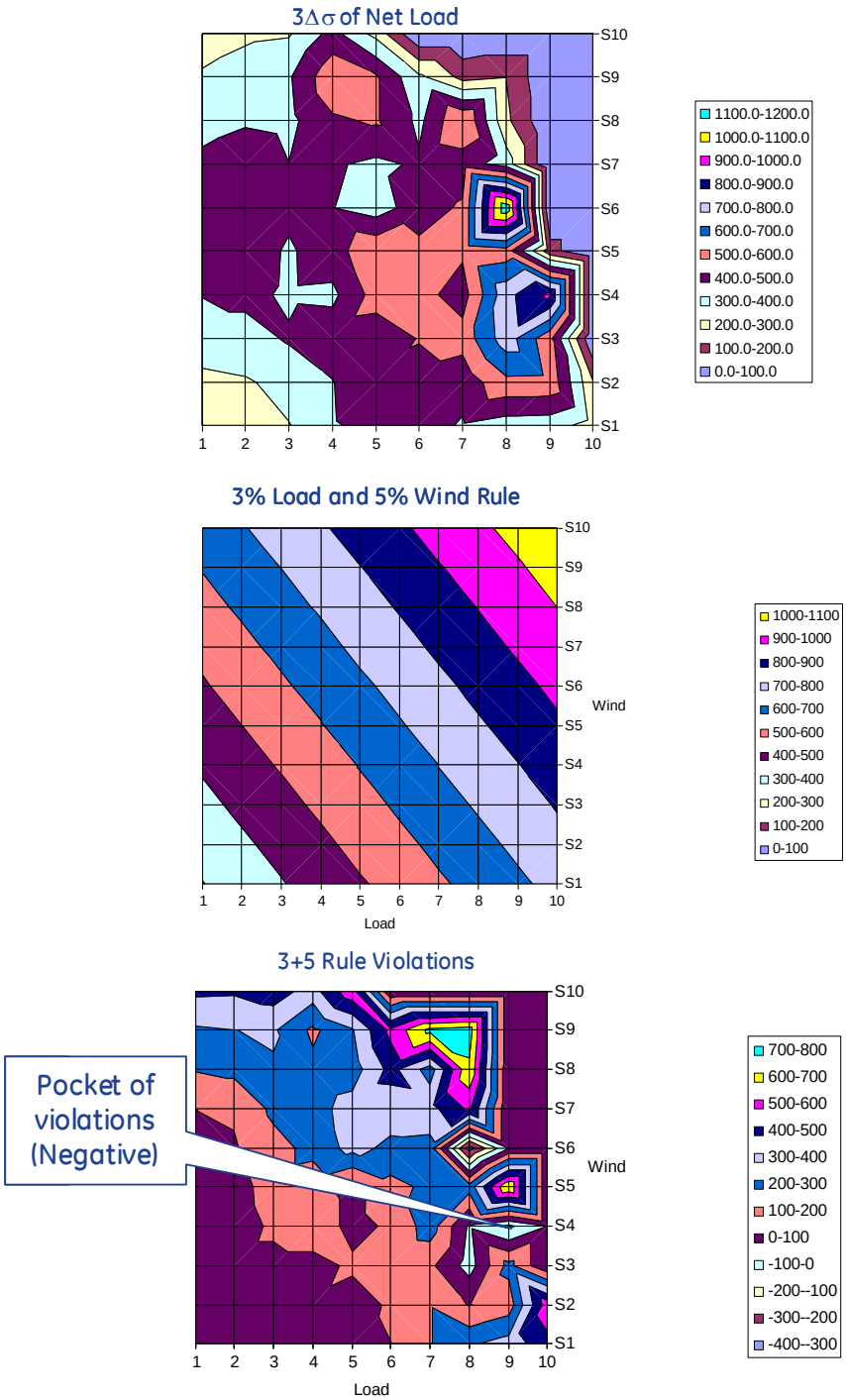


Figure 7.83 Arizona L30R 3% Load plus 5% Wind Rule

Wyoming - The 3+5 rule performance for Wyoming is shown in Figure 7.84. The reserves in this case are generally short of the requirements. They are severely negative in the area of very high load that was observed earlier to have limited statistical validity.

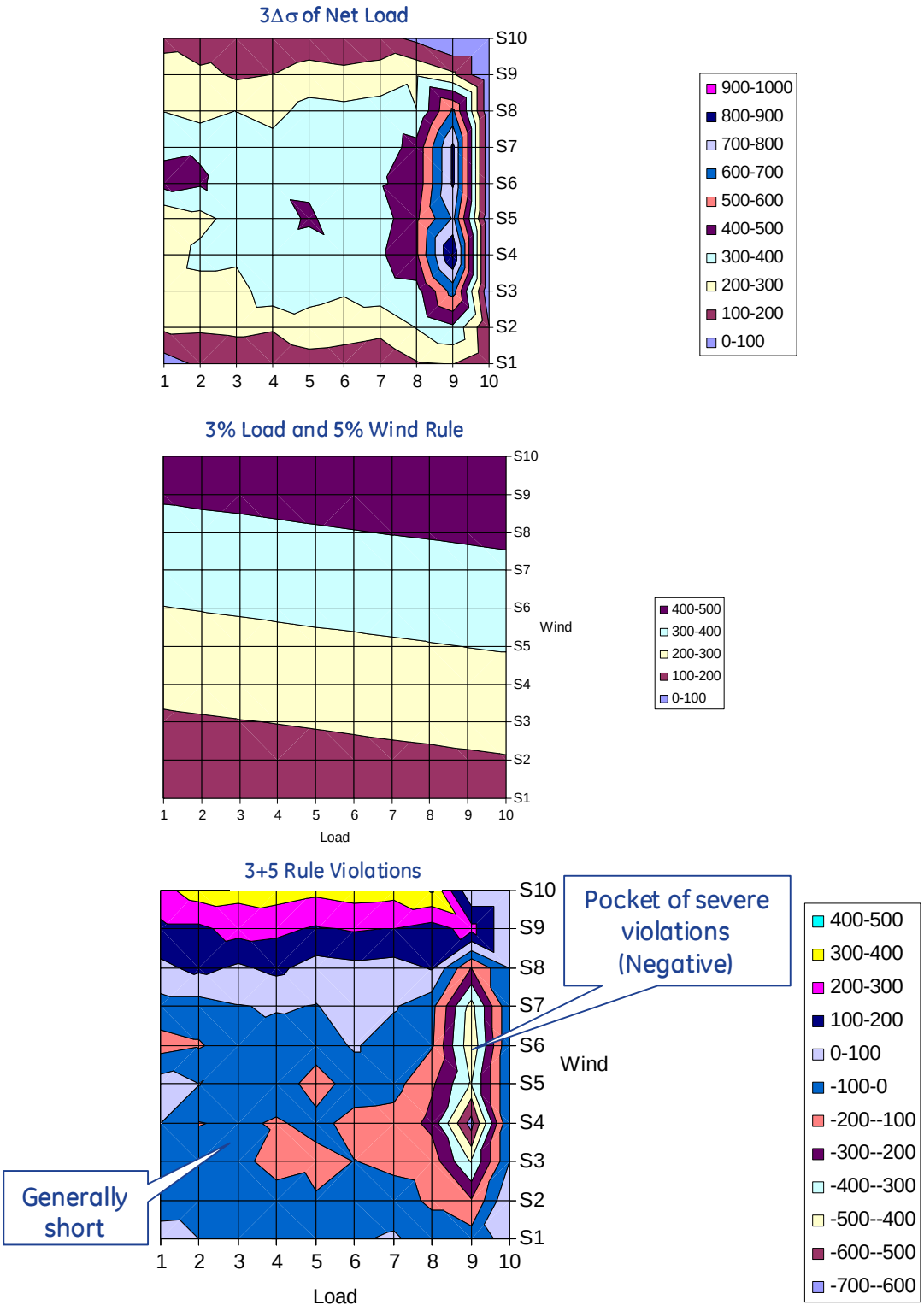


Figure 7.84 Wyoming L30R 3% Load plus 5% Wind Rule

Colorado East - The 3+5 rule performance for Colorado East is shown in Figure 7.85. There are pockets of violation at high wind and moderately light load. Colorado East shows higher volatility at high wind than is observed in other areas. This reinforces the idea that reserve rules may benefit from customization by area.

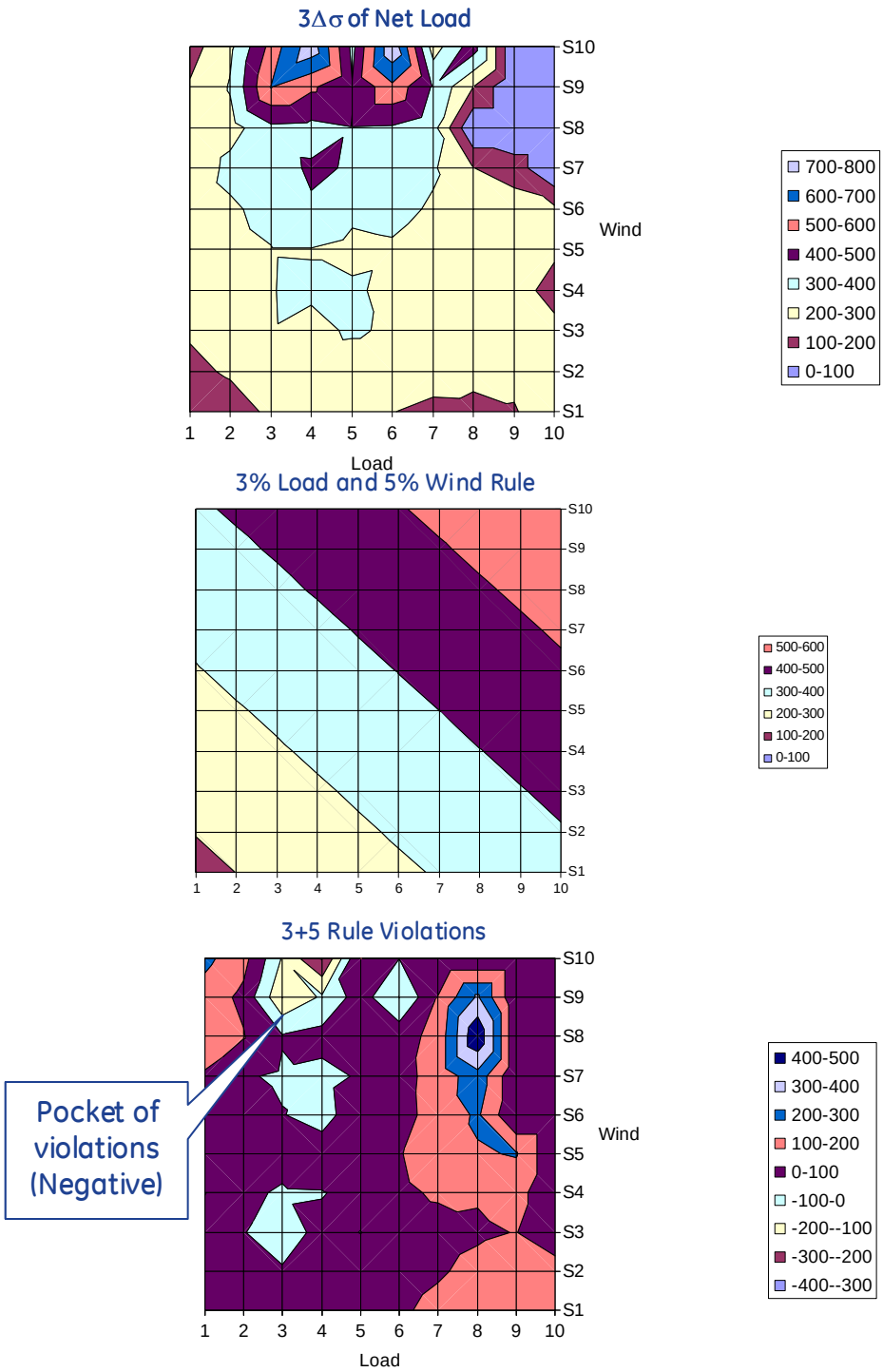


Figure 7.85 Colorado East L30R 3% Load plus 5% Wind Rule

Nevada - The 3+5 rule performance for Nevada is shown in Figure 7.86. Some violations occur at moderate wind and light load.

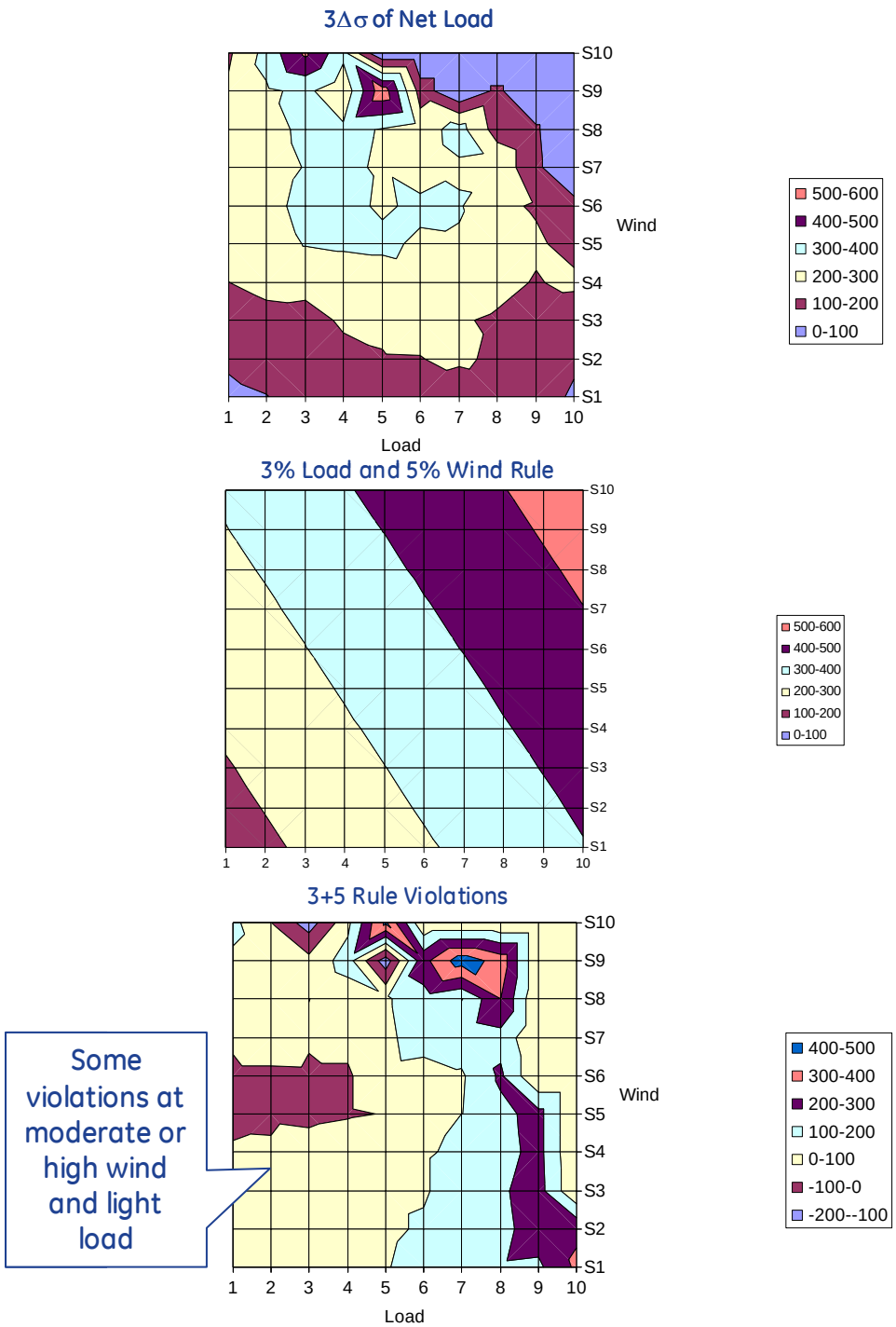


Figure 7.86 Nevada L30R 3% Load plus 5% Wind Rule

New Mexico - The 3+5 rule performance for New Mexico is shown in Figure 7.87. Small violations are shown at unusually high wind and light load conditions.

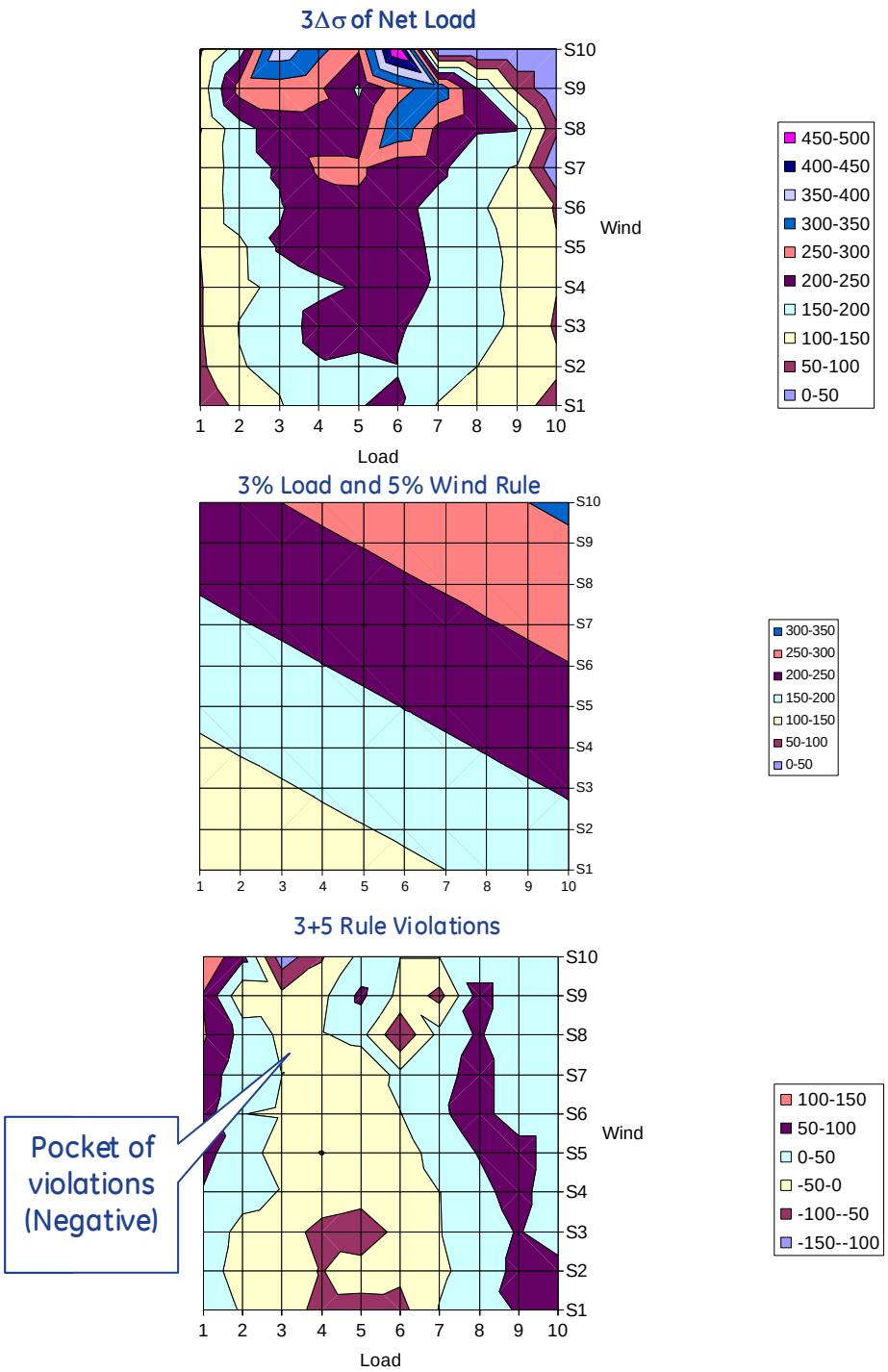


Figure 7.87 New Mexico L30R 3% Load plus 5% Wind Rule

Colorado West - The 3+5 rule performance for Colorado West is shown in Figure 7.88. The reserves here are almost entirely inadequate across the entire load and wind space.

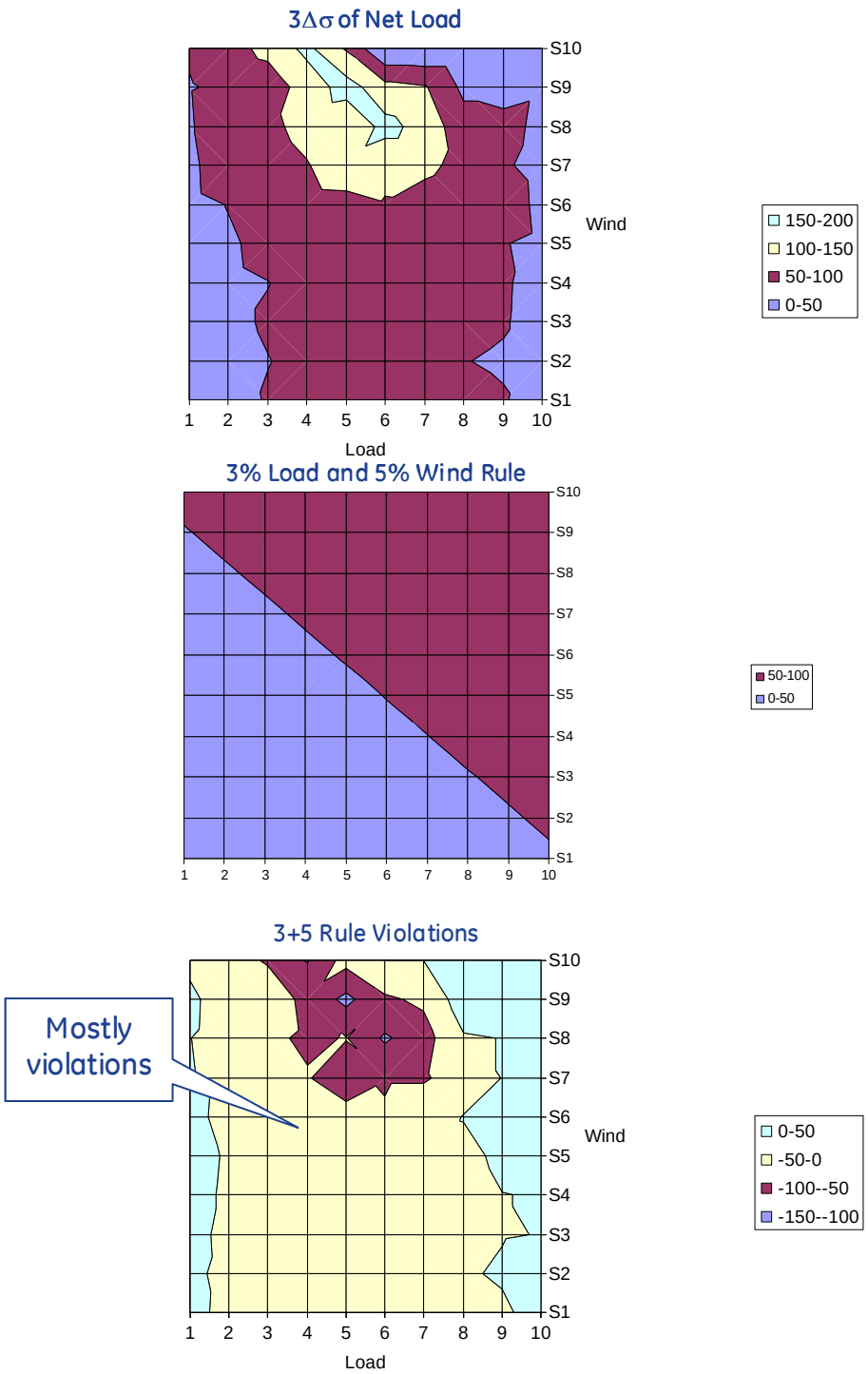


Figure 7.88 Colorado West L30R 3% Load plus 5% Wind Rule

In summary, the 3+5 rule works and is apparently conservative at the study footprint level, i.e. assuming control areas cooperate for intrahour balancing. The performance of individual areas ranges from good coverage of $3\Delta\sigma$ reserve requirements to frequent violations. This suggests that refinements of the simple 3+5 rule by area would be beneficial.

7.5.3 General Load + Wind Rules

The results shown in the preceding section suggest that simple rules, like the 3+5 rule hold promise. As noted above, the 3+5 is a logical extension of the linear fit of the 3% load rule. While the 3% rule is a line dependent only on load, the 3+5 rule is, by extension, a plane in the load and wind space. However, the 3+5 rule was chosen heuristically, i.e. it was an educated guess. In this section, we introduce the idea of a more rigorous mapping from the complexity of the $3\Delta\sigma$ requirement surfaces to a "best" linear (planar) fit rule to approximate that requirement.

The idea of a fit is relatively simple: we determine single scalar values of X (a "load coefficient") and Y (a "wind coefficient"), such that the error, given by:

Equation 7.1

$$\text{error} = \iint \beta(\lambda,\omega) * (3\Delta\sigma(\lambda,\omega) - (X\lambda + Y\omega))^2 \, d\lambda \, d\omega$$

is minimized, where

λ is a particular load level

ω is a particular wind level

$\beta(\lambda,\omega)$ is the probability of being at a particular load λ and wind power ω

$\Delta\sigma(\lambda,\omega)$ is the 10-minute delta sigma

The equation is integrated over the entire load and wind space, as previously described. The net result is an "RMS" best fit.

To find the minimum error, the equation is solved using a simple gradient descent algorithm. The resulting optimum X (the load coefficient) and optimum Y (the wind coefficient) provide a new rule of the same character as the 3+5 rule, but with a best fit. For this subsequent discussion, we call these "X+Y" rules.

Results are again presented by area in order of descending wind nameplate.

In footprint - The X+Y rule is shown in the left surface of Figure 7.89. The load and wind coefficients are 1.3 and 3.6, respectively. The right surface plot shows the 3Δσ requirement for which the X +Y surface is the best fit.

Arizona - The X+Y rule performance for Arizona is shown in Figure 7.90 . The load and wind coefficients are 2.5 and 2.0, respectively. The fit is broadly consistent with the complex 3Δσ surface.

Wyoming - The X+Y rule performance for Wyoming is shown in Figure 7.91 . The load and wind coefficients are: 5.6% Load + 2.1% Wind. The result is difficult to accept, with apparently too little reserve, especially at lower wind and load levels. The explanation is that, as observed in Figure 7.61, the net load variability is dominated by wind, which has a roughly quadratic shape. We are mathematically forcing a plane through roughly a section of a cone, which is not great for curve fitting. Additional experiments with Wyoming are presented in Figure 7.92. This is a purely heuristic approach, using load and wind coefficients of 3 + 10. This, while a worse fit from an RMS perspective, is an improvement. The result gives better coverage at low wind power, but is overkill at high power. We will examine this further in the next sections.

Colorado East - The X+Y rule performance for Colorado East is shown in Figure 7.93. The load and wind coefficients are 2% Load + 5.5% Wind. As we saw in Figure 7.84, Colorado East seems to have uncharacteristically high variability at high wind and moderate load. This could possibly reflect something particular to the terrain or wind regime at high wind conditions. This tends to reinforce the notion that reserve requirements can benefit from customization for each area.

Nevada - The X+Y rule performance for Nevada is shown in Figure 7.94 . The load and wind coefficients are 1.3% Load + 7.8% Wind. The fit is not bad.

New Mexico - The X+Y rule performance for New Mexico is shown in Figure 7.95. The load and wind coefficients are 3% Load + 3.6% Wind. This is a relatively good fit, but not great. The reserves are somewhat generous at high load moderate wind and a little skinny in highest wind conditions.

Colorado West - The X+Y rule performance for Colorado West is shown in Figure 7.96. The load and wind coefficients are 3.1% Load + 7.3% Wind.

The plots provided in this section do a reasonable job of matching the implied 3Δσ requirements for net load. Nevertheless, they do tend to exceed the requirements at high load and wind conditions, and to be a bit short at lower load and wind. This suggests that further refinement may be desirable. One possible refinement is presented in the next section.

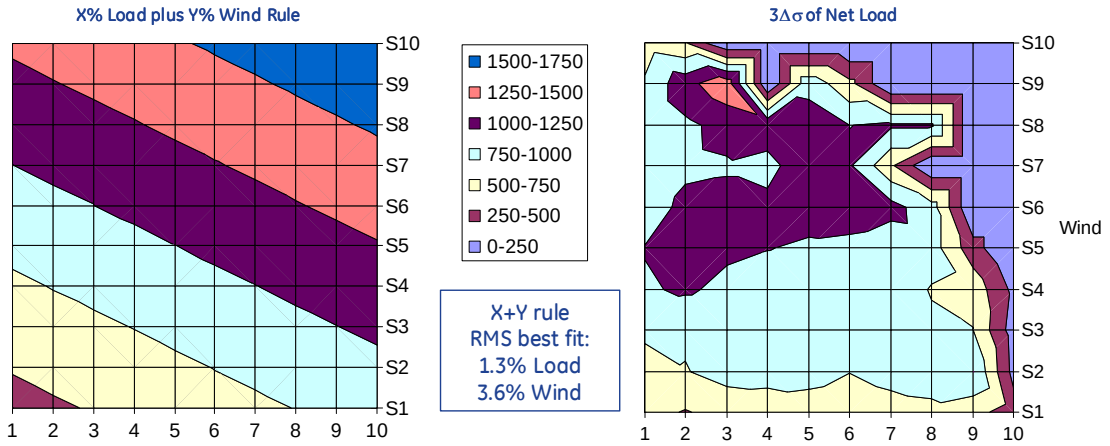


Figure 7.89 In Footprint L30R Best RMS Fit X% Load plus Y% Wind Rule

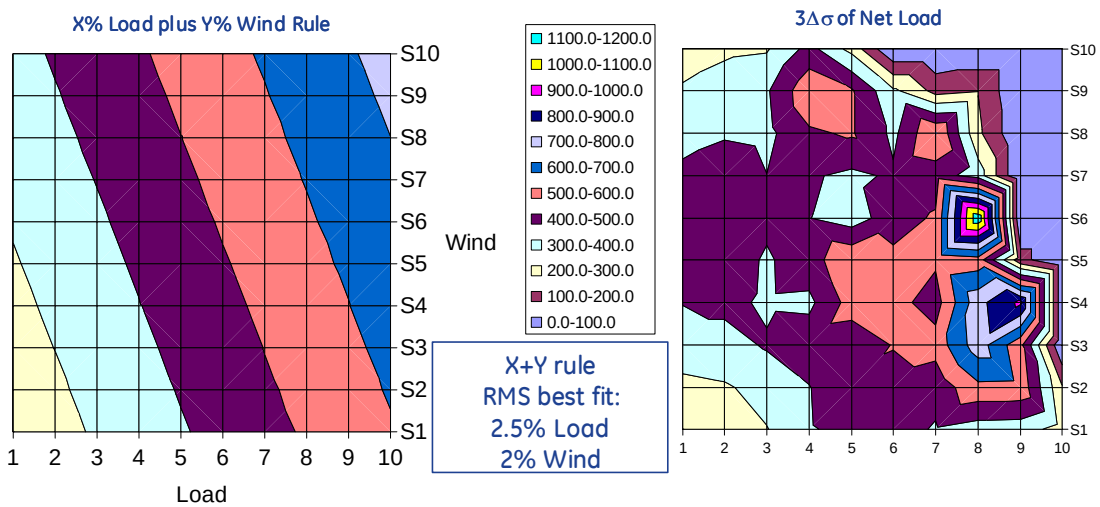


Figure 7.90 Arizona L30R Best RMS Fit X% Load plus Y% Wind Rule

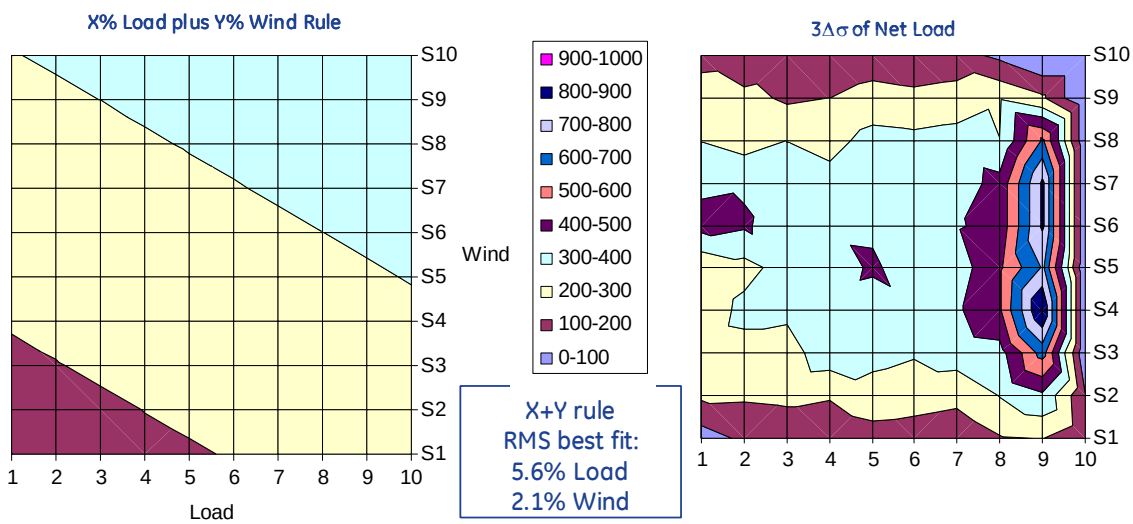


Figure 7.91 Wyoming L30R Best RMS Fit X% Load plus Y% Wind Rule

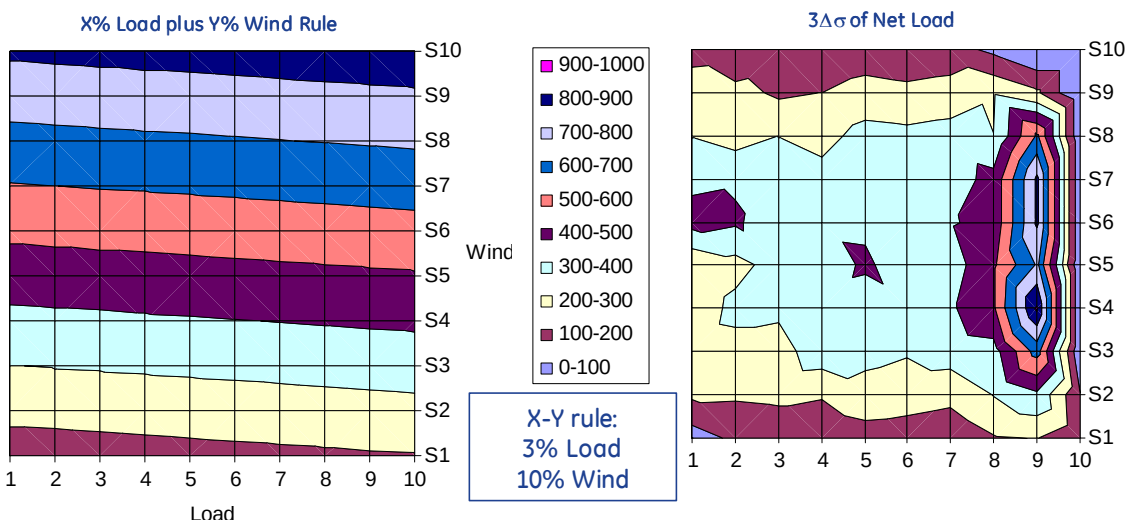


Figure 7.92 Wyoming L30R Heuristic 3% Load plus 10% Wind rule

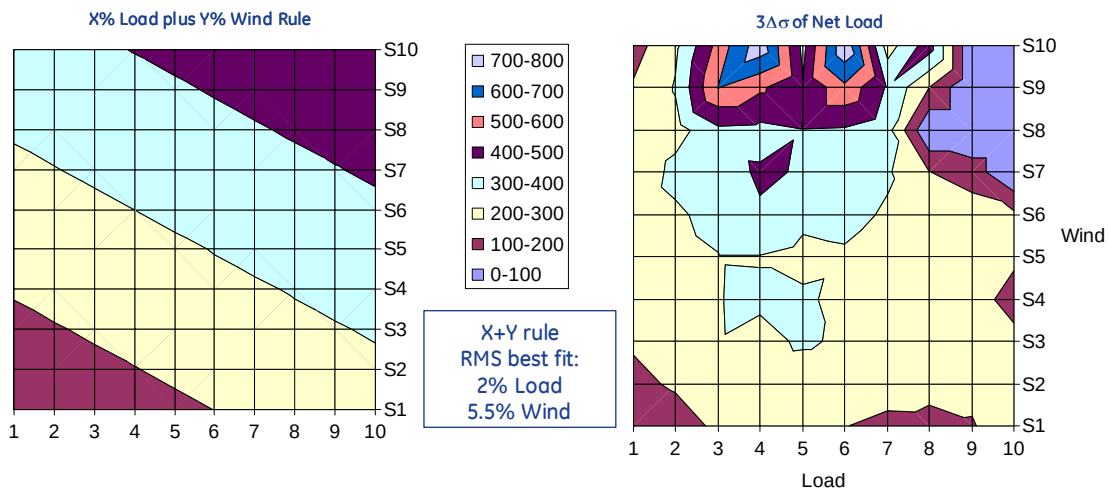


Figure 7.93 Colorado East L30R Best RMS Fit X% Load plus Y% Wind Rule

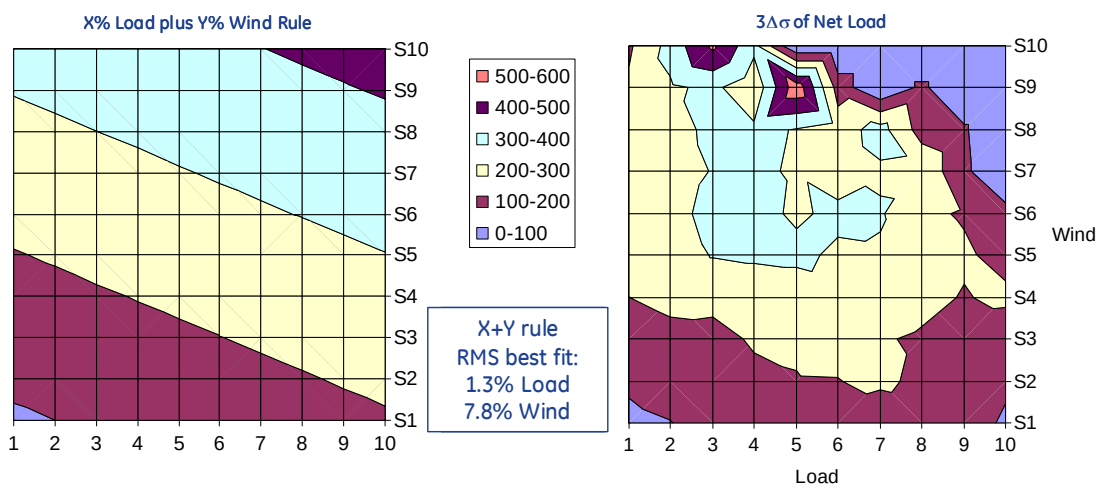


Figure 7.94 Nevada L30R Best RMS Fit X% Load plus Y% Wind Rule

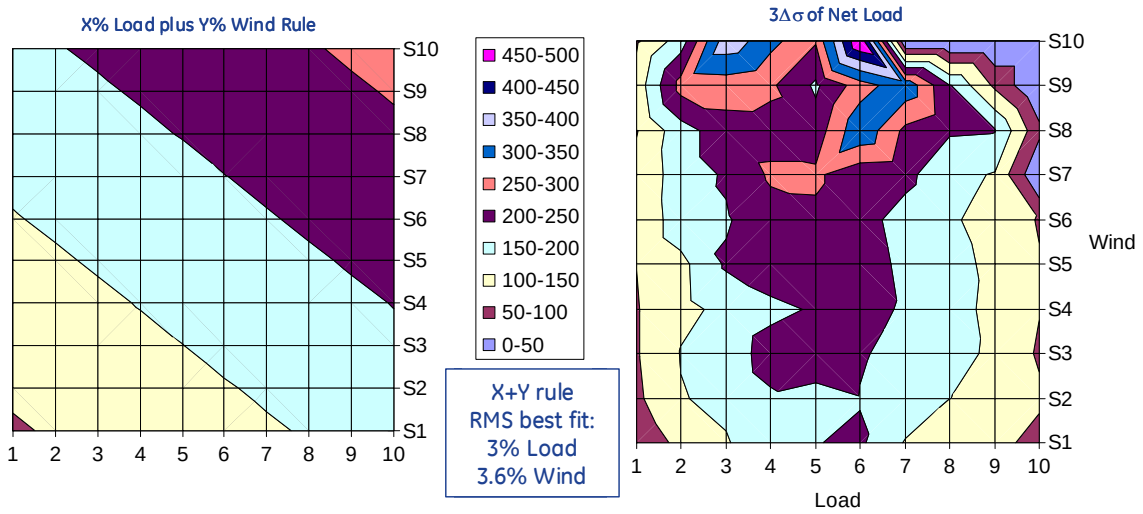


Figure 7.95 New Mexico L30R Best RMS Fit X% Load plus Y% Wind Rule

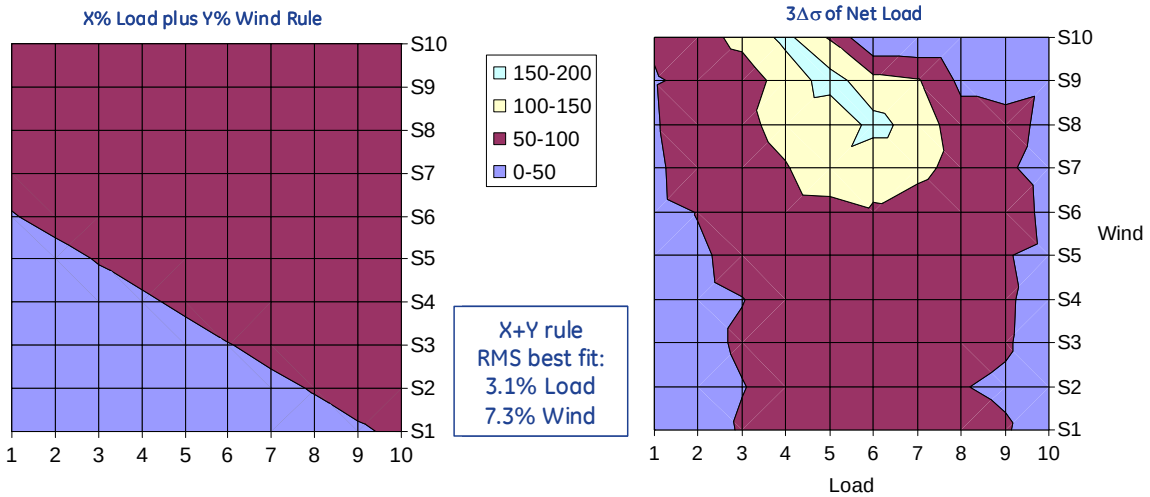


Figure 7.96 Colorado West L30R Best RMS Fit X% Load plus Y% Wind Rule

7.5.4 Conditional Load + Wind Rules

The variability due to wind, as shown in Figure 7.47, tends to reach a relative maximum at part power. Therefore it makes sense to avoid increasing the reserves above a certain level of wind. In this section, we examine modification of the Load plus Wind rules to include conditionality on the wind. Specifically, we identify a wind power level above which no additional reserves are added.

In order to determine the level of this conditionality, the error minimization of Equation 7.1 is used with an extra degree of freedom: at a specific wind level we stop increasing reserves in proportion to the wind power. The optimization problem has three degrees of freedom: the load coefficient (X), the wind coefficient (Y), and now, the maximum wind above which we stop adding reserves. Using this approach, the RMS fit (i.e. the

least error) to the 3Δσ requirements surface can be greatly improved. In each case presented here then, the minimization of Equation 7.1 includes a conditional maximum.

Results are presented, once again in descending order of wind nameplate, in the following figures.

In footprint - X+Y conditional rule is shown in Figure 7.97. The results for the X+Y conditional rule best fit are: 1.1% load + 5.0% wind < 47% wind nameplate. This fit is generally satisfactory. The conditionality is closely related to the simple piecewise linear curve fit of Figure 7.44. The 3Δσ slope fit for that figure is 10% wind up to 30% wind nameplate. This is somewhat different because of the presence of the load term in the fit and because of the RMS optimization.

Arizona - The X+Y conditional rule performance for Arizona is shown in Figure 7.98. The results for the X+Y conditional rule best fit are: 2.2% load + 5.6% wind < 36% wind nameplate. With the conditionality added the fit is generally satisfactory.

Wyoming - The X+Y rule conditional performance for Wyoming is shown in Figure 7.99. The results for the X+Y conditional rule best fit are: 2.2% load + 8.7% wind < 33% wind nameplate. This is fit is better, but even this approach tends to carry too much reserve at high wind (based on 3Δσ rule), so RMS minimization reduces coverage at low wind. Further improvements seem desirable.

Additional experiments in selecting reserve rules for Wyoming are shown in Figure 7.100. In this case, the X+Y conditional approach is skewed to give more priority to low power conditions. The resulting, purely heuristic rule of 3% load and 10% wind < 40% wind nameplate appears satisfactory. The rule is simple, a little conservative and purely heuristic. It could be tuned.

Colorado East - The X+Y conditional rule performance for Colorado East is shown in Figure 7.101. The results for the X+Y conditional rule best fit are: 2.0% load + 5.7% wind < 68% wind nameplate. In this case, the conditionality is not so obviously beneficial for the high volatility, high wind and moderate load condition.

Nevada - The X+Y conditional rule performance for Nevada is shown in Figure 7.102. The results for the X+Y conditional rule best fit are: 1.0% load + 10.7% wind < 54% wind nameplate. This fit is generally satisfactory. The heavy weight on wind is somewhat at odds with the results from the other fits. However, convergence of the gradient descent optimization for this area was very sensitive. Therefore, the optimum locus must be relatively flat in load and wind space. This suggests that a different set of load + wind coefficients could give similar results.

New Mexico - The X+Y conditional rule performance for New Mexico is shown in Figure 7.103. The results for the X+Y conditional rule best fit are: 3% Load + 3.5% Wind <70% wind. Inspection suggests that the result is no better than with just X+Y.

Some additional experiments in New Mexico are shown in Figure 7.104. In this case, the load term is fixed at a level proportional to the peak load. This is a different conditional rule. The best fit is: 2.2% *peak* load + 3.8% wind <47% wind. This gives essentially the same quality of fit (in the error sense), and it is not obviously better. A heuristic fit of 3.0% peak load + 4.5% wind is shown in figure as well. It is not numerically as good of a fit, but it is arguably better. It is not clearly better than the simple 3+5 rule.

Colorado West - The X+Y conditional rule performance for Colorado West is the same as the simple X+Y rule. That is, the wind term increases linearly at a rate of 7.3% of wind up to maximum wind. The conditional surface is therefore the same as that shown in Figure 7.96.

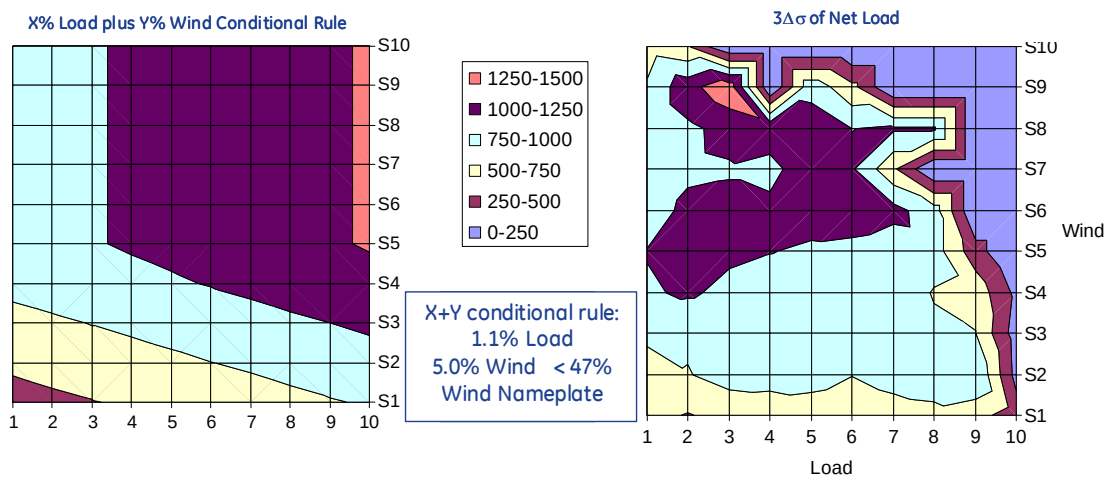


Figure 7.97 In Foot print L30R X% Load plus Y% Conditional Wind Rule

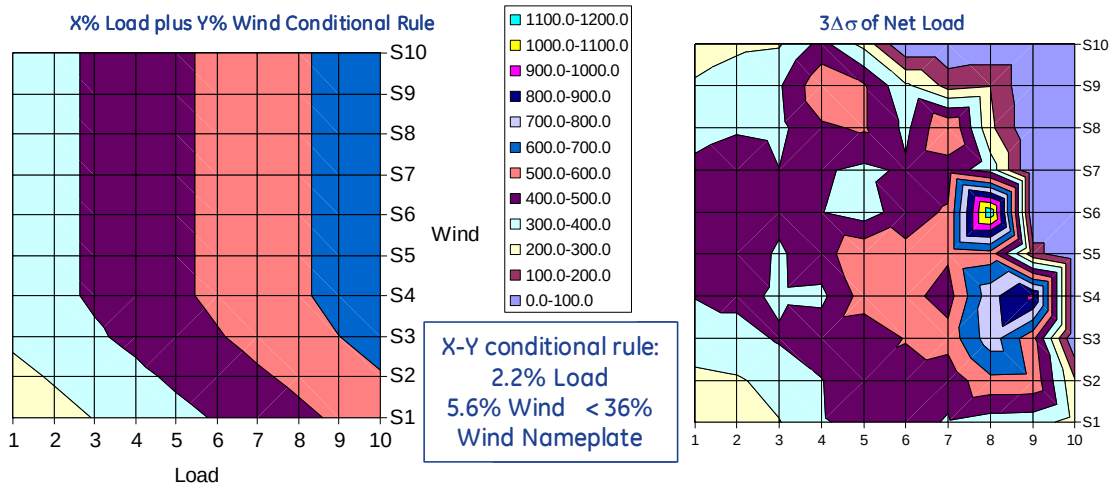


Figure 7.98 Arizona L30R X% Load plus Y% Conditional Wind Rule

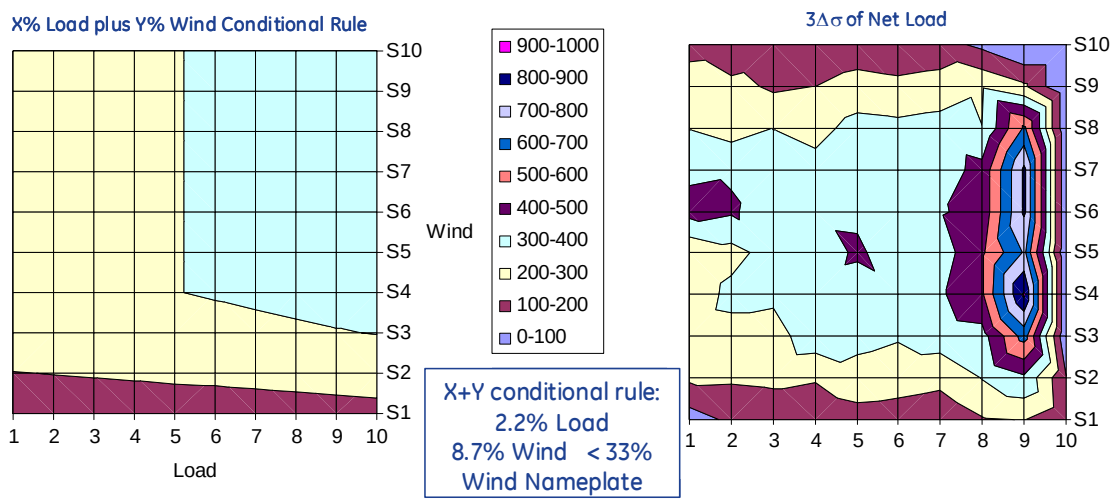


Figure 7.99 Wyoming L30R X% Load plus Y% Conditional Wind Rule

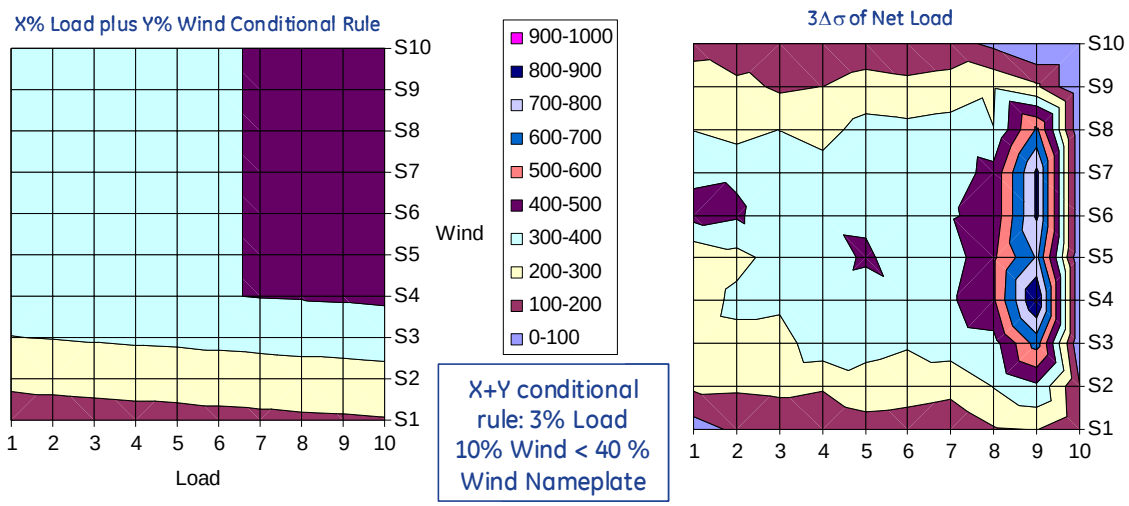


Figure 7.100 Wyoming L30R X% Load plus Y% Conditional Wind Rule, low power priority

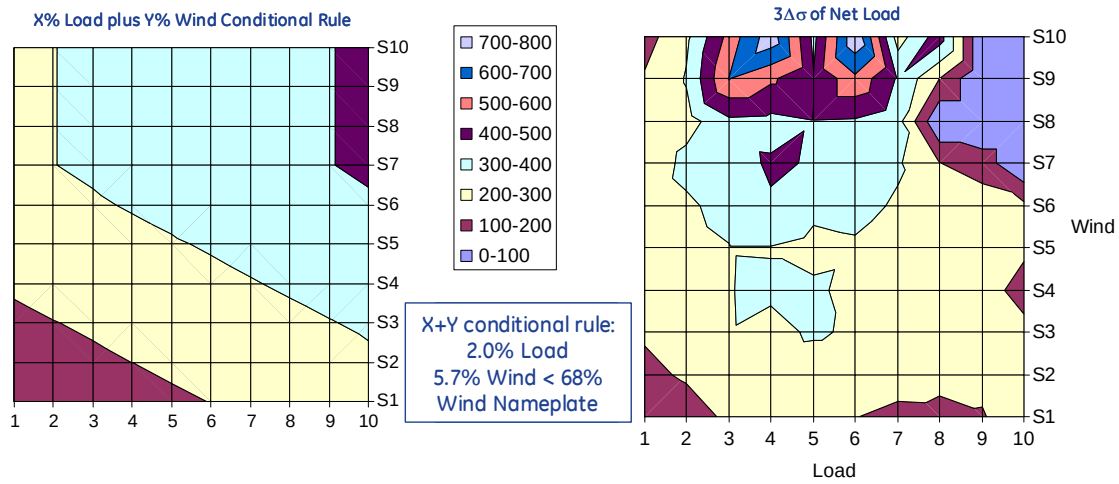


Figure 7.101 Colorado East L30R X% Load plus Y% Conditional Wind Rule

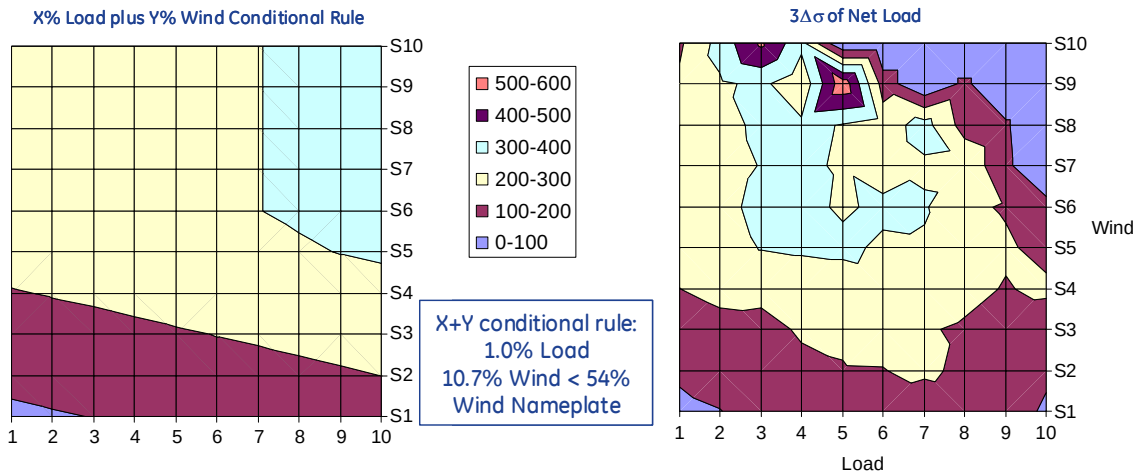


Figure 7.102 Nevada L30R X% Load plus Y% Conditional Wind Rule

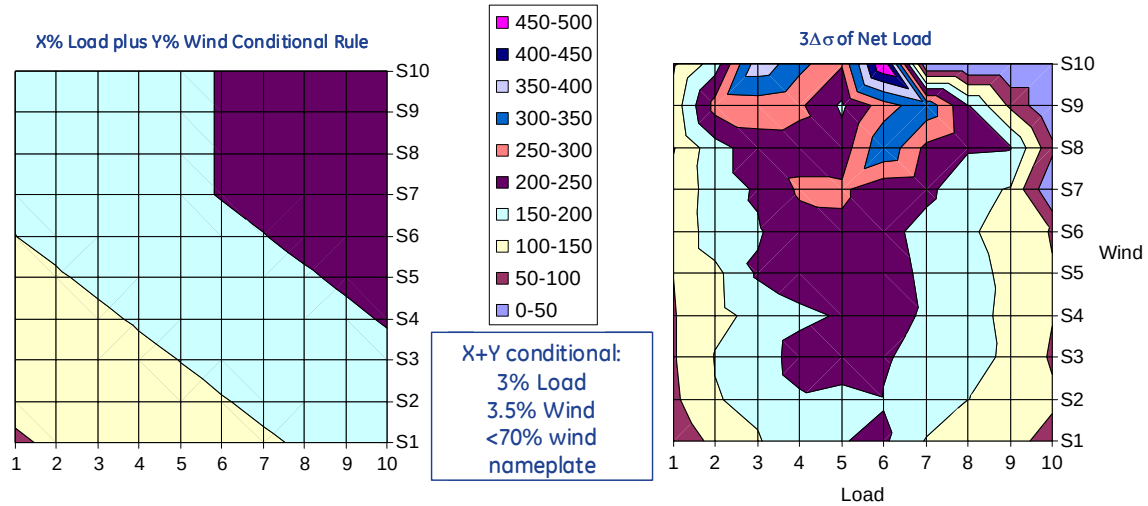


Figure 7.103 New Mexico L30R X% Load plus Y% Conditional Wind Rule

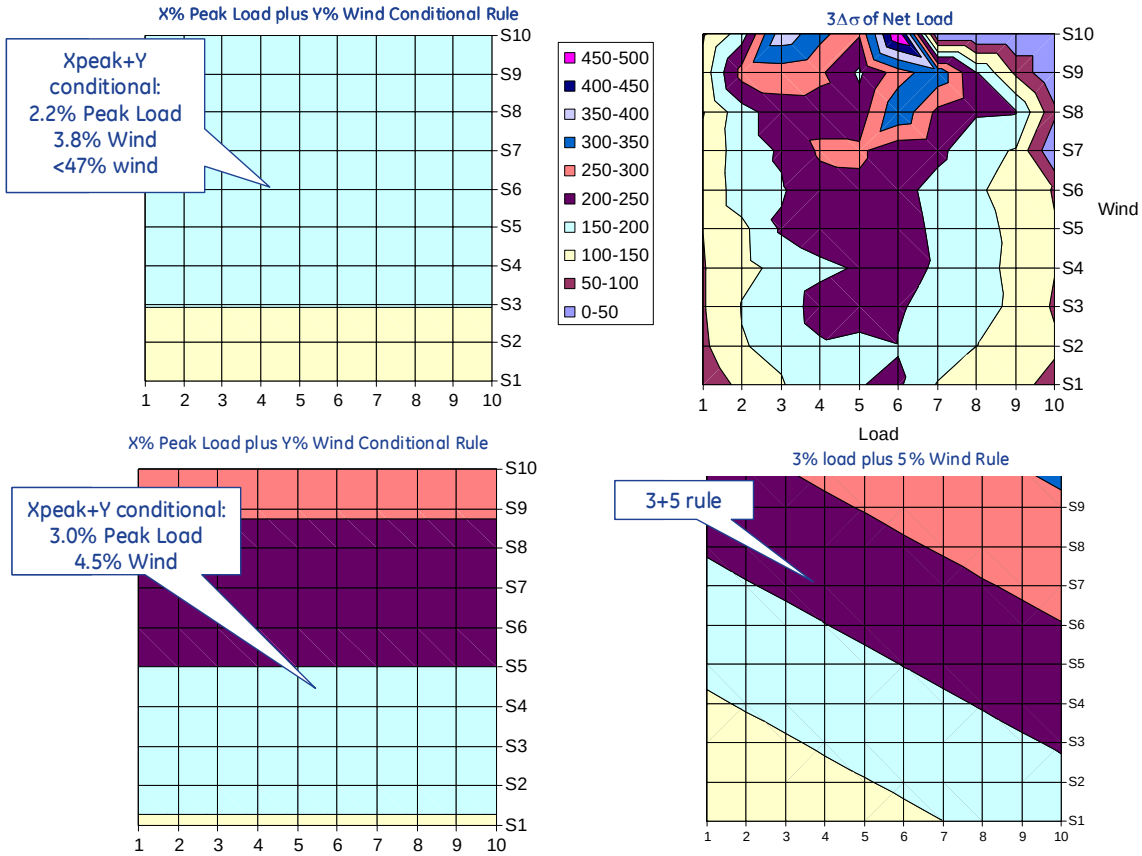


Figure 7.104 New Mexico L30R Other heuristics on X+Y Conditional rule

7.5.5 Load only Rules

The results presented throughout this section raise some questions about existing practice for determining reserves. The "need" for incremental reserves is based on the presumption that without wind, the reserves carried are "right." This is a conundrum. If the primary driver for reserves is load variability, then the 3% rule, as we showed, is roughly rational. It is, however, far from exact. As we see in the detailed statistical fitting process, sometimes it is too much, or perhaps more accurately it is conservative. At other times, it seems marginal. The RMS fits show that in some broad sense, more reserve is indeed required.

In this section, we examine the 3% load rule and test it by the same RMS fit philosophy use to generate the X+Y and X+Y conditional rules presented in the previous sections. The intent is to provide context or a consistent basis of comparison between the baseline (no wind) variability rules and those with wind. Results are presented by area here.

Arizona - The 3+0 rule for performance for Arizona is shown in Figure 7.105. The surface on the left of the figure is the load variability surface. The center surface is the 3% of load rule, which since it lacks dependence on wind, is very simple. On the right,

the difference between 3% of load rule and 3Δσ of *load only* is shown. There is one small area of violation, but overall the 3% of load is overkill throughout the load range, especially at high load levels.

Some experiments on load-only rules for Arizona are shown in Figure 7.106 . The best RMS fit to 3Δσ of *load only*, is 2.2% of load. The surface for this rule is shown in the upper right hand part of the figure. Like the rules for wind, and as we observed in the discussion of Figure 7.49, the 3% rule tends to result in excess reserves being carried at high load. This holds true for this 2.2% best fit as well. This suggests that a rule that reaches a maximum condition would fit better. The best conditional fit for load only is shown in the lower left surface. For this rule, 2.4 % of load up to 50% of the load range (NOT 50% of peak load!), gives a better fit. The relationship between the two surfaces is sketched onto the net load variable curves (from Figure 7.49) for illustration. The blue line shows the steeper, 2.4% slope reaching a maximum at 50% of the load range.

In the next five figures, for each area, the 3Δσ of *load only* surface is shown in the upper left. The 3% of load surface is in the upper right. The reserve margin, i.e. the difference between 3% of load and 3Δσ of load only, is shown in the lower left. And the best RMS fit to load only with a maximum condition is shown in the lower right.

Wyoming - The load only results for Wyoming are shown in Figure 7.107. The 3% rule results in no short falls of reserve margin. The best RMS fit is for 1.4% of load up to 50% of load range. For loads above 50% of load range, the reserve requirement is capped at a maximum of 44 MW.

Colorado East - The load only results for Colorado East are shown in Figure 7.108. The 3% rule shows some minor violations at low power. The conditional best fit is for 2.6 % of load up to 38% of the load range. This corresponds to a maximum of 187 MW.

Nevada - The load only results for Nevada are shown in Figure 7.109. The 3% rule shows no violations. The conditional best fit is for 2.1 % of load up to 60% of the load range. This corresponds to a maximum of 193 MW.

New Mexico - The load only results for New Mexico are shown in Figure 7.110. The conditional best fit is for 2.1 % of load up to 43% of the load range. This corresponds to a maximum of 75 MW.

Colorado West - The load only results for Colorado West are shown in Figure 7.111. The conditional best fit is for 1.8 % of load up to 50% of the load range. This corresponds to a maximum of 20 MW.

These load only results are summarized in Figure 7.112. In this figure the average reserves carried to meet the 3% of load rule is shown by area, with a red triangle. The

average for the entire footprint is 979 MW. For comparison, the average reserve needed to meet 3Δσ of load-only is shown in blue diamonds. The average for the study footprint is 730 MW, somewhat less than the 3% rule. The maximum of the load-only conditional rule is 880 MW, which is similar to the other metrics.

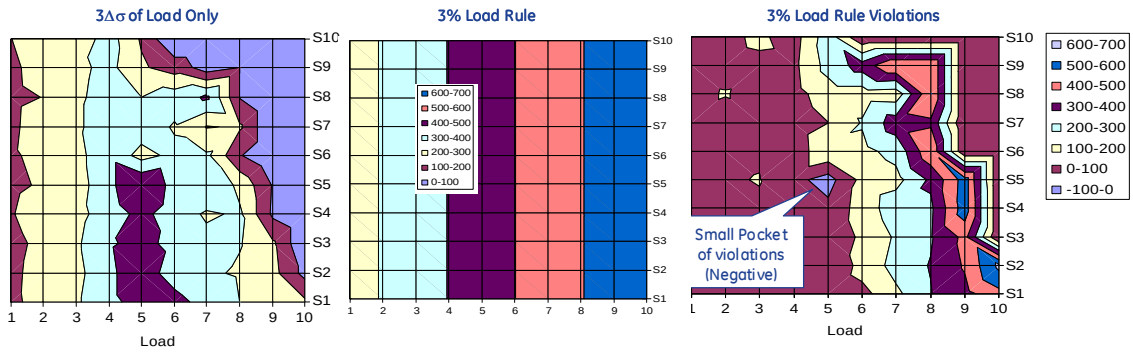


Figure 7.105 Arizona L30R Load Only Variability

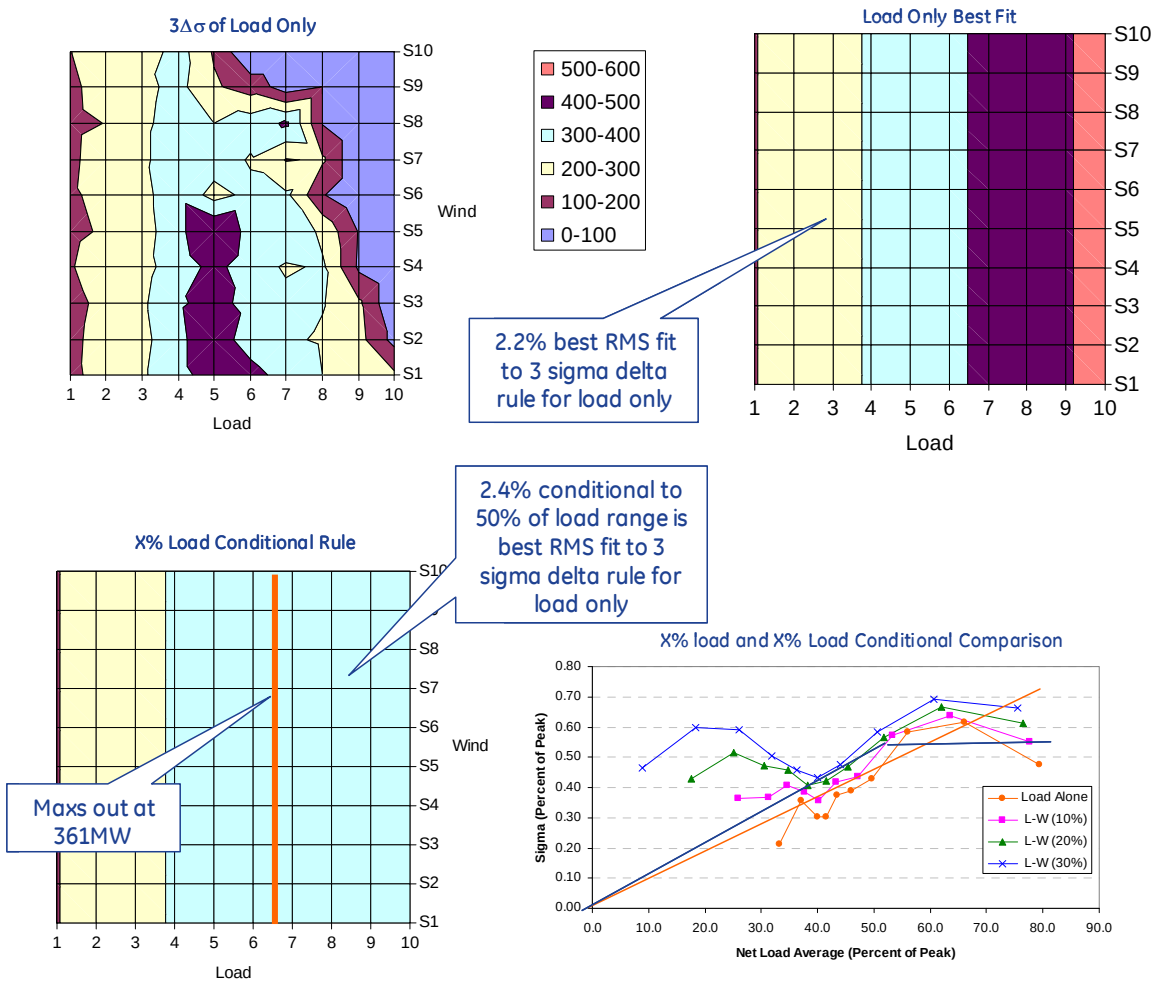


Figure 7.106 Arizona L30R Scenario Load Only Variability

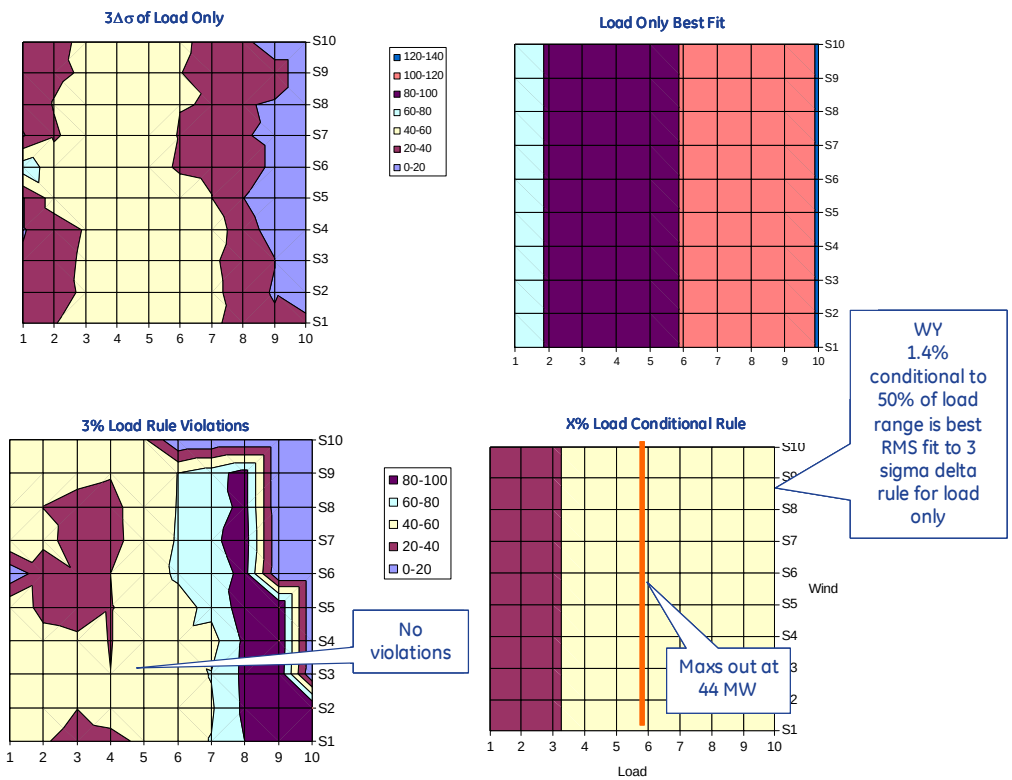


Figure 7.107 Wyoming L30R Scenario Load Only Variability

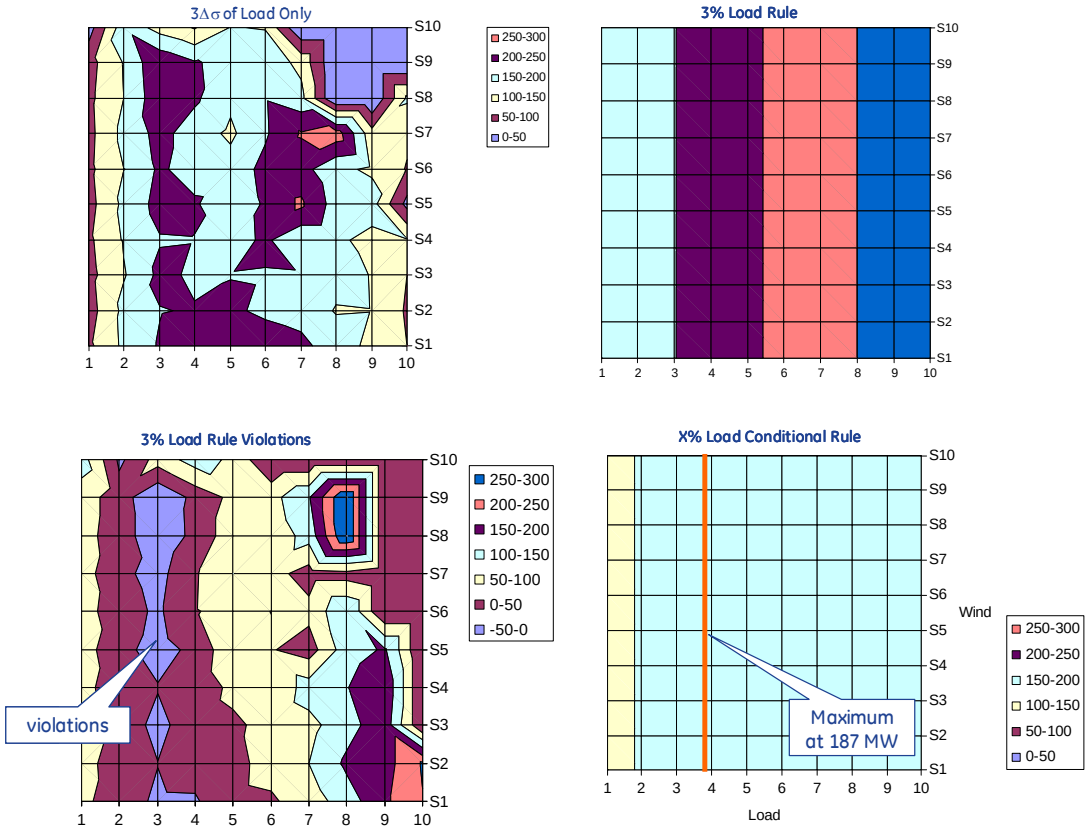


Figure 7.108 Colorado East L30R Scenario Load Only Variability

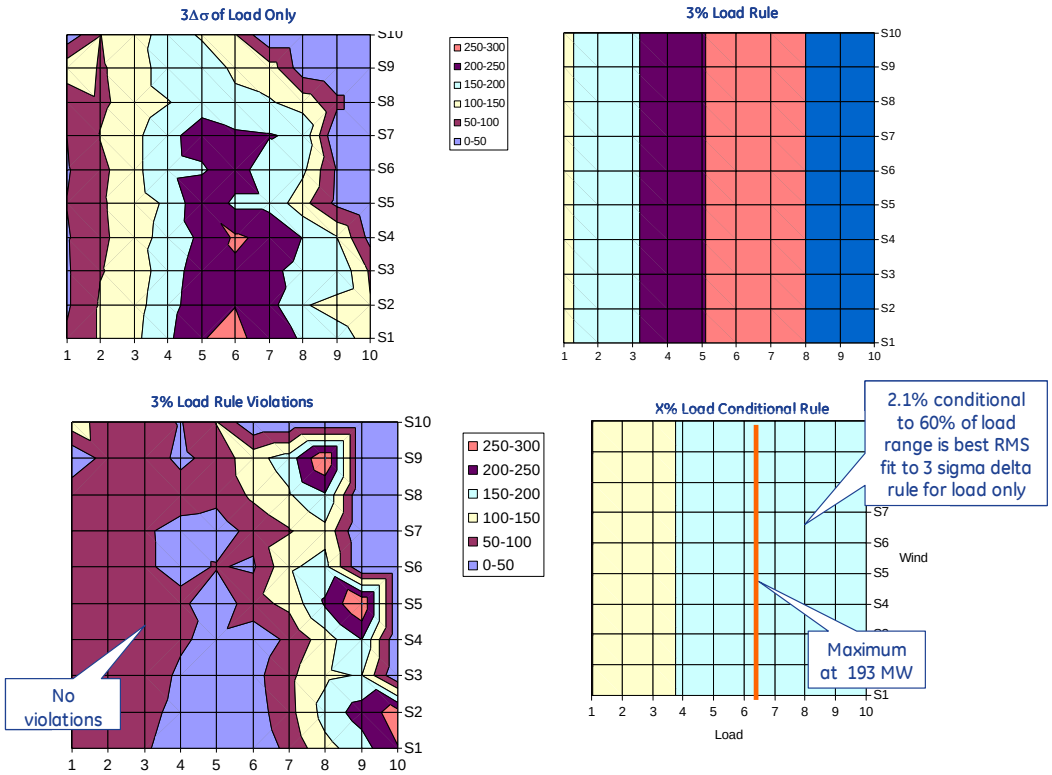


Figure 7.109 Nevada L30R Scenario Load Only Variability

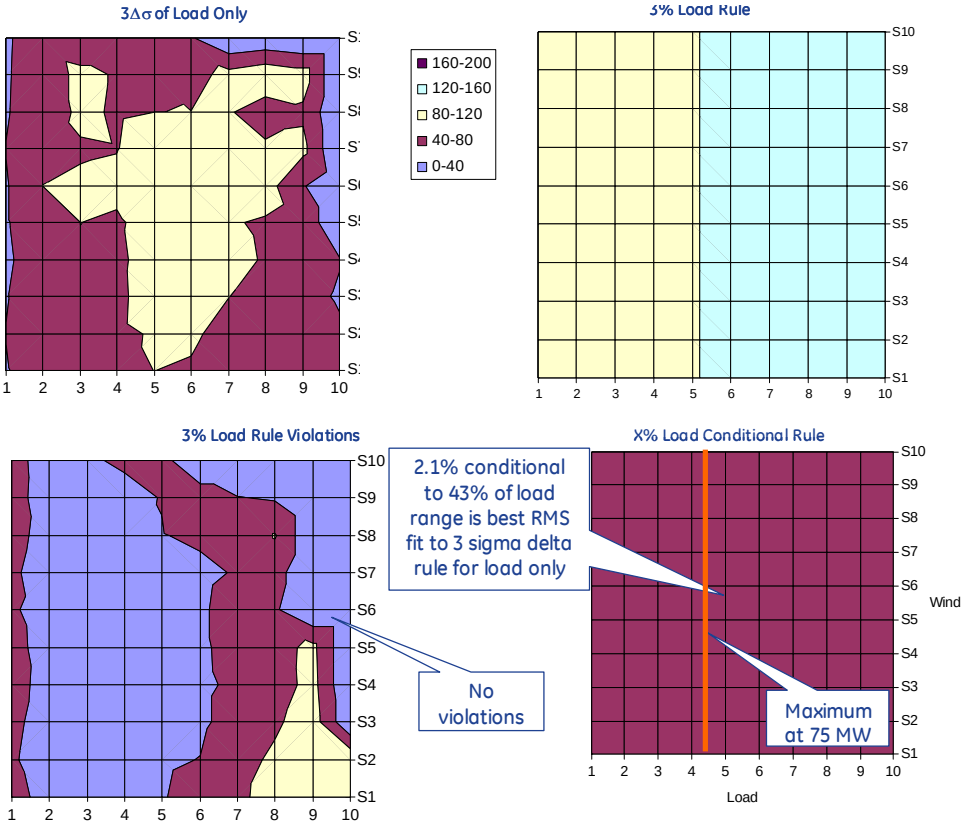


Figure 7.110 New Mexico L30R Scenario Load Only Variability

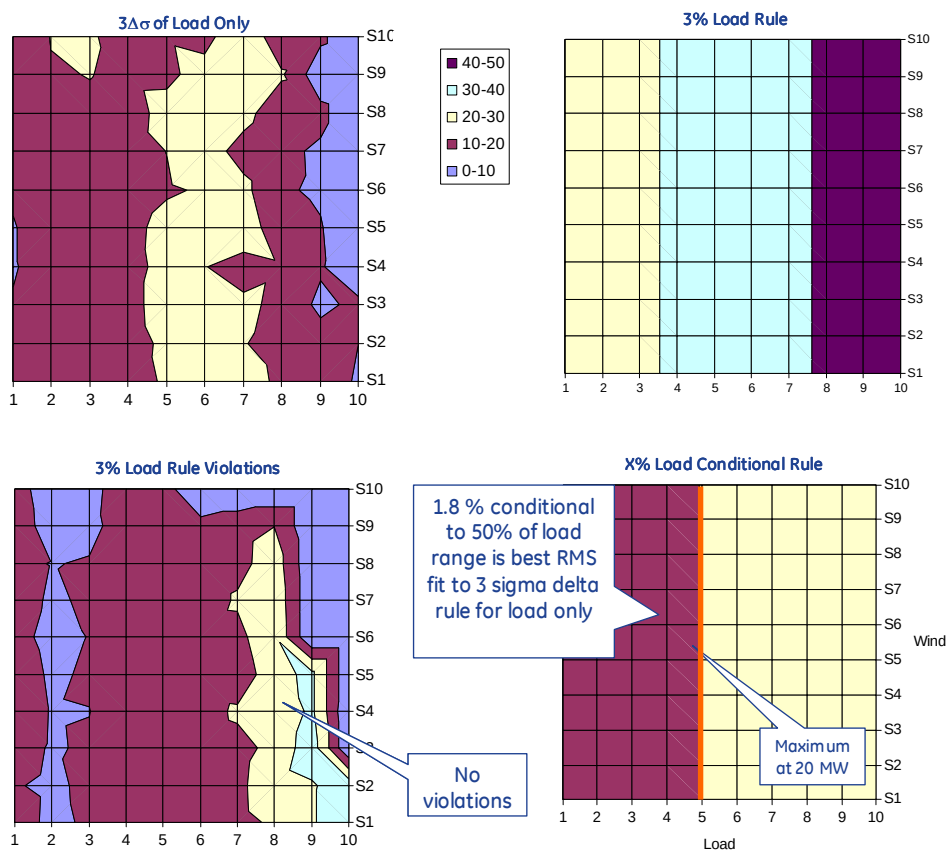


Figure 7.111 Colorado West L30R Scenario Load Only Variability

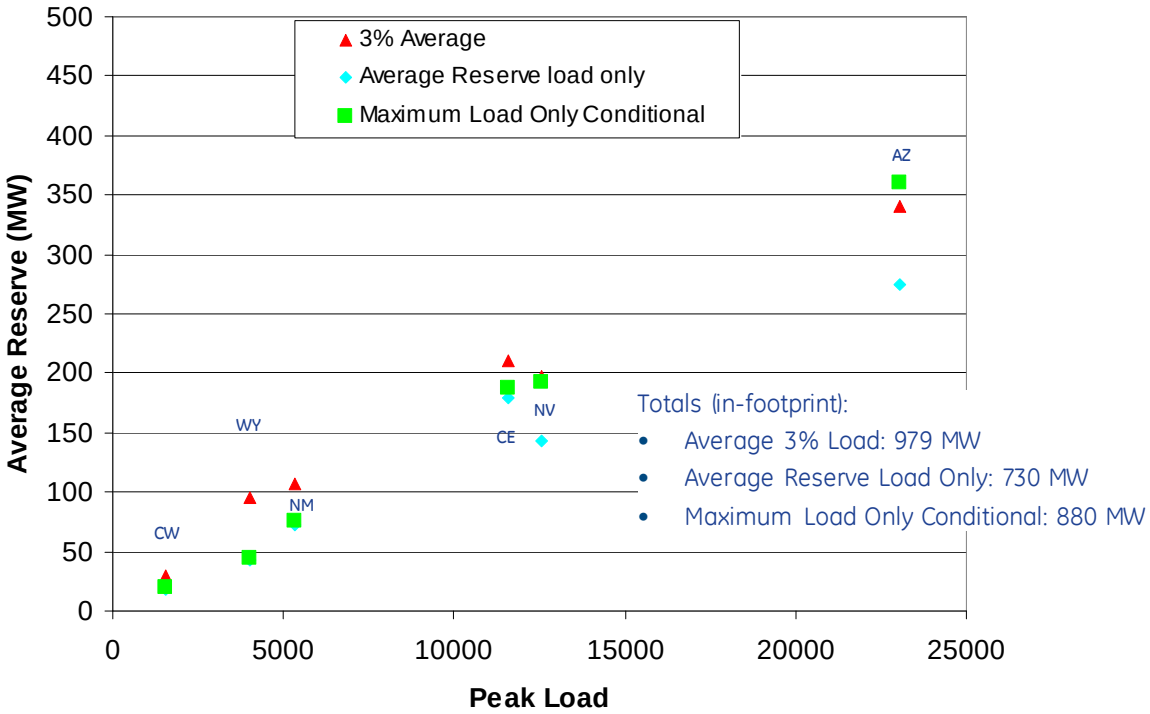


Figure 7.112 Regulation Reserve Requirements for Load Only (by Area)

7.5.6 Summary and Trends for Simplified Reserve Rules

The reserves provided by the two simplified reserve rules, the X+Y rule and the X+Y conditional rule, are shown in Figure 7.113 in comparison to the present 3% of load rule. The values in the figure are the maximum reserve carried, corresponding to peak load and/or peak wind. This figure shows two overall results emerging from the analysis presented above: (a) that overall the present 3% of load rule results in about the right amount of reserve being carried to meet expected net load variability, and (b) some refinements, based on the particular characteristics of the individual areas will tend to redistribute those reserves.

The average amount of reserve required is shown in Figure 7.114. Here the average reserves, for all 8760 hours in the year, associated with the load (X or Load Coefficient) and wind (Y or Wind Coefficient) are plotted. Further, the wind coefficient (Y) *assuming* 3% load, i.e. the 3+Y rule are shown as yellow points. This plot illustrates a number of interesting points. Most important, it reinforces the observation that at the footprint level, the 3% of load rule is about right. When reserves are allocated at the footprint level, no additional reserves that are a function of wind power level need to be added beyond those provided by the 3% of load rule. That is, the best fit for overall reserves against the $3\Delta\sigma$ rule of net load, is for no wind coefficient ($Y = 0$) when the load coefficient, X, is 3%. This is the reserve strategy used for dispatch in the MAPS simulations. Second, the figure shows that if the reserves are allocated by area in accordance with the net load variability of that particular area, the amount of reserves needed to increase. The average of the Y coefficients for all six areas, weighted by actual MW, is 2.2%. Thus, to carry incremental reserves over 3% of load, by area, to account for incremental variability of wind, would require carrying, on average, 2.2% of wind power (*not*, to emphasize the point again, 2.2% of installed nameplate, but rather 2.2% of actual or forecasted wind).

There is substantial diversity between areas in the amount of incremental reserves, as a fraction of wind power, that are required. The relationships between area size, wind penetration, and incremental reserve requirements are not straightforward. The diversity of reserve requirements is shown in different ways in Figure 7.115. In the top plot, the load and wind coefficients (X and Y, respectively) are shown relative to the total MW of installed wind. There is a roughly negative correlation between amount of wind installed and the required reserves. This is as expected, and is a different manifestation of the benefits of diversity. Interestingly, when viewed from the perspective of power penetration in the middle plot (MW wind installed/MW peak load), and against area size (peak load) in the bottom plot, the correlation is also somewhat negative. All of these are driven by spatial diversity. The highest amount of reserves, on a per unit basis, are required in Colorado West. This is not surprising, as Colorado West has relatively few wind plants (a total of 570 MW), that are all in rather tight geographic

proximity. The spatial diversity here is relatively poor, and the incremental reserve requirement is higher.

The observation that there is diversity of reserve requirements by area is consistent with evidence presented throughout this work that shows that cooperation between neighboring areas is needed. That different areas have different levels of reserve needs is not surprising and nor does it imply that those reserves must necessarily be provided within the particular area. We have seen that, for example, Wyoming is a major exporter in the scenario examined here. It is clear that in heavily exporting Wyoming, providing the reserve balancing necessary to assure that *exports* can be maintained is suboptimal, and maybe even nonsensical. Higher reserves in the receiving systems may make sense. Indeed, we do see an *overall* increase in the need for reserves due to wind generation.

Specifying the exact increase in reserve requirement is a matter of perspective. In Figure 7.64, the foot print wide average requirements for reserves were shown to be 979 MW, 730 MW and 1393 MW, for the 3% of load rule, average load only variability and net load variability, respectively. As noted with that figure, the increase for net load over the 3% rule is 42%. For practical rules, such as the X+Y and conditional load rules outlined in this section, the maximum requirements increase. The maxima, listed in the call out of Figure 7.113, show a 37% increase for the X+Y rule (2387 MW vs. 1743 MW), and a 12% increase for the conditional X+Y rule (1946 MW vs. 1743 MW). However, when viewed against the load only conditional maximum of 880 MW (from Figure 7.112), the increase in reserve requirement is 121% (1946 MW vs. 880 MW).

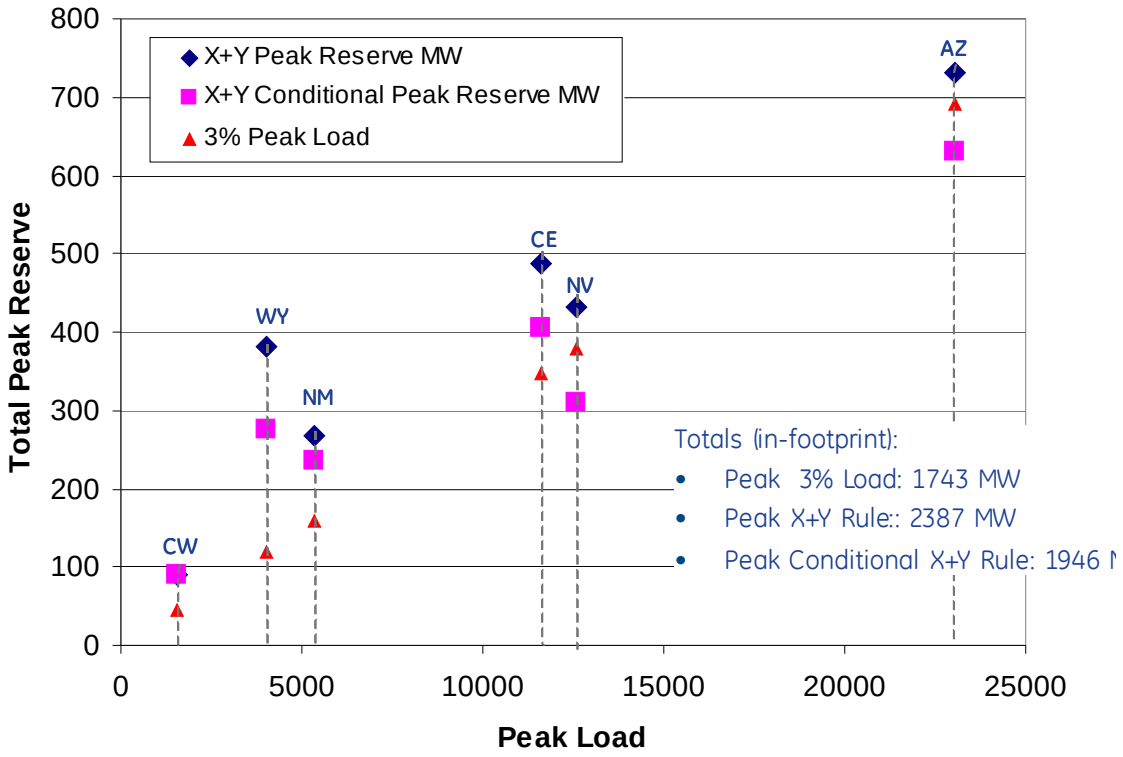


Figure 7.113 Comparison of Peak Reserve Requirement Rules (by Area)

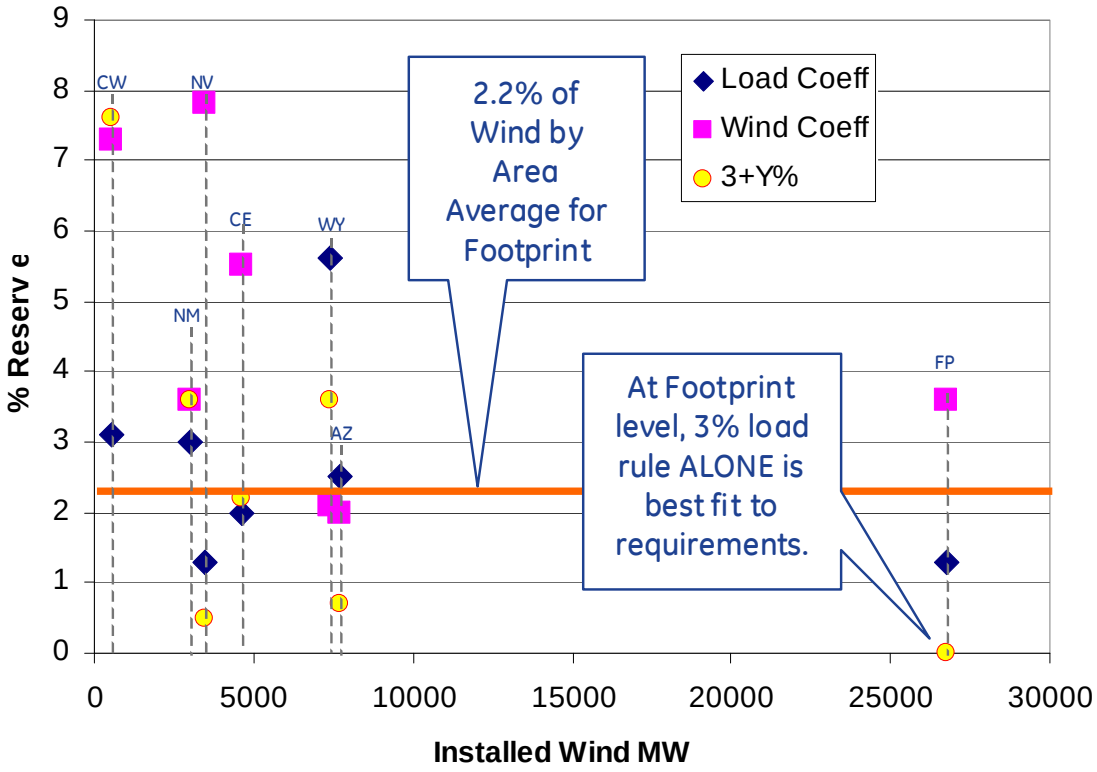


Figure 7.114 Incremental Reserves over 3% Load Rule

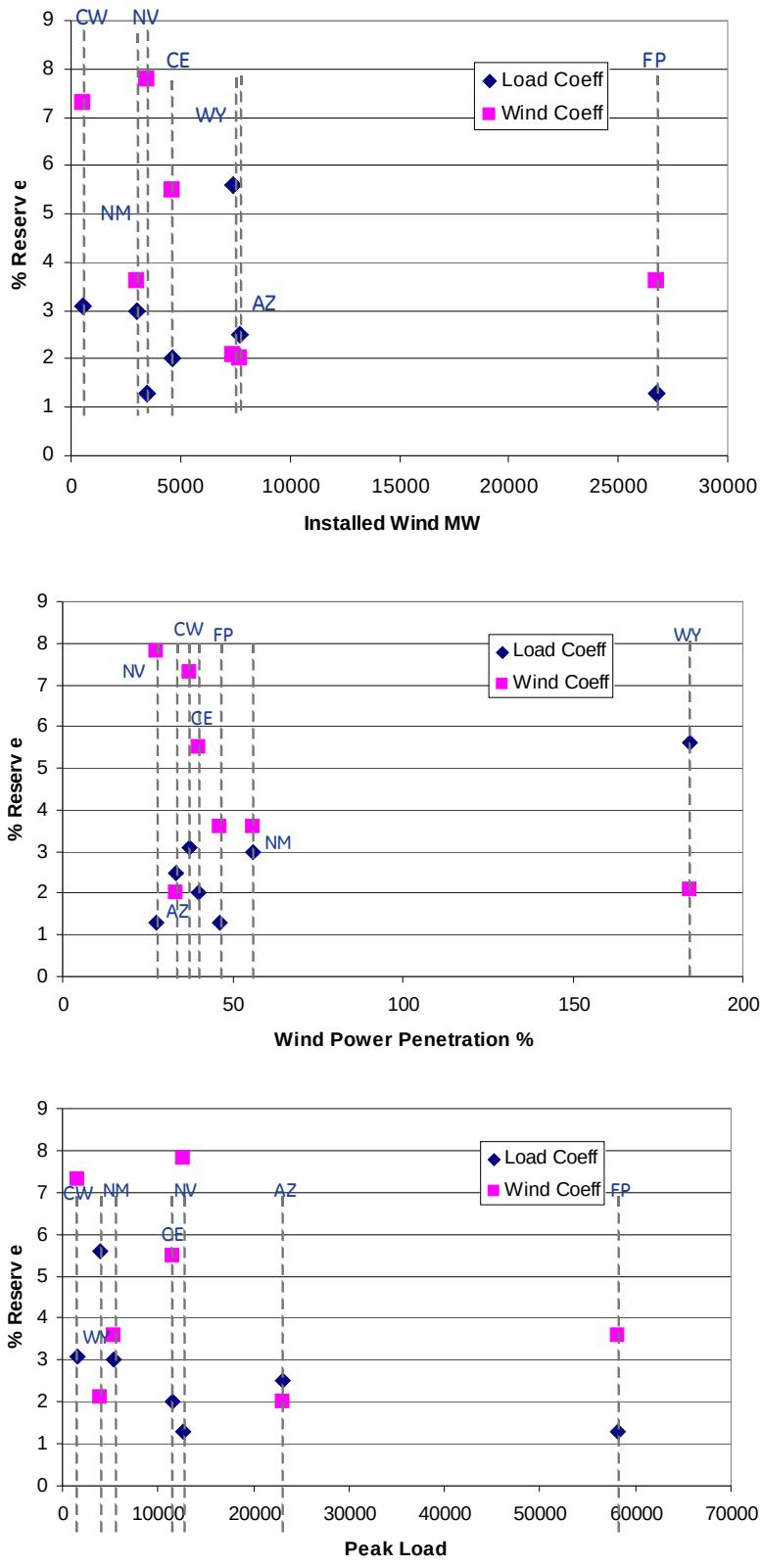


Figure 7.115 X% Load and Y% Wind Reserve Rule – Relationships to Penetration

7.5.7 Other Concepts for Rules

All the results of Sections 7.5.2 through 7.5.5 are based on very simplified linear rules. As the statistical variations show (including Figure 7.47 and Figure 7.48) the relationships between load and wind variability are not especially linear. In this section we point out some areas of possible improved "fit" to the system requirements afforded by more complex rules.

Figure 7.116 shows quadratic fits to the net load variability curves of Figure 7.45. This approach does not seem to hold much promise, as the distinct drivers of load and wind are netted out in this curve fit. However, this fitting approach does suggest that the wind term, which we have made piece-wise linear in Sections 7.5.3 and 7.5.4, might be made more complex.

Figure 7.117 shows the variability of wind as a function of average wind. These are the same traces that were shown on the right side of Figure 7.47, but they have been overlaid with quadratic best fit equations. The equations are color coded on the figure. The curvature of the In-area curves — and especially of the mega project curves — are more obviously quadratic than for the local priority curves. Similarly, the net load variability curves of Figure 7.46 show that the quadratic relationship with net load is much more distinct for the MP scenarios. This suggests that there may be more benefit, in terms of matching reserves to actual requirements driven by variability, with developing more complex non-linear reserve rules for some areas. For example, the Wyoming results (Figure 7.99 and Figure 7.100) are not great, and might benefit from a more sophisticated relationship.

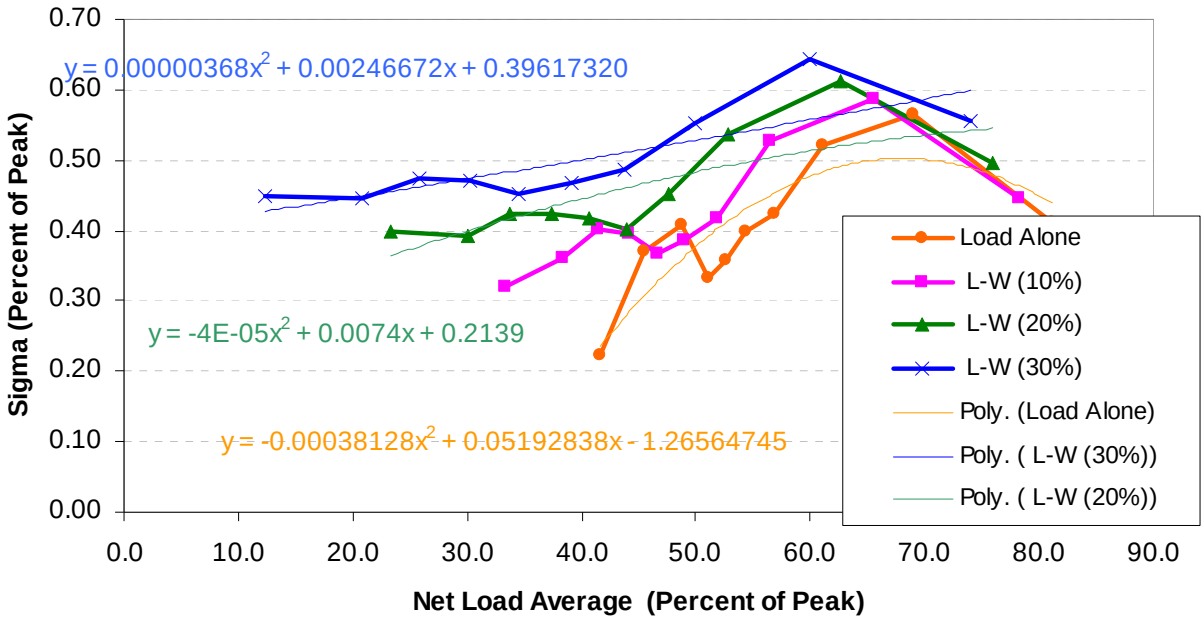
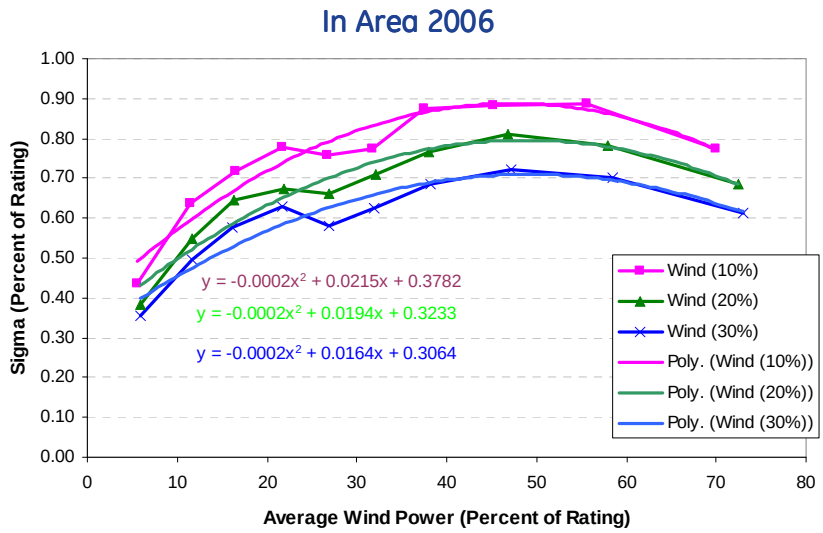
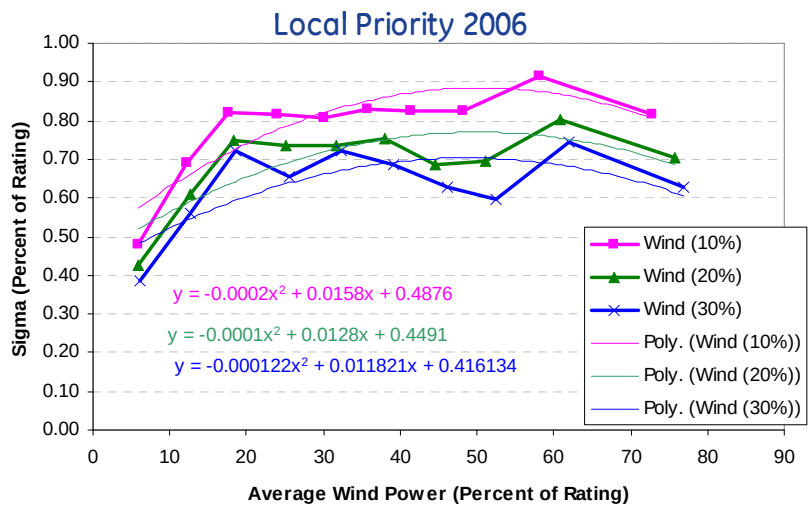


Figure 7.116 Footprint - Polynomial Fits to Net Load Variability (L30 scenario)





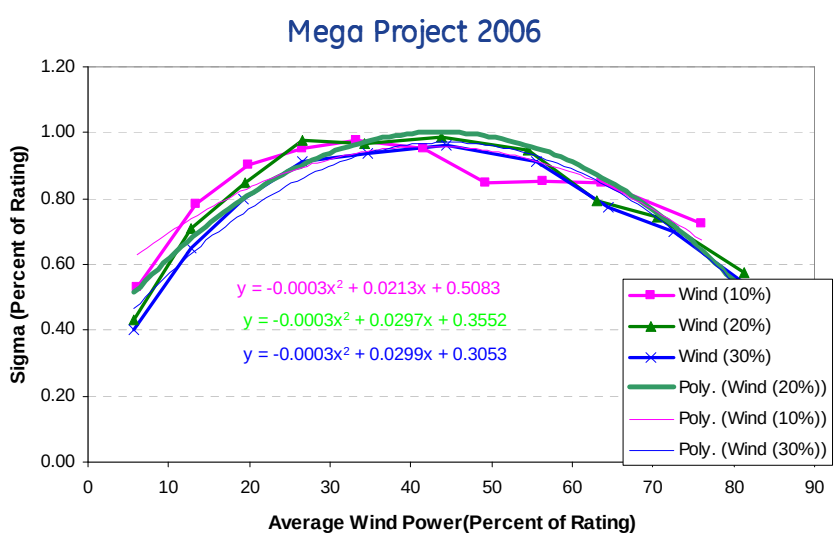


Figure 7.117 Footprint - Polynomial Fits to Wind Variability

7.5.8 Demand Participation in Reserves

The reserves shown throughout this section are required to maintain sufficient on-line agility to handle net load fluctuations. In order to have those reserves, resources must be available. Uncertainty will, under some conditions (e.g. over forecasting wind or under forecasting load), consume reserves needed to address variability. These mismatches in reserve must be addressed as they occur.

In the end, the most likely and realistic use of demand participation covers the misses due to uncertainty. The results of Section 6.2.2 show high economic benefit to this approach. Load demand is reduced, so that reserve range on committed generation is freed up to provide reserves for variability.

A more ambitious, and yet to be demonstrated, avenue for demand participation is for demand resources to actually provide the reserve: responding to short term changes in economic dispatch or even regulation signals. Such functionality is clearly possible, and could ultimately prove to be highly economic. However, in the near term future, performance of this type is likely to be limited to a narrow group of industrial and commercial loads that can practically respond and can economically justify the incremental control infrastructure.

7.5.9 Energy Storage Contribution to Reserves

The QSS traces of Sections 7.2.5 and 7.2.6 and reserve requirements described in 7.3.1 show that reserve requirements during periods when relatively limited amounts of flexible generation is on-line can be substantial. Unlike energy storage for arbitrage, energy storage technologies that can provide reserve services, both regulation and subhourly spinning reserve, may be economically attractive. The economics of energy storage for these services must compete with the costs, both operational and opportunity costs, of providing these services with conventional generation.

7.6 Conclusions on Subhourly Reserves

1. Reserve requirements for resources needed to meet system variability increase with wind penetration. The required reserves are a function of the expected variability for the load and wind (and solar) power at a given operating condition. The incremental variability is a function of system size, wind penetration, and wind site diversity. At 30% energy, overall subhourly reserve requirements roughly double over those necessary for load variability alone.
2. The present reserve rules, based on 3% of load, provide adequate performance at 30% wind energy penetration. Reserves available within the study area, when the system is both committed and dispatched to maintain a minimum of 3% of load, are generally sufficient to meet variability.

3. Uncertainty can cause resources (i.e. control range for reserves) needed for variability to be depleted. Unit commitment strategies are required to maintain reserve range. These include, adding reserves in the day-ahead unit commitment to cover forecast uncertainty, changing unit commitment in time frames shorter than day-ahead to take advantage of higher fidelity forecasts (i.e. nearer in time), and use of non-generation resources to free up reserves.
4. Operational analysis in Chapter 6 showed demand side participation (DSM) to be highly effective. DSM will be a key component in managing uncertainty. Managing uncertainty is critical to assuring that sufficient subhourly reserves are available to manage variability.
5. Subhourly reserves can be consumed by hourly schedule changes. Therefore, scheduling strategies (including more continuous interchange schedules) that avoid unnecessary consumption of subhourly reserves will improve system performance. Further investigation into economic aspects of various dispatch strategies for maintaining subhourly reserves is warranted.
6. Operating reserve rules based on load and wind power levels would provide improvements. Relatively simple linear rules, based on load and wind level, will tend to allocate maneuverable reserves to better match times and conditions of load and wind variability. The 3+5 rule conservatively covers most conditions. Some high penetration subsystems will need more reserves, if reserve sharing is not realized.
7. Control area cooperation is essential. Small control areas will not be able to balance large amounts of wind. State-size areas will benefit, in terms of reduced reserve requirements, by sharing reserve burdens with other areas.
8. If each individual (state-size) area is required to provide its own subhourly reserves, the total amount of reserves required increase. To meet reserve requirements on an area-by-area basis will require, on average, that reserves equal to about 2% of the wind power, be added to those required by the 3% of load rule.
9. Energy storage may be a cost effective alternative to generation options for providing subhourly reserves.
10. Subhourly reserves need to be allocated between regulation and economic dispatch range. The existing rule of thumb, 1% of peak load for regulation, appears to be adequate for modest wind penetrations. A rule that allocates regulation equal to the standard deviation of 10-minute net load changes, i.e. 1 x $\Delta\sigma$, is analytically rational and was found to work well under some extreme conditions.

References:

[7.1] Standard BAL-001-0.1a — Real Power Balancing Control Performance, http://www.nerc.com/files/BAL-001-0_1a.pdf

[7.2] California Energy Commission's Intermittency Analysis Project Study "Appendix B - Impact of Intermittent Generation on Operation of California Power Grid" http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081-APB.PDF

8 Impact of Energy Storage and PHEV

Conventional wisdom states that if you have large amounts of wind then you must have storage. As is often the case, conventional wisdom seems to be wrong. Often storage is viewed as a means to correct shortcomings better handled through system operation. For example, storage can be used to compensate for wind forecast uncertainty and thereby allow wind to bid into the day-ahead markets for commitment. However, this study indicates that it makes more economic sense, from a system standpoint, to commit the system generation based on the State-of-the-Art forecast and cover the shortfalls with the operating reserve and quick start generation rather than to pay the roughly 25% roundtrip inefficiencies associated with storage. And that is assuming that the storage already exists. Nothing seems to indicate any economic justification to construct new storage devices.

This section only considered the application of energy storage for the hourly arbitrage of energy throughout the day or week. The sub-hourly application of storage for regulation is addressed in Chapter 7.

8.1 Base Pumped Storage Operation

Figure 8.1 shows annual duration curves for all of the WECC pumped storage hydro, PSH, units for a range of renewable penetrations. The individual plants in WECC were modeled separately and summed chronologically before being sorted for this graph. As can be seen, increased renewables increases the utilization of the storage slightly but does not push the usage to a point where more storage would seem to be required. This would be indicated by flat portions at either extreme of the curve that indicates saturation.

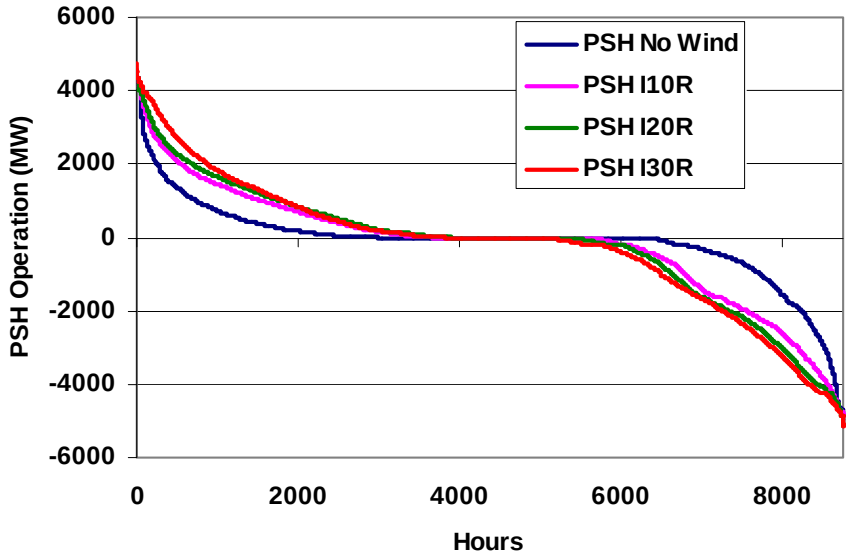


Figure 8.1 PSH annual duration curve

The storage schedule is planned based on the assumed cost of pumping versus the assumed value of the displaced generation for the coming days and week. In order to verify that these assumptions were not being overly conservative, simulations were made with the cost of pumping multiplied by either .75 or .50 before being compared to the generation savings. For example, in the base case it would make economic sense to displace $500 of generation on peak with off peak pumping energy that cost $400 to produce. However, if the pumping energy costs $600 then the action wouldn't take place. In the ".75" case the pumping cost would be multiplied by 0.75 so that the "effective pumping costs" would appear to only be $450 and the action would occur. These factors are used only for PSH decision purposes; they do dot effect the actual costs of operations. The resulting utilization curves are shown in Figure 8.2. Clearly the PSH operation has increased as the assumed cost of pumping has decreased.

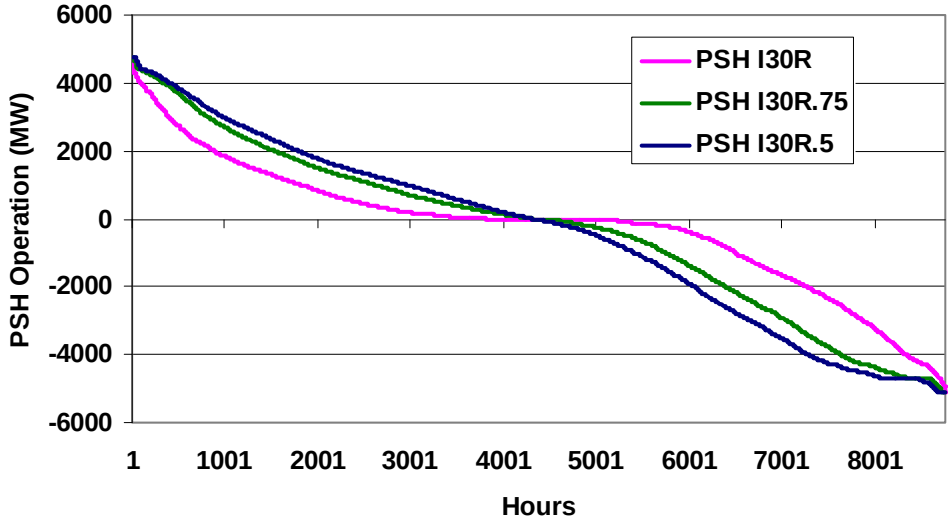


Figure 8.2 PSH operation with discounted pumping costs

Figure 8.3 shows the impact on the WECC operating costs. Forcing the PSH to operate more than the model felt was necessary did indeed increase the annual total cost of operations by $60M to $120M. This confirms that the base case assumptions on the PSH operation were valid. The next section digs deeper into how storage could be optimized to improve the integration of renewable energy.

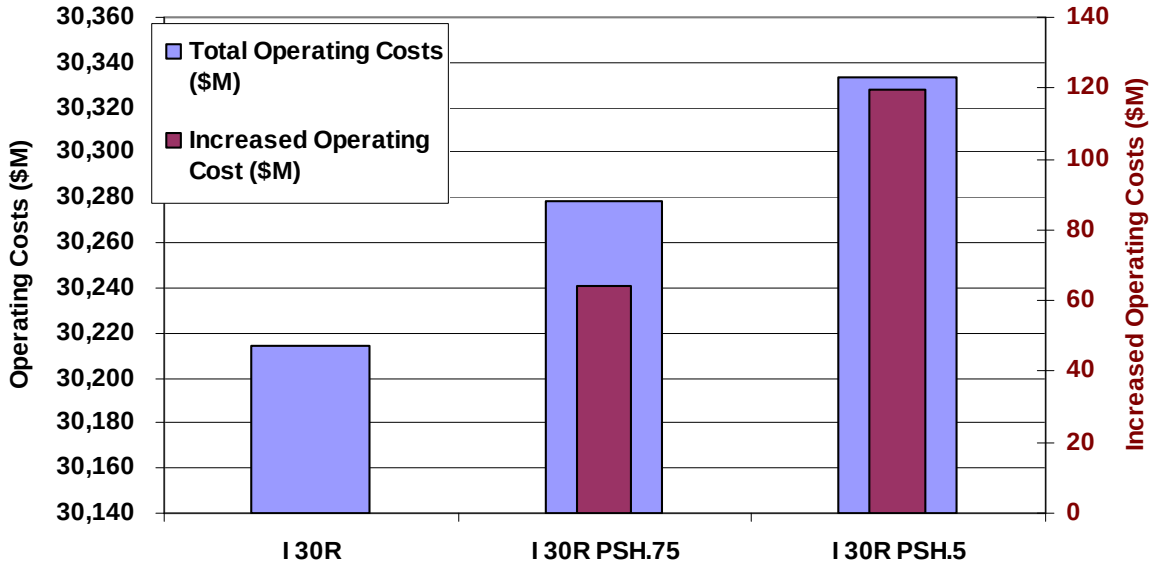


Figure 8.3 Operational impact of forcing PSH operation

8.2 Pumped Storage Optimization

In order to examine the phenomenon of storage operation a little closer we looked at a spot price curve for the Arizona/New Mexico portion of the system. Figure 8.4 shows the hourly load (against the right hand axis) and the hourly spot price for a range of wind and solar penetrations for the week of April 10th assuming a perfect forecast. The prices were relatively low since this is a relatively low load week. More importantly, the price variation across the week was small. This is consistent with what was seen in the dispatch curve in Figure 6.40. The marginal cost is coming pretty consistently from combined cycle generation and so the variation is due to heat rate differences on similar units. As more renewable generation is introduced with a perfect forecast it simply depresses the spot price across the week. The prices dip significantly on Saturday when the marginal cost is being set by coal plants, but otherwise there does not appear to be sufficient price variation across the day to overcome the 25% round trip losses inherent in a conventional storage plant.

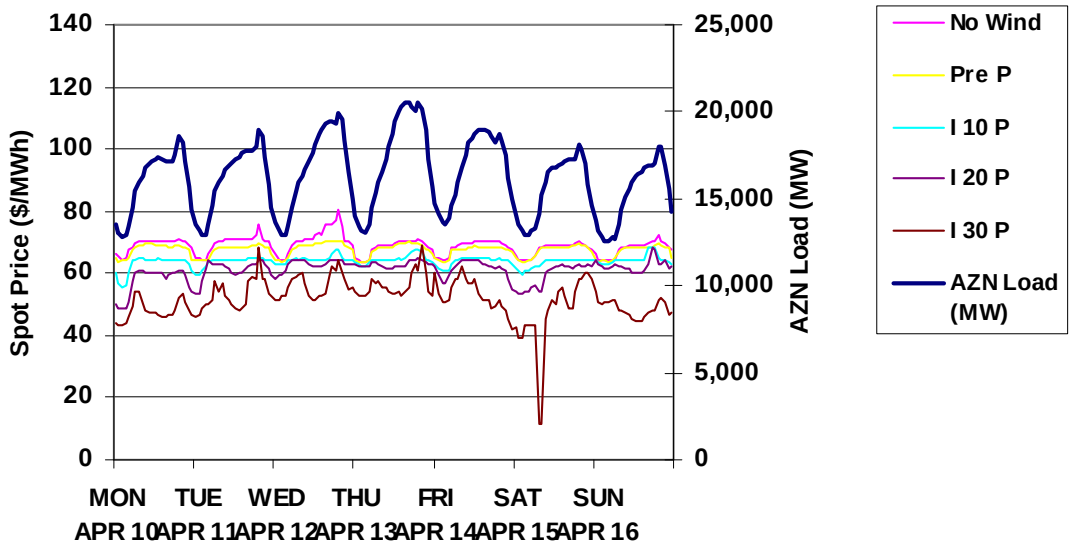


Figure 8.4 Arizona spot prices, week of April 10th, perfect forecasting

This all changes rather significantly in Figure 8.5, which assumes a state-of-the-art forecast. The no-wind curve is the same as above and even the low penetration curves are similar. At the higher penetrations, particularly the 20% and 30% cases, the impact of the imperfect forecast can be seen. Under-forecasts at the beginning of the week result in over commitment of generation and drive the spot prices down significantly. This is then followed closely by an over-forecast that forces the system to turn on peaking units and drives the spot prices up. And so it continues throughout the week.

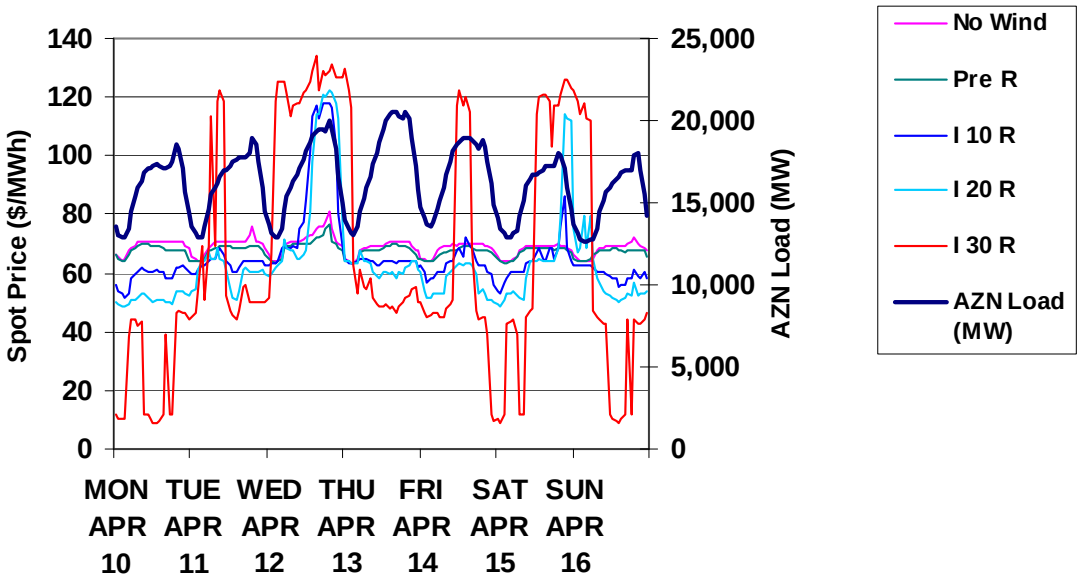


Figure 8.5 Arizona spot prices, week of April 10th, S-o-A forecasting

It would be very desirable to schedule the storage against these curves. *Unfortunately, this would require perfect foreknowledge of when the wind was being over-forecasted and when it was being under-forecasted.* If this were known in advance then the forecasts could be adjusted to bring the results back to the perfect forecast as shown in Figure 8.4.

But let's assume that a new PSH plant had a tool that could predict when the spot price would be high and low. A separate model was used to dispatch a 100 MW PSH unit against the spot price curves shown in Figure 8.4 and Figure 8.5 for the entire year. The results in Figure 8.6 show the number of hours and the operating value resulting from this simulation. With no renewables, the PSH unit would run about 2200 hours (total pumping and generating time) and have an operating value of about $2.6 M for the year. With a 15% fixed charge rate this would result in a capitalized value of roughly $175/KW. This is far less than the $4000/KW estimated cost for a new storage facility. As expected, with a perfect forecast the value of the PSH unit decreased as the renewable penetration increased. With 30% penetration and a perfect forecast the 100 MW PSH plant only had an annual operating value of $0.5 million which would only yield a capitalized value of about $35/KW.

With the State-of-the-Art forecast the values initially decreased some, but not as much as with the perfect forecast. At the 30% penetration level the value jumps up significantly, but is still only $3.8 million/year of operating value. This translates to roughly $250/KW which is still more than an order of magnitude below the cost of a new facility. *Even perfect foreknowledge of when the prices will spike and drop does not seem to provide sufficient value to justify adding any new storage facilities.*

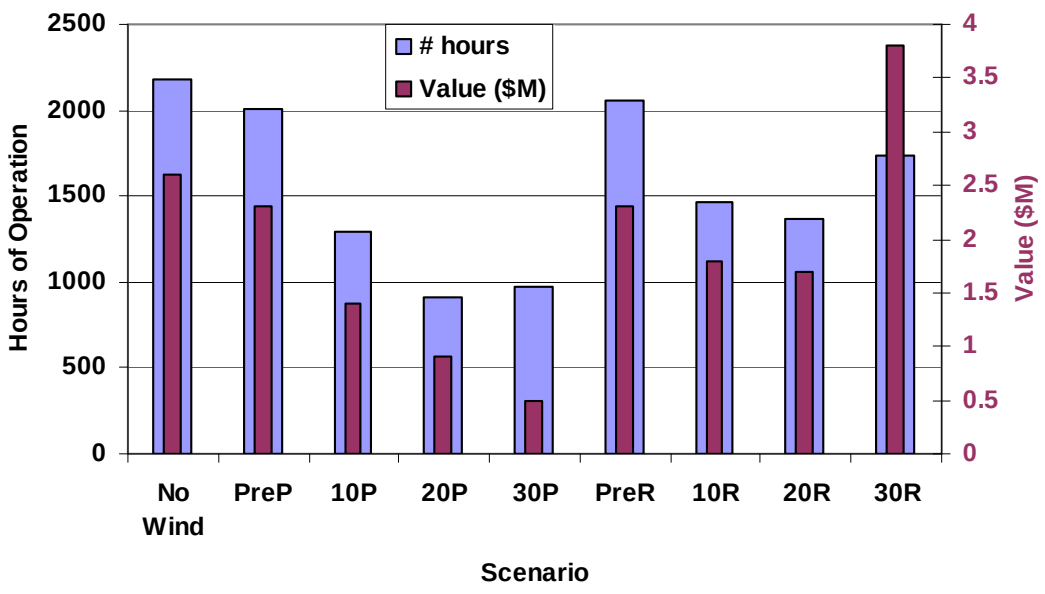


Figure 8.6 Incremental value of a 100 MW PSH plant

8.3 CSP Operation Optimization

The Concentrating Solar Plants, CSP, simulated in this analysis were designed with six hours of thermal storage included. The collector field was over sized relative to the steam turbine and generator and the additional heat was stored to allow the unit to continue producing electricity after the sun went down. The question was posed if a different schedule could generate more revenue. The curves in Figure 8.7 examine the operation of a single plant for one day. The blue curve is the schedule as operated. The purple curve is the hourly spot price. The green curve is the operation which maximizes the daily revenue while recognizing the six-hour storage limit, and specifying that the energy must be used up within the day. Rather than using the energy as it became available at 7 a.m., the energy was stored until prices spiked at 10 a.m., and then stored again until after noon. Output was curtailed when the spot price dipped at 7 p.m. and then run at rated power for the balance of the day. The daily revenue (= hourly spot price times hourly generation) for the base operation was $656,781 while the revised revenue was $772,376 an increase of 17.6%. Although there may be ramping limits that were not considered in this simple analysis, and this approach assumes perfect foreknowledge of the price curve, this analysis provides an operational bookend and gives an insight into potential rescheduling benefits.

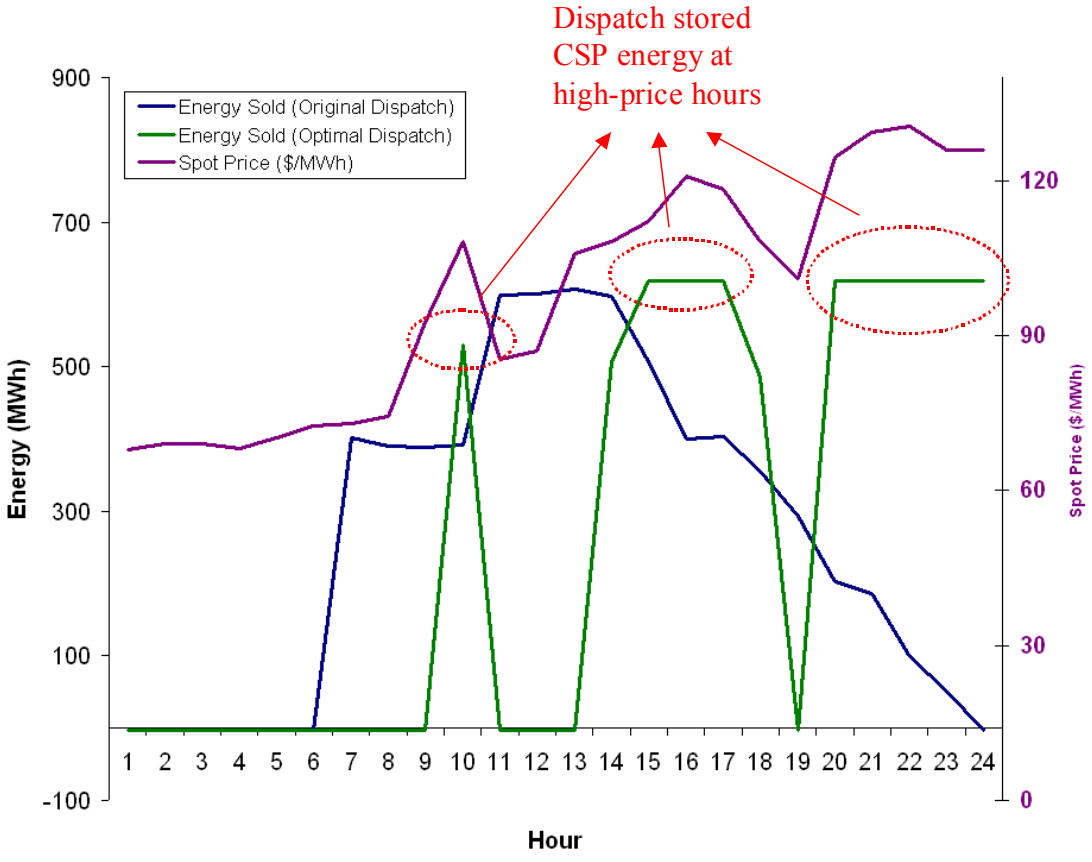


Figure 8.7 Sample energy shift for CSP "optimal" dispatch

The curves in Figure 8.8 show the monthly energy production for all of the CSP plants. The "CAL" in all of the names refers to **C**SP, **A**ctual generation, **L**ocal priority scenario. The remainder of the name refers to the region of the system, as described in Chapter 3. As might be expected the energy is highest in May through October and drops off for the rest of the year. This actually corresponds well with the load profiles for the system. Figure 8.9 shows the total annual energy by zone.

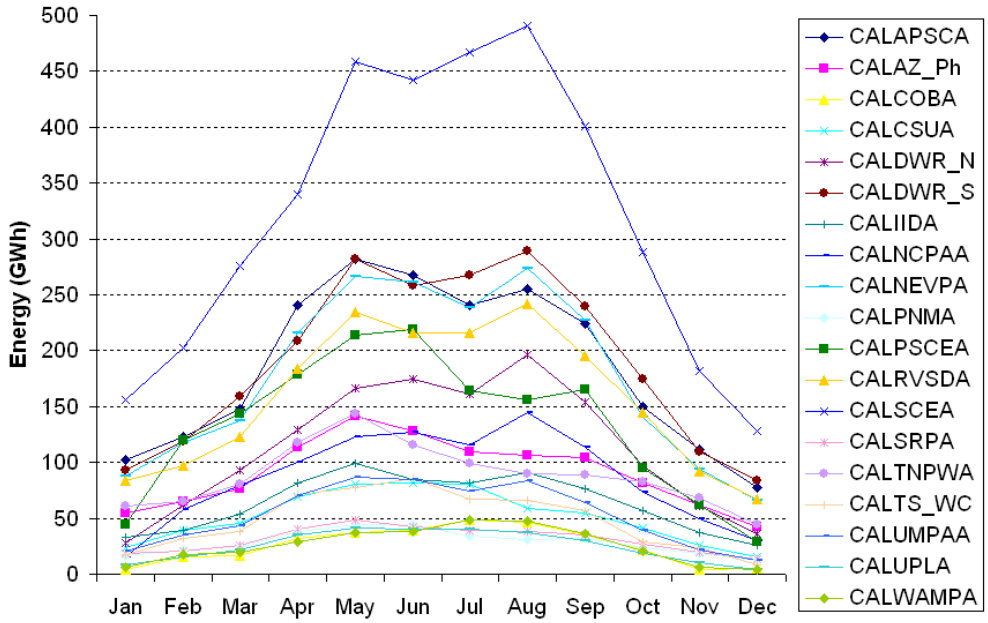


Figure 8.8 Monthly CSP energy by zone

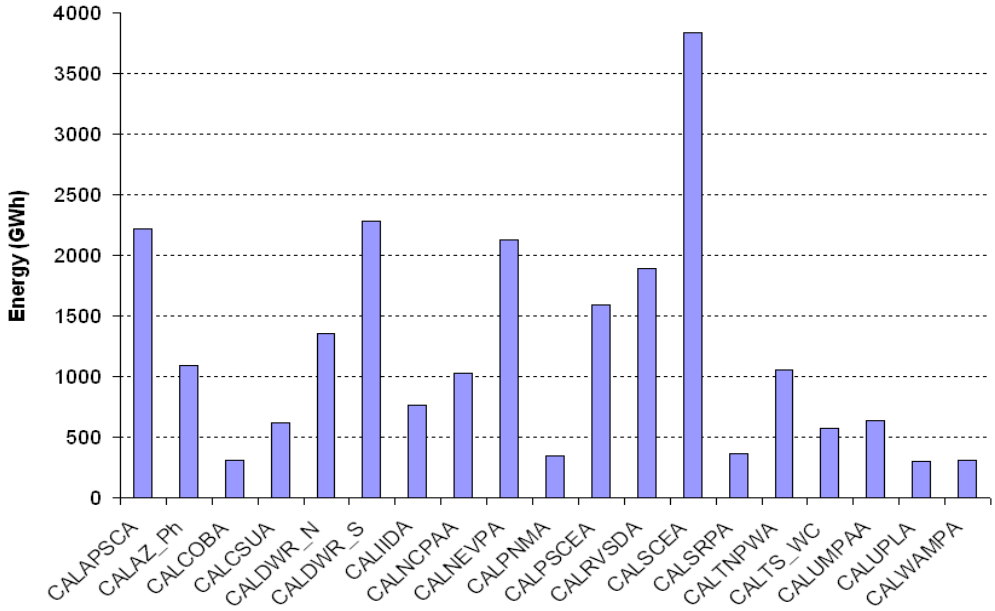


Figure 8.9 Annual CSP energy by zone

As could be seen in Figure 8.7, having more storage capability would allow more energy to be saved for hours with higher spot prices. Conversely, having less storage would reduce the value. Figure 8.10 shows the range in increased value for each of the plants as a function of the hours of storage. Six hours seems to be a reasonable saturation point.

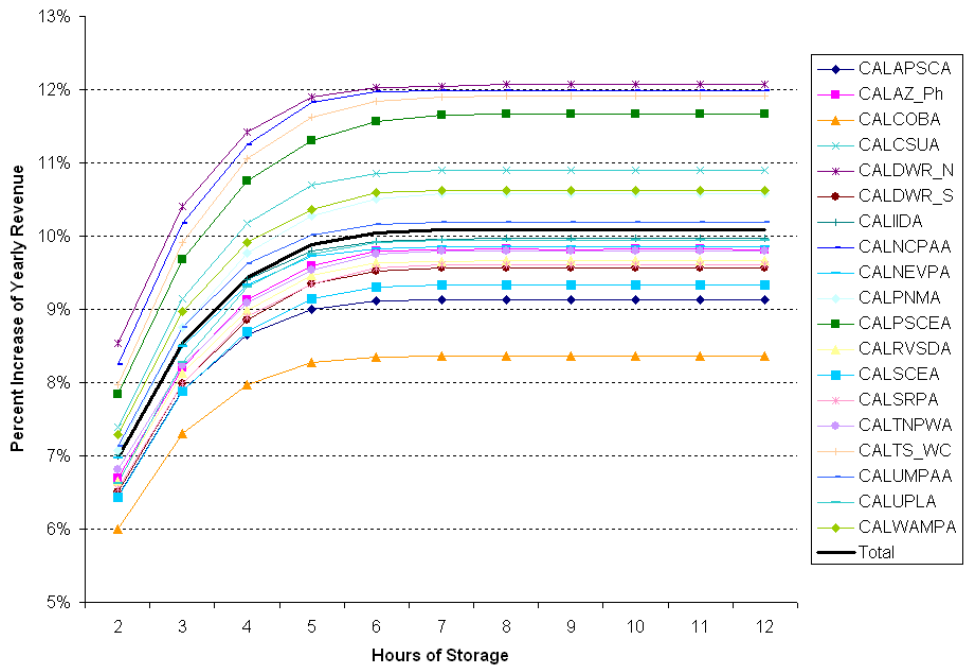


Figure 8.10 Annual CSP revenue increase vs. hours of storage

Figure 8.11 shows the annual increase in revenue over the original operating schedule for all of the sites assuming six hours of storage. There is roughly a 10 to 12% improvement for all of the locations.

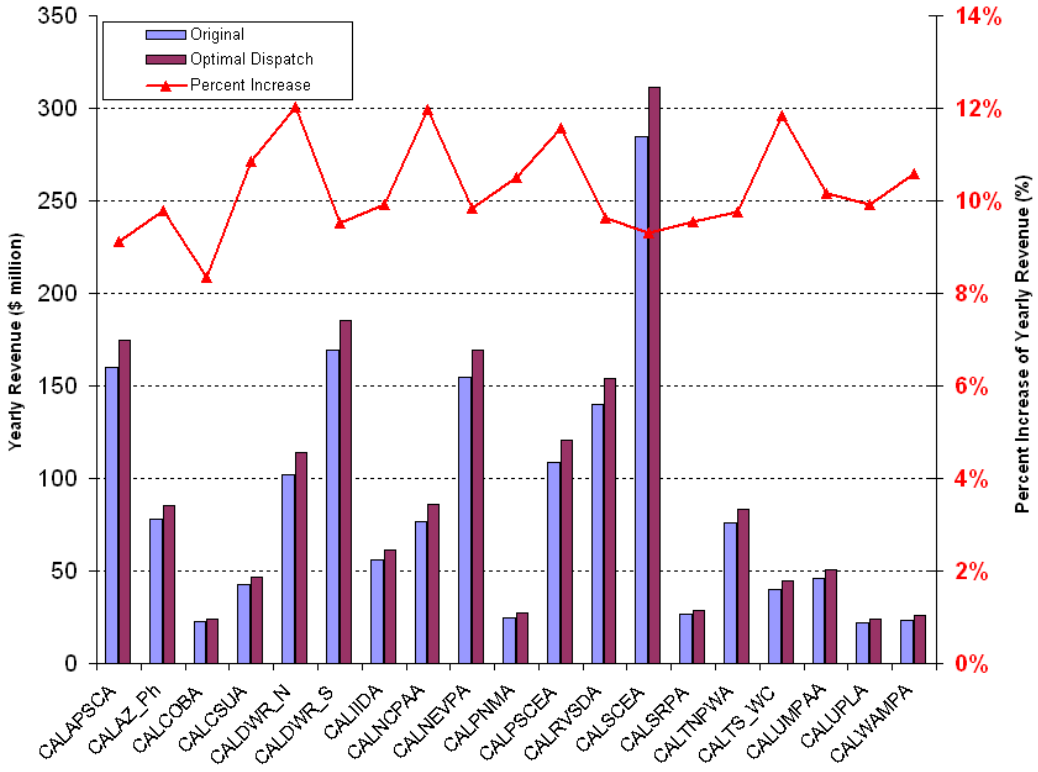


Figure 8.11 Annual CSP revenue increase by zone due to optimal dispatch.

Figure 8.12 depicts the increases by plant on a monthly basis. The on-peak periods of the year, which had the greatest amount of energy, had a modest 5 to 10% increase. This is because the six hours of storage inherent in the base operation was largely saturated in these months so there was little room for improvement. The off peak months, which had less energy available, showed that there was significant room for improvement by storing more of the energy during the day for use at night when the spot prices were higher. The base operation only stored energy during the day that was in excess of the system's capability to utilize directly. Figure 8.13 shows the monthly results for the total system.

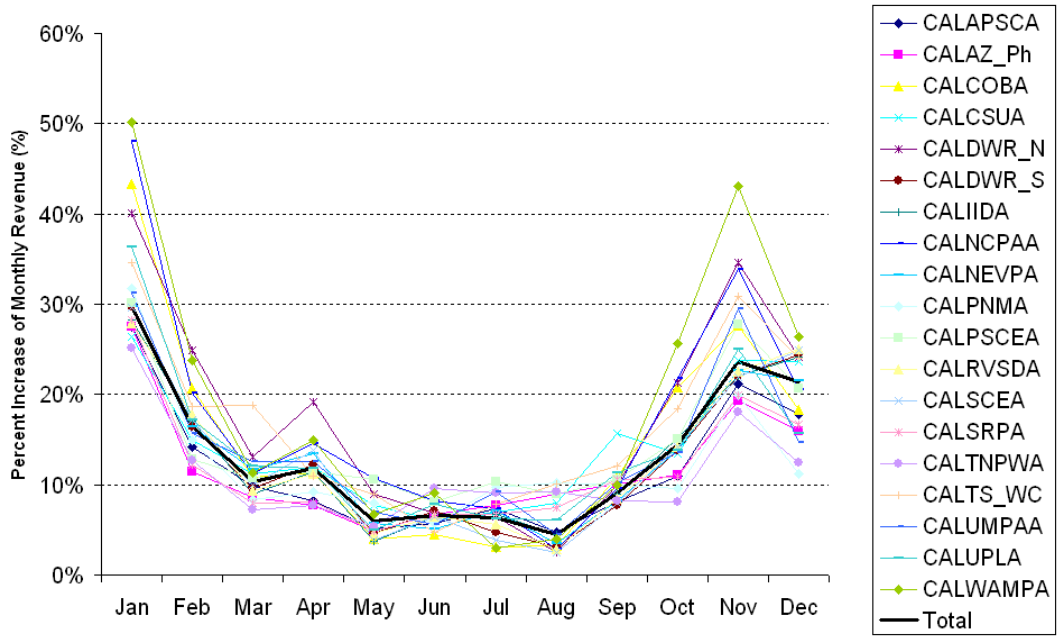


Figure 8.12 Monthly CSP % revenue increase by zone due to optimal dispatch

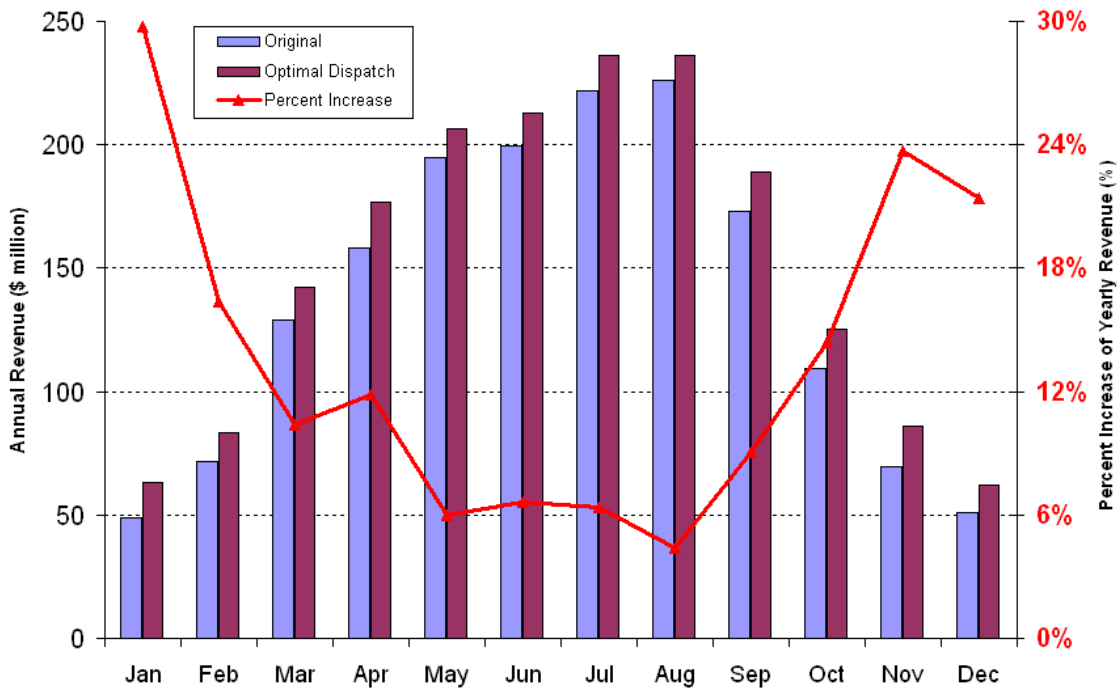


Figure 8.13 Total monthly CSP revenue increase

8.4 Plug-in Hybrid Electric Vehicles, PHEV

Some of the difficulties that arise with large amounts of wind generation on the system are due to the fact that much of the wind generation occurs at night when the loads are lower. One potential solution would be to increase the off peak loads with the charging demands of plug-in hybrid electric vehicles, PHEV. Table 8.1 lists the potential daily and annual load increase by state if 15% of all light duty vehicles and 3% of heavy duty vehicles were converted to PHEVs.

Table 8.1 Annual PHEV energy by State

State	Daily Load (MWh)	Annual Load (GWH)
Arizona	2,558	934
California	21,734	7,933
Colorado	1,051	384
Idaho	704	257
Montana	585	213
Nevada	812	296
New Mexico	885	323
Oregon	1,734	633
Utah	1,312	479
Washington	3,547	1,295
Wyoming	327	119
WECC Total	35,248	12,865

The curve in Figure 8.14 shows the assumed chronological distribution of the PHEV charging load in each area. 5% was assigned to 11 p.m., 10% to 12 p.m. and 6 a.m. and 15% to 1 a.m. through 5 a.m. On a WECC-wide basis this represented about a 5,000 MW load increase in the middle of the night.

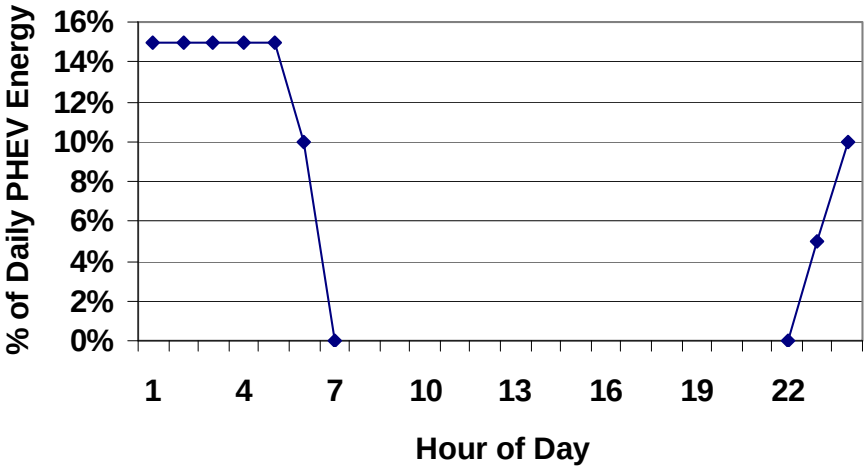


Figure 8.14 Distribution of PHEV load

Figure 8.15 shows the operational cost impact of adding the PHEV loads to the system for the range of renewable penetrations. The left hand side shows the increase in millions of dollars and the right hand scale shows the costs in $/MWh of PHEV load. Figure 8.16 shows that adding PHEVs increased the value of the renewable energy by about 50 cents per megawatt hour. Adding the PHEV demand did not significantly change either the unserved or spilled energy.

However, it should be noted that this PHEV load could be used to implement the demand side management, or load participation, that was shown to be so valuable in Section 6.6.2 and will be addressed further in Section 7.5.

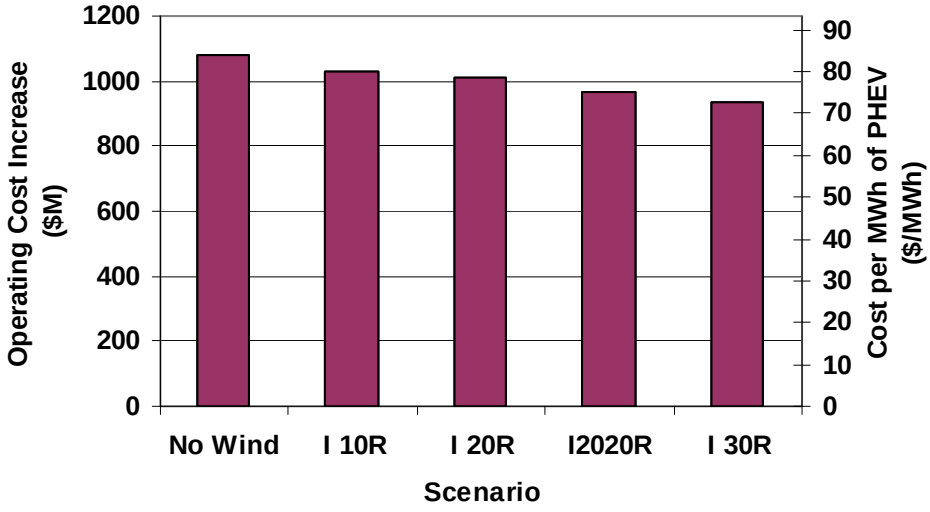


Figure 8.15 Cost impact of adding PHEV load

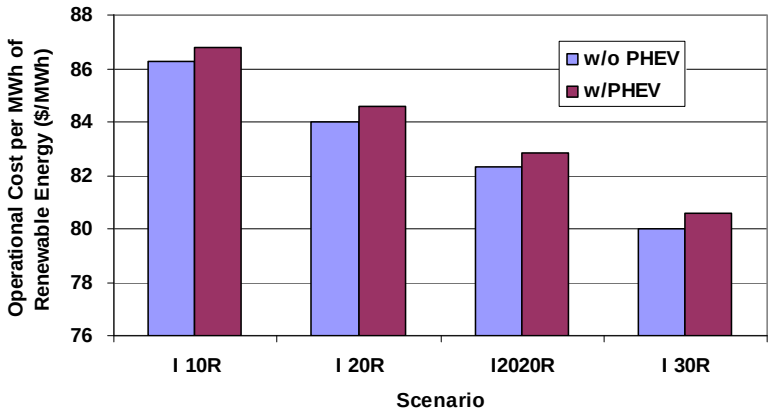


Figure 8.16 Operational impact of renewable energy

8.5 Storage and PHEV Observations

The best way to integrate wind and solar generation into the system is to make full use of the capabilities of all of the generating units in the system. As long as balancing area issues don't interfere, utilizing the ramping capabilities of system's dispatchable generation is generally more efficient than paying the 25% losses associated with pumped storage hydro or batteries. With perfect forecasts of the renewable generation, the spot prices drop throughout the day and generally reduce the price ranges needed throughout the day to make storage attractive. Broader price ranges may exist with state-of-the-art forecasts and high levels of renewables but even then the value falls more than an order of magnitude short of what is needed to make new storage economically attractive.

If thermal storage is added to Concentrating Solar Plants, CSP, it may be possible to improve the revenue stream beyond the operating mode of simply using the storage to handle excess thermal energy. Storing all of the energy early in the day when energy prices are low and releasing it later in the evening when prices are higher was shown to increase revenues in some months by 30%. This study did not look at the cost of the additional collector fields and storage facilities.

Wind generation and plug-in hybrid electric vehicles are synergistic. Adding PHEVs to a system make it more attractive to wind generation and adding high penetrations of wind reduce the cost of charging PHEV. However, they appear to both have to stand on their own merits. The synergy allows them to add some value to each other but not enough to significantly change the economic viability of either one. The presumed ability of PHEVs to participate in DSM for maintaining reserve margins increases their attractiveness.

9 Reliability Analysis

Chapter 6 of this report examined the economic and operating impact of intermittent renewable generation. This chapter uses a reliability analysis, or Loss of Load Probability analysis, of the system to determine the capacity value of the wind and solar generation. The GE Multi-Area Reliability Simulation program, MARS, was used in this analysis.

9.1 Introduction

A Loss of Load Probability, LOLP, analysis is typically performed on a system to determine the amount of capacity that needs to be installed to meet the desired reliability target, generally one day in ten years, commonly expressed as 0.1 days/year. This calculation involves convolving the load profiles and the scheduled generator outages with the probability of generator forced outages to determine the expected number of days in the year when a shortage might occur. Because the result is actually an expected value, the index is often referred to as Loss of Load Expectation, or LOLE, but the historical terminology is LOLP. Either term is valid and they are often used interchangeably. It is important to note that the historical measure was interested in "the number of days of shortage" rather than the total outage time. Since generator outages tended to last for several days, if a shortage was to occur, it would happen at the time of the daily peak load. Therefore the calculations were only done for the peak hour of each day. (Note: the historical calculation method was developed long before computers.)

This historical focus on the peak hour is very important to the treatment of intermittent resources. If a particular resource produces 100 MW of generation for 23 hours of the day but only generates 10 MW at the hour of the daily peak then the calculation will see it as just 10 MW. It will have no greater capacity value than a generator that puts out 10 MW for every hour of the day. This explains why the capacity value of wind is often much lower than traditional thermal generation. Likewise, a device that can consistently generate 100 MW at the daily peak but zero MW the rest of the day will have the same capacity value as a unit that produces 100 MW all day long.

One shortfall of this methodology is that with the capacity output changing hourly, it is possible to have capacity shortages at times other than the peak hour. This could occur if a resource was generating 100 MW in the peak hour but only 10 MW in the next hour when the load only dropped 30 MW. In order to capture this effect the model was adjusted to look at all 24 hours in the day. In addition to calculating the number of hours that the system might be short, which is a measure used in some regions, the model counted up the number of days in which an outage occurred at any time of the day. In this manner all shortages are captured regardless of the time of day and all

capacity levels are also considered. This method also captures the synergy between the capacity impacts of different types of intermittent renewable generation. PV and wind generation tend to occur more during off-peak periods which reduces their capacity value. CSP with storage, on the other hand, can be shifted to reduce the peak loads. This then pushes the relative peaks into the shoulder hours, allowing the PV and wind to have more of an impact. This will be shown in the results.

In addition to the daily and hourly indices, the program also determined the magnitude of any shortages so that total energy shortfalls could be calculated. This value will differ from the value calculated in the production simulation analysis. A reliability analysis assumes that all capacity not on outage is available to serve load. Most of the shortages — or unserved energy — in the production modeling were due to forecast errors that caused units to not be committed and available for dispatch.

9.1.1 Location, Location, Location

One aspect of capacity value is where the unit is located. A perfectly reliable generator located behind a transmission constraint may not add any capacity value to the system. In this analysis we wanted to capture the capacity value of the renewable generation based on their generation profiles, the area load profiles and the characteristics of the rest of the generators in the study area. In order to do that it was assumed that there were no transmission constraints within the study area for the reliability analysis. In this way the capacity values will not be penalized due to transmission constraints.

The study area has thousands of megawatts of interconnections to the rest of WECC. In order to calculate non-zero reliability indices these ties were set to zero. This resulted in an LOLE index of 3.58 days/year for the single-area, isolated study footprint. This provided a good starting point for the capacity value calculations.

9.2 Capacity Value

The question "How much capacity is a wind plant worth?" can be answered in a few different ways. It could be compared to the number of gas turbines or coal plants that would be needed to get the same reliability impact. Or it could be a measure of the amount of peak load increase that could be allowed while still maintaining the original reliability level. Or a third measure would be how much "perfect capacity" would be needed to achieve the same level of reliability. All of these measures produce similar results. This analysis used the "perfect capacity" measure and will relate the results to the other methods in a later section. An advantage of perfect capacity is that it is independent of forced outage rate, unit size and load profiles which affect the other measures.

Figure 9.1 shows how the daily LOLP of the study footprint improved with the addition of a series of 500 MW blocks of perfect capacity. It is important to note that the scale on

the y-axis is exponential. Figure 9.2 shows the results of multiple simulations with various combinations of renewable generation added, and then plotted on the same curve as the previous figure. Each of the three types of generators was examined separately as well as combined with the others for different levels of penetration. For example, the three red triangles represent the impact of wind generation alone at the 10%, 20% and 30% penetration levels.

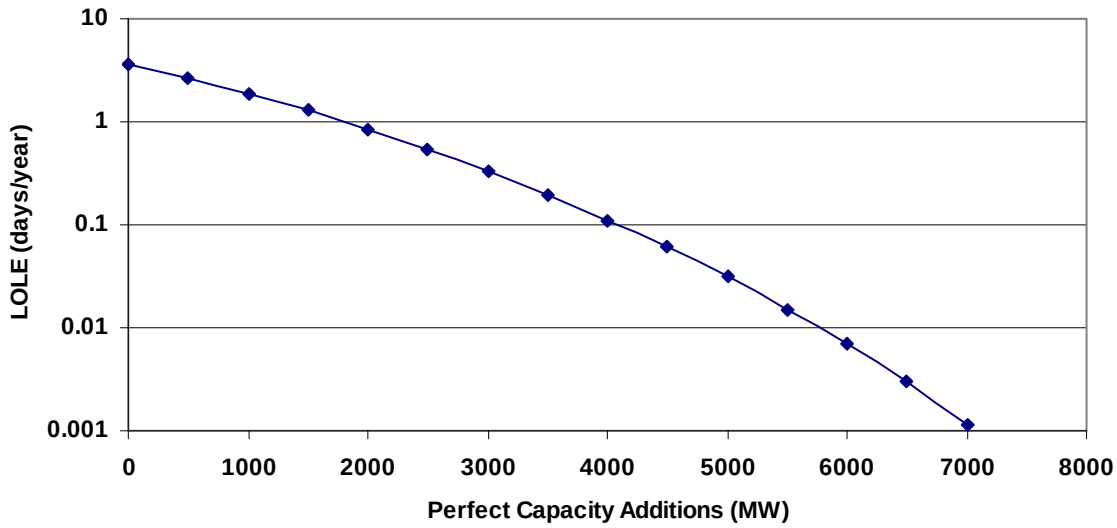


Figure 9.1 Study area risk vs. capacity additions

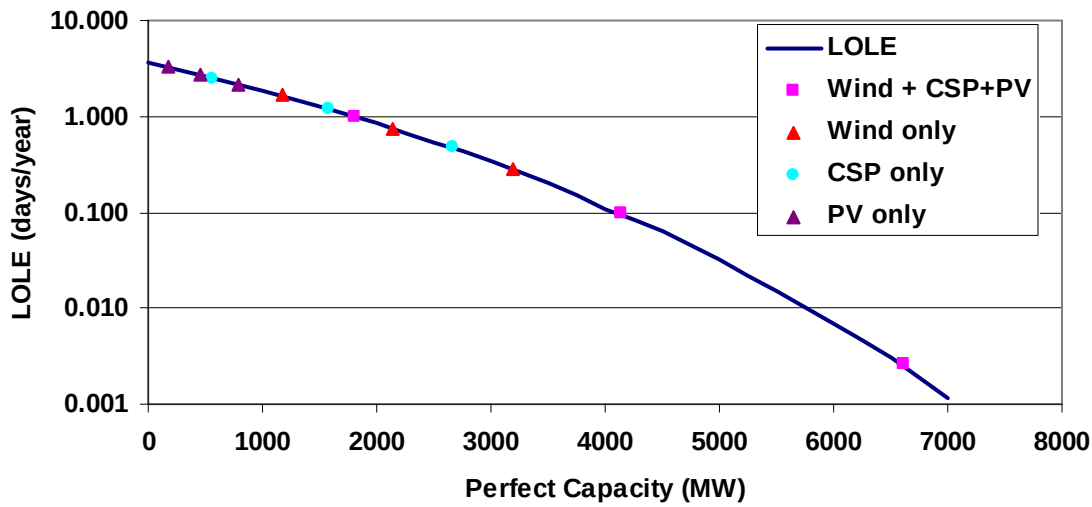


Figure 9.2 Study area risk with renewable additions

Table 9.1 shows the nameplate capacity of the wind, CSP and PV generation added in the three levels of penetration. Table 9.2 shows how the capacity values derived from Figure 9.2 compare to their nameplate ratings on a percentage basis. It is clear that there is significant variation in capacity value among the different types of renewable generation.

Table 9.1 Renewable capacities by type

Penetration	Total Renewables (MW)	Wind Capacity (MW)	CSP Capacity (MW)	PV Capacity (MW)
10% wind, 1% solar	11,490	10,290	600	600
20% wind, 3% solar	23,350	19,950	1,700	1,700
30% wind, 5% solar	35,740	29,940	2,900	2,900

Table 9.2 Renewable capacity values by type, 2006 shapes, perfect capacity, daily LOLE.

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	15.8%	11.4%	92.6%	28.6%
20% wind, 3% solar	17.7%	10.8%	93.3%	26.9%
30% wind, 5% solar	18.5%	10.7%	92.2%	26.9%

9.2.1 Timing is Everything

Figure 9.3 shows the average daily profile of the study area load and wind generation for the 30% scenario in the peak month of July. Although the 30% In-Area scenario includes 30,000 MW of wind plants, their total output is less than 6,000 MW at the peak hour.

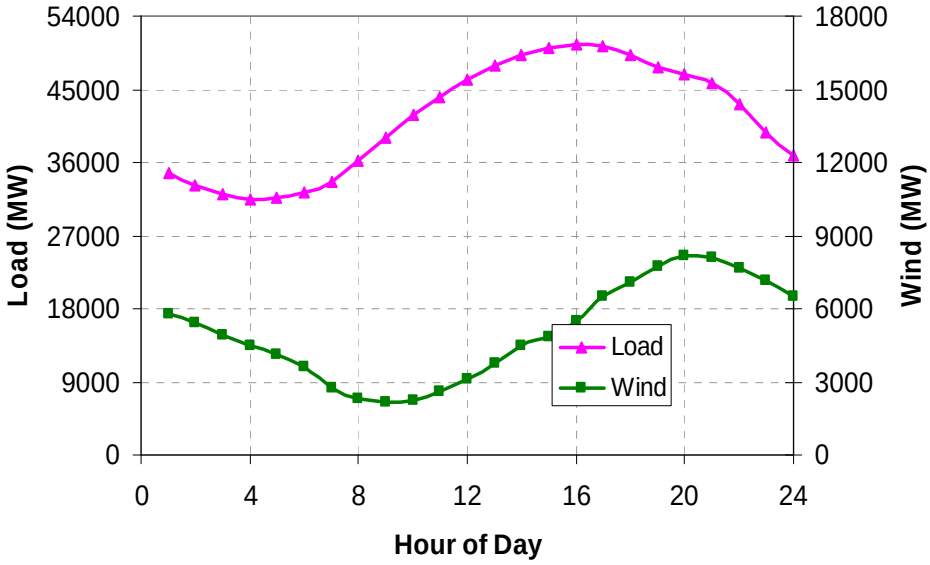


Figure 9.3 Hourly average wind and load shape

This can be compared to the curves in Figure 9.4 that shows the average CSP and PV outputs. The CSP (with storage) had an average output of about 2,400 MW and the PV was about 800 MW at the peak load hour. Both of them had an installed capacity of 2,900 MW. Figure 9.5 shows the wind and solar energy production by month for the 2006 shapes. When the daily and monthly profiles are compared to the load it is not

surprising that the wind capacity value is low. The PV value is limited by the fact that the solar energy peaks at noon and has dropped significantly by the time that the load reaches its peak in late afternoon. The storage on the CSP allows the output to be held near its full rating later in the day and this is what contributes to its high capacity values.

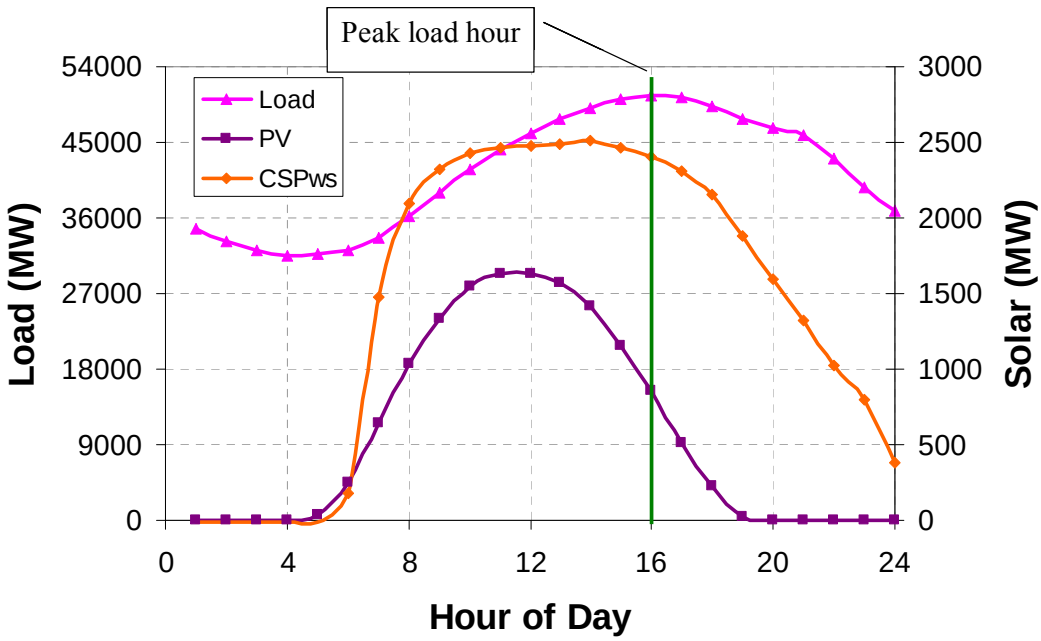


Figure 9.4 Average solar and load shapes

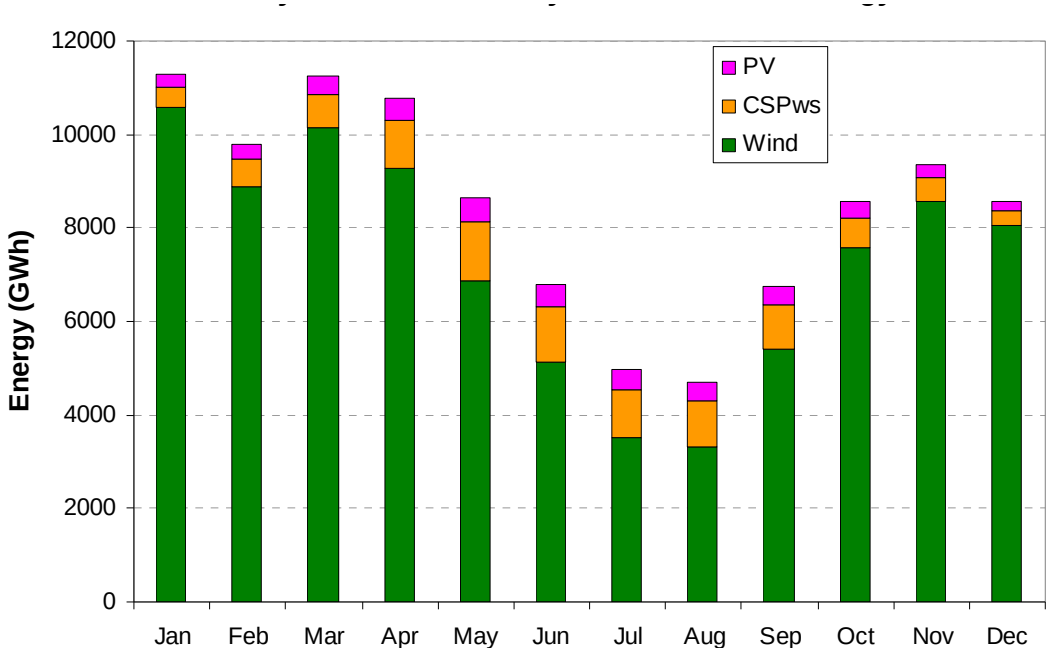


Figure 9.5 Study area total monthly wind and solar energy

9.2.2 Hourly and Unserved Energy Measures

The same type of analysis can be done using the hourly LOLP index and the unserved energy. Just as the daily LOLP analysis calculated the expected number of *days* of shortage, applying the same calculations to all of the hours of the day can calculate the expected number of *hours* of shortage. If each hour of shortage is combined with the corresponding magnitude of the shortage then the expected unserved energy for the year can be determined. Wind and solar generation can then be added to the system to determine the equivalent amount of perfect capacity required to have the same impact on the hourly and unserved energy indices. Figure 9.6 and Figure 9.7 show the curves corresponding to these calculations. Table 9.3 and Table 9.4 are the companion capacity values.

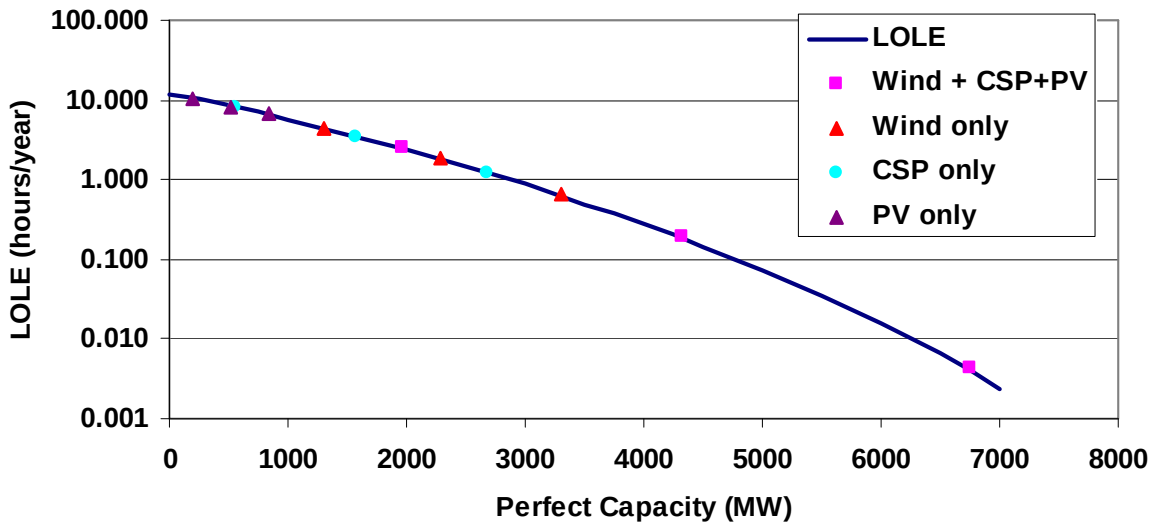


Figure 9.6 Study area risk in hours/year

Table 9.3 Renewable capacity values by type, 2006 shapes, perfect capacity, hourly LOLE.

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	17.1%	12.6%	90.8%	32.1%
20% wind, 3% solar	18.5%	11.5%	92.7%	30.3%
30% wind, 5% solar	18.9%	11.0%	92.6%	29.0%

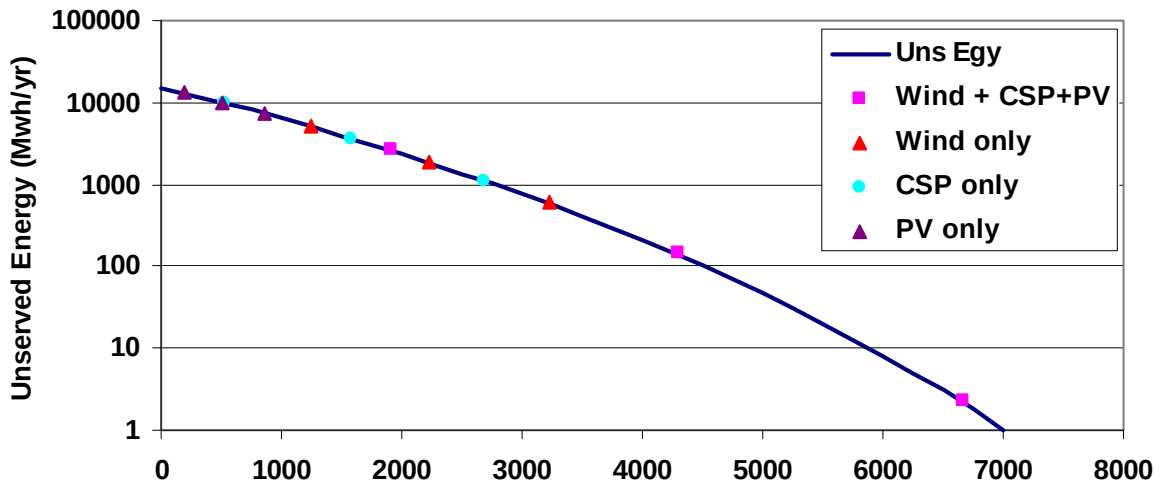


Figure 9.7 Study area risk in unserved energy

Table 9.4 Renewable capacity values by type, 2006 shapes, perfect capacity

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	16.6%	12.1%	88.5%	33.2%
20% wind, 3% solar	18.4%	11.2%	92.6%	30.0%
30% wind, 5% solar	18.6%	10.8%	92.6%	29.3%

Table 9.5 Renewable capacity values by type, 2006 shapes, perfect capacity, average across indices

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	17%	12%	91%	31%
20% wind, 3% solar	18%	11%	93%	29%
30% wind, 5% solar	19%	11%	92%	28%

9.3 Capacity Value Variation by Scenario

The 2006 analysis was repeated for the three different siting scenarios. Although the megawatts in each area, and in total, changed between the scenarios, particularly for the wind generation, there was very little change in the capacity value as shown in Table 9.6. The results are shown graphically in Figure 9.8, Figure 9.9 and Figure 9.10.

Table 9.6 Renewable capacity values by type, perfect capacity, daily LOLE, by Scenario.

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
In-Area				
10% wind, 1% solar	15.8%	11.4%	92.6%	28.6%
20% wind, 3% solar	17.7%	10.8%	93.3%	26.9%
30% wind, 5% solar	18.5%	10.7%	92.2%	26.9%
Local Priority				
10% wind, 1% solar	16.5%	11.4%	92.6%	28.6%
20% wind, 3% solar	18.7%	11.3%	93.3%	26.9%
30% wind, 5% solar	18.8%	10.5%	92.2%	26.9%
Mega Project				
10% wind, 1% solar	18.5%	13.0%	91.6%	25.8%
20% wind, 3% solar	19.0%	11.9%	94.1%	24.7%
30% wind, 5% solar	19.3%	10.0%	92.8%	24.8%

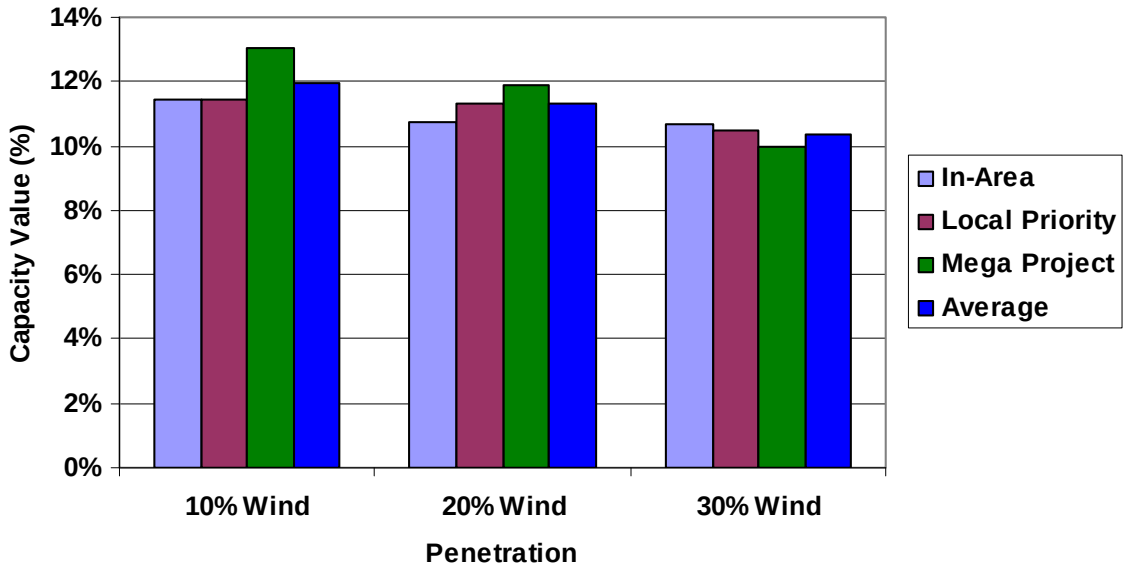


Figure 9.8 Wind capacity values by scenario, 2006 shapes, perfect capacity

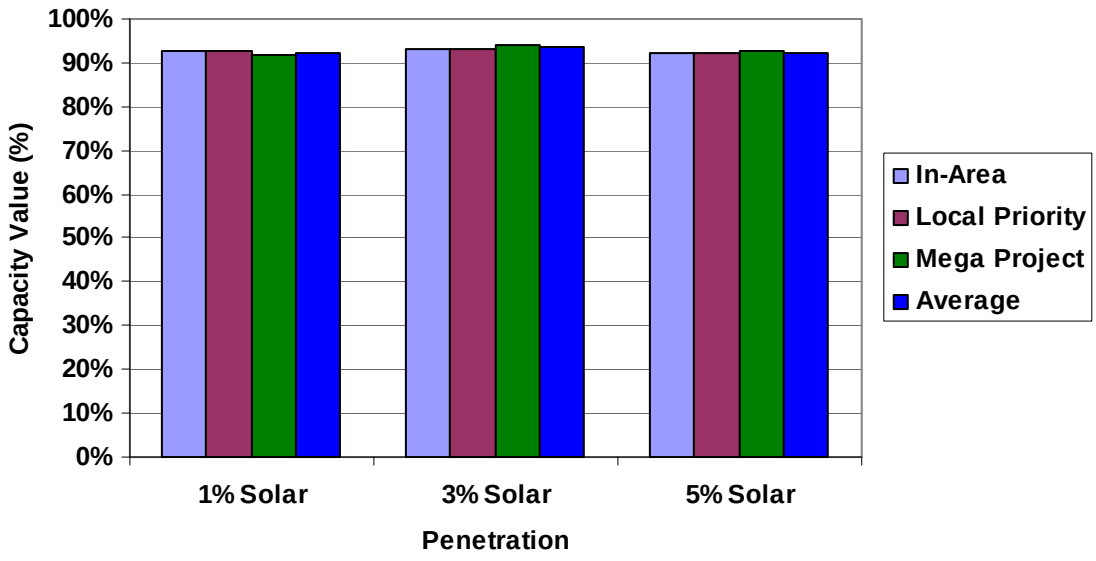


Figure 9.9 CSP with storage capacity values by scenario, 2006 shapes, perfect capacity

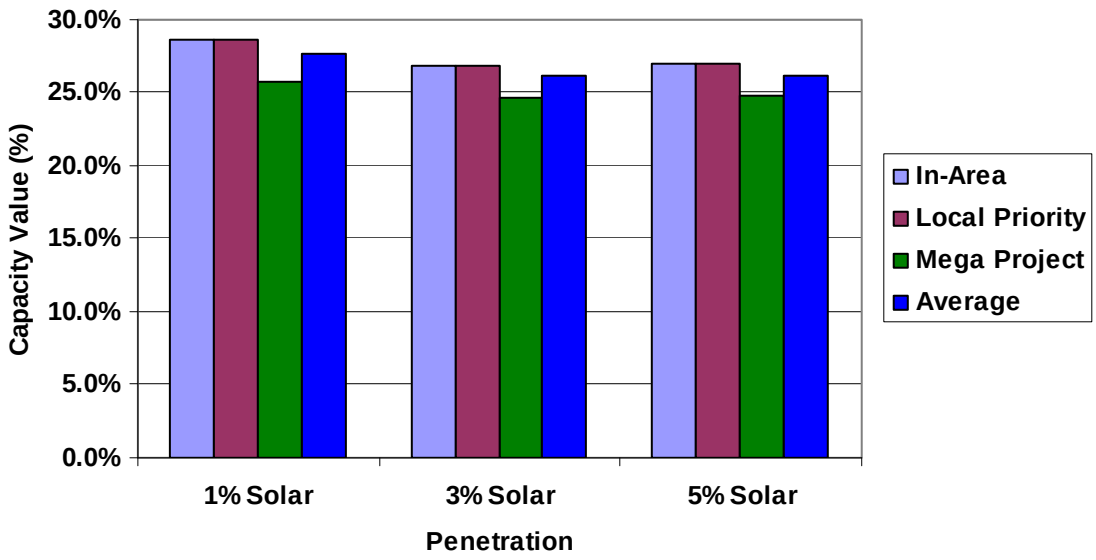


Figure 9.10 PV capacity values by scenario, 2006 shapes, perfect capacity

9.4 Capacity Value Variation by Shape Year

The results shown so far were based on the 2006 load and weather shapes. The In-Area analysis was also done using the shapes from 2004 and 2005. Figure 9.11 shows the monthly energy variation by type for the three years for the In-Area scenario. The green bar indicates the wind energy, the orange is for the CSP and the pink is for the PV plants. Figure 9.12, Figure 9.13, Figure 9.14 and Figure 9.15 show the variations in

capacity value for the individual generation types and well as the combined total for the three shape years. There is some year-to-year variation but it does not appear to be significant.

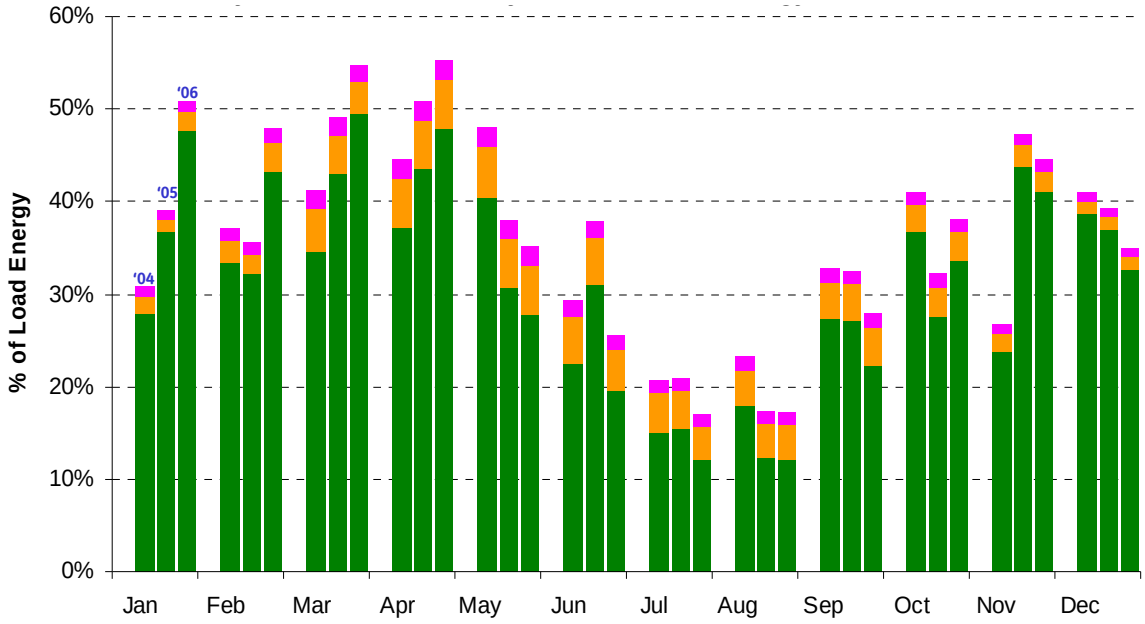


Figure 9.11 Annual and monthly variation in renewable energy

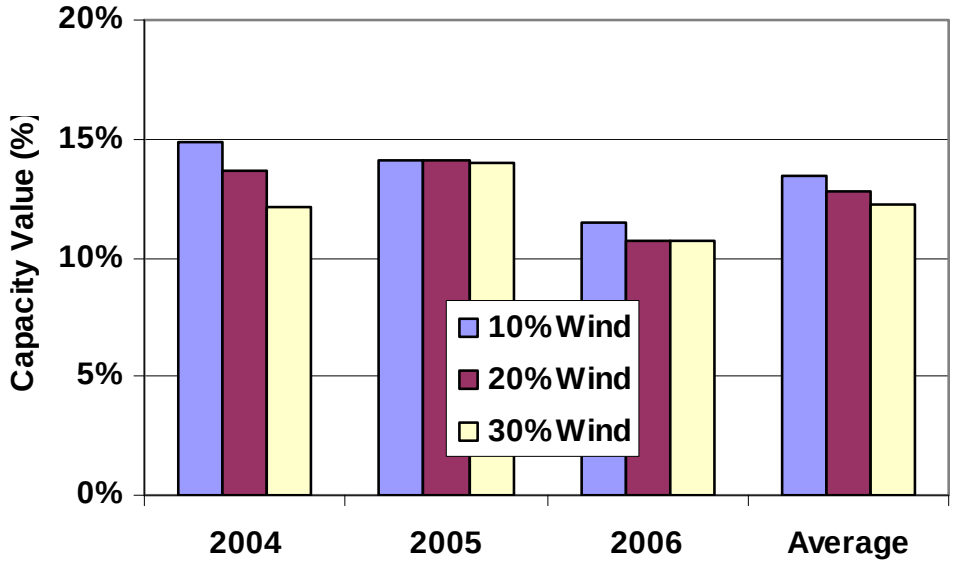


Figure 9.12 Capacity value for wind, perfect capacity, daily LOLE, all years

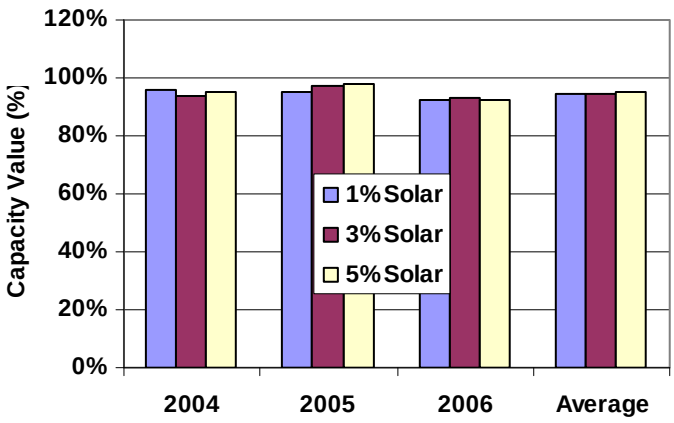


Figure 9.13 Capacity value for CSP with 6 hours of storage, perfect capacity, daily LOLE, all years

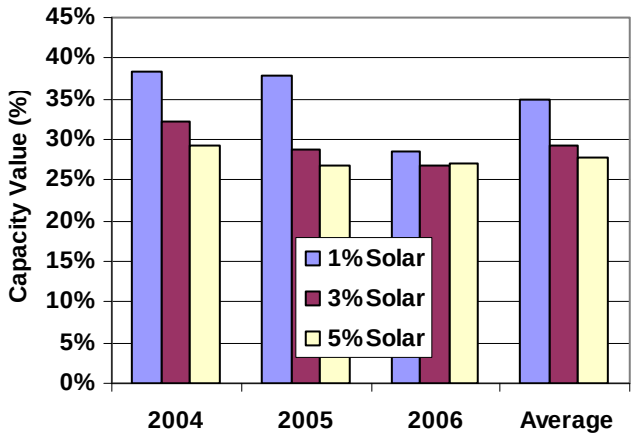


Figure 9.14 Capacity value for PV, perfect capacity, daily LOLE, all years

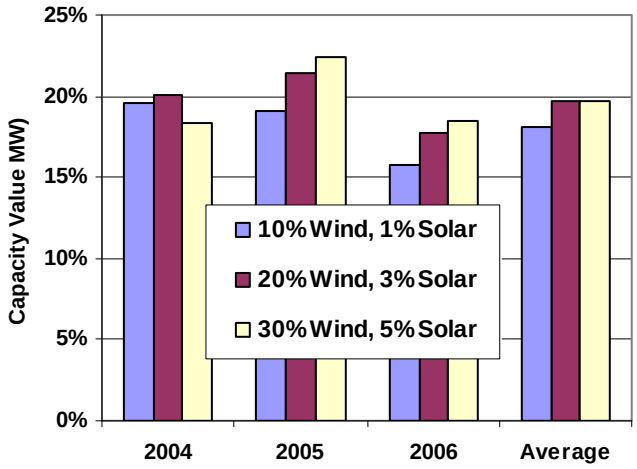


Figure 9.15 Combined capacity value for wind, CSP and PV, perfect capacity, daily LOLE, all years

9.5 Comparison to Other Measures

This analysis has equated the renewable generation to the amount of perfect capacity that would produce the same result. Other studies have considered the amount of equivalent generators or increased load that could be carried. This section will compare the measures.

If a unit is large relative to the size of the system then this will distort its capacity value. However, if the unit's capacity is small relative to the system size then its effective capacity is typically estimated as its nameplate capacity times one minus the forced outage rate. For example, a 100 MW gas turbine with a 5% forced outage rate would have an effective capacity of 95 MW. Therefore, to convert the perfect capacity values to an equivalent capacity of gas turbines with 5% forced outage rates you would divide the previous values by 0.95. Similarly, to convert the perfect capacity to equivalent units with a 10% forced outage rate you would divide by 0.90. Referring back to the "wind only" value for the 30% scenario in Table 9.2, 100 MW of nameplate wind generation would have a value of 10.7 MW of "perfect" capacity. This would correspond to 11.3 MW of capacity when compared to gas turbines or 11.8 MW capacity when compared to a unit with a 10% force outage rate.

Another method that is used in the industry is the effective load carrying capability or ELCC. In this case, after a generator is added to the system, the peak load is increased until the risk is back to its original value. When the peak load is increased, the other loads are also increased proportionately. So if the annual peak load is 1000 MW and another day has a peak of 900 MW, when the peak is increased by 100 MW, or 10%, the other day is only increased by 90 MW. This has the effect of increasing the value over the perfect capacity method since 100 MW of perfect capacity is worth 100 MW in every other hour. For comparison purposes we examined the case with 2006 shapes, 30% In-Area scenario. The perfect capacity value for all of the renewables was 6610 MW or 18.5%. The ELCC method shows that increasing the peak load by 7260 MW returns the system with all of the renewables back to its original daily LOLE value. Therefore the ELCC produces values roughly 10% higher (=7260/6610) than the perfect capacity method.

All of these methods are roughly equivalent within the general level of accuracy. Switching from the perfect capacity measure to effective capacity or effective load carrying capability increases the values by 5 to 10%. But as seen in Figure 9.15 the perfect capacity values change by +/- 10% when looking at three different shape years. Similar variations were seen for a given shape when varying the penetration levels and the siting scenarios. The important aspect is the relative capacity value of the different types of renewable generation compared to more conventional generation. Thermal generators typically have capacity values in the 90 to 95% range. For this system, wind generation has capacity values in the 10 to 15% range. Photovoltaic generation is in the

25 to 30% range and concentrating solar plants with six hours of storage had values in the 90 to 95% range. It is this relative capacity value that is important.

9.6 Yet Another Calculation Method

Much care has been taken to keep the load data and weather data coincident. The 2004 load shapes are used with the 2004 weather patterns to insure that any correlation between load and wind and solar generation is captured. From the statistical analysis in Chapter 4 it is clear that loads, wind generation and solar generation have a clear seasonal and diurnal pattern. However, the variations in reliability value from year to year imply more randomness in the daily correlation. If it is windy or sunny on the peak day then the capacity value is high. Alternatively if the wind dies down or a cloud passes by at the time of peak then the capacity value is lower.

The reliability model was adjusted to randomly pick a day of weather from within the month. In this way when the risk for a day in July is being evaluated it will be matched up with a wind and solar generation pattern from a randomly selected day in July. Two a.m. will still occur at two a.m. and July generation will still occur in July but the specific line up of good days and bad days will be shuffled within the month. The Monte Carlo analysis will match up the loads from every day in the month with every day of the wind and solar generation in the month. It is hoped that this will produce a more robust result.

The results of this analysis are shown for the individual technologies in Figure 9.16, Figure 9.17 and Figure 9.18. Figure 9.19 shows the combined results for all renewables.

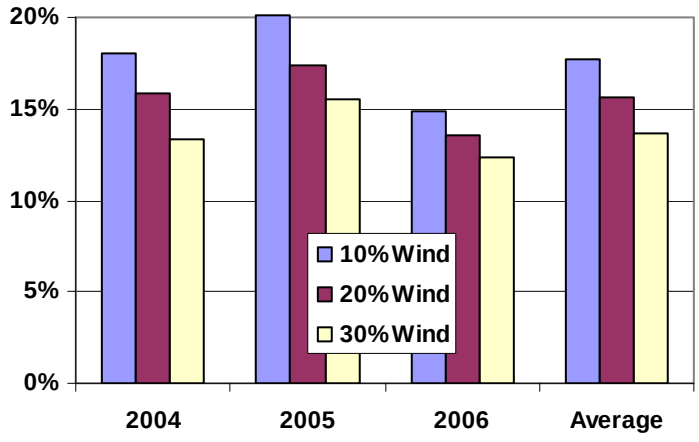


Figure 9.16 Capacity value for wind only, 2006 load shapes, random wind shapes.

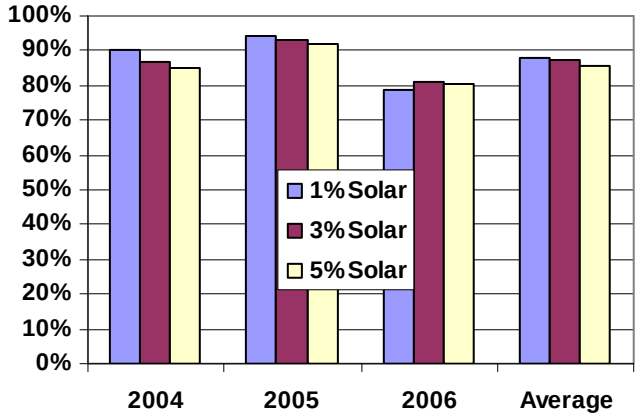


Figure 9.17 Capacity value for CSP with storage, 2006 load shapes, random solar shapes

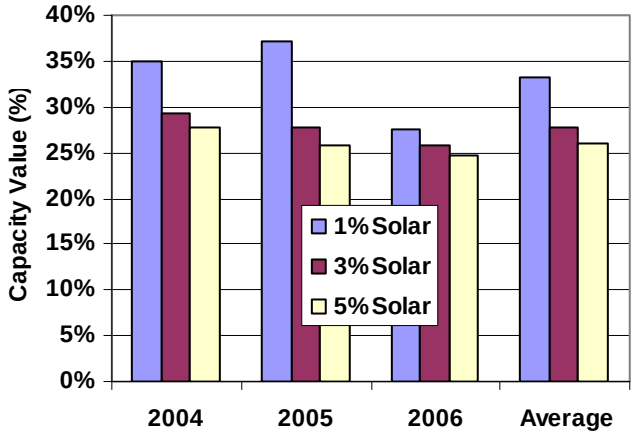


Figure 9.18 Capacity value for PV only, 2006 load shapes, random solar shapes

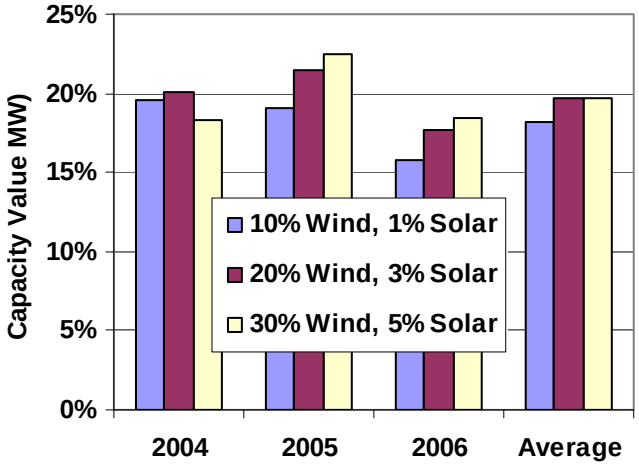


Figure 9.19 Capacity value for wind, CSP and PV, 2006 load shapes, random wind and solar shapes

Figure 9.20, Figure 9.21 and Figure 9.22 show the average capacity values for the three years by type and penetration level. The results appear to be relatively consistent between the two approaches. The advantage of this approach is that it is not subject to the possibly random hit or miss of good generation days at the time of peak load. The disadvantage is that it will miss whatever correlation may exist within the month between the loads and wind and solar generation.

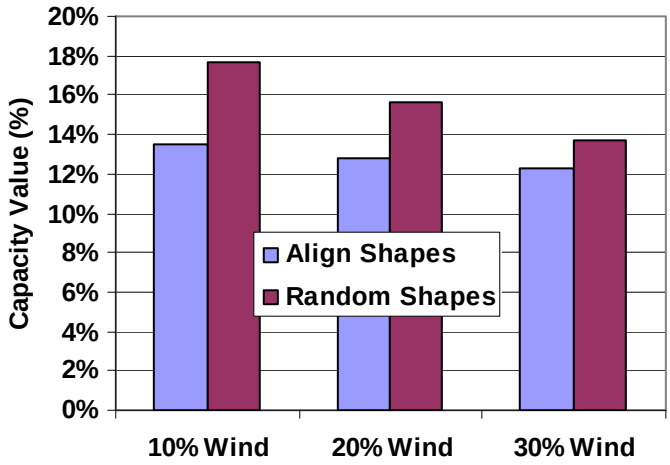


Figure 9.20 Comparison of wind capacity values, random and aligned shapes

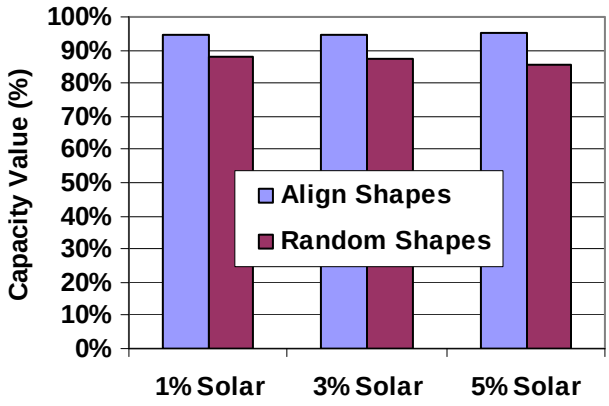


Figure 9.21 Comparison of CSP capacity values, random and aligned shapes

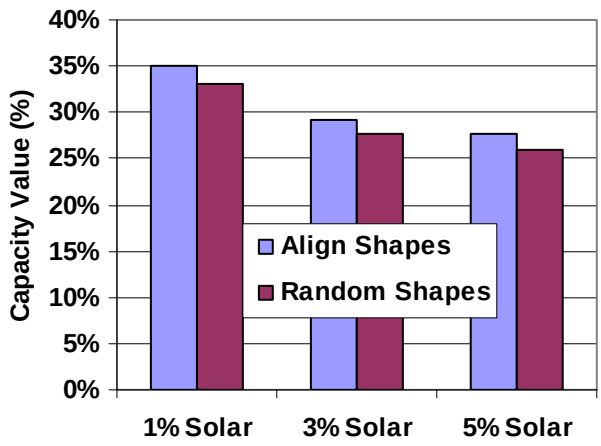


Figure 9.22 Comparison of PV capacity values, random and aligned shapes

9.7 Capacity Value Observations

Wind generation is added to a system for its energy value, not its capacity value; having said that, its capacity value is not zero, but tends to fall more in the 10 to 15% of nameplate range as compared to thermal units that are in the 90 to 95% range. These results reflect the fact that the summer peak load months tend to have lower values of wind generation than the low load spring and fall months. Also, within the day, wind generation tends to be higher in the middle of the night rather than during the day.

Photovoltaic generation has capacity values in the 25 to 30% range. The generation comes, naturally, during the day rather than at night which gives it a better capacity value than wind. Also, PV tends to do well in the summer peak load months. The only reason for the relatively low value is that the peak loads tend to come later in the day when the solar energy has begun to wane.

Concentrating solar plants would normally tend to suffer the same capacity value fate as the PV. However, by their very nature the CSPs lend themselves well to storage. The collector field can be oversized and the collection medium can store the thermal energy without the large collection losses inherent with battery or pumped storage hydro. Because of this, the CSP with six hours of storage was seen to have capacity values in the 90 to 95% range that is on par with conventional thermal generation.

Different methods can be used to determine capacity value, including daily LOLE, hourly LOLE and unserved energy. All of the measures tend to produce results within the same range.

10 Key Findings

The following findings are broadly drawn from the overall body of work that comprised this study. Where appropriate, specific section citations are listed to support the findings. In some cases, the findings are drawn from the overall study results. The items that quantify specific economic impacts and operating costs are primarily focused on the 30% wind penetration scenarios (30% wind and 5% solar energy in the study footprint, 20% wind and 3% solar energy in the rest of WECC).

1. The technical analysis performed in this study shows that it is feasible for the WestConnect region to accommodate 30% wind and 5% solar energy penetration, but it would require extensive control area cooperation or consolidation. Renewable energy penetration outside the WestConnect footprint is an important factor, as it significantly affects performance and economics of renewable energy operations within WestConnect.
2. Location of Wind and Solar Generation: The In-Area, Local Priority and Mega Project scenarios showed similar overall performance and economics for a given penetration level. This indicates that the specific locations of the wind and solar resources within WestConnect are not critical, provided there is adequate transmission infrastructure and control area cooperation. (See Sections 4.2.3, 5.5, 6.4.1, 6.4.6, 7.3.1.)
3. The 30% wind penetration scenarios show WECC operating cost savings of $20 billion per year due to the wind and solar generation resources. This equates to $80/MWh of wind and solar energy produced. Lower penetrations of renewables showed values up to $88/MWh. (See Section 6.2.)
4. Emissions: CO2 emissions would be reduced by nearly 120 million tons per year for the 30% wind penetration scenarios. SOx emissions would be reduced by approximately 45,000 tons and NOx would be reduced nearly 100,000 tons per year. (See Section 6.2.1.)
5. Wind and Solar Forecasts: Integrating day-ahead wind and solar forecasts into the unit commitment process is essential. Using state-of-the-art wind and solar forecasts would reduce annual WECC production costs by $5 billion, compared to ignoring renewables in the day-ahead forecast. Perfect wind and solar day-ahead forecasts would reduce WECC operating costs by another $500 million per year. (See Section 6.2.1.)
6. Fuel Displacement: Given the fuel prices and carbon tax assumed for this study ($2 Mbtu coal, $9.5Mbtu gas, $30/ton carbon), wind and solar generation displace gas resources nearly all hours of the year. Since gas-fired generation is typically more flexible than coal generation, the natural economic displacement of gas generation by wind and solar generation makes the balance of dispatchable

generation on-line less flexible (fewer gas units, more coal units). If the economic dispatch priority were reversed (for example, by lower gas price or by increased carbon tax), wind and solar generation would displace coal generation, leaving the more flexible gas generation resources to operate together with the wind and solar generation, and also further reducing overall emissions.

7. Hydro Plant Operation: Hydro generation is capable of quick start/stop cycling and fast ramping, which makes it very well matched with variable wind and solar generation. This study assumed that hydro generation is normally committed and dispatched to serve daily peak load periods. If hydro energy dispatch is adjusted to account for day-ahead wind and solar forecasts, WECC operating costs would be reduced by $200 million per year, increasing the value of wind and solar energy by about $1/MWh. On the other hand, if hydro operation were severely constrained (such as a requirement to maintain constant river flow), WECC operating costs would increase by up to $1 billion per year. (Section 6.4.2.)

8. Coal Plant Operation: Coal plants are normally expected to have minimum operating load in the range of 40% to 50% of full rating. If coal plants are restricted to only operate above 70% load, then WECC operating costs would increase by $160 million per year.

9. Capacity Value: Wind generation resources selected for this study were found to have capacity values in the range of 10% to 15%. Wind plant energy output tends to be higher during winter and spring seasons, and during nighttime hours, which is contrary to system peak load periods. Hence the capacity value is low relative to the plant rating. PV solar plants have capacity values in the range of 25% to 30%. Although PV solar produces its energy during the daytime, output tends to decline in the late afternoon and early evening when peak load hours often occur. Concentrating solar plants with thermal energy storage have capacity values in the range of 90% to 95%, similar to thermal generating plants. Their maximum energy production tends to be during the long summer days, and the storage capability extends the energy output through the late afternoon and early evening hours when peak loads occur. (See Sections 4.2, 4.3, 9.2 through 9.7.)

10. Reserves: Subhourly operating reserves are expected to increase by 1% to 5% of total wind plant MW production during each hour (not total MW rating of wind plants on line), depending on the degree of cooperation between neighboring control areas (Section 7.5.6). With 35% wind and solar penetration, the additional subhourly reserves would increase operating costs by less than $1 per MWh of wind energy. (See Section 6.2.2.)

11. Demand Response: Demand response is an attractive alternative for sub-hourly operating reserves. Using demand response instead of committing additional generation for operating reserves would save up to $600 million in operating

costs per year. The value of demand response resources would be in the range of $3,000 to $100,000 per MWh reduction in unserved energy. (See Sections 5.4, 7.2, and 6.2.2.)

12. Down-Reserves from Wind Plants: A wind plant can reduce its output very quickly in response to a command signal. This capability enables wind plants to provide down reserves (i.e., curtailment) in response to commands from system operators. Such a function could be implemented via the system ACE signal, as demonstrated by simulations performed in this study. (See Sections 7.2.7 and 7.4.1.)
13. Energy Storage: In the 10% and 20% wind penetration scenarios, gas generation is always on the margin (meaning that there are only small spot price variations during most days). As a result, there is no apparent opportunity to economically justify energy storage based on price arbitrage. Spot price variations increase in the 30% wind penetration scenarios, primarily due to errors in day-ahead wind energy forecasts. However, because this is driven by forecast uncertainty, it is not possible to strategically schedule the use of storage resources to take advantage of the price variations (and subsequently help eliminate the operational problems due to wind forecast errors). A hypothetical experiment to schedule operation of energy storage resources with perfect foresight of next day wind and solar generation showed that the value of the storage would be approximately $250/kW, based on capitalized cost. Typical capitalized cost values for pumped storage hydro and other long-term energy storage technologies are in the range of $4,000/kW. (See Section 8.2.)
14. Storage for Reserves or Regulation: Short-term energy storage may be a cost effective alternative to conventional generation resources for sub-hourly spinning reserves or regulation. (See Section 7.5.9.)

In addition to the key findings listed here, there are observations and conclusions at the end of Chapters 4 through 9.