2017 INTEGRATED RESOURCE PLAN

Volume II - Appendices

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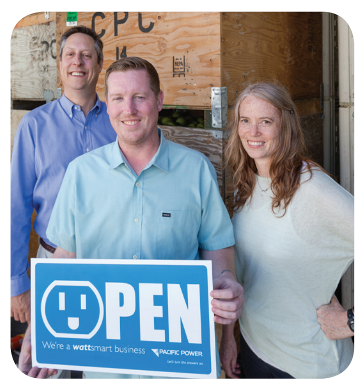

This 2017 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Demand-Side Management: *Smart thermostat*
Pacific Power wattsmart Business Customer Meeting
Thermal-Gas: *Blundell Geothermal Plant*

TABLE OF CONTENTS

TABLE OF CONTENTS i

INDEX OF TABLES vi

INDEX OF FIGURES x

APPENDIX A – LOAD FORECAST DETAILS 1

INTRODUCTION 1
SUMMARY LOAD FORECAST 1
LOAD FORECAST ASSUMPTIONS 3
REGIONAL ECONOMY BY JURISDICTION 3
UTAH 5
OREGON 6
WYOMING 7
WASHINGTON 7
IDAHO 8
CALIFORNIA 8
WEATHER 9
STATISTICALLY ADJUSTED END-USE (SAE) 10
INDIVIDUAL CUSTOMER FORECAST 11
ACTUAL LOAD DATA 11
SYSTEM LOSSES 13
FORECAST METHODOLOGY OVERVIEW 13
CLASS 2 DEMAND-SIDE MANAGEMENT (DSM) RESOURCES IN THE LOAD FORECAST 13
MODELING OVERVIEW 13
SALES FORECAST AT THE CUSTOMER METER 14
RESIDENTIAL 15
COMMERCIAL 15
INDUSTRIAL 15
STATE SUMMARIES 16
OREGON 16
WASHINGTON 16
CALIFORNIA 17
UTAH 17
IDAHO 18
WYOMING 18
ALTERNATIVE LOAD FORECAST SCENARIOS 18

APPENDIX B – IRP REGULATORY COMPLIANCE 21

INTRODUCTION 21
GENERAL COMPLIANCE 21
CALIFORNIA 22
IDAHO 23
OREGON 23

UTAH ... *23*
WASHINGTON ... *23*
WYOMING ... *24*

APPENDIX C – PUBLIC INPUT PROCESS ... 57

PARTICIPANT LIST ... 57
COMMISSIONS ... *57*
STAKEHOLDERS AND INDUSTRY EXPERTS ... *58*
PUBLIC INPUT MEETINGS ... 59
GENERAL MEETINGS ... *59*
June 21, 2016 – General Public Meeting ... 59
July 20, 2016 – General Public Meeting ... 59
August 25-26, 2016 – General Public Meeting ... 59
September 22-23, 2016 – General Public Meeting ... 59
November 17, 2016 – General Public Meeting ... 60
January 26-27, 2017 – General Public Meeting ... 60
March 2-3, 2017 – General Public Meeting ... 60
STATE MEETINGS ... *60*
June 6, 2016 – Washington State Stakeholder Meeting ... 60
June 10, 2016 – Oregon State Stakeholder Meeting ... 60
June 13, 2016 – Utah State Stakeholder Meeting ... 60
June 14, 2016 – Wyoming State Stakeholder Meeting ... 60
STAKEHOLDER COMMENTS ... 61
CONTACT INFORMATION ... 62

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES ... 63

INTRODUCTION ... 63
DEMAND-SIDE RESOURCE POTENTIAL ASSESSMENTS FOR 2017-2036 ... 63
CURRENT DSM PROGRAM OFFERINGS BY STATE ... 64
PREFERRED PORTFOLIO DSM RESOURCE SELECTIONS ... 67
STATE-SPECIFIC DSM PLANNING PROCESSES ... 68

APPENDIX E – SMART GRID ... 69

INTRODUCTION ... 69
TRANSMISSION SYSTEM EFFORTS ... *69*
Dynamic Line Rating ... 69
Thermal Replicating Relays ... 70
Synchrophasors ... 70
DISTRIBUTION SYSTEM EFFORTS ... *71*
Distribution Automation ... 71
CUSTOMER INFORMATION EFFORTS ... *72*
Advanced Metering Infrastructure ... 72
FUTURE SMART GRID ... 72

APPENDIX F – FLEXIBLE RESERVE STUDY 73

INTRODUCTION 73
EXECUTIVE SUMMARY 75
FLEXIBLE RESOURCE REQUIREMENTS 76
CONTINGENCY RESERVE 76
REGULATION RESERVE 76
FREQUENCY RESPONSE RESERVE 77
DESCRIPTION OF DATA INPUTS 78
OVERVIEW 78
LOAD DATA 79
WIND DATA 80
NON-VER DATA 80
DATA ANALYSIS AND ADJUSTMENT 81
OVERVIEW 81
LOAD BASE SCHEDULE DEVELOPMENT 81
BASE SCHEDULE RAMPING ADJUSTMENT 84
DATA CORRECTIONS 84
NON-VER DEVIATION ADJUSTMENT 86
METHODOLOGY TO DETERMINE INITIAL REGULATION RESERVE REQUIREMENT 88
OVERVIEW 88
COMPONENTS OF OPERATING RESERVE METHODOLOGY 89
Operating Reserve: Reserve Categories 89
Calculation of Regulation Reserve Need 92
Balancing Authority ACE Limit: Allowed Deviations 94
Planning Reliability Target: Loss of Load Probability 96
Regulation Reserve Forecast: Amount Held 96
2015 REGULATION RESERVE FORECAST 97
Wind 97
Non-VERs 100
Load 102
2015 PACIFICORP SYSTEM DIVERSITY AND EIM DIVERSITY BENEFITS 104
PACIFICORP SYSTEM-WIDE PORTFOLIO DIVERSITY BENEFIT 104
EIM INTRA-HOUR BENEFIT 105
INCREMENTAL WIND REGULATION RESERVE REQUIREMENTS 107
SOLAR REGULATION RESERVE REQUIREMENTS 108
OVERVIEW 108
PROXY SOLAR BASE SCHEDULE DEVELOPMENT 109
SOLAR DIVERSITY 111
SOLAR LOCATIONS 112
SOLAR PORTFOLIO 114
SOLAR REGULATION RESERVE FORECAST 115
PORTFOLIO REGULATION RESERVE REQUIREMENTS 117
OVERVIEW 117
METHODOLOGY 117
RESULTS 118
REGULATION RESERVE COST 119
DAY-AHEAD SYSTEM BALANCING COSTS 121
TECHNICAL REVIEW COMMITTEE 123
FLEXIBLE RESOURCE NEEDS ASSESSMENT 125

OVERVIEW *125*
FORECASTED RESERVE REQUIREMENTS *126*
FLEXIBLE RESOURCE SUPPLY FORECAST *128*
FLEXIBLE RESOURCE SUPPLY PLANNING *131*
SUMMARY 132
REFERENCE TABLES 134

APPENDIX G – PLANT WATER CONSUMPTION 139

APPENDIX H – STOCHASTIC PARAMETERS 143

INTRODUCTION 144
VOLATILITY 144
MEAN REVERSION 144
ESTIMATING SHORT-TERM PROCESS PARAMETERS 146
STOCHASTIC PROCESS DESCRIPTION 146
DATA DEVELOPMENT 147
PARAMETER ESTIMATION – AUTOREGRESSIVE MODEL 150
ELECTRICITY PRICE PROCESS 151
REGIONAL LOAD PROCESS 153
HYDRO GENERATION PROCESS 155
SHORT-TERM CORRELATION ESTIMATION 156
CONCLUSION 158

APPENDIX I – PLANNING RESERVE MARGIN STUDY 159

INTRODUCTION 159
METHODOLOGY 160
DEVELOPMENT OF RESOURCE PORTFOLIOS *160*
DEVELOPMENT OF RELIABILITY METRICS *161*
DEVELOPMENT OF SYSTEM VARIABLE PRODUCTION COSTS *161*
RESULTS 163
RESOURCE PORTFOLIOS *163*
RELIABILITY METRICS *164*
SYSTEM COSTS *167*
INCREMENTAL COST OF RELIABILITY *168*
CONCLUSION 169

APPENDIX J – WESTERN RESOURCE ADEQUACY EVALUATION 171

INTRODUCTION 171
WESTERN ELECTRICITY COORDINATING COUNCIL RESOURCE ADEQUACY ASSESSMENT 171
PACIFIC NORTHWEST RESOURCE ADEQUACY FORUM'S ADEQUACY ASSESSMENT 175
CUSTOMER VERSUS SHAREHOLDER RISK ALLOCATION 176
MARKET PURCHASES 176

APPENDIX K – CAPACITY EXPANSION RESULTS DETAIL ... 179

PORTFOLIO CASE BUILD TABLES ... 179

APPENDIX L – STOCHASTIC PRODUCTION COST SIMULATION RESULTS ... 225

APPENDIX M – CASE STUDY FACT SHEETS ... 263

CASE FACT SHEET OVERVIEW ... 263
MASTER FACT SHEET ... 267
REGIONAL HAZE CASE FACT SHEETS ... 269
CORE CASE FACT SHEETS ... 276
SENSITIVITY FACT SHEETS ... 287
FINAL SELECTION FACT SHEETS ... 309

APPENDIX N – WIND AND SOLAR CAPACITY CONTRIBUTION STUDY ... 313

INTRODUCTION ... 313
METHODOLOGY ... 314
RESULTS ... 315
CONCLUSION ... 318

APPENDIX O – PRIVATE GENERATION STUDY ... 319

APPENDIX P – ENERGY STORAGE STUDIES ... 415

INDEX OF TABLES

TABLE A.1 – FORECASTED ANNUAL LOAD GROWTH, 2017 THROUGH 2026 (MEGAWATT-HOURS), AT GENERATION, PRE-DSM 2
TABLE A.2 – FORECASTED ANNUAL COINCIDENT PEAK LOAD (MEGAWATTS) AT GENERATION, PRE-DSM 3
TABLE A.3 – ANNUAL LOAD GROWTH CHANGE: DECEMBER 2016 FORECAST LESS OCTOBER 2015 FORECAST (MEGAWATT-HOURS) AT GENERATION, PRE-DSM 3
TABLE A.4 – ANNUAL COINCIDENT PEAK GROWTH CHANGE: JULY 2016 FORECAST LESS OCTOBER 2015 FORECAST (MEGAWATTS) AT GENERATION, PRE-DSM 3
TABLE A.5 – WEATHER NORMALIZED JURISDICTIONAL RETAIL SALES 2000 THROUGH 2016 11
TABLE A.6 – NON-COINCIDENT JURISDICTIONAL PEAK 2000 THROUGH 2016 12
TABLE A.7 – JURISDICTIONAL CONTRIBUTION TO COINCIDENT PEAK 2000 THROUGH 2016 12
TABLE A.8 – SYSTEM ANNUAL RETAIL SALES FORECAST 2017 THROUGH 2026, POST-DSM 14
TABLE A. 9 – FORECASTED RETAIL SALES GROWTH IN OREGON, POST-DSM 16
TABLE A.10 – FORECASTED RETAIL SALES GROWTH IN WASHINGTON, POST-DSM 16
TABLE A.11 – FORECASTED RETAIL SALES GROWTH IN CALIFORNIA, POST-DSM 17
TABLE A.12 – FORECASTED RETAIL SALES GROWTH IN UTAH, POST-DSM 17
TABLE A.13 – FORECASTED RETAIL SALES GROWTH IN IDAHO, POST-DSM 18
TABLE A.14 – FORECASTED RETAIL SALES GROWTH IN WYOMING, POST-DSM 18
TABLE B.1 – INTEGRATED RESOURCE PLANNING STANDARDS AND GUIDELINES SUMMARY BY STATE 25
TABLE B.2 – HANDLING OF 2015 IRP ACKNOWLEDGMENT AND OTHER IRP REQUIREMENTS 30
TABLE B.3 – OREGON PUBLIC UTILITY COMMISSION IRP STANDARD AND GUIDELINES 38
TABLE B.4 – UTAH PUBLIC SERVICE COMMISSION IRP STANDARD AND GUIDELINES 47
TABLE B.5 – WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION IRP STANDARD AND GUIDELINES (RCW 19.280.030 AND WAC 480-100-238) 52
TABLE B.6 – WYOMING PUBLIC SERVICE COMMISSION GUIDELINES REGARDING ELECTRIC IRP. 56
TABLE D.1– CURRENT CLASS 1 AND 2 DSM PROGRAM SERVICES AND OFFERINGS BY SECTOR AND STATE 65
TABLE D.2 – CURRENT WATTSMART OUTREACH AND COMMUNICATIONS ACTIVITIES 66
TABLE D.3 – INCREMENTAL AND CUMULATIVE CLASS 1 DSM RESOURCE SELECTIONS (2017 IRP PREFERRED PORTFOLIO) 67
TABLE D.4 – INCREMENTAL CLASS 2 DSM RESOURCE SELECTIONS (2017 IRP PREFERRED PORTFOLIO) 67
TABLE F.1 – PORTFOLIO REGULATION RESERVE REQUIREMENTS, BY SCENARIO 75
TABLE F.2 – 2017 FRS FLEXIBLE RESOURCE COSTS AS COMPARED TO 2014 WIS COSTS, $/MWH 75
TABLE F.3 – BAL-001-1 VS BAL-001-2 91
TABLE F.4 – DEVIATION AND REGULATION RESERVE REQUIREMENT EXAMPLE 92
TABLE F.5 – RESULTS WITH PACIFICORP PORTFOLIO DIVERSITY 105
TABLE F.6 – EIM FLEXIBLE RESERVE DIVERSITY BENEFIT APPLICATION EXAMPLE 106
TABLE F.7 – 2015 RESULTS WITH PACIFICORP PORTFOLIO DIVERSITY AND EIM INTRA-HOUR BENEFIT 107
TABLE F.8 – EAST SOLAR CLUSTERS BY SCENARIO 114
TABLE F.9 – WEST SOLAR CLUSTERS BY SCENARIO 114

TABLE F.10 – SOLAR AND WIND STAND-ALONE REGULATION REQUIREMENTS, AS PERCENTAGE OF NAMEPLATE CAPACITY 116
TABLE F.11 – PORTFOLIO REGULATION REQUIREMENT RESULTS, BY SCENARIO 118
TABLE F.12 – PORTFOLIO REGULATION REQUIREMENT RESULTS, PERCENT OF NAMEPLATE CAPACITY 119
TABLE F.13 – REGULATION RESERVE PAR SCENARIOS 119
TABLE F.14 – REGULATION RESERVE COST CALCULATIONS 120
TABLE F.15 – SYSTEM BALANCING COST SIMULATIONS IN PAR 122
TABLE F.16 – DAY-AHEAD FORECAST SYSTEM BALANCING COST RESULTS 122
TABLE F.17 – DAY-AHEAD SYSTEM BALANCING COST COMPARISON 123
TABLE F.18 – FRS TRC RECOMMENDATIONS 124
TABLE F.19 – RESERVE REQUIREMENTS (MW) 127
TABLE F.20 – FLEXIBLE RESOURCE SUPPLY FORECAST (MW) 129
TABLE F.21 – PORTFOLIO REGULATION RESERVE REQUIREMENTS, BY SCENARIO 132
TABLE F.22 – 2017 FRS FLEXIBLE RESOURCE COSTS AS COMPARED TO 2014 WIS COSTS, $/MWH 133
TABLE F.23 – WIND 134
TABLE F.24 – NON-VERS 134
TABLE F.25 – SOLAR 136
TABLE G.1 – PLANT WATER CONSUMPTION WITH ACRE-FEET PER YEAR 140
TABLE G.2 – PLANT WATER CONSUMPTION BY STATE (ACRE-FEET) 141
TABLE G.3 – PLANT WATER CONSUMPTION BY FUEL TYPE (ACRE-FEET) 141
TABLE G.4 – PLANT WATER CONSUMPTION FOR PLANTS LOCATED IN THE UPPER COLORADO RIVER BASIN (ACRE-FEET) 142
TABLE H.1 – SEASONAL DEFINITION 147
TABLE H.2 – UNCERTAINTY PARAMETERS FOR NATURAL GAS 151
TABLE H.3 – UNCERTAINTY PARAMETERS FOR ELECTRICITY REGIONS 153
TABLE H.4 – UNCERTAINTY PARAMETERS FOR LOAD REGIONS 155
TABLE H.5 – UNCERTAINTY PARAMETERS FOR HYDRO GENERATION 156
TABLE H.6 – SHORT-TERM CORRELATIONS BY SEASON 157
TABLE I.1 – EXPANSION RESOURCE ADDITIONS BY PRM FOR SUMMER 163
TABLE I.2 – EXPANSION RESOURCE ADDITIONS BY PRM FOR WINTER 164
TABLE I.3 – EXPECTED RELIABILITY METRICS BY PRM 165
TABLE I.4 – FITTED RELIABILITY METRICS BY PRM 165
TABLE I.5 – SYSTEM VARIABLE, UP-FRONT CAPITAL, AND RUN-RATE FIXED COSTS BY PRM 168
TABLE I.6 – 10-YEAR NOMINAL LEVELIZED COST OF EUE RELATIVE TO 10 PERCENT PRM 168
TABLE J.1 – 2016 WECC FORECASTED PLANNING RESERVE MARGINS (SUMMER) 175
TABLE J.2 – 2016 WECC FORECASTED PLANNING RESERVE MARGINS (WINTER) 175
TABLE J.3 – MAXIMUM AVAILABLE FRONT OFFICE TRANSACTIONS BY MARKET HUB 177
TABLE K.1– REGIONAL HAZE STUDY REFERENCE GUIDE 179
TABLE K.2 – CORE CASE STUDY REFERENCE GUIDE 179
TABLE K.3 – SENSITIVITY CASE STUDY REFERENCE GUIDE 180
TABLE K.4 – FINAL CASE STUDY REFERENCE GUIDE 180
TABLE K.5 – EAST SIDE RESOURCE NAME AND DESCRIPTION 181
TABLE K.6 – WEST-SIDE RESOURCE NAME AND DESCRIPTION 182
TABLE L.1 – STOCHASTIC MEAN PVRR BY PRICE SCENARIO, REGIONAL HAZE CASES 225
TABLE L.2 – STOCHASTIC MEAN PVRR BY PRICE SCENARIO, CORE CASES 226
TABLE L.3 – STOCHASTIC MEAN PVRR BY PRICE SCENARIO, SENSITIVITY CASES 226
TABLE L.4 – STOCHASTIC MEAN PVRR BY PRICE SCENARIO, FINAL SCREENING CASES 227

TABLE L.5 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – LOW GAS, MC A 227
TABLE L.6 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – MEDIUM GAS, MC A 227
TABLE L.7 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – HIGH GAS, MC A 228
TABLE L.8 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – LOW GAS, MC B 228
TABLE L.9 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – MEDIUM GAS, MC B 228
TABLE L.10 – STOCHASTIC RISK RESULTS, REGIONAL HAZE CASES – HIGH GAS, MC B........... 229
TABLE L.11 – STOCHASTIC RISK RESULTS, CORE CASES – LOW GAS, MC A............................. 229
TABLE L.12 – STOCHASTIC RISK RESULTS, CORE CASES – MEDIUM GAS, MC A 230
TABLE L.13 – STOCHASTIC RISK RESULTS, CORE CASES – HIGH GAS, MC A............................ 230
TABLE L.14 – STOCHASTIC RISK RESULTS, CORE CASES – LOW GAS, MC B............................. 231
TABLE L.15 – STOCHASTIC RISK RESULTS, CORE CASES – MEDIUM GAS, MC B....................... 231
TABLE L.16 – STOCHASTIC RISK RESULTS, CORE CASES – HIGH GAS, MC B 232
TABLE L.17 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – LOW GAS, MC A.................. 232
TABLE L.18 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – MEDIUM GAS, MC A............ 233
TABLE L.19 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – HIGH GAS, MC A 233
TABLE L.20 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – LOW GAS, MC B 234
TABLE L.21 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – MEDIUM GAS, MC B............ 235
TABLE L.22 – STOCHASTIC RISK RESULTS, SENSITIVITY CASES – HIGH GAS, MC B 236
TABLE L.23 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, LOW GAS, MC A........... 236
TABLE L.24 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, MEDIUM GAS, MC A 236
TABLE L.25 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, HIGH GAS, MC A.......... 237
TABLE L.26 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, LOW GAS, MC B........... 237
TABLE L.27 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, MEDIUM GAS, MC B...... 237
TABLE L.28 – STOCHASTIC RISK RESULTS, FINAL SCREENING CASES, HIGH GAS, MC B 238
TABLE L.29 – STOCHASTIC RISK ADJUSTED PVRR BY PRICE SCENARIO, REGIONAL HAZE CASES 238
TABLE L.30 – STOCHASTIC RISK ADJUSTED PVRR BY PRICE SCENARIO, CORE CASES 238
TABLE L.31 – STOCHASTIC RISK ADJUSTED PVRR BY PRICE SCENARIO, SENSITIVITY CASES ... 239
TABLE L.32 – STOCHASTIC RISK ADJUSTED PVRR BY PRICE SCENARIO, FINAL SCREENING CASES 239
TABLE L.33 – CARBON DIOXIDE EMISSIONS BY PRICE SCENARIO, REGIONAL HAZE CASES........ 240
TABLE L.34 – CARBON DIOXIDE EMISSIONS BY PRICE SCENARIO, CORE CASES 240
TABLE L.35 – CARBON DIOXIDE EMISSIONS BY PRICE SCENARIO, SENSITIVITY CASES 241
TABLE L.36 – CARBON DIOXIDE EMISSIONS BY PRICE SCENARIO, FINAL SCREENING CASES 241
TABLE L.37 – ENERGY NOT SERVED, REGIONAL HAZE CASES, LOW GAS 242
TABLE L.38 – ENERGY NOT SERVED, REGIONAL HAZE CASES, MEDIUM GAS 242
TABLE L.39 – ENERGY NOT SERVED, REGIONAL HAZE CASES, HIGH GAS................................. 243
TABLE L.40 – ENERGY NOT SERVED, CORE CASES, LOW GAS... 243
TABLE L.41 – ENERGY NOT SERVED, CORE CASES, MEDIUM GAS... 244
TABLE L.42 – ENERGY NOT SERVED, CORE CASES, HIGH GAS 244
TABLE L.43 – ENERGY NOT SERVED, SENSITIVITY CASES, LOW GAS 245
TABLE L.44 – ENERGY NOT SERVED, SENSITIVITY CASES, MEDIUM GAS.................................. 246
TABLE L.45 – ENERGY NOT SERVED, SENSITIVITY CASES, HIGH GAS 247
TABLE L.46 – ENERGY NOT SERVED, FINAL SCREENING CASES, LOW GAS 247
TABLE L.47 – ENERGY NOT SERVED, FINAL SCREENING CASES, MEDIUM GAS......................... 248
TABLE L.48 – ENERGY NOT SERVED, FINAL SCREENING CASES, HIGH GAS 248
TABLE L.49 – PVRR COST COMPONENTS BY PRICE SCENARIO, REGIONAL HAZE CASES, MC A 249
TABLE L.50 – PVRR COST COMPONENTS BY PRICE SCENARIO, REGIONAL HAZE CASES, MC B 250

TABLE L.51 – PVRR COST COMPONENTS BY PRICE SCENARIO, CORE CASES, MC A 251
TABLE L.52 – PVRR COST COMPONENTS BY PRICE SCENARIO, CORE CASES, MC B 252
TABLE L.53 – PVRR COST COMPONENTS BY PRICE SCENARIO, SENSITIVITY CASES, MC A 254
TABLE L.54 – PVRR COST COMPONENTS BY PRICE SCENARIO, SENSITIVITY CASES, MC B....... 255
TABLE L.55 – PVRR COST COMPONENTS BY PRICE SCENARIO, FINAL SCREENING CASES, MC A 257
TABLE L.56 – PVRR COST COMPONENTS BY PRICE SCENARIO, FINAL SCREENING CASES, MC B 258
TABLE L.57 – 10-YEAR AVERAGE INCREMENTAL CUSTOMER RATE IMPACT, FINAL SCREENING CASES 259
TABLE L.58 – LOSS OF LOAD PROBABILITY, MAJOR (> 25,000 MWH) JULY EVENT, FINAL SCREENING CASES, MEDIUM GAS, MC B 260
TABLE L.59 – SUMMER PEAK, AVERAGE LOSS OF LOAD PROBABILITY, FINAL SCREENING CASES, MEDIUM GAS, MC B 261
TABLE N.1 – PEAK CAPACITY CONTRIBUTION VALUES FOR WIND AND SOLAR 315

INDEX OF FIGURES

FIGURE A.1 – PACIFICORP SYSTEM ENERGY LOAD FORECAST CHANGE, AT GENERATION, PRE-DSM 2
FIGURE A.2 – PACIFICORP ANNUAL RETAIL SALES 2000 THROUGH 2016 AND WESTERN REGION EMPLOYMENT 4
FIGURE A.3 – PACIFICORP ANNUAL RESIDENTIAL USE PER CUSTOMER 2001 THROUGH 2016 5
FIGURE A.4 – IHS GLOBAL INSIGHT UTAH HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 6
FIGURE A.5 – IHS GLOBAL INSIGHT OREGON HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 6
FIGURE A.6 – IHS GLOBAL INSIGHT WYOMING HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 7
FIGURE A.7 – IHS GLOBAL INSIGHT WASHINGTON HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 8
FIGURE A.8 – IHS GLOBAL INSIGHT IDAHO HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 8
FIGURE A.9 – IHS GLOBAL INSIGHT CALIFORNIA HOUSEHOLD AND EMPLOYMENT FORECASTS FROM THE OCTOBER 2015 LOAD FORECAST AND THE DECEMBER 2016 LOAD FORECAST 9
FIGURE A.10 – COMPARISON OF UTAH 5, 10, AND 20 YEAR AVERAGE PEAK PRODUCING TEMPERATURES 10
FIGURE A.11 – LOAD FORECAST SCENARIOS FOR 1-IN-20 WEATHER, HIGH, BASE CASE AND LOW, PRE-DSM 19
FIGURE F.1 – EXPECTED LOAD CHANGE FROM PRIOR WEEK 82
FIGURE F.2 – PROXY LOAD BASE SCHEDULE 83
FIGURE F.3 – BASE SCHEDULE RAMPING ADJUSTMENT 84
FIGURE F.4 – ORIGINAL PACW NON-VER DEVIATIONS 87
FIGURE F.5 – ADJUSTED PACW NON-VER DEVIATIONS 88
FIGURE F.6 – DEVIATION AND REGULATION RESERVE REQUIREMENT EXAMPLE 93
FIGURE F.7 – PROBABILITY DISTRIBUTION OF PACE COMBINED PORTFOLIO DEVIATIONS 94
FIGURE F.8 – PROBABILITY OF EXCEEDING ALLOWED DEVIATION 95
FIGURE F.9 – WIND REGULATION RESERVE REQUIREMENTS BY FORECAST CAPACITY FACTOR ... 98
FIGURE F.10 – STAND-ALONE WIND REGULATION RESERVE FORECAST 99
FIGURE F.11 – NON-VER REGULATION RESERVE REQUIREMENTS BY FORECAST CAPACITY FACTOR 100
FIGURE F.12 – NON-VER REGULATION RESERVE REQUIREMENTS BY HOUR OF THE DAY 101
FIGURE F.13 – STAND-ALONE NON-VER REGULATION RESERVE FORECAST 102
FIGURE F.14 – STAND-ALONE LOAD REGULATION RESERVE REQUIREMENTS BY HOUR OF THE DAY 103
FIGURE F.15 – STAND-ALONE LOAD REGULATION RESERVE FORECAST 104
FIGURE F.16 – SOLAR CAPACITY ADDITIONS 109
FIGURE F.17 – SOLAR REGULATION RESERVE REQUIREMENTS: PROXY VS EIM 111
FIGURE F.18 – SOLAR DIVERSITY 112
FIGURE F.19 – SOLAR RESOURCE LOCATIONS 113
FIGURE F.20 – STAND-ALONE SOLAR REGULATION RESERVE REQUIREMENTS, BY CAPACITY..... 116
FIGURE F.21 – COMPARISON OF RESERVE REQUIREMENTS AND RESOURCES, EAST BALANCING AUTHORITY AREA (MW) 130

FIGURE F.22 – COMPARISON OF RESERVE REQUIREMENTS AND RESOURCES, WEST BALANCING AUTHORITY AREA (MW) 131
FIGURE H.1 – STOCHASTIC PROCESSES 145
FIGURE H.2 – RANDOM WALK PRICE PROCESS AND MEAN REVERTING PROCESS 145
FIGURE H.3 – LOGNORMAL DISTRIBUTION AND CUMULATIVE LOGNORMAL DISTRIBUTION 146
FIGURE H.4 – DAILY GAS PRICES FOR SUMAS BASIN 147
FIGURE H.5 – DAILY GAS PRICES FOR SUMAS BASIN WITH "EXPECTED" PRICES 149
FIGURE H.6 – GAS PRICE INDEX FOR SUMAS BASIN 149
FIGURE H.7 – REGRESSION FOR SUMAS GAS BASIN 150
FIGURE H.8 – DAILY ELECTRICITY PRICES FOR FOUR CORNERS 152
FIGURE H.9 – PROBABILITY DISTRIBUTION FOR PORTLAND LOAD 153
FIGURE H.10 – DAILY AVERAGE LOAD FOR PORTLAND 154
FIGURE H.11 – WEEKLY AVERAGE HYDRO GENERATION IN THE WEST 156
FIGURE I.1 – WORKFLOW FOR PLANNING RESERVE MARGIN STUDY 160
FIGURE I.2 – EXPECTED AND FITTED RELATIONSHIP OF EUE TO PRM 166
FIGURE I.3 – EXPECTED AND FITTED RELATIONSHIP OF LOLH TO PRM 166
FIGURE I.4 – SIMULATED RELATIONSHIP OF LOSS OF LOAD EPISODE TO PRM 167
FIGURE I.5 – INCREMENTAL COST OF RELIABILITY BY PRM 169
FIGURE J.1 – WECC FORECASTED POWER SUPPLY MARGINS, ISSUED 2009 TO 2016 (SUMMER) 173
FIGURE J.2 – 2016 LESS 2014 WECC PSA (FOR SUMMER PERIODS) 174
FIGURE J.3 – PACIFICORP SUMMER PEAK MARKET PURCHASES 2009-2015 178
FIGURE J.4 – PACIFICORP WINTER PEAK MARKET PURCHASES 2009-2015 178
FIGURE N.1 – DAILY LOLP 316
FIGURE N.2 – MONTHLY RESOURCE CAPACITY FACTORS AS COMPARED TO LOLP 316
FIGURE N.3 – HOURLY RESOURCE CAPACITY FACTORS AS COMPARED TO LOLP FOR AN AVERAGE DAY IN JULY 317

APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2017 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales, and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand in order to develop timely response of resources.

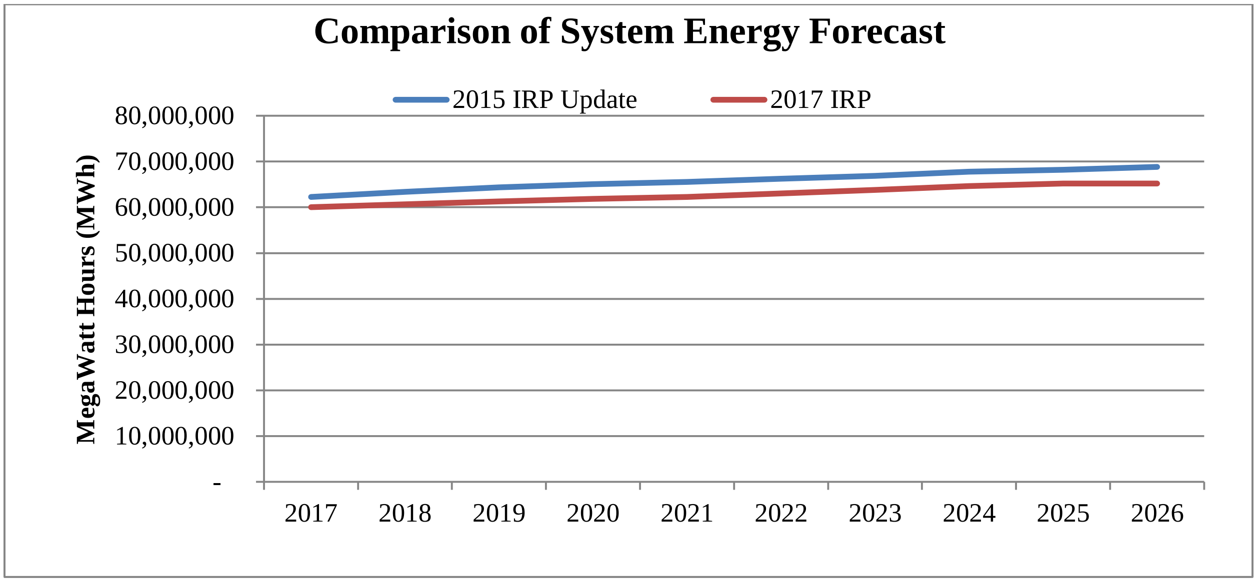
In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, lighting, and public authority customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Summary Load Forecast

The Company updated its load forecast in December 2016. The average annual energy growth rate for the 10-year period (2017 through 2026) is 0.91 percent. Relative to the load forecast prepared for the 2015 IRP update, PacifiCorp 2026 energy forecasted energy requirement decreased in all jurisdictions other than Idaho, while PacifiCorp system energy requirement decreased approximately 5.3 percent. Figure A.1 has a comparison of energy forecasts from the 2017 IRP compared to the 2015 IRP Update.

Figure A.1 - PacifiCorp System Energy Load Forecast Change, at Generation, pre-DSM



Tables A.1 and A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1] Tables A.3 and A.4 show the forecast changes relative to the 2015 IRP Update load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load Growth, 2017 through 2026 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	60,061,400	14,605,160	4,458,290	905,140	26,276,610	10,004,230	3,811,970	-
2018	60,670,450	14,736,700	4,497,430	904,220	26,637,690	10,050,920	3,843,490	-
2019	61,301,370	14,881,630	4,536,810	901,890	26,956,500	10,150,590	3,873,950	-
2020	61,863,300	14,951,780	4,563,240	897,830	27,260,420	10,292,840	3,897,190	-
2021	62,297,200	15,019,870	4,585,510	892,140	27,547,010	10,334,140	3,918,530	-
2022	63,007,030	15,144,810	4,615,090	889,900	27,962,140	10,445,060	3,950,030	-
2023	63,799,730	15,276,170	4,646,900	887,920	28,398,470	10,606,930	3,983,340	-
2024	64,610,360	15,448,030	4,692,480	888,010	28,896,420	10,663,800	4,021,620	-
2025	65,171,560	15,534,760	4,720,510	882,810	29,224,630	10,763,560	4,045,290	-
2026	65,182,980	15,634,920	4,753,180	879,280	28,894,200	10,947,860	4,073,540	-
Average Annual Growth Rate for 2017-2026								
2017 - 2026	**0.91%**	**0.76%**	**0.71%**	**-0.32%**	**1.06%**	**1.01%**	**0.74%**	

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.2 - Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	10,130	2,285	718	151	5,012	1,246	719	-
2018	10,225	2,308	724	151	5,071	1,248	724	-
2019	10,310	2,349	739	152	5,097	1,245	727	-
2020	10,403	2,359	742	152	5,152	1,267	731	-
2021	10,518	2,374	747	151	5,217	1,279	750	-
2022	10,624	2,391	752	151	5,281	1,292	756	-
2023	10,706	2,407	757	151	5,341	1,303	747	-
2024	10,804	2,425	763	151	5,409	1,305	752	-
2025	10,920	2,443	768	151	5,483	1,318	757	-
2026	10,931	2,457	773	150	5,446	1,343	762	-
Average Annual Growth Rate for 2017-2026								
2017 - 2026	0.85%	0.81%	0.82%	-0.06%	0.93%	0.84%	0.65%	

Table A.3 – Annual Load Growth Change: December 2016 Forecast less October 2015 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	(2,207,700)	(282,280)	(216,490)	18,670	(1,306,230)	(447,850)	26,480	-
2018	(2,711,610)	(404,400)	(213,910)	16,230	(1,595,750)	(549,600)	35,820	-
2019	(3,080,850)	(415,220)	(210,950)	13,080	(1,914,340)	(596,700)	43,280	-
2020	(3,219,990)	(429,430)	(214,930)	9,540	(2,136,110)	(499,850)	50,790	-
2021	(3,275,870)	(410,960)	(204,530)	7,180	(2,246,040)	(479,490)	57,970	-
2022	(3,231,080)	(396,300)	(200,300)	5,500	(2,309,120)	(397,770)	66,910	-
2023	(3,104,490)	(393,620)	(193,660)	6,790	(2,351,250)	(248,360)	75,610	-
2024	(3,150,500)	(397,080)	(186,540)	10,390	(2,400,790)	(260,370)	83,890	-
2025	(3,065,130)	(397,820)	(168,980)	15,410	(2,451,900)	(151,930)	90,090	-
2026	(3,674,160)	(424,310)	(161,420)	17,830	(3,226,920)	24,970	95,690	-

Table A.4 – Annual Coincident Peak Growth Change: July 2016 Forecast less October 2015 Forecast (Megawatts) at Generation, pre-DSM

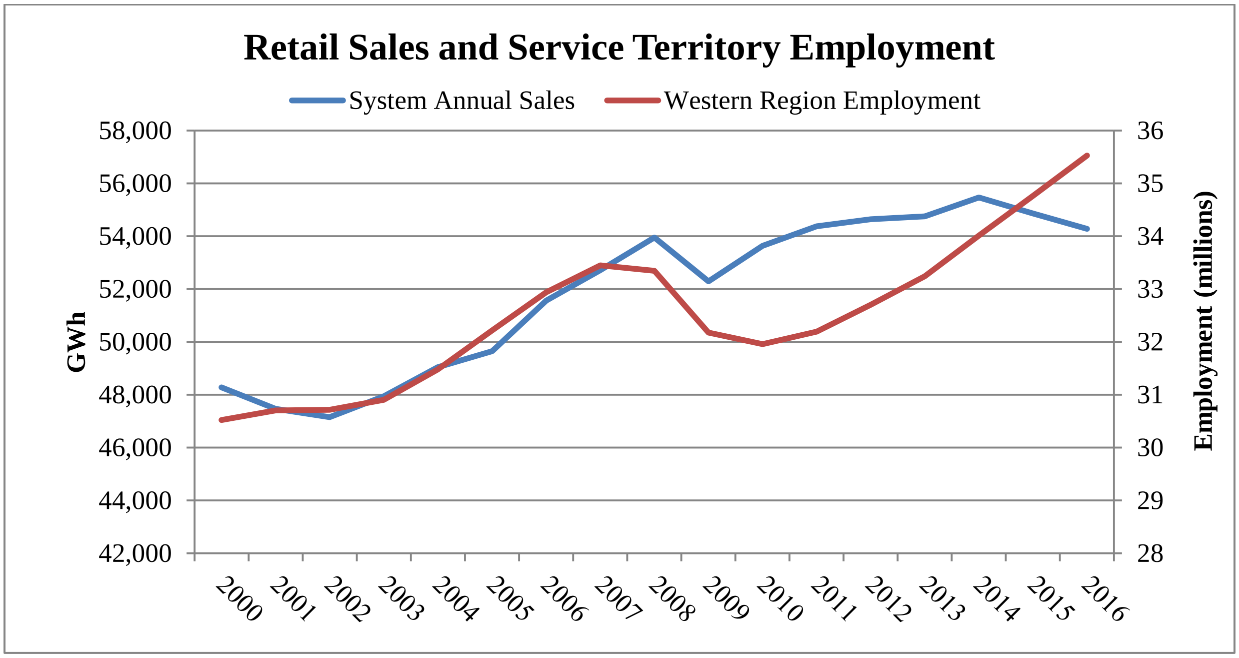
Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	(153)	(23)	(25)	4	7	(111)	(4)	-
2018	(245)	(29)	(26)	4	(66)	(125)	(2)	-
2019	(306)	(6)	(15)	4	(145)	(143)	(2)	-
2020	(319)	(11)	(18)	6	(177)	(126)	6	-
2021	(323)	(9)	(17)	5	(199)	(118)	14	-
2022	(326)	(6)	(17)	5	(215)	(108)	16	-
2023	(343)	(5)	(16)	4	(231)	(99)	3	-
2024	(350)	1	(15)	6	(244)	(104)	5	-
2025	(333)	(5)	(16)	10	(258)	(91)	27	-
2026	(438)	(7)	(16)	12	(375)	(67)	14	-

Load Forecast Assumptions

Regional Economy by Jurisdiction

The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 88 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. The Company uses both economic data, such as employment, and population data, to forecast its retail sales. Looking at historical sales and employment data for PacifiCorp's service territory, 2000 through 2016, in Figure A.2, it is apparent that the Company's retail sales generally follow economic conditions in its service territory, and most recently the 2008-2009 recession.

Figure A.2 - PacifiCorp Annual Retail Sales 2000 through 2016 and Western Region Employment

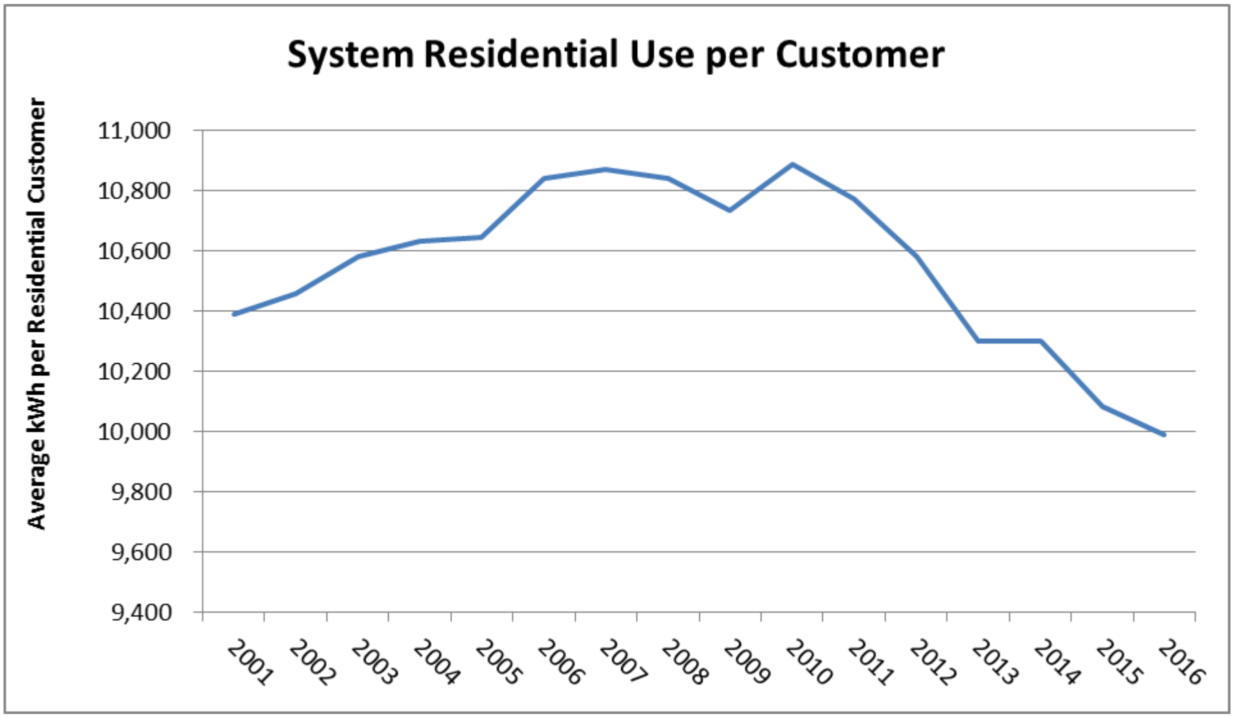


Sources: PacifiCorp and United States Department of Labor, Bureau of Labor Statistics

As discussed below, although both the economic and demographic forecast is relatively unchanged from the 2015 IRP Update, the load forecast has decreased. There are two changes which are driving the 2017 IRP load and peak forecast down. First, the relationship between the economic variable and sales has "flattened", meaning electric usage has become less responsive to the economic variable as seen in years 2015 and 2016 in Figure A.2 above. Second, there have been changes in expected sales to our customers due in large part to lower commodity prices.

Figure A.3 shows the weather normalized average system residential use per customer. As illustrated, residential use per customer has been decreasing since 2010.

Figure A.3 - PacifiCorp Annual Residential Use per Customer 2001 through 2016

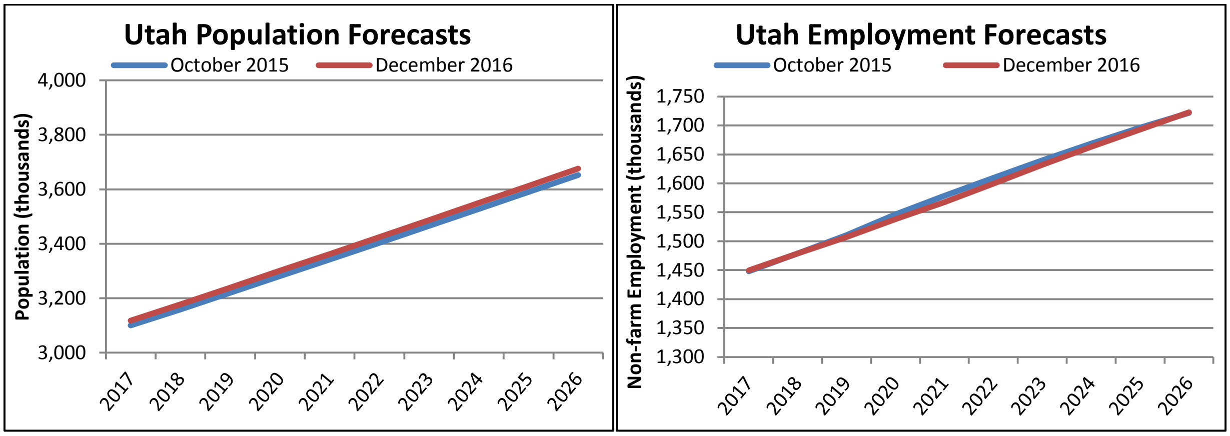


Residential use per customer across all six of PacifiCorp's states is changing due to increased energy efficiency driven primarily by lighting efficiency standards resulting from the 2007 Federal Energy legislation. In addition, there has been a shift from single-family and manufactured housing to multi-dwelling units and a trend of replacing older electric appliances with more energy efficient appliances.

Utah

PacifiCorp serves 25 of the 29 counties in the state of Utah, with Salt Lake City being the largest metropolitan area served by the Company within the state. Utah is expected to experience a 1.9 percent increase in non-farm employment over the next 10 years. Figure A.4 shows the change in population and employment forecasts between the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast is slightly higher while the employment forecasts is slightly lower. Relative to the load forecast prepared for the 2015 IRP update, the Utah 2026 retail load forecast decreased approximately 6.7 percent. This decrease is attributable to the projected impact of additional private generation and the impact of a relatively less favorable economic outlook compared to the 2015 IRP Update.

Figure A.4 – IHS Global Insight Utah Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

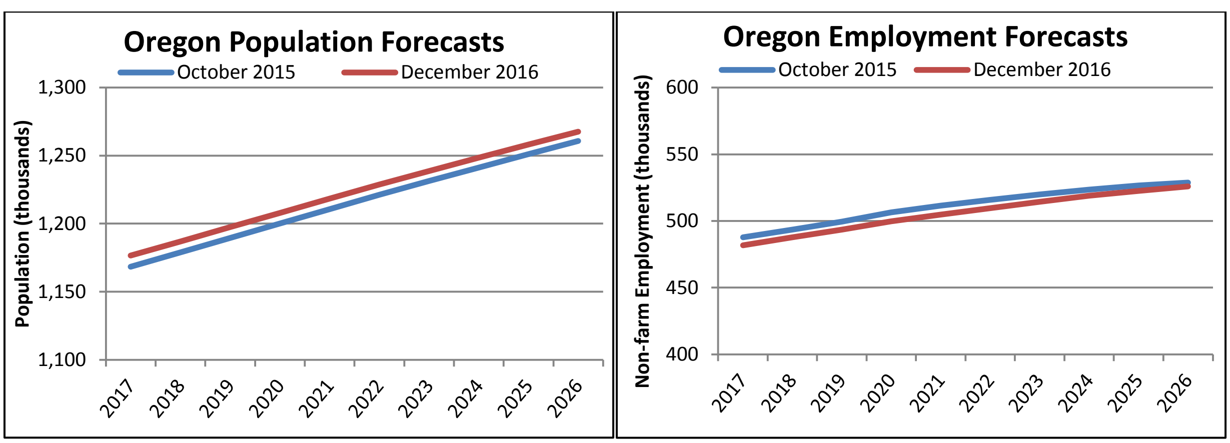


A risk to the Utah forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment potentially translating to swings in the retail sales forecast.

Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 27.2 percent of ultimate electric retail sales in the state of Oregon in 2015.[2] In 2014 and 2015, Oregon employment growth has outpaced national employment by approximately one percentage point.[3] Figure A.5 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the Oregon forecast of population has increased slightly, while the employment forecast has decreased slightly. Relative to the load forecast prepared for the 2015 IRP Update, the Oregon 2026 retail load forecast has decreased approximately 2.6 percent.

Figure A.5 – IHS Global Insight Oregon Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

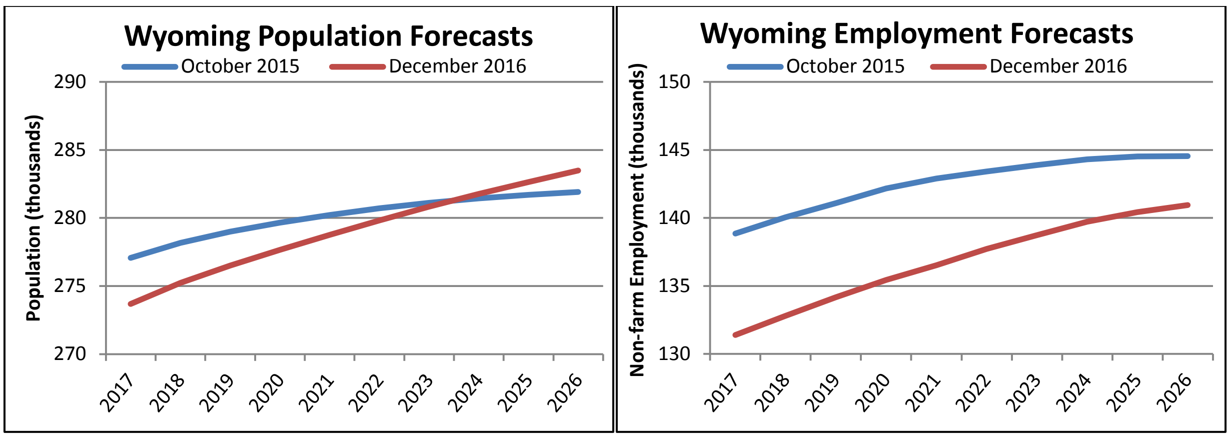


[2] Source: Oregon Public Utility Commission, 2015 Oregon Utility Statistics.
[3] Source: Bureau of Labor Statistics.

Wyoming

The Company serves 15 of the 23 counties in Wyoming, with Casper being the largest metropolitan area served by the Company in the state. Industrial sales make up approximately 73 percent of the Company's Wyoming sales. Figure A.6 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the Wyoming population forecast has decreased over the 2017 to 2022 timeframe, while it increased over the 2023 to 2026 period. The employment forecast has decreased. Relative to the load forecast prepared for the 2015 IRP Update, the Wyoming 2026 retail load forecast increased approximately 1.2 percent.

Figure A.6 – IHS Global Insight Wyoming Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

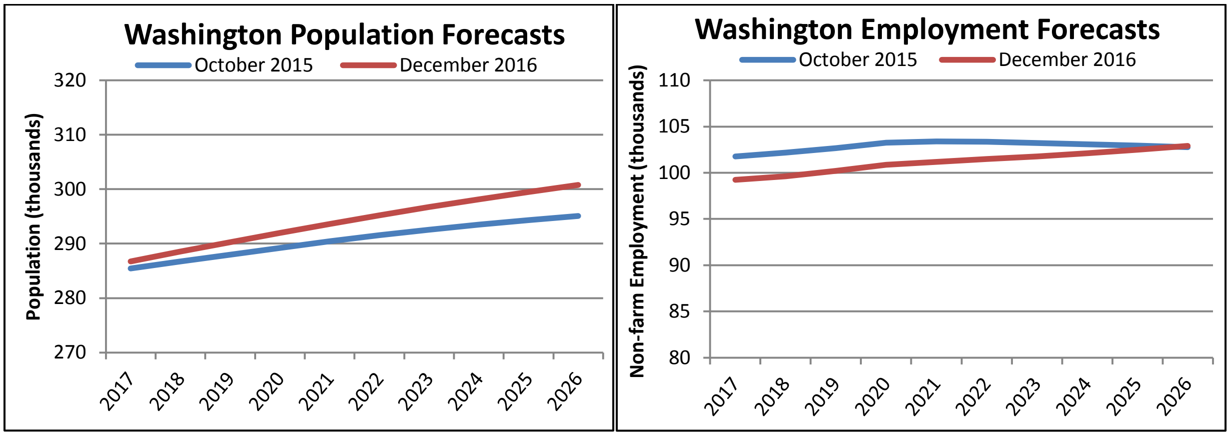


A risk to the Wyoming forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment which translates to potential swings in the retail sales forecast.

Washington

PacifiCorp serves the following counties in Washington State: Benton, Columbia, Garfield, Klickitat, Walla Walla, and Yakima. Yakima is the most populated county that the Company serves in Washington State and has a large concentration of agriculture and food processing businesses. Residential and commercial sales are roughly equal in size each making up approximately 38 percent of the Company's Washington sales. Figure A.7 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast is higher and the employment forecast has decreased. Relative to the load forecast prepared for the 2015 IRP Update, the Washington 2026 retail load forecast decreased approximately 1.3 percent.

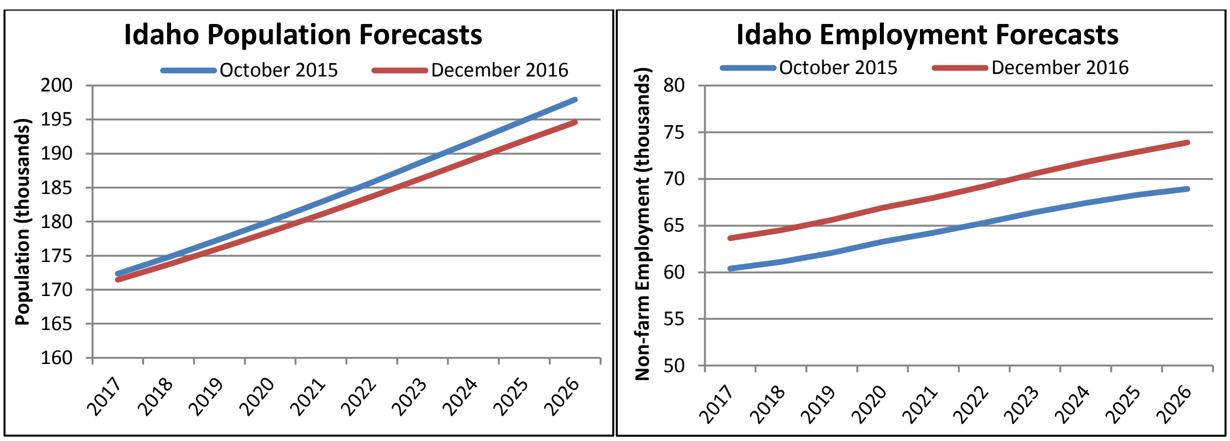
Figure A.7 – IHS Global Insight Washington Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast



Idaho

The Company serves 13 of the 44 counties in the state of Idaho, with the majority of the Company's service territory in rural Idaho. Industrial sales make up approximately 47 percent of the Company's Idaho sales. Figure A.8 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the forecast for population has decreased, while the employment forecast has increased. Relative to the load forecast prepared for the 2015 IRP Update, the Idaho 2026 retail load forecast increased approximately 3.0 percent.

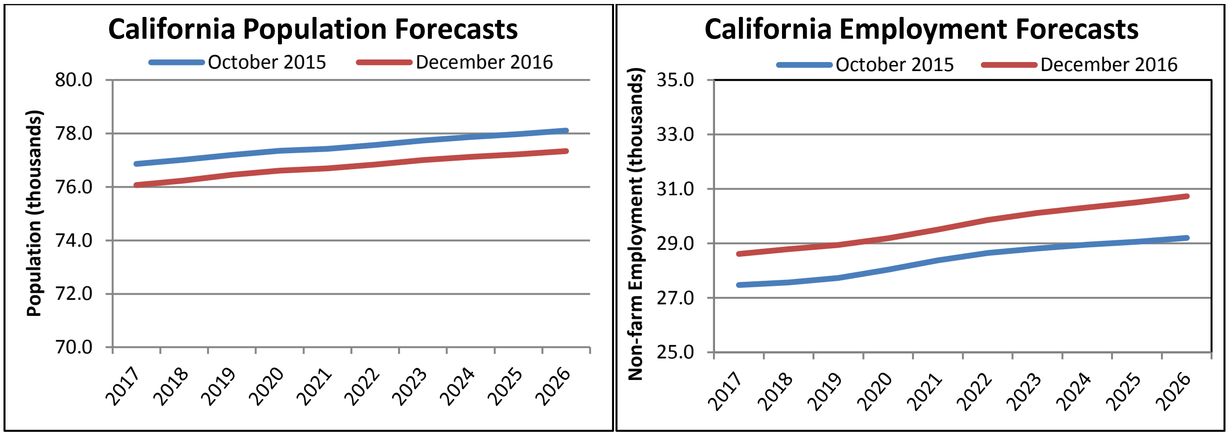
Figure A.8 – IHS Global Insight Idaho Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast



California

The four northern California counties served by PacifiCorp are largely rural, which include Del Norte, Modoc, Shasta and Siskiyou Counties. Crescent City is the largest metropolitan area served by the Company in California. Residential sales make up approximately 49 percent of the Company's California sales. Figure A.9 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast has decreased, while the employment forecast had increased. Relative to the load forecast prepared for the 2015 IRP Update, the California 2026 retail load forecast increased approximately 6.5 percent.

Figure A.9 – IHS Global Insight California Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

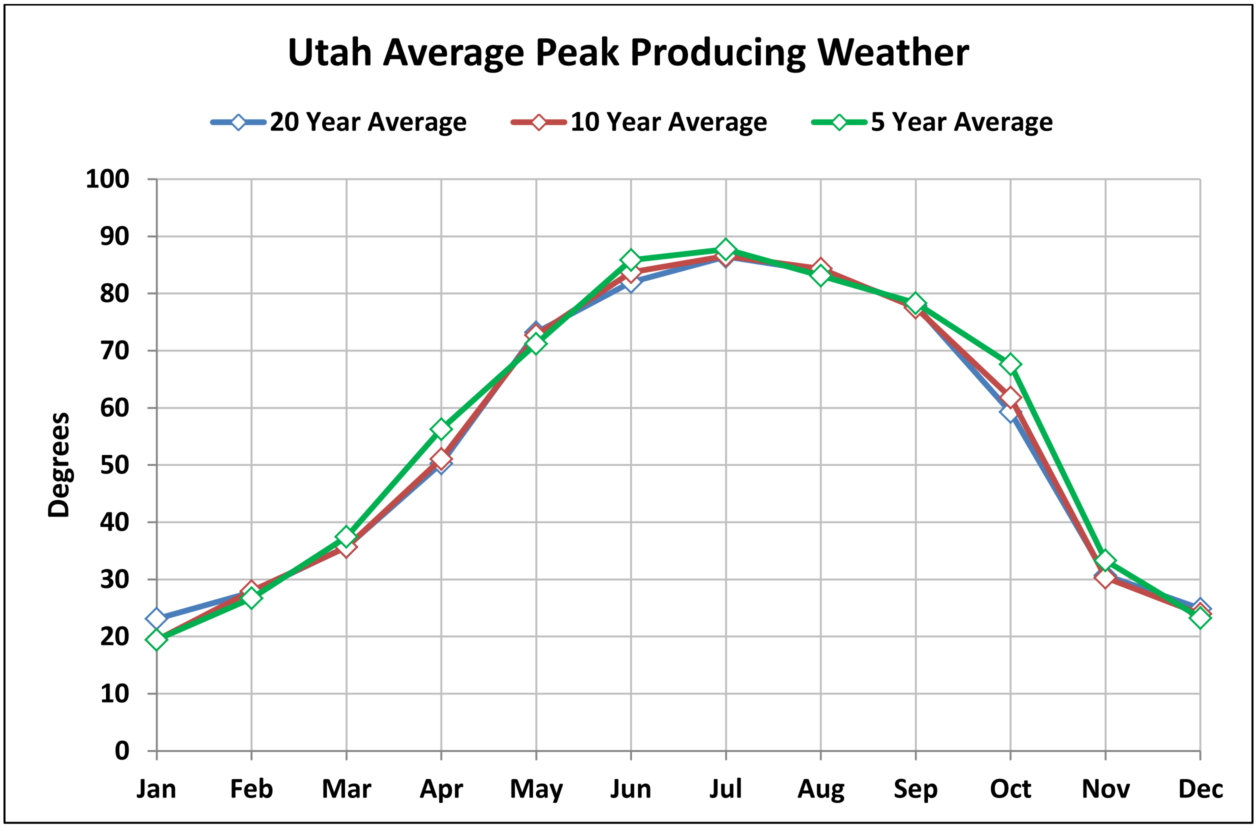


Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 1996-2015. The Company updated its temperature spline models to the five-year time period of 2011-2015. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

The Company has reviewed the appropriateness of using the average weather from a shorter time period as its "normal" peak weather. Figure A.10 indicates that peak producing weather does not change significantly when comparing five, 10, or 20 year average weather.

Figure A.10 - Comparison of Utah 5, 10, and 20 Year Average Peak Producing Temperatures



Statistically Adjusted End-Use (SAE)

The Company models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The Company uses ITRON for its load forecasting software and services, as well as SAE. To predict future changes in the efficiency of the various end uses for the residential class, an excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The SAE model reflects the US Department of Energy’s Energy Information Administration (EIA) assumptions for changes in energy efficiency of each appliance category, which are updated annually to take into consideration for new codes and standards including lighting standards from the Energy Independence and Security Act of 2007. The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e. newer more efficient equipment replacing older less efficient equipment.

Individual Customer Forecast

The Company updated its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a regional business manager (RBM).

Actual Load Data

With the exception of the industrial class, the Company uses actual load data from January 2000 through February 2016. The historical data period used to develop the industrial monthly sales is from January 2000 through February 2016 in Utah and Wyoming, January 2002 through February 2016 in Idaho, and Washington, and January 2003 through February 2016 in California and Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2017 IRP retail sales forecast.

Table A.5 - Weather Normalized Jurisdictional Retail Sales 2000 through 2016

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	776,665	3,077,264	14,194,244	18,793,616	4,091,310	7,347,453	**48,280,553**
2001	778,162	2,976,494	13,523,805	18,484,442	4,026,937	7,680,809	**47,470,649**
2002	799,939	3,232,113	13,085,474	18,620,633	4,013,855	7,406,900	**47,158,914**
2003	819,108	3,227,070	13,108,396	19,249,531	4,067,382	7,471,050	**47,942,536**
2004	844,582	3,304,254	13,156,747	19,832,347	4,100,463	7,814,422	**49,052,814**
2005	835,402	3,222,870	13,160,345	20,214,262	4,213,148	8,009,888	**49,655,914**
2006	859,303	3,344,385	13,910,585	21,079,795	4,126,393	8,254,237	**51,574,698**
2007	874,819	3,358,414	13,973,359	21,962,447	4,071,975	8,482,587	**52,723,603**
2008	867,587	3,402,821	13,775,175	22,636,955	4,064,372	9,213,810	**53,960,720**
2009	829,879	2,962,976	13,116,677	22,094,266	4,037,211	9,259,753	**52,300,763**
2010	840,479	3,395,472	13,122,473	22,570,702	4,051,355	9,664,607	**53,645,087**
2011	803,948	3,432,628	13,000,020	23,357,025	4,017,580	9,766,930	**54,378,131**
2012	785,803	3,494,537	13,024,670	23,814,679	4,046,167	9,479,742	**54,645,597**
2013	774,660	3,517,060	13,061,037	23,794,419	4,058,252	9,552,400	**54,757,828**
2014	774,113	3,524,860	13,123,680	24,352,495	4,113,824	9,589,358	**55,478,330**
2015	746,136	3,459,937	13,082,915	24,081,112	4,114,642	9,379,936	**54,864,679**
2016	757,816	3,475,328	13,019,288	23,782,480	4,055,425	9,195,353	**54,285,689**
Average Annual Growth Rate							
2000-16	**-0.15%**	**0.76%**	**-0.54%**	**1.48%**	**-0.06%**	**1.41%**	**0.74%**

*System retail sales do not include sales for resale

Table A.6 - Non-Coincident Jurisdictional Peak 2000 through 2016

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,062	**8,995**
2001	162	616	2,739	3,480	755	1,124	**8,876**
2002	174	713	2,639	3,773	771	1,113	**9,184**
2003	169	722	2,451	4,004	788	1,126	**9,260**
2004	193	708	2,524	3,862	920	1,111	**9,318**
2005	189	753	2,721	4,081	844	1,224	**9,811**
2006	180	723	2,724	4,314	822	1,208	**9,970**
2007	187	789	2,856	4,571	834	1,230	**10,466**
2008	187	759	2,921	4,479	923	1,339	**10,609**
2009	193	688	3,121	4,404	917	1,383	**10,705**
2010	176	777	2,552	4,448	893	1,366	**10,213**
2011	177	770	2,686	4,596	854	1,404	**10,486**
2012	159	800	2,550	4,732	797	1,338	**10,376**
2013	182	814	2,980	5,091	886	1,398	**11,351**
2014	161	818	2,598	5,024	871	1,360	**10,831**
2015	157	843	2,598	5,226	837	1,326	**10,986**
2016	155	848	2,584	5,018	819	1,300	**10,724**
Average Annual Growth Rate							
2000-16	**-0.78%**	**1.33%**	**-0.05%**	**1.95%**	**0.27%**	**1.28%**	**1.11%**

*Non-coincident peaks do not include sales for resale

Table A.7 - Jurisdictional Contribution to Coincident Peak 2000 through 2016

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	154	523	2,347	3,684	756	979	**8,443**
2001	124	421	2,121	3,479	627	1,091	**7,863**
2002	162	689	2,138	3,721	758	1,043	**8,511**
2003	155	573	2,359	4,004	774	1,022	**8,887**
2004	120	603	2,200	3,831	740	1,094	**8,588**
2005	171	681	2,238	4,015	708	1,081	**8,895**
2006	156	561	2,684	3,972	816	1,094	**9,283**
2007	160	701	2,604	4,381	754	1,129	**9,730**
2008	171	682	2,521	4,145	728	1,208	**9,456**
2009	153	517	2,573	4,351	795	987	**9,375**
2010	144	527	2,442	4,294	757	1,208	**9,373**
2011	143	549	2,187	4,596	707	1,204	**9,387**
2012	156	782	2,163	4,731	749	1,225	**9,806**
2013	156	674	2,407	5,091	797	1,349	**10,474**
2014	150	630	2,345	5,024	819	1,294	**10,263**
2015	152	805	2,472	5,081	833	1,259	**10,601**
2016	139	575	2,462	4,940	817	1,201	**10,135**
Average Annual Growth Rate							
2000-16	**-0.63%**	**0.59%**	**0.30%**	**1.85%**	**0.49%**	**1.29%**	**1.15%**

*Coincident peaks do not include sales for resale

System Losses

Line loss factors are derived using the five-year average of the percent difference between the annual system load by jurisdiction and the retail sales by jurisdiction. System line losses were updated to reflect actual losses for the five-year period ending December 31, 2015.

Forecast Methodology Overview

Class 2 Demand-side Management (DSM) Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; System Optimizer then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario.

Modeling overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecast number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2000 to February 2016. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of each state's number of population as the major driver.

The Company models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment and non-farm employment designated as the major economic drivers, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's RBM's. Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

The majority of industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver in all states with exception of Utah, in which an Industrial Production Index is used. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the RBM's.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period, 1996 through 2015. Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures as identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Hourly loads are then adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Sales Forecast at the Customer Meter

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2017 IRP preferred portfolio.

Table A.8 – System Annual Retail Sales Forecast 2017 through 2026, post-DSM

System Retail Sales – Megawatt-hours (MWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	**Total**
2017	15,760,322	16,973,309	19,610,575	1,402,815	142,837	280,969	**54,170,827**
2018	15,665,011	17,100,676	19,507,344	1,392,957	143,073	280,959	**54,090,019**
2019	15,535,613	17,165,098	19,643,268	1,381,347	143,191	280,959	**54,149,477**
2020	15,362,775	17,233,844	19,795,688	1,369,343	143,651	281,715	**54,187,017**
2021	15,210,722	17,262,252	19,845,887	1,357,840	143,273	280,959	**54,100,934**
2022	15,217,032	17,346,947	19,968,520	1,347,604	143,286	280,959	**54,304,348**
2023	15,222,916	17,445,564	20,161,584	1,336,707	143,293	280,959	**54,591,023**
2024	15,313,009	17,579,119	20,252,811	1,322,691	143,701	281,715	**54,893,047**
2025	15,205,483	17,645,518	20,422,452	1,291,633	143,297	280,959	**54,989,343**
2026	15,213,345	17,741,890	19,943,873	1,243,850	143,298	280,959	**54,567,215**
Average Annual Growth Rate							
2017-26	**-0.4%**	**0.5%**	**0.2%**	**-1.3%**	**0.0%**	**0.0%**	**0.1%**

Residential

Over the 2017-2026 timeframe, the average annual growth of the residential class sales forecast declined from -0.1 percent in the 2015 IRP Update to -0.4 percent in the 2017 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.0 percent, reaching approximately 1.8 million customers in 2026, with Rocky Mountain Power states adding 1.4 percent per year and Pacific Power states adding 0.4 percent per year. New customers on PacifiCorp's system will also contribute to declining average use of the residential class. It is expected that new single-family homes are likely to use more efficient appliances and use gas instead of electricity for both space and water heating.

Commercial

Average annual growth of the commercial class sales forecast increased from 0.0 percent annual average growth in the 2015 IRP Update to 0.5 percent expected average annual growth. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.9 percent, reaching approximately 223,000 customers in 2026, with Rocky Mountain Power states adding 1.2 percent per year and Pacific Power states adding 0.4 percent per year. The Company lowered its commercial load expectations in Oregon, Wyoming and Washington in the 2017 IRP load forecast due to lower than expected loads and adverse economic conditions for particular commercial sectors.

Industrial

Average annual growth of the industrial class sales forecast declined from 0.5 percent annual average growth in the 2015 IRP Update to 0.2 percent expected annual growth. A portion of the Company's industrial load is in the extractive industry in Utah and Wyoming; therefore, changes in commodity prices can impact the Company's load forecast. The Company has seen several large industrial customers cancel expected new load when prices have fallen. The risk to the Company's load forecast due to commodity price changes is reflected in the high and low economic growth scenarios discussed below.

State Summaries

Oregon

Table A.9 summarizes Oregon state forecasted retail sales growth by customer class.

Table A. 9 – Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	5,408,380	5,076,308	1,849,639	330,637	37,893	**12,702,857**
2018	5,393,855	5,115,251	1,769,573	327,078	37,923	**12,643,680**
2019	5,378,539	5,098,874	1,763,691	322,898	37,934	**12,601,937**
2020	5,293,038	5,103,759	1,762,377	318,439	38,046	**12,515,659**
2021	5,223,123	5,104,908	1,770,168	313,909	37,941	**12,450,049**
2022	5,229,132	5,103,511	1,774,498	309,780	37,941	**12,454,862**
2023	5,234,327	5,106,544	1,794,852	305,586	37,942	**12,479,251**
2024	5,263,095	5,136,531	1,803,903	300,173	38,049	**12,541,752**
2025	5,236,271	5,145,302	1,826,703	294,032	37,942	**12,540,250**
2026	5,230,030	5,155,635	1,844,084	287,757	37,942	**12,555,448**
Average Annual Growth Rate						
2017-26	**-0.37%**	**0.17%**	**-0.03%**	**-1.53%**	**0.01%**	**-0.13%**

Washington

Table A.10 summarizes Washington state forecasted retail sales growth by customer class.

Table A.10 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	1,575,461	1,415,068	772,436	157,910	10,231	**3,931,105**
2018	1,572,606	1,430,519	764,944	157,185	10,227	**3,935,480**
2019	1,568,255	1,449,111	754,477	156,282	10,228	**3,938,353**
2020	1,562,912	1,460,871	742,346	155,494	10,256	**3,931,880**
2021	1,549,095	1,476,203	726,969	154,890	10,227	**3,917,385**
2022	1,544,682	1,495,077	707,110	154,532	10,227	**3,911,628**
2023	1,539,012	1,517,008	689,349	154,010	10,227	**3,909,606**
2024	1,542,678	1,537,227	676,877	152,734	10,256	**3,919,772**
2025	1,531,595	1,557,097	666,360	151,066	10,227	**3,916,346**
2026	1,528,077	1,576,410	655,792	149,274	10,227	**3,919,780**
Average Annual Growth Rate						
2017-26	**-0.34%**	**1.21%**	**-1.80%**	**-0.62%**	**0.00%**	**-0.03%**

California

Table A.11 summarizes California state forecasted sales growth by customer class.

Table A.11 – Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	363,268	233,137	59,312	96,753	2,421	**754,891**
2018	361,543	228,011	59,389	96,523	2,415	**747,882**
2019	360,225	223,517	59,337	96,063	2,415	**741,557**
2020	360,738	216,437	58,516	95,553	2,422	**733,666**
2021	357,443	211,498	58,100	94,980	2,415	**724,437**
2022	356,265	207,254	57,817	94,489	2,415	**718,240**
2023	354,361	204,046	57,719	93,948	2,415	**712,489**
2024	354,910	200,624	57,479	93,239	2,422	**708,674**
2025	351,419	197,037	57,138	92,501	2,415	**700,511**
2026	349,167	193,931	56,803	91,810	2,415	**694,126**
Average Annual Growth Rate						
2017-26	**-0.44%**	**-2.03%**	**-0.48%**	**-0.58%**	**-0.03%**	**-0.93%**

Utah

Table A.12 summarizes Utah state forecasted sales growth by customer class.

Table A.12 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	**Total**
2017	6,696,419	8,402,810	8,329,787	199,895	77,765	280,969	**23,987,646**
2018	6,625,352	8,470,814	8,317,408	196,470	77,982	280,959	**23,968,985**
2019	6,526,580	8,528,238	8,422,789	192,466	78,087	280,959	**24,029,121**
2020	6,454,747	8,575,851	8,504,675	188,368	78,358	281,715	**24,083,714**
2021	6,410,141	8,588,882	8,572,928	184,763	78,164	280,959	**24,115,838**
2022	6,420,793	8,648,462	8,671,514	181,250	78,176	280,959	**24,281,155**
2023	6,433,763	8,713,821	8,773,258	177,495	78,182	280,959	**24,457,479**
2024	6,484,638	8,788,396	8,884,190	173,538	78,404	281,715	**24,690,881**
2025	6,440,021	8,839,447	8,984,607	154,147	78,186	280,959	**24,777,368**
2026	6,463,388	8,896,420	8,396,408	118,936	78,187	280,959	**24,234,297**
Average Annual Growth Rate							
2017-26	**-0.39%**	**0.64%**	**0.09%**	**-5.61%**	**0.06%**	**0.00%**	**0.11%**

Idaho

Table A.13 summarizes Idaho state forecasted sales growth by customer class.

Table A.13 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	690,259	474,749	1,735,017	594,801	2,634	**3,497,459**
2018	689,058	485,148	1,735,211	593,351	2,634	**3,505,401**
2019	686,683	495,579	1,735,443	591,908	2,634	**3,512,247**
2020	677,472	508,489	1,736,923	590,466	2,641	**3,515,992**
2021	672,104	516,761	1,736,760	589,043	2,634	**3,517,301**
2022	672,994	528,327	1,737,300	587,953	2,634	**3,529,207**
2023	675,008	541,033	1,737,637	586,913	2,634	**3,543,225**
2024	680,047	553,976	1,738,600	585,564	2,641	**3,560,828**
2025	678,023	562,833	1,737,847	584,140	2,634	**3,565,476**
2026	678,865	572,063	1,737,599	582,674	2,634	**3,573,835**
Average Annual Growth Rate						
2017-26	**-0.18%**	**2.09%**	**0.02%**	**-0.23%**	**0.00%**	**0.24%**

Wyoming

Table A.14 summarizes Wyoming state forecasted sales growth by customer class.

Table A.14 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	1,026,536	1,371,237	6,864,383	22,819	11,893	**9,296,868**
2018	1,022,597	1,370,933	6,860,818	22,349	11,893	**9,288,592**
2019	1,015,332	1,369,779	6,907,530	21,730	11,893	**9,326,263**
2020	1,013,869	1,368,436	6,990,851	21,023	11,928	**9,406,107**
2021	998,816	1,363,999	6,980,961	20,255	11,893	**9,375,925**
2022	993,165	1,364,316	7,020,281	19,600	11,893	**9,409,255**
2023	986,444	1,363,112	7,108,770	18,754	11,893	**9,488,973**
2024	987,641	1,362,366	7,091,762	17,442	11,928	**9,471,139**
2025	968,155	1,343,801	7,149,796	15,747	11,893	**9,489,391**
2026	963,818	1,347,430	7,253,188	13,399	11,893	**9,589,729**
Average Annual Growth Rate						
2017-26	**-0.70%**	**-0.19%**	**0.61%**	**-5.74%**	**0.00%**	**0.35%**

Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of higher than normal temperatures.

The December 2016 forecast is the baseline scenario. For the high and low economic growth scenarios assumptions from IHS Global Insight were applied to the economic drivers in the

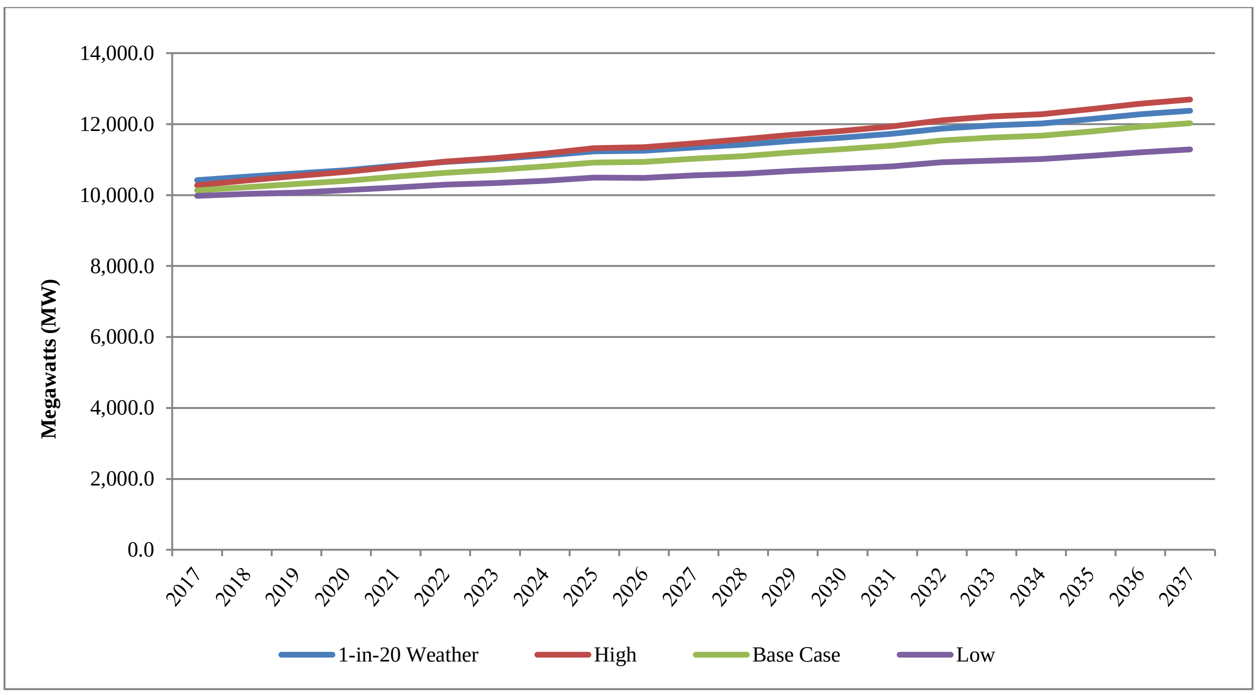
Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon.

Recognizing the volatility associated with the oil and gas extraction industries, PacifiCorp applied additional assumptions for the Utah and Wyoming industrial class load forecasts in the high and low scenario. Specifically, the Company focused on the increased uncertainty of the industrial load forecast as it moves further out in time. In order to capture this increased uncertainty the Company modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The 1,000 load values are then ranked and the Company selected the 95th percentile and 5th percentile of the Utah and Wyoming industrial loads for both the low and high growth scenarios.

For the 1-in-20 year (5 percent probability) extreme weather scenario, the Company used 1-in-20 year peak weather for summer (July) months for each state. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years.

Figure A.11 shows the comparison of the above scenarios relative to the base case scenario.

Figure A.11 – Load Forecast Scenarios for 1-in-20 Weather, High, Base Case and Low, pre-DSM



APPENDIX B – IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2017 IRP complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the Company's last IRP ("2015 IRP"), and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[1]
- Table B.2 – Provides a description of how PacifiCorp addressed the 2015 IRP acknowledgement requirements and other commission directives.
- Table B.3 – Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 – Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Trade Commission IRP guidelines issued in January 2006.
- Table B.6 – Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public Input Process) fully complies with IRP Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the resources required to meet this load.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource

[1] California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the Company plan for compliance with the California RPS requirements.

options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 9 (Action Plan). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 2015 IRP and 2015 IRP Update.

The 2017 IRP and related Action Plan are filed with each commission with a request for acknowledgment. Acknowledgment means that a commission recognizes the IRP as meeting all regulatory requirements at the time of acknowledgment. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets their acknowledgment standards.

State commission acknowledgment orders or letters typically stress that an acknowledgment does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgment does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Public Utilities Code Section 454.52, mandates that the California Public Utilities Commission (CPUC) adopt a process for load serving entities to file an IRP beginning in 2017. In February 2016, the CPUC opened a rulemaking to adopt an IRP process and address the scope of the IRP to be filed with the CPUC. As of the date PacifiCorp's 2017 IRP was finalized, the CPUC has not adopted any IRP requirements.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. The Order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold*.

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2017, and fully addresses the above report components.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its planning guidelines issued in January 2007 (Order No. 07-002). The Commission's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), and flexible resource capacity (Order No. 12-013[2]). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgment does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table B.3 provides detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Public Service Commission of Utah in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table B.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238) (as amended, January 2006). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the

2 Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on March 30, 2016, in Docket UE-160353. Table B.5 provides detail on how this plan addresses each of the rule requirements.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on March 21, 2016. Chapter 3, Section 33 outlines the requirements on filing IRPs for any utility serving Wyoming customers. The rule, shown below, went into effect in March 2016. Table B.6 provides detail on how this plan addresses the rule requirements.

> ***Section 33. Integrated Resource Plan (IRP).***
> *Each utility serving in Wyoming that files an IRP in another jurisdiction shall file that IRP with the Commission. The Commission may require any utility to file an IRP.*

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation, low-income programs, lost opportunities and capability building.	Each utility serving in Wyoming that files and IRP in another jurisdiction, shall file the IRP with the Commission.

Frequency	Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	File biennially.	RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually.	The Commission may require any utility to file an IRP.
Commission Response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.	Commission advisory staff reviews the IRP as directed by the Commission and drafts a memo to report its findings to the Commission in an open meeting or technical conference.

Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.	The review may be conducted in accordance with guidelines set from time to time as conditions warrant. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 2000-346-EA-09) adopted Commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.	Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations.

Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability. • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued July 2016 cover: • Sufficiency of the public comment process • Utility strategic goals, resource planning goals and preferred resource portfolio • Resource need over the near-term and long-term planning horizons • Types of resources considered • Changes in expected resource acquisitions and load growth from the previous IRP • Environmental impacts considered • Market purchase evaluation • Reserve margin analysis • Demand-side management and conservation options

	transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment.		"lowest reasonable cost" criteria. • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan.		

Table B.2 – Handling of 2015 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
Idaho		
Case No. PAC-E-15-04, Order No. 33396	Suggests the Company consider conducting a reasonable evaluation, similar to the Wind Integration Study previously commissioned, of the costs and benefits associated with the integration of additional solar resources into its system.	PacifiCorp has included analysis of solar integration as part of Volume II, Appendix H (Flexible Reserve Study) of the 2017 IRP.
Oregon		
Order No. 14-252, p. 3	Beginning in the third quarter of 2014, PacifiCorp will appear before the Commission to provide quarterly updates on coal plant compliance requirements, legal proceedings, pollution control investments, and other major capital expenditures on its coal plants or transmission projects. PacifiCorp may provide a written report and need not appear if there are no significant changes between the quarterly updates.	Order No. 14-288 modified the requirements, moving the date of the first meeting from the third quarter of 2014 to the fourth quarter of 2014. Order No. 16-071 further streamlined this requirement by requiring the company to continue to provide twice yearly updates on the status of DSM IRP acquisition goals at public meetings and include in these updates information on future coal plant and transmission investment decisions. Also include information on 111(d) rule compliance analysis; Environmental/coal and transmission expenditures quarterly presentations were made at Commission special public meetings on October 28, 2014 and March 16, 2015. Quarterly presentations via written reports were provided on June 30, 2015 and October 1, 2015. The 2015 fourth quarter presentation was made at the Commission special public meeting on December 17, 2015. A biannual DSM update was provided at the Commission public meetings on March 10, 2015 and December 15, 2015 Biannual presentations for both Environmental/coal and transmission expenditures/111(d) and DSM were provided on August 30, 2016 and December 20, 2016. Please see Commission website for public meeting history and Docket RE 163 for presentations and written reports provided.
Order No. 14-252, p. 3	In future IRPs, PacifiCorp will provide: • Timelines and key decision points for expected pollution control options and transmission investments; and • Tables detailing major planned expenditures with estimated costs in each year for each plant or transmission project, under different modeled scenarios.	PacifiCorp has included seven Regional Haze scenarios in its 2017 IRP. See case study fact sheets (Volume II, Appendix M (Case Study Fact Sheets) for discussion on specific Regional Haze assumptions. For modeling purposes PacifiCorp has included incremental transmission costs associated with specific resources. See Volume I, Chapter 6

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
		(Resource Options) for discussion of these potential costs. Additional detail is provided on the data discs included with the 2017 IRP filing.
Order No. 14-252, p. 13	In the acknowledgement order the Commission provided the following recommendation: As part of the 2015, 2017, and 2019 IRPs, PacifiCorp will provide an updated version of the screening tool spreadsheet model that was provided to participants in the 2011 (docket LC 52) IRP Update.	The screening tool is no longer used to model competing retirement scenarios. The variety of retirement scenarios represented by the Regional Haze cases and the addition of an endogenous retirement case in the 2017 IRP has made the use of this tool unnecessary.
Order No. 14-252, p. 16	In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state.	See Volume II, Appendix D (Demand-Side Management Resources) for the breakdown by state and year for both energy and capacity selected for the preferred portfolio.
Order No. 16-071, Appendix A, p.1 (action item 1a-1c)	Include sensitivity studies around solar costs. Provide analysis of the system benefits of storage.	See Volume II, Appendix N (Wind and Solar Capacity Contribution Study), and two energy storage sensitivities (Storage – Battery, Storage – CAES) described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order No. 16-071, p. 4	If HB 4036 (passed as SB 1547) is enacted, PacifiCorp will revisit action item 1c, to conclude negotiations with shortlisted bids from the Company's 2013 RFP seeking up to 7 MW of qualifying solar capacity, and bring forth its recommendation for Commission review.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547. This action item was deleted from the updated action plan presented in PacifiCorp's 2015 IRP Update.
Order No. 16-071, p. 4	The Commission expects the company to update its Clean Power Plan modeling in its 2015 IRP update or its next IRP (depending on when Oregon's compliance plan is known) to correctly reflect the final rule and Oregon's implementation plan.	PacifiCorp's 2017 IRP reflects the final version of the Clean Power Plan, however, at the time of the 2017 IRP, the rule is stayed and Oregon has not issued a draft or final implementation plan therefore Oregon's compliance plan is not known and not reflected in the 2017 IRP. The 2017 IRP does include two Clean Power Plan modeling assumptions (CPP(a) and CPP(b)) plus two Clean Power Plan sensitivities (Mass Cap C and Mass Cap D), described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order No. 16-071, Appendix A, p.1 (action item 2a) Order No. 16-071, p. 5	Provide quantitative justification for assumed levels of trading hub liquidity and depth. The Commission noted that the Company has committed to conducting a market reliance risk analysis and urge the Company to also address concerns about reliance on Front Office Transactions in its analysis.	See Volume II, Appendix J (Western Resource Adequacy Evaluation).
Order No. 16-071, Appendix A, p.1 (action item 3a)	Present at a public meeting within six months of this order, potential demand response pilot programs including: a time-varying rate pilot, peak-time rebate, and direct load control programs for other	PacifiCorp presented this information to the Commission at the August 16, 2016 public meeting. Ongoing. The Company engaged stakeholders in the development of its proposed transportation electrification pilot programs, including

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	sectors. The company may also consider demand bidding programs. Engage Oregon stakeholders in an informal process to address increased voluntary participation in time-of-use pricing and present the outcome of this informal process to the Portfolio Options Committee.	considerations for time-of-use rates for electric vehicle owners. The Company plans to promote the benefits of time-of-use rates to customers through its proposed Outreach and Education program, if approved. After program approval, the Company will present initial strategies to promote time-of-use rates to current and potential electric vehicle owners to the POC.
Order No. 16-071, p. 5	In addition to the action item 3a irrigation pilot program, the Commission directs PacifiCorp to design and present additional pilots.	PacifiCorp presented information on potential demand response pilot opportunities at the Commission's August 16, 2016 public input meeting and explained that the 2017 IRP would inform whether the Company would propose additional pilot programs.
Order No. 16-071, Appendix A, p.1 (action item 3b)	Continue to provide twice yearly updates on the status of DSM IRP acquisition goals at public meetings. Include in these updates information on future coal plant and transmission investment decisions, as a streamlined continuation of Order No. 14-288. Also include information on 111 (d) rule compliance analysis; Provide more risk analysis on portfolios that include accelerated energy efficiency as a resource; Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Class 2 DSM annual energy savings targets; For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes; Perform stochastic modeling on all portfolios with accelerated DSM.	PacifiCorp provided updates on the status of DSM acquisition goals to the Commission on August 30, 2016 and December 20, 2016. PacifiCorp did not conduct a sensitivity on accelerated DSM in the 2017 IRP. See Volume I, Chapter 8 (Modeling Portfolio Selection Results) for the annual summer and winter peak demand capacity (MW) for Class 2 DSM. PacifiCorp provided a portfolio comparison of its accelerated DSM study and the 2015 IRP Update preferred portfolio in Chapter 5 (Portfolio Development) of the 2015 IRP Update. See response to the second item above. PacifiCorp did not conduct a sensitivity on accelerated DSM in the 2017 IRP.
Order No. 16-071, Appendix A, p.2 (action item 5a) and Order No. 16-071, p. 9.	Continue permitting Energy Gateway Segments D, E, F, and H until PacifiCorp files its 2017 IRP. The Commission acknowledges this action item only to the extent of PacifiCorp's permitting actions. The Commission expects to see updated analysis in the next IRP or before the Company makes significant commitments to these transmission lines.	See Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Chapter 9 (Action Plan) for updated analysis on the Company's Energy Gateway transmission segments.
Order No. 16-071, Appendix A, p.2 (action item 5b)	1. In the next IRP, evaluate the benefits of freed-up transmission due to plant closures;	1. Seven Regional Haze cases are examined in the 2017 IRP, representing alternate retirement scenarios and accounting for the PVRR costs and benefits applicable to new resources selected at closure sites. PacifiCorp's modeling

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	2. Update the available dynamic transfer capability between east and west balancing authority areas (BAAs) in modeling; 3. Incorporate an analysis of California Independent System Operator (CAISO) membership in the 2017 IRP as appropriate.	approach captures any benefits associated with freed-up transmission due to assumed plant/unit closures. 2. The transfer capability of west/east transmission availability (the 'overlay') is recognized in 2017 IRP modeling, consistent with the most current assumptions tied to operational practice. 3. California Senate Bill No. 350, which was passed in October 2015, authorizes the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO up until the conclusion of the 2017 legislative session which ends September 15, 2017. In the event that legislation is passed, PacifiCorp will coordinate with its state regulatory authorities on evaluation of next steps. As such, an analysis of participation in a regional ISO is not included in the 2017 IRP.
Order No. 16-071, Appendix A, p.2 (additional actions - modeling)	1. Include more robust analysis regarding the west BAA winter peak load/resource balance and portfolios to meet this peak load; 2. Provide quantitative justification for the planning reserve margin of 13 percent; 3. Utilize the Balancing Authority's Area Control Error (ACE) Limit (BAAL) NERC standard in forthcoming wind integration studies, and confirm and demonstrate that the study is based on implementation of the BAAL standard; 4. Use the same regional haze assumptions when directly comparing portfolios.	1. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) including winter and summer peak load and resource tables. 2. See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost. 3. The Company's Flexible Reserve Study (Appendix H) incorporates the specific requirements of the BAAL standard (BAL-001-2). 4. In the 2017 IRP, the least-cost, least-risk Regional Haze case is assumed for all subsequent portfolios.
Order No. 16-071, Appendix A, p.3 (additional actions – Clean Power Plan Analysis)	1. Provide alternate 111(d) rule compliance paths, including mass-based solutions, with stochastic analysis for each; 2. Include the constraints needed for 111(d) rule compliance in all cost risk analysis ("PaR" analyses); 3. Estimate the effects of 111(d) rule compliance on western wholesale power prices;	1. The 2017 IRP includes two distinct Clean Power Plan modeling strategies (CPP(a) and CPP(b)) plus two Clean Power Plan sensitivities (Mass Cap C and Mass Cap D), described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the 2017 IRP. Portfolios are evaluated on the basis of stochastic modeling, analysis and metrics. 2. PaR uses optimized shadow prices to drive stochastic model behavior. Please refer to Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for discussion.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	4. Provide additional analysis in the IRP update on 111 (d) rule compliance alternatives that do not double count Renewable Energy Credits (RECs) and the Emission Rate Credits (ERCs).	3. The price curves developed for CPP(a) and CPP(b) capture the effects of emissions policy on power prices. CO_2 emissions, and therefore developed prices, are not significantly constrained by Clean Power Plan limits except under high gas price conditions. Please refer to Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). 4. Clean Power Plan modeling for the 2017 IRP assumes a fixed cap on emissions, unaffected by RECs or ERCs.
Order No. 16-071, p. 10.	The Company is directed to confirm and demonstrate that its upcoming wind integration study is based on implementation of the BAAL standard.	The Company's Flexible Reserve Study (Appendix H) incorporates the specific requirements of the BAAL standard (BAL-001-2).
Utah		
Order, Docket No. 15-035-04, p.18	If PacifiCorp plans to use the System Benefit Tool type of transmission analytical tool in future IRPs, PacifiCorp should introduce and vet the tool in an IRP workshop setting prior to utilizing the tool.	The System Benefit Tool is not used in the 2017 IRP.
Order, Docket No. 15-035-04, p.19	Encourage PacifiCorp in future IRP processes, to provide a stronger demonstration of the reasonableness of the range of renewable resource costs analyzed.	PacifiCorp discussed its 2017 IRP supply-side resource table and inputs at the August 25-26, 2016 public input meeting. The supply-side resource table was updated based on stakeholder feedback.
Order, Docket No. 15-035-04, p.20	Direct PacifiCorp to identify the amount of distributed generation in the baseload forecast in its load and resource table, as it does for existing DSM and curtailment.	See Volume I, Chapter 5 (Load and Resource Balance), which breaks out private generation in the same manner as DSM and interruptible load curtailment.
Order, Docket No. 15-035-04, p.21	Direct PacifiCorp to continue to evaluate the depth of the western wholesale market, and to use sensitivity cases and acquisition path analysis, including development of a contingency plan, to monitor the feasibility of long-term reliance on Front Office Transactions to meet near-term load growth.	See Volume II, Appendix J (Western Resource Adequacy Evaluation) for an evaluation of market depth, and also the Front Office Transaction sensitivity provided in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Also refer to acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).
Order, Docket No. 15-035-04, p.21	Recommend continued analysis of the planning reserve margin in future IRPs using results from both loss of load probability studies and analysis of the tradeoffs between reliability and cost.	See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost.
Order, Docket No. 15-035-04, p.25	Analysis behind Near-Term and Long-Term Resource Acquisition Paths (Table 9.3 in the 2015 IRP) could be improved in terms of identifying potential exogenous changes that would cause a significant change in acquisition path. Encourage PacifiCorp in future IRPs to further define the critical contingencies it is monitoring	See acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	and identify the magnitude of changes that would be required to potentially trigger movement to any of the different paths listed in the table.	
Order, Docket No. 15-035-04, p.25	Encourage PacifiCorp to file an update of the energy storage screening study in its 2017 IRP, update the storage cost assumptions, and consider modeling changes for energy storage following discussion with stakeholders. Request that PacifiCorp present the findings of the updated study, with the study authors accessible for stakeholder questions and discussion, at a public input meeting.	See Volume II, Appendix P (Energy Storage Studies). PacifiCorp presented results of its updated Energy Storage Studies at the August 25-26, 2017 public input meeting with the study authors participating via phone.
Order, Docket No. 15-035-04, p.26	The Commission is interested in examining the impact on Present Value Revenue Requirement and investment decisions of varying levels of Qualifying Facilities on the system. Direct PacifiCorp to develop a set of sensitivity runs addressing this issue following discussion with interested stakeholders.	PacifiCorp continues to assume that executed qualifying facility contracts, as of the time modeling assumptions are locked down, are considered in the resource mix when performing 2017 IRP analysis. Stakeholders did not request additional sensitivity cases to assess alternative qualifying facility penetration scenarios during the public input process. Such sensitivities would be difficult to produce, as it is not reasonably feasible to derive avoided cost pricing for hypothetical qualifying facility projects on the system as there is no information on project location or technology type. Without a sound avoided cost price estimate, which would significantly influence system costs under a qualifying facility sensitivity, PVRR cost implications could be misleading.
Order, Docket No. 15-035-04, p.28	Encourage PacifiCorp to explain in the 2017 IRP how the effects of the federal standards on lighting technologies are accounted for in updated potentials studies or load forecasts.	See Volume II, Appendix A (Load Forecast Details).
Order, Docket No. 15-035-04, p.31	Remind PacifiCorp of the requirement to future IRPs to present the Business Plan as a sensitivity case. If PacifiCorp has substantive objections to this requirement, PacifiCorp should file a motion for Commission action within 90 days of this order explaining the objection and requesting relief.	Please refer to the Business Plan sensitivity (BP) presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) consistent with the Order in Docket No. 15-035-04.
Washington		
UE-140546, Acknowledgement Letter, p.1	Encourage the Company to continue the practice of including data discs with the filing in future IRP filings.	Data discs have been included with the 2017 IRP filing.
UE-140546, Acknowledgement Letter, p.2	Encourage the Company to continue to evaluate how its method of developing capacity value of renewable resources compares to the effective load carrying capability method on which it was based, to ensure that the Company's model is yielding accurate results.	See Volume II, Appendix N (Wind and Solar Capacity Contribution Study), analyzing updated hourly profiles and transmission availability impacts to determine effectiveness in meeting system load. The 2017 IRP also adds winter peak (in addition to summer peak) in its assumptions, allowing enhanced insight into solar penetration concerns.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
UE-140546, Acknowledgement Letter, p.3	Requests the Company model a sensitivity for both a trading system and carbon tax system in its 2017 IRP, and consult with commission staff regarding the appropriate assumptions and inputs.	PacifiCorp included Clean Power Plan modeling studies and an alternative CO_2 price sensitivity. The CO_2 price sensitivity reflects an alternative policy mechanism, without defining whether that policy is implemented as a tax or trading system, than what is contemplated in the Clean Power Plan. The effects of the policy (tax vs. trading system) would not influence the impacts on system variable costs. Under a CO_2 tax, PacifiCorp would incur a direct cost for CO_2 emissions. Under a CO_2 trading system, presumably with some type of allowance allocation, PacifiCorp would be faced with either the direct cost of buying allowances from the market if its emissions were higher than its allowance allocation or the opportunity cost of not selling allowances into the market if its emissions were below its allowance allocation. Consequently, the impact on system dispatch and the associated variable costs is the same under a tax or trading system policy approach.
UE-140546, Acknowledgement Letter, p.3	It would be useful for the Company to develop a supply curve of emissions abatement. This supply curve would identify, specific to Pacific Power, the available technologies and their associated costs that could reach a given emissions goal. This type of tool would lend increased transparency to the issue, and would allow the Company, regulators and stakeholders to engage in meaningful and informed conversations regarding the costs and benefits of reducing Pacific Power's emissions.	The company did not develop a cost abatement curve, as linear model optimizations are ideally suited to endogenously and simultaneously assess finely detailed and incremental trade-offs among resources, requirements and constraints to achieve least-cost least-risk outcomes influenced by dynamic market conditions. Emissions constraints are included in the simultaneous optimization of all resource (technology) selections, reflecting a PacifiCorp-specific marginal cost of compliance expressed in dollars per ton. In addition, six price-emissions scenarios were evaluated in each Regional Haze and core case. Variant CO_2 sensitivities are also included in the 2017 IRP.
UE-140546, Acknowledgement Letter, p.3	Appreciate sensitivity case in the 2015 IRP S-15, but question approach in assuming the only compliance alternative would be to shut down Chehalis gas plant. It would be more appropriate to allow the model to conduct a full run to see if it can identify some other combination of compliance options consistent with the final CPP that would allow the Company to meet its obligations without have to double allocate renewable energy. Request that the Company provide such an analysis with the 2015 IRP Update.	These concerns were addressed in the 2015 IRP Update covering both Chehalis shutdown assumptions and the potential double-counting issue based on ERCs (2015 IRP Update, pages 61-62). ERCs are not explicitly included 2017 IRP analytics.
UE-140546, Acknowledgement Letter, p.4	The cost impacts in S-10 in the 2015 IRP were on a system basis and the commission would like to see them on a balancing authority area basis. Requests the analysis be redone in the 2017 IRP and that the Company use inputs consistent	See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for a description regarding the West and East balancing authority area sensitivities and response to this request.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	with the staff MSP power flow data or explain why different inputs are more appropriate. Request that the Company incorporate the balancing area analysis in all future IRPs.	
UE-140546, Acknowledgement Letter, p.5	Expect the Company to conduct a more in-depth analysis of energy storage in its 2017 IRP. Analysis should include benefits associated with ancillary services such as frequency regulation and include batteries and other forms of storage. It should also value specific projects on Pacific Power's system both at the transmission and distribution levels and ensure cost assumptions are based on current price trends.	Two energy storage sensitivities (Storage – Battery and Storage – CAES) were conducted for the 2017 IRP, using updated cost assumptions. Please refer to Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for a discussion of these sensitivity cases and energy storage. See also Volume II, Appendix P (Energy Storage Studies).
UE-140546, Acknowledgement Letter, p.6	Request that the 2017 IRP re-assess the overall potential and levelized costs for demand response and add a sensitivity analysis that evaluates the portfolio impact of adding additional demand response resources. Encourage the Company to consider demand response along with traditional energy efficiency programs in the context of Clean Power Plan compliance planning.	In the 2017 IRP, demand response programs, which do not produce emissions, and with their selection in any portfolio, potentially defer emissions from alternative generating resources, are directly competitive with alternate strategies to keep total emissions below CPP limits. Also, in the 2017 IRP, core case DLC-1 includes the forced addition of Class 1 DSM resources equal to 5 percent of the incremental L&R balance estimated at the time the study was prepared. Please refer to Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).
UR-140546, Acknowledgement Letter, p.7	Request that the Company update its RPS compliance analysis in the 2015 IRP Update based on a more accurate projection of Washington's future renewable energy allocations.	PacifiCorp met this requirement in its 2015 IRP Update, page 57.
UE-140546, Acknowledgement Letter, p.7	Note that the Company agreed, as a condition of the commission's granting of the waivers requested in Docket UE-151694, to conduct a market reliance risk assessment in conjunction with the 2017 IRP. Encourage the Company to work with staff on the design of that analysis.	Please see Volume II, Appendix J (Western Resource Adequacy Evaluation) for an evaluation of market depth, and also the Front Office Transaction sensitivity provided in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
UE-140546, Acknowledgement Letter, p.8	Encourage the Company to continue to integrate the EIM into its IRP model, in particular to develop modeling capability to capture how different resources with different generation profiles would interact with the EIM, based on the Company's experience with the market. Also expect the Company to work with staff on incorporating an analysis of CAISO membership in the 2017 IRP as appropriate.	PacifiCorp incorporated flexible ramping procurement diversity savings from the EIM in its Flexible Reserve Study. See Volume II, Appendix H (Flexible Reserve Study). California Senate Bill No. 350, which was passed in October 2015, authorizes the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO up until the conclusion of the 2017 legislative session which ends September 15, 2017. In the event that legislation is passed, PacifiCorp will coordinate with its state regulatory authorities on evaluation of next steps. As such, an

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
		analysis of participation in a regional ISO is not included in the 2017 IRP. This is discussed further in Volume I, Chapter 3 (Planning Environment) of the 2017 IRP.
Wyoming		
The Wyoming Public Service Commission provided the following comment in its Letter Order (Docket No. 20000-474474-EA-15, record No. 14089, dated January 11, 2015) on PacifiCorp's 2015 IRP: *Pursuant to open meeting action taken on December 29, 2015, Rocky Mountain Power's 2015 Integrated Resource Plan is hereby placed in the Commission's files. No further action will be taken and this matter is closed.*		

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Volume I, Chapter 4 (Transmission Planning), Chapter 6 (Resource Options), and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the Company's capacity expansion optimization model, System Optimizer, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with System Optimizer were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Volume I, Chapter 5 (Load and

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
		Resource Balance), Chapter 6 (Resource Alternatives), and Chapter 7 (Modeling and Portfolio Evaluation Approach) as well as Volume II, Appendix D (Demand-Side Management and Supplemental Resources).
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its nominal after-tax WACC of 6.57 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk and evaluated via the 111(d) modeling approach. Additional scenario risk is used to evaluate load sensitivities. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 9 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (The Planning Environment), Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), and Chapter 8 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results), Chapter 9 (Action Plan), and Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results) for the Company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period (2017-2036) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum:	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	several measures, including stochastic upper-tail mean PVRR (mean of highest three Monte Carlo iterations) and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on hedging is provided in Volume I, Chapter 9 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the Company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Volume I, Chapter 3 (The Planning Environment). Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 9 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PacifiCorp fully complies with this requirement. Volume I, Chapter 2 (Introduction) provides an overview of the public process, all public meetings held for the 2017 IRP, which are documented in Volume II, Appendix C (Public Input Process). PacifiCorp also made use of a Feedback Form for stakeholders to provide comments and offer suggestions. Feedback Forms along with the public meeting presentations and handouts are available on PacifiCorp's webpage at: http://www.pacificorp.com/es/irp.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	2017 IRP Volumes I and II provide non-confidential information the Company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email. Data discs will be available with public data. Additionally, data discs with confidential data will be protected through use of a protective order.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2017 IRP. The materials shared with stakeholders at these

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
		meetings, outlined in Volume I Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2017 IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case and sensitivity definitions. The Company considered comments received via Feedback Forms in developing its final plan.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	The 2017 IRP complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	This activity will be conducted subsequent to filing this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted subsequent to filing this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted subsequent to filing this IRP.
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	This activity will be conducted subsequent to filing this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan;	This activity will be conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	• Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the System Optimizer model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 5 (Load and Resource Balance) and Chapter 7 (Modeling and Portfolio Evaluation Approach), and Volume II, Appendix A (Load Forecast) for load forecast information.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 5 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach)
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology.	Volume I, Chapter 6 (Resource Options) identifies the resources included in this IRP, and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management and Supplemental Resources) referencing additional information on PacifiCorp's IRP Web, site see footnote 3 of this Appendix B.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a 13 percent planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix I), the Company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II,

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	compliance costs) and alternative scenarios considered.	Appendix M (Case Study Fact Sheets) includes summaries of assumptions used for each case definition analyzed in the 2017 IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system.	This Plan documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) presents the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
4.n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Volume I Chapter 9 (Action Plan) presents the 2017 IRP action plan.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated four sensitivities on Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. Where new resources would require additional transmission facilities the associated costs were factored into the analysis. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potential study was completed in 2017, and those results were incorporated into this plan.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Volume I, Chapter 6 (Resource Alternatives), the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 9 (Action Plan) and the implementation steps outlined in Volume II, Appendix D.
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 1 DSM) on a consistent basis with other resources.
Guideline 8: Environmental Costs		
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). For the 2017 IRP PacifiCorp used the EPA's proposed 11(d) rule as the basis for future regulations. The proposed rules limit carbon emissions either through a state-level rate per MWh, or a hard cap amount. PacifiCorp looked at both approaches in determining portfolio selections. PacifiCorp examined compliance through EPA's 111(d) along with a carbon tax adder.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix L (Stochastic Production Costs Simulation Results) provides the Stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.a above. The Company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and uses a 20-year planning horizon. Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios. Alternate scenarios were applied in the 2017 IRP to capture the possibility of more stringent Regional Haze compliance obligations.
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance “turning point” scenario, which, if anticipated now, would lead to, or “trigger” the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio’s expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of core case definitions. Regional Haze cases were developed to represent “triggered” portfolios with coal unit retirements and gas conversions that differ substantially from the preferred portfolio. PacifiCorp also performed CO_2 price sensitivities showing portfolios that differ significantly from the preferred portfolio. Comparative analysis of these case results is included in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
8.d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Guideline 9: Direct Access Loads		
9	An electric utility’s load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Oregon docket UE 267 established a long-term opt out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers).
Guideline 10: Multi-state Utilities		

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2017 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 under the section "The Role of PacifiCorp's Integrated Resource Planning". The Company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	See the response to 1.c.3.1 above. Volume I, Chapter 8 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp contracted with Navigant to provide estimates of expected private generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for private generation. The study is included in Volume II, Appendix P (Energy Storage Studies).
Guideline 13: Resource Acquisition		
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Chapter 9 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9 (Action Plan). PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 2017 IRP action plan.
13.b	For gas utilities only.	Not applicable.
Flexible Capacity Resources		
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.	See Volume II, Appendix F (Flexible Reserve Study).

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.	See Volume II, Appendix F (Flexible Reserve Study).
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	See Volume II, Appendix F (Flexible Reserve Study).

Table B.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence reviews of new resource acquisitions will occur during ratemaking proceedings.	Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model. Also see the response to number 4.b.ii below.
7	Avoided cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs in Utah will be handled in a manner consistent with the IRP, with the

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Volume I, Chapter 9 (Action Plan) describes the linkage between the 2017 IRP preferred portfolio and fall 2016 business plan resources. Significant resource differences are highlighted. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on March 31, 2015, and filed this IRP on April 4, 2017 meeting the requirement.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2017 IRP are provided in Volume I, Chapter 5 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast Details).
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly	Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Volume I, Chapter 5 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast Details). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
	incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	included in IRP modeling and are used for system balancing purposes.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Volume II, Appendix A (Load Forecast Details) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model using both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 6 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Volume I, Chapter 6 (Resource Options).
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Volume I, Chapters 6 (Resource Options) and 7 (Modeling and Portfolio Evaluation Approach) contain assumptions and describe the process under which PacifiCorp developed and assessed these technologies and resources.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves used for portfolio modeling explicitly incorporate estimated rates of program and event participation. The private generation study, modeled as a reduction to load, also considered rates of participation. Replacement capacity is considered in the case of early coal unit retirements as evaluated in this IRP as an alternative to coal unit environmental investments. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Volume I, Chapter 9 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2017-2036)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 9 (Action Plan). A status report of the actions outlined in the previous action plan (2015 IRP Update) is provided in Volume I, Chapter 9 (Action Plan). In Volume I, Chapter 9 (Action Plan) Table 9.1 identifies actions anticipated in the next two years and in the next four years.
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Volume I, Chapter 9 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 6 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using a range of CO_2 compliance methods, most included emissions rate targets, but there was examination of additional CO_2 tax adders. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Volume I, Chapter 3 (The Planning Environment). ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). ● Volume II, Appendix G (Plant Water Consumption) of reports historical water consumption for PacifiCorp's thermal plants.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 9 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 6 (Resource Options).

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 9 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 9 (Action Plan), specifically, Table 9.1.
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), and highlighted through the use of scatter-plot graphs showing the relationship between stochastic mean and upper-tail mean stochastic PVRR.
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp incorporated environmental externality costs for CO_2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO_2 externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. These modeling assumptions are described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	See Volume I, Chapter 3 (The Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Volume I, Chapter 6 (Resource Options).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2017 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2017IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case and sensitivity definitions. The Company also considered comments received via Feedback Forms in developing its final plan.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines (RCW 19.280.030 and WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Requirements prior to IRP Filing		
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the 2017 IRP work plan on March 30, 2016 in Docket No. UE-160353, given an anticipated IRP filing date of March 31, 2017. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of anticipated IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 3-5 of the Work Plan document for a summarization of anticipated resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See pages 5-6 of the Work Plan. Table 1, page 6, document for the anticipated IRP schedule. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket No. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. PacifiCorp filed the 2015 IRP on March 31, 2015. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(5)	Commission issues notice of public hearing after company files plan for review.	This activity is conducted subsequent to filing this IRP.
(5)	Commission holds public hearing.	This activity is conducted subsequent to filing this IRP.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Requirements specific to IRP filing		
(2)(a)	Plan describes the mix of energy supply resources.	Volume I, Chapter 5 (Load and Resource Balance) describes the mix of existing resources, while Volume I, Chapter 8 (Modeling and Portfolio Selection Results) describes the 2015 IRP preferred portfolio.
(2)(a)	Plan describes conservation supply.	See Volume I, Chapter 6 (Resource Options) for a description of how conservation supplies are represented and modeled, and Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for conservation supply in the preferred portfolio. Additional information on energy efficiency resource characteristics is available on PacifiCorp's IRP Web site.
(2)(a)	Plan addresses supply in terms of current and future needs at the lowest reasonable cost to the utility and its ratepayers.	The 2017 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Volume I, Chapter 5 (Load and Resource Balance).
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Volume I Chapter 8 (Modeling and Portfolio Selection Results).
(2)(b)	LRC analysis considers resource costs.	Volume I, Chapter 6 (Resource Options), provides detailed information on costs and other attributes for all resources analyzed for the IRP.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints.
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory regimes, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Volume I, Chapter 9 (Action Plan) covers the following

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		topics: (1) managing carbon risk for existing plants, (2) assessment of owning vs. purchasing power, (3) purpose of hedging, (4) procurement delays and (5) treatment of customer and investor risks. Volume I, Chapter 4 (Transmission) covers similar risks associated with transmission system expansion.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	In Volume I, Chapter 7 (Modeling and Portfolio Evaluation) the IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington. PacifiCorp also evaluated various CO_2 regulatory schemes, and future Regional Haze compliance requirements. The I-937 conservation requirements are also explicitly accounted for in developing Washington conservation resource costs.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See (2)(b) above.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Volume I, Chapter 6 (Resource Options).
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range. Details concerning the load forecasts used in the 2017 IRP (high, low, and extreme peak temperature) are provided in Volume II, Appendix A (Load Forecast Details).
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Volume II, Appendix A (Load Forecast Details) for a description of the load forecasting methodology.
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Volume II, Appendix A (Load Forecast Details), for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp updated the system-wide demand-side management potential study in the 2017 IRP, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. The DSM potential study is included on the data disc, and available on PacifiCorp's IRP website at: http://www.pacificorp.com/es/irp/irpsupport.html.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Volume I, Chapter 5 (Load and Resource Balance).
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Volume I, Chapters 6 (Resource Options and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed and assessed these technologies.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
(3)(d)	Plan includes an assessment of transmission system capability and reliability; to the extent such information can be provided consistent with applicable laws.	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans explained in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. Potential energy savings associated with conservation voltage reduction are discussed in Chapter 5.
(3)(f)	Plan includes integration of the demand forecasts and resource evaluations into a long range integrated resource plan describing the mix of resources that is designated to meet current and project future needs at the lowest reasonable cost to the utility and its ratepayers.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio evaluation covers a 20-year period (2017-2036). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.1 in Volume I, Chapter 9 (Action Plan), for PacifiCorp's 2017 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	See Table 9.2 for a status report on action plan implementation in Volume I, Chapter 9 (Action Plan).
Requirements from RCW 19.280.030 not discussed above		
(1)(e)	An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio;	Volume I, Chapter 6 for discussion of options available for selection in the 2017 IRP. Also see Volume II, Appendix H (Wind and Solar Integration Study).
(1)(f)	The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events, at the lowest reasonable cost and risk to the utility and its ratepayers;	See Volume II, Appendix A for a discussion of the load forecasts, Supply-side and demand-side are discussed in Volume I, Chapter 6. Also included is a discussion of DSM in Volume II, Appendix D are included in Volume I, Chapters 7 and 8 go through the modeling methodology and discussion of selecting the preferred portfolio using least cost/least risk metrics.

Table B.6 – Wyoming Public Service Commission Guidelines Regarding Electric IRP

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input Process).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 9 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 5 (Load and Resource Balance).
D	A study detailing the types of resources considered;	Volume, I Chapter 6 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
F	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2015 IRP Update is presented in Volume I, Chapter 9 (Action Plan). A chart comparing the peak load forecasts for the 2015 IRP, 2015 IRP Update, and 2017 IRP is included in Volume II, Appendix A (Load Forecast Details).
G	The environmental impacts considered;	Portfolio comparisons for CO_2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection) as well as Volume II, Appendix L (Stochastic production Cost Simulation Results).
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in this IRP.
I	Reserve Margin analysis; and	PacifiCorp's planning reserve margin study, which documents selection of a capacity planning reserve margin is in Volume I, Appendix I (Stochastic Loss of Load Study).
J	Demand-side management and conservation options;	See Volume I, Chapter 6 (Resource Options) for a detailed discussion on DSM and conservation resource options. Additional information on energy efficiency resource characteristics is available on the Company's website.

APPENDIX C – PUBLIC INPUT PROCESS

A critical element of this Integrated Resource Plan (IRP) is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp's IRP prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the IRP with transparency and full participation from interested and affected parties is essential.

Stakeholders have been involved in the development of the 2017 IRP from the beginning. The public input meetings (PIM) held beginning in June 2016 were the cornerstone of the direct public input process. There were a total of seven PIM, with four lasting two days, the remainder being single days. Meetings were held jointly in both Salt Lake City, Utah and Portland, Oregon via video conference, with expanded video conference locations in Denver, Colorado and Cheyenne, Wyoming. One meeting was held via phone conference. For all meetings, attendees off-site for were able to conference in via phone.

The IRP public input process also included state-specific stakeholder dialogue sessions held in June 2016. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as discuss how to tackle these from a system planning perspective. PacifiCorp also wanted to ensure that stakeholders understood IRP planning principles. These meetings continued to enhance interaction with stakeholders in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during public input meetings.

PacifiCorp solicited agenda item recommendations from the state stakeholders in advance of the state meetings. There was additional open time to ensure that participants had adequate time for dialogue.

PacifiCorp's comment website housed the feedback form discussed earlier in Chapter 2 - Introduction. This standardized form allowed stakeholders opportunities to provide comments, questions, and suggestions. Feedback forms can be found via the following link: (http://www.pacificorp.com/es/irp/irpcomments.html).

Participant List

PacifiCorp's 2017 IRP was a robust process involving input from many parties throughout. Organizations actively participated in the development of material, modeling process, and public meetings. Participants included Commissions, stakeholders, and industry experts. Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission

- Wyoming Public Service Commission

Stakeholders and Industry Experts

- ABB Enterprise Software Inc. (formerly known as Ventyx Inc.)
- Applied Energy Group
- Avista Utilities
- Black & Veatch
- Blue Castle Holdings, Inc.
- Citizen's Utility Board of Oregon
- Energy Trust of Oregon
- DNV-GL
- Idaho Conservation League
- Idaho Power Company
- Individual Customers
- Industrial Customers of Northwest Utilities
- Intermountain Wind
- Interwest Energy Alliance
- Mitsubishi
- National Renewable Energy Laboratory
- Natural Resources Defense Council
- Navigant Consulting, Inc.
- Northwest Power and Conservation Council
- Northwest Pipeline GP
- NW Energy Coalition
- Oregon Department of Energy
- Oregon Department of Environmental Quality
- Portland General Electric
- Powder River Basin Resource Council
- Renewable Energy Coalition
- Renewables Northwest
- Sierra Club
- Siemens
- For Utah Association of Energy Users
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Industrial Energy Consumers
- Utah Office of Consumer Services
- Utah Office of Energy Development
- Western Clean Energy Campaign
- Western Electricity Coordination Council
- Western Resource Advocates
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocate

PacifiCorp extends its gratitude for the time and energy participants have given to the IRP process. Their participation has contributed significantly to the quality of this plan, and their continued participation will help PacifiCorp as it strives to improve its planning efforts going forward.

Public Input Meetings

As mentioned above, PacifiCorp hosted seven public input meetings, as well as five state meetings during the public input process. During the 2017 IRP public input process presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings; the presentations may be found on the PacifiCorp website at: http://www.pacificorp.com/es/irp.html.

General Meetings

June 21, 2016 – General Public Meeting

- Introductions
- 2017 IRP Timeline
- 2015 IRP Update Highlights
- Overview of Changes Since 2015 IRP
- 2015 IRP Order Requirements
- 2015 IRP Action Plan status updates

July 20, 2016 – General Public Meeting

Day One

- Introductions
- Environmental Policy
- Transmission and Regional Integration
- Renewable Portfolio Standards and Request for Proposals

August 25-26, 2016 – General Public Meeting

Day 1

- Introductions
- Portfolio Development
- Private Generation Study
- Supply-Side Resources
- Energy Storage

Day 2

- Update on Renewable Portfolio Standards and Request for Proposals
- Conservation Potential Assessment
- Load Forecast

September 22-23, 2016 – General Public Meeting

Day 1

- Introductions
- Portfolio Development
- Stochastic Modeling & Portfolio Selection Process
- Resource Adequacy and Front Office Transactions

- Loss of Load Probability and Planning Reserve Margin
- Capacity Contribution Study

Day 2
- Load and Resource Balance
- Flexible Capacity Reserve Study
- Smart Grid Update

November 17, 2016 – General Public Meeting
- Introductions
- Updated Capacity Contribution Study
- Official Forward Price Curve

January 26-27, 2017 – General Public Meeting

Day 1
- Portfolio Summaries

Day 2
- Sensitivity Studies

March 2-3, 2017 – General Public Meeting

Day 1
- Draft Preferred Portfolio Overview
- Market Price Scenarios
- Regional Haze and Core Cases

Day 2
- Sensitivity Studies
- Preferred Portfolio Selection Process

State Meetings

June 6, 2016 – Washington State Stakeholder Meeting
June 7, 2016 – Idaho State Stakeholder Meeting
June 10, 2016 – Oregon State Stakeholder Meeting
June 13, 2016 – Utah State Stakeholder Meeting
June 14, 2016 – Wyoming State Stakeholder Meeting

Stakeholder Comments

For the 2017 IRP, PacifiCorp provided a Feedback Form which offered stakeholders a direct opportunity to provide comments, questions, and suggestions outside the public input meetings. PacifiCorp recognizes the importance of stakeholder feedback to the IRP public input process. A blank form, as well as those submitted by stakeholders, is housed on the PacifiCorp website at the IRP comments webpage at: http://www.pacificorp.com/es/irp/irpcomments.html

The Feedback Form allowed the Company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected was used to inform issues included in the 2017 IRP, including, process improvements, and input assumptions, as well as responding directly to stakeholder questions. Feedback Forms were received from the following stakeholders:

- HEAL Utah
- Idaho Conservation League
- Interwest Energy Alliance
- Natural Resources Defense Council
- NW Energy Coalition
- Oregon Public Utility Commission
- Powder River Basin Resource Council
- Renewable Energy Coalition
- Renewable Northwest
- Sierra Club
- Utah Clean Energy
- Utah Division of Public Utilities
- Western Clean Energy Campaign
- Western Resource Advocates

Some topics of note addressed in the forms include:

- Modeling of EPA's 111(d) rules
- Supply-side resources
- Demand Side Management
- Energy Storage
- Renewable Portfolio Standards
- Load forecast
- Renewable capacity values
- Wholesale power availability
- Portfolios and sensitivity cases
- IRP Public Input Meeting Process

Contact Information

PacifiCorp's IRP website contains many of the documents and presentations that support recent Integrated Resource Plans. To access it, please visit the company's website at http://www.pacificorp.com/es/irp.html

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

PacifiCorp
IRP Resource Planning Department
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Email Address:
IRP@PacifiCorp.com

Phone Number:
(503) 813-5245

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

Introduction

Appendix D reviews the studies and reports used to support the demand-side management (DSM) resource information used in the modeling and analysis of the 2017 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2017 IRP's Preferred Portfolio, a summary of existing DSM program services and offerings, and an overview of the DSM planning process in each of PacifiCorp's service areas.

Demand-Side Resource Potential Assessments for 2017-2036

Since 1989, PacifiCorp has developed biennial IRPs to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including: traditional generation and market purchases, renewable generation, and DSM resources such as energy efficiency, and demand response or capacity-focused resources. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to guide decisions regarding resource mixes, based on cost and risk.

The Demand-side Resource Potential Assessment for 2017-2036[1] study, conducted by Applied Energy Group (AEG), primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over a 20-year planning horizon, beginning in 2017. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder resource acquisition. Study results were incorporated into PacifiCorp's 2017 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed in 2007, 2011, 2013 and 2015.

For resource planning purposes, PacifiCorp classifies DSM resources into four classifications, differentiated by two primary characteristics: reliability and customer choice. These resources classifications can be defined as: Class 1 DSM (firm, capacity focused), Class 2 DSM (energy efficiency), Class 3 DSM (non-firm, capacity focused), and Class 4 DSM (educational).

From a system-planning perspective, Class 1 DSM resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral changes, resulting from voluntary educational programs included in Class 4 DSM, tend to be the least reliable. With respect to customer choice, Class 1 DSM and Class 2 DSM resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period of time. Class 3 and Class 4 DSM activities involve greater customer choice and control. This assessment estimates potential from Class 1, 2, and 3 DSM.

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2017-2036, completed by AEG, can be found at: http://www.pacificorp.com/es/dsm.html

This study excludes an assessment of Oregon's Class 2 DSM resource potential, as this work is performed by the Energy Trust of Oregon, which provides energy-efficiency potential in Oregon to PacifiCorp for resource planning purposes.

Current DSM Program Offerings by State

Currently there are two Class 1 DSM programs running within PacifiCorp's six-state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program and the irrigation load control program in Utah, Idaho, and Oregon.[2] The two programs contribute approximately 308 MW of load reduction capability, helping the Company better manage demand during peak periods.[3]

In addition to the Class 1 DSM products, the Company offers a robust portfolio of distinct Class 2 DSM programs and initiatives, most of which are offered in multiple states, depending on size of opportunity and need. Table D.1 provides an overview of the breadth of Class 1 and 2 DSM program services and offerings available by Sector and State. Energy efficiency services listed for Oregon, except for low income weatherization services, are provided in collaboration with the Energy Trust of Oregon.[4]

[2] The Oregon Irrigation Load Control Pilot was approved in May of 2016.

[3] Actual reductions may vary by event (temperature and month and time dependent), cited load reduction represents the sum of the highest event performance available across the three states for the two programs and account for line losses (are "at generator" values). In addition to these two programs, the Company has additional interruptible load under contract with select Utah and Idaho special contract customers, see Table 5.12 in the 2015 IRP for additional detail.

[4] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

Table D.1– Current Class 1 and 2 DSM Program Services and Offerings by Sector and State

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Residential Sector						
Air Conditioner Direct Load Control					√	
Lighting Incentives	√	√	√	√	√	√
New Appliance Incentives	√	√	√	√		√
Heating And Cooling Incentives	√	√	√	√	√	√
Weatherization Incentives - Windows, Insulation, Duct Sealing, etc.	√	√	√	√	√	√
New Homes	√	√	√	√	√	√
Low-Income Weatherization	√	√	√	√	√	√
Home Energy Reports			√	√	√	√
School Curriculum		√	√		√	
Energy Saving Kits	√	√	√	√	√	√
Financing Options With On-Bill Payments		√				
Trade Ally Outreach	√	√	√	√	√	√
Non-Residential Sector						
Air Conditioner Direct Load Control					√	
Irrigation Load Control		√		√	√	
Standard Incentives	√	√	√	√	√	√
Energy Engineering Services	√	√	√	√	√	√
Billing Credit Incentive (offset to DSM charge)		√			√	√
Energy Management	√	√	√	√	√	√
Energy Profiler Online	√	√	√	√	√	√
Business Solutions Toolkit	√	√	√	√	√	√
Trade Ally Outreach	√	√	√	√	√	√
Small Business Lighting	√	√	√	√	√	√
Lighting instant incentives		√	√	√	√	√
Small to Mid-Sized Business Facilitation	√	√	√	√	√	√
DSM Project Managers Partner With Customer Account Managers	√	√	√	√	√	√

The Company has numerous Class 3 DSM offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted block rates (Idaho and Utah) and residential year-round inverted block rates (California, Oregon, Washington, and Wyoming). System-wide, approximately 18,700 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2014.[5] All of the Company's residential customers not opting for a time-of-use rates are

[5] Year-end 2014 participation data was used in the development of the 2017 DSM Potential Study. By the end of 2015, participation levels had declined slightly to approximately 18,300 participants.

currently subject to seasonal or year-round inverted block rate plans. Savings associated with these resources are captured within the Company's load forecast and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning.

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to Class 4 DSM activity will show up in Class 1 and Class 2 DSM program results and non-program reductions in the load forecast over time. Table D.2 provides an overview of DSM related ***watt***smart Outreach and Communication activities (Class 4 DSM activities) by state.

Table D.2 – Current wattsmart Outreach and Communications Activities

wattsmart Outreach & Communications (incremental to program specific advertising)	**California**	**Oregon**	**Washington**	**Idaho**	**Utah**	**Wyoming**
Advertising		√	√	√	√	√
Sponsorships		√			√	
Social Media	√	√	√	√	√	√
Contests (video)					√	
Public Relations (Habitat for Humanity, other)		√	√		√	√
Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership)		√		√	√	√
wattsmart Workshops		√				
Rockin wattsmart Assemblies					√	

Preferred Portfolio DSM Resource Selections

The following tables shows the economic DSM resource selections by state and year in the 2017 IRP preferred portfolio, OP_GW4b.

Table D.3 – Incremental and Cumulative Class 1 DSM Resource Selections (2017 IRP Preferred Portfolio)

State/Product by Year	2028	2029	2030	2032	2033	2034	2035	Total/Products (MW)
California Load Control - Res./Com./Indust. Cooling & Wtr Htg	2.4							2.4
California Curtailment Agreements	1.2							1.2
California Load Control - Irrigation	3.7							3.7
Oregon Load Control - Res./Com./Indust. Cooling & Wtr Htg	11.4	24.7		3.3				39.4
Oregon Curtailment Agreements	35.0							35.0
Oregon Load Control - Irrigation	12.8							12.8
Washington Load Control - Res./Com./Indust. Cooling & Wtr Htg	3.8	9.2						13.0
Washington Curtailment Agreements	9.1							9.1
Washington Load Control - Irrigation	4.8							4.8
Utah Load Control - Res./Com./Indust. Cooling & Wtr Htg	68.4							68.4
Utah Curtailment Agreements	75.3		4.8			3.7		83.7
Utah Load Control - Irrigation	3.1							3.1
Idaho Load Control - Res./Com./Indust. Cooling & Wtr Htg		3.4						3.4
Idaho Curtailment Agreements		1.9						1.9
Idaho Load Control - Irrigation	10.9	3.9		3.4			3.1	21.3
Wyoming Load Control - Res./Com./Indust. Cooling & Wtr Htg	4.8							4.8
Wyoming Curtailment Agreements	40.7				3.1			43.8
Wyoming Load Control - Irrigation	1.9							1.9
Cumulative Total by Year (MW)	**289.3**	**43.1**	**4.8**	**6.7**	**3.1**	**3.7**	**3.1**	**353.6**

Table D.4 – Incremental Class 2 DSM Resource Selections (2017 IRP Preferred Portfolio)

Energy Efficiency Energy (MWh) Selected by State and Year										
State	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CA	7,450	7,340	5,130	5,250	5,190	5,070	4,800	4,590	4,420	4,000
OR	198,680	197,720	191,550	166,590	141,410	119,530	104,130	102,010	88,400	83,220
WA	44,600	34,300	36,170	33,650	38,370	35,970	34,060	34,300	31,830	28,860
UT	333,400	240,790	255,190	245,260	253,480	239,730	249,190	249,390	237,350	246,620
ID	17,570	22,950	23,060	19,200	19,920	18,630	18,160	19,280	18,640	19,220
WY	43,800	56,030	59,550	56,690	74,090	75,440	76,460	76,450	80,390	76,950
Total System	645,500	559,130	570,650	526,640	532,460	494,370	486,800	486,020	461,030	458,870

Energy Efficiency Energy (MWh) Selected by State and Year										
State	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
CA	4,880	4,320	3,880	4,190	3,830	3,080	2,690	2,200	1,240	1,060
OR	82,810	76,970	73,750	73,890	71,890	74,280	68,090	67,880	72,400	72,350
WA	27,160	24,780	22,300	20,360	19,630	15,260	12,870	9,860	8,590	6,760
UT	241,950	228,310	213,700	216,120	220,390	182,340	161,080	135,140	124,270	127,670
ID	18,120	17,080	16,590	16,000	15,510	13,010	12,190	9,970	8,910	9,180
WY	69,050	62,320	62,910	58,670	56,430	47,440	40,530	36,690	36,310	36,460
Total System	443,970	413,780	393,130	389,230	387,680	335,410	297,450	261,740	251,720	253,480

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the Class 2 DSM resource selections above, see Table 8.7 – PacifiCorp's 2017 IRP Preferred Portfolio, in Volume I of the 2017 IRP.

State-Specific DSM Planning Processes

PacifiCorp offers robust portfolios of DSM resource options in each of its state service areas. A summary of the DSM planning process in each state is provided below.

Washington

The Company is one of three investor-owned utilities required to comply with the Energy Independence Act (also referred to as I-937) approved in November 2006. The Act requires utilities to pursue all conservation that is cost-effective, reliable, and feasible. Every two years, each utility must identify its 10-year conservation potential and two-year acquisition target based on its IRP and using methodologies that are consistent with those used by the Northwest Power and Conservation Council. Each utility must maintain and use an external conservation stakeholder group to advise on a range of issues including conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs. During 2017, the Company will be working with stakeholders to establish the conservation target for 2018-2019.

California

The Company has historically structured its energy efficiency programs on a multi-year cycle to align with the three large California investor-owned utilities' portfolio and budget schedules when possible.[6] In October 2015, the California Public Utility Commission (CPUC) issued Decision D.15-10-028, which imposes a new rolling portfolio review process on the large investor-owned utilities' energy efficiency program. In addition to the Commission's new review process, California Senate Bill (SB) 350 requires the California Energy Commission (CEC) to set annual targets for statewide energy efficiency savings that will cumulatively double energy efficiency by 2030. In 2016, the Company filed to extend its existing energy efficiency programs through 2017 and during 2017, the Company will file with the CPUC to transition into the new multi-year program cycle, incorporating components of SB 350, as appropriate.

Utah, Wyoming and Idaho

The Company's biennial IRP and associated action plan provides the foundation for DSM acquisition targets in each state Where appropriate, the Company maintains and uses external stakeholder groups and vendors to advise on a range of issues including annual goals for conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs.

Oregon

Energy efficiency programs for Oregon customers are planned and delivered by the Energy Trust of Oregon in collaboration with PacifiCorp. The Energy Trust's planning process is comparable to PacifiCorp's other states, including establishing resource acquisition targets based on resource assessment and integrated resource planning, developing programs based on local market conditions, and coordinating with stakeholders and regulators to ensure efficient and cost-effective delivery of energy efficiency resources.

[6] In California, the company is considered to be a small multi-jurisdictional utility and is not typically required to comply with the energy efficiency requirements of the three large investor owned electric utilities.

APPENDIX E – SMART GRID

Introduction

The smart grid is the application of advanced communications and controls to the electric power system. Areas of installation include generation, transmission, distribution, and customer facilities. A wide array of applications can be defined under the smart grid umbrella. Smart grid includes technologies such as dynamic line rating, phasor measurement units (synchrophasors), energy storage, power line sensors, distribution automation, integrated volt/var optimization, advanced metering infrastructure, automated demand response, and smart renewable and/or distributed generation controls (e.g., smart inverters).

PacifiCorp has reviewed relevant smart grid technologies for transmission, substation, and distribution systems. When considering smart grid technologies, the communications network is often the most critical infrastructure decision. This network must have high speed, reliability, and security. It must be interoperable for many device types, manufacturers, and generations of technology and must be scalable in order to support PacifiCorp's entire service territory.

PacifiCorp regularly evaluates integrating smart grid technologies and implements those that show a positive net benefit for its customers. PacifiCorp has tested or implemented smart grid devices and functions such as dynamic line rating, synchrophasors, and communicating faulted circuit indicators. Advanced metering infrastructure, distribution automation, and distributed energy resource systems (including electric vehicles) are also underway or under consideration.

PacifiCorp will leverage smart grid technologies to align investments with the least-cost/least-risk goals of the Integrated Resource Plan (IRP). This will optimize the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers. PacifiCorp is committed to consistently evaluating the value of emerging technologies and recommend them for demonstration or integration if they are found to be appropriate investments. PacifiCorp is working with state commissions to improve reliability, energy efficiency, customer service, and integration of renewable resources by analyzing the total cost of ownership, performing thorough cost-benefit analyses, and reaching out to customers concerning smart grid applications and technologies. As technology advances and development continues, PacifiCorp is able to improve estimates of the costs and benefits of smart grid technologies. Progressing large-scale deployments and demonstration projects will reveal the effect of large-scale rollouts and assist PacifiCorp in identifying the best suited technologies for implementation.

Transmission System Efforts

Dynamic Line Rating

Dynamic line rating is the application of sensors to transmission lines to indicate the real-time current-carrying capacity of the lines in relation to thermal restrictions. Transmission line ratings are typically based on line loading calculations given a set of worst-case weather assumptions, such as high ambient temperatures and very low wind speeds. Dynamic line rating allows an increase in current-carrying capacity when more favorable weather conditions are present and the transmission path is not constrained by other operating elements. Two dynamic line rating projects were implemented in 2014, Miners-Platte and West-of-Populus.

The Miners-Platte project uses a dynamic line rating system to determine the resulting cooling effect of the wind on the line. The current carrying capacity is then updated to a new weather dependent line rating. The Miners-Platte 230 kV transmission line was one of the limitations of the TOT4A transmission path with wind farms significantly impacting the loading of the line. As a result of this project, the TOT4A WECC non-simultaneous path rating was increased.

The West-of-Populus project was the second dynamic line rating project in 2014. The dynamic line rating enabled lines experienced low line loading due to peak loads between Pacific Power and Rocky Mountain Power coinciding over time. As a result of this low loading, the thermal reading of the lines is dependent upon ambient weather conditions without being greatly affected by line loading. Until higher line loading is experienced from high flow scenarios or outages, conclusions concerning the dynamic line rating project in West-of-Populus are difficult to ascertain. PacifiCorp will continue to collect and analyze future data as high line loading is experienced.

Dynamic line rating will be considered for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. Dynamic line rating is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods. It may or may not align with the expected transmission need of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems.

Thermal Replicating Relays

PacifiCorp extensively considered a project to install thermal replicating relays to adhere to protection and control compliance standards in the Soda Springs area of Idaho. Thermal replicating relays utilize dynamic line rating to monitor the thermal properties of the line, then send a trip signal if the thermal limit has been exceeded. These relays may only be used where line tripping will not cause cascading outages. A remedial action scheme (RAS) was also analyzed as an alternative to thermal replicating relays for the Soda Springs area. In this particular case, because the remedial action scheme was deemed more cost-effective, the thermal replicating relay project alternative will not be employed.

Synchrophasors

Synchrophasors, also called phasor measurement units, can lead to a more reliable transmission network by comparing phase angles of certain network elements with a base element measurement. Phasor measurement units can also be used to increase reliability by relaying line condition data through the communication network quickly. Phasor measurement unit implementation may enable transmission operators to integrate variable resources and energy storage more effectively while minimizing service disruptions.

PacifiCorp participated in the Western Interconnection Synchrophasor Project (WISP). The project resulted in eight phasor measurement units installed in eight PacifiCorp substations. These devices are currently collecting data and will support PacifiCorp's and Peak Reliability's[1] goal of maintaining power system stability. The system of synchrophasors will be used to identify and analyze system vulnerabilities and disturbances. It will also assist in preventing system blackouts and provide historical data for the analysis of any future power system failure. Peak Reliability is continuing to develop data access for utility participants. PacifiCorp has discontinued sending data to Peak Reliability as part of their WISP program since they currently do not operationally utilize the data. Once Peak Reliability has their advanced application functionality enabled, which is expected in 2017, PacifiCorp expects to reinitiate data flow to Peak Reliability.

Phasor measurement units will also be used to satisfy the validation requirements in NERC-MOD-033, a reliability standard proposed to improve accurate data collection and planning models. Planning models analyzing the transmission system reliability are required to compare model results to real-world values in order to meet model validation requirements.

Distribution System Efforts

Distribution Automation

Distribution automation (DA) is a wide field of smart grid technology and applications, which focuses on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. It can also provide operational efficiency, peak load management, equipment failure prediction, and decreased restoration times after failure. PacifiCorp is working on several distribution automation initiatives.

- In Oregon, PacifiCorp has identified 40 circuits on which a DA cost benefit analysis will be performed. These 40 circuits were selected based on a set of criteria intended to minimize the cost of implementation and maximize the reliability benefit. The feasibility of utilizing an advanced metering infrastructure network for the communications of the distribution automation system will also be addressed.
- PacifiCorp has installed Fusesaver™ devices and electronic reclosers with the capability of enabling communications through a retrofit in the future.
- A pilot project in Walla Walla, Washington is underway to demonstrate the feasibility and effectiveness of distribution automation, including a fault location isolation and restoration application.
- A feasibility study to determine the cost and benefit of retrofitting an existing source/transfer scheme to a distribution automation scheme is underway in Salt Lake City, Utah.
- PacifiCorp installed communicating faulted circuit indicators on five circuits in eastern Utah in March 2014. These devices have proven capable of improving reliability by reducing the time required to report and locate a fault. PacifiCorp is still evaluating the cost and feasibility of integrating these devices in its outage management system before further deployment.

[1] Peak Reliability (Peak) is a company wholly independent of WECC that performs the Reliability Coordinator (RC) function in its RC Area in the Western Interconnection.

Customer Information Efforts

Advanced Metering Infrastructure

A key effort for PacifiCorp in 2016 was the development of a detailed business case for advanced metering infrastructure in Oregon. Advanced metering infrastructure is an integrated system of smart meters, communications networks, and data management systems with two-way communication. PacifiCorp's objectives were to identify a solution and strategy that would deliver tangible projected benefits to our customers and deliver economically-driven financial results while minimizing the impact on consumer rates. A request for information followed by a request for proposals was solicited to further evaluate the economics and impacts of an advanced metering infrastructure rollout in Oregon. The financial analysis of proposals indicated a positive business case due to decreasing costs of advance metering technology and increasing operations and maintenance costs. As a result, Pacific Power committed to proceed with deployment of an advanced metering infrastructure system in Oregon.

The advanced metering infrastructure program in Oregon will replace 590,000 existing customer meters with smart meters and install an advanced metering system to remotely read and operate customer meters. The project will provide a web portal for customers, capture hourly meter data, perform on demand meter reads, remotely connect and disconnect power, verify outage inquiries, remotely reprogram meters, and collect data on power quality and tampering. This advanced metering infrastructure project will provide a network and metering infrastructure to improve customer service and enable future smart grid applications. Project benefits include reduced operations and maintenance costs, a platform for future smart grid applications, increased worker safety, reduced emissions, and increased data for efficient management of the network. Meter installations begin in 2017 and the project completion date is scheduled for the end of 2019.

Future Smart Grid

PacifiCorp is continuing to evaluate smart grid technologies and piloted projects that might benefit customers. PacifiCorp regularly develops smart grid reports to examine the quantifiable costs and benefits of individual components of the smart grid. While the net present value of implementing a comprehensive smart grid system throughout PacifiCorp is negative at this time, PacifiCorp has implemented specific projects and programs that have positive benefits for customers, and continues to explore pilot projects in other areas of interest. In order to reduce risks to the company, grid, customers, and supporting systems, it is essential to identify affordable leading technologies and implement industry best practices.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

This 2017 Flexible Reserve Study ("FRS") estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the IRP study period.

PacifiCorp operates two Balancing Authority Areas ("BAAs") in the Western Electricity Coordinating Council ("WECC") NERC region, PacifiCorp East ("PACE") and PacifiCorp West ("PACW"). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error ("ACE") limit in compliance with BAL-001-2,[1] as well as the amount of contingency reserve required in order to comply with NERC standard BAL-002-WECC-2.[2] BAL-001-2 is a new regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2 is a contingency reserve standard that became effective October 1, 2014. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[3]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output, so as to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[4] ("VERs"), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels. Specifically, PacifiCorp's calculations demonstrate that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three times the amount associated with load, and four times the amount associated with Non-

1 NERC Standard BAL-001-2, http://www.nerc.com/files/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and Load within that BAA.

2 NERC Standard BAL-002-WECC-2, http://www.nerc.com/files/BAL-002-WECC-2.pdf, which became effective October 1, 2014.

3 NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated July 13, 2016.

4 VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

VERs. As a result, PacifiCorp attributes different levels of regulation reserve to load, wind, solar, and Non-VERs.

The FRS is based on PacifiCorp operational data recorded from January 2015 through December 2015 for load, wind, and Non-VERs. Solar generation on PacifiCorp's system was insignificant during that time period, but is expected to amount to over 1,000 MW by the end of 2017. PacifiCorp's primary analysis, focuses on the variability of load, wind, and Non-VERs during 2015. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement for the combined portfolio is the sum of the individual requirements for load, wind, solar, and Non-VERs, less the reserve "savings" associated with diversity between the different classes, including diversity benefits realized as a result of PacifiCorp's participation in the Energy Imbalance Market ("EIM") operated by the California Independent System Operator Corporation ("CAISO").

The methodology in the FRS differs in several ways from that employed in PacifiCorp's previous regulation reserve requirement analyses.[5,6,7] First, regulation reserve requirements are now tied directly to compliance with the BAL-001-2 standard. Second, the FRS uses a portfolio wide approach to determine the overall regulation reserve requirement, including the aggregated diversity benefits for all customer classes. Third, all customer classes that contribute to the overall regulation reserve requirement are now allocated a share of the diversity benefits resulting from aggregating their requirement with that of the system as a whole. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the EIM.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted wind and solar output.

The regulation reserve requirements produced by the FRS were applied in the Planning and Risk (PaR) production cost model to determine the cost of the reserve requirements associated with incremental wind and solar capacity. These costs are attributed to the integration of wind and solar generation resources in the 2017 Integrated Resource Plan (IRP).

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[5] 2012 Wind Integration Study report, Appendix H in Volume II of PacifiCorp's 2013 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

[6] 2013 PacifiCorp Schedule 3 and 3A Study, Exhibit PAC-8 in testimony of Greg Duvall, FERC Docket No. ER13-1206 (filed April 1, 2013).

[7] 2014 Wind Integration Study, Appendix H in Volume II of PacifiCorp's 2015 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

Executive Summary

The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and flexibility reserve benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in this analysis including values from the 2014 Wind Integration Study for reference are shown in Table F.1.

Table F.1 - Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.2 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for reference.

Table F.2 - 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2014$)	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with the North American Electric Reliability Corporation (NERC) regional reliability standards. Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-2.[8] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[9] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[10] Each type of operating reserve is further defined below.

Contingency Reserve

NERC regional reliability standard BAL-002-WECC-2 specifies that each BAA must hold as contingency reserve an amount of capacity equal to three percent of load and three percent of generation in that BAA. Contingency reserve must be available within ten minutes, and at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. Contingency reserve may be deployed when unexpected outages of a generator or a transmission line occur. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output.

Regulation Reserve

NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error ("ACE"), which is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit*

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[8] NERC Standard BAL-002-WECC-2 – Contingency Reserve: http://www.nerc.com/files/BAL-002-WECC-2.pdf

[9] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: http://www.nerc.com/files/BAL-001-2.pdf

[10] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

(BAAL) for more than 30 consecutive clock-minutes…

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2. Because Requirement 2 includes a 30 minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. PacifiCorp has not specifically evaluated reserve needs for CPS1 compliance. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2, but may require that a subset of resources held for Requirement 2 be able to make frequent rapid changes to manage ACE relative to interconnection frequency. Regulation reserve requirements are discussed in more detail later on in the study.

Frequency Response Reserve

NERC standard BAL-003-1 specifies that each BAA must arrest frequency deviations and support interconnection frequency when it drops below the scheduled level. When a frequency drop occurs, each BAA is expected to deploy resources that are at least equal to its Frequency Response Obligation. The incremental requirement is based on the size of the frequency drop and the BAA's Frequency Response Obligation, expressed in MW/0.1Hz. The additional capacity must be deployed immediately, and performance is measured over a period of seconds, amounting to under a minute. To comply with the standard, a BAA's median measured frequency response during a sampling of under-frequency events must be equal to or greater than its Frequency Response Obligation. PacifiCorp's 2017 Frequency Response Obligation was 19.51 MW/0.1Hz for PACW, and 48.93 MW/0.1Hz for PACE. PacifiCorp's combined obligation amounts to 68.44 MW for a frequency drop of 0.1 Hz, or 205.32 MW for a frequency drop of 0.3 Hz.

Because the performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-1) is similar to that for BAL-003-1, frequency response capacity is effectively incremental to contingency reserve obligations. As Standard BAL-003-1 is based on median performance under selected WECC-wide events, while regulation reserve obligations under BAL-001-2 are based on minimum performance during BAA-specific events, frequency response capacity can be considered a subset of the BAL-001-2 obligation. Since median performance is adequate for BAL-003-1 compliance, BAL-001-2 compliance can take precedence, so long as the overlap is sufficiently low, i.e. BAL-001-2 events are rare and there don't have a positive correlation with BAL-003-1 events.

While frequency response reserve can meet regulation reserve requirements, the reverse is not necessarily true. Frequency response must occur very rapidly, and a generating unit's capability is limited based on the unit's size, governor controls, and available capacity, as well as the size of the frequency drop. As a result, while a few resources could hold a large amount of regulation reserve, frequency response needs to be spread over a larger number of resources. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the 2017 IRP analysis beyond those already included for contingency and regulation reserve.

Description of Data Inputs

Overview

This section describes the data used to determine PacifiCorp's regulation reserve requirements. In order to estimate PacifiCorp's required regulation reserve amount, PacifiCorp must determine the difference between the expected load and resources and actual load and resources. The difference between load and resources is calculated every four seconds and is represented by the ACE. ACE must be maintained within the limits established by BAL-001-2, so PacifiCorp must estimate the amount of regulation reserve that is necessary in order to maintain ACE within these limits.

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[11]

The deviation from scheduled use was derived from data provided through participation in the EIM. The deviations of generation resources in EIM were measured on a five-minute basis, so the Regulation Reserve Study used five-minute intervals throughout the analysis.

EIM base schedule and deviation data for each wind and Non-VER transaction point were downloaded using the Report Explorer application to query PacifiCorp's nMarket Application database, which is populated with data provided by the CAISO. Since PacifiCorp's implementation of EIM on November 1, 2014, PacifiCorp requires certain operational forecast data from all of its transmission customers pursuant to the provisions of Attachment T to

[11] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes ("T-75") prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes ("T-77") prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes ("T-55") prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's transmission customers are required to submit updated, final base schedules no later than 57 minutes ("T-57") prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes ("T-40") prior to the delivery hour in response to CAISO sufficiency tests. T-55 is the base schedule time point used throughout this study because it is the deadline which most closely corresponds to the final T-57 deadline for all transmission customers to submit final base schedules.

PacifiCorp's Federal Energy Regulatory Commission ("FERC")-approved Open Access Transmission Tariff ("OATT"). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

A summary of the data gathered for this analysis is listed below, and a more detailed description of each type of source data is contained in the following subsections.

Source data:

- Load data
    - Five-minute interval actual Load
    - Proxy hourly base schedules developed from actual prior hour and prior week data

- VER data
    - Five-minute EIM deviations
    - Hourly base schedules

- Non-VER data
    - Five-minute EIM deviations
    - Hourly base schedules

Load Data

The Load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The Load class can generally be described to include three components: (1) average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," during the hour and from hour-to-hour; and (3) the rapid fluctuations in load that depart from the underlying trend. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

The PACE BAA includes several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind the meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up the majority of PacifiCorp's loads.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the FRS. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW operations), which also nets these interruptible customer loads out of the PACE BAA.

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval over the Study Term. Load data for the Study Term was downloaded from PacifiCorp's Ranger PI system and has not been adjusted for transmission and distribution losses. Only actual load data is available from Ranger PI, not base schedule data that could be used to determine the deviation associated with Load. Because of differences in the load defined in EIM and in the Ranger PI system, the EIM load base schedules are not consistent with the Ranger PI actual results. To address the inconsistency, PacifiCorp developed proxy load base schedules, as discussed below.

Wind Data

The Wind class includes resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[12] Wind, in comparison to load, often has larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[13] The data included in the FRS for the Wind class includes all wind resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. Appendix F.B, Table 1 contains the list of the wind plants included in the study. In total, the FRS includes 2,588 megawatts of wind.

Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[14] The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the Wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. Appendix F.B, Table 2 contains the list of the Non-VERs included in the study. In total, the FRS includes 2,228 megawatts of Non-VERs.

In the FRS, resources that provide contingency or regulation reserve are considered a separate, dispatchable resource class. The dispatchable resource class compensates for deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources may offset deviations in loads and other resources in some hours, they are not in the control of the system operator and contribute to the overall requirement in other hours. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve

[12] Order No. 764 at P 281; Order No. 764-B at P 210.

[13] Order No. 764 at P 20 (emphasis added).

[14] *Id.* at P 92.

requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later on in the study..

Data Analysis and Adjustment

Overview

This section provides details on adjustments made to the data to develop base schedules that correspond to the load data, align the ACE calculation with actual operations, and address data issues.

Load Base Schedule Development

Load deviations are settled using hourly imbalance data in EIM, whereas resource deviations are settled using fifteen-minute and five-minute imbalance data. As a result, the five-minute deviations necessary to assess the regulation reserve requirements associated with Load were not available through EIM. For the FRS, PacifiCorp used actual load data from its Ranger PI system, which can provide data at a five-minute granularity. The Ranger PI system does not have the associated base schedules necessary to calculate deviations, however, so PacifiCorp developed proxy load base schedules consistent with the measured actual loads.

The load base schedule for each hour was calculated from actual load at 55 minutes prior to the hour ("T-55") in question, with a scaling factor applied based on the change in load over that same interval in the prior week. The five-minute interval ending at T-55 is the last load data point available prior to base schedule submission to CAISO at hour T-55 and represents the current state of load in the PacifiCorp BAAs. Load follows different patterns depending on season and day of the week. Using data from one week prior ensures that recent conditions on a similar day are used in the calculation of the load base schedule.

Figure F.1 below illustrates measurement of the expected load change between T-55 data and the hourly base schedule over three hours. The five-minute interval ending at 17:05 (first green column) has a load of 2,643 MW. The actual load in hour 18 averages 2,837 MW (middle solid horizontal line), an increase of 7.4 percent. Similarly, the expected load change from the five-minute interval ending at 18:05 to hour 19 is a decrease of 1.1 percent (difference between second green column and second horizontal line). Figure F.2 below shows how those load measurements are applied seven days later to determine the proxy load base schedules for hours 18 and 19. The proxy load base schedule for hour 18 is calculated as the actual load in the five-minute interval ending at 17:05, plus an additional 7.4 percent. The proxy load base schedule for hour 19 is calculated as the actual load in the five-minute interval ending at 18:05, minus 1.1 percent. Deviations are then calculated as the difference between the proxy load base schedule and actual five-minute loads over the hour.

Figure F.1 - Expected Load Change from Prior Week

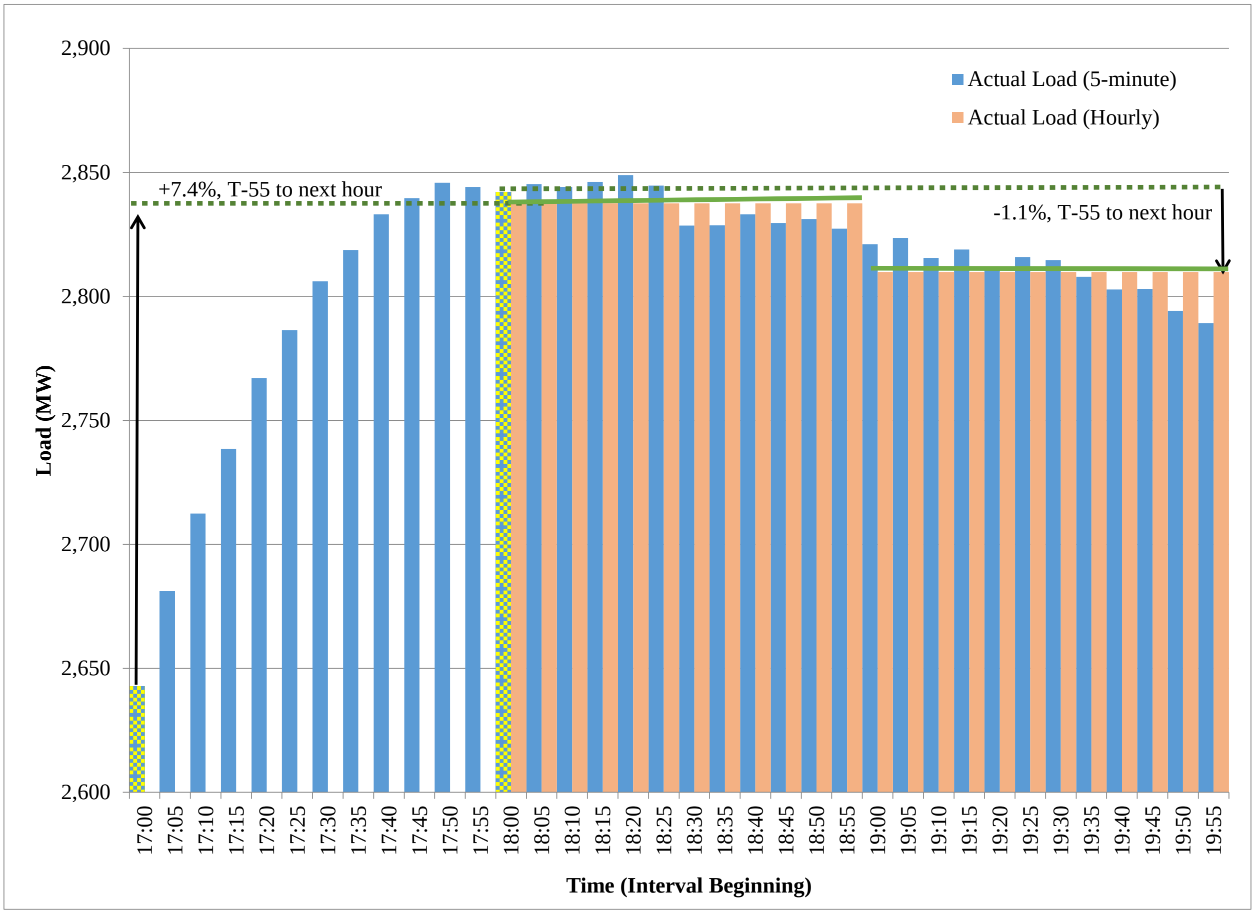
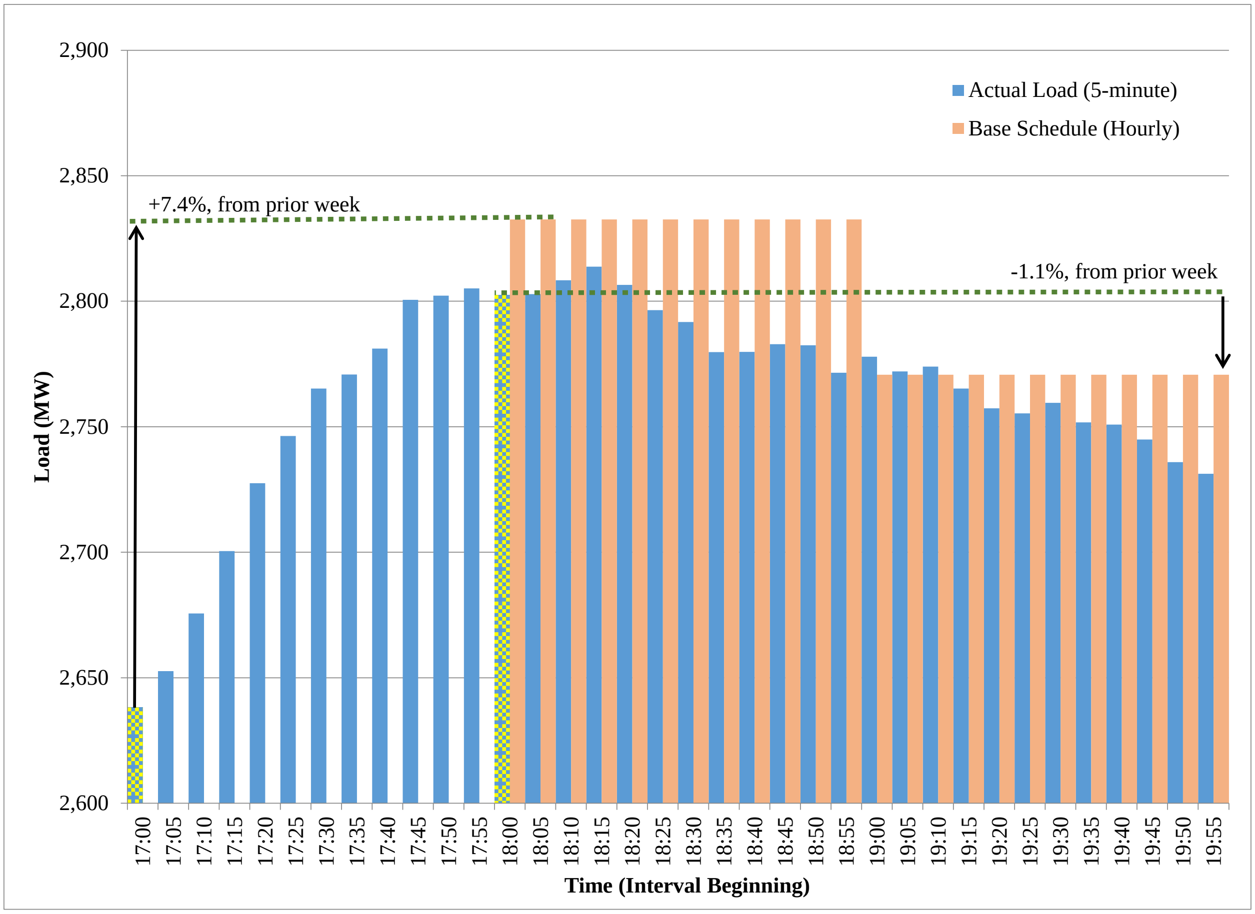


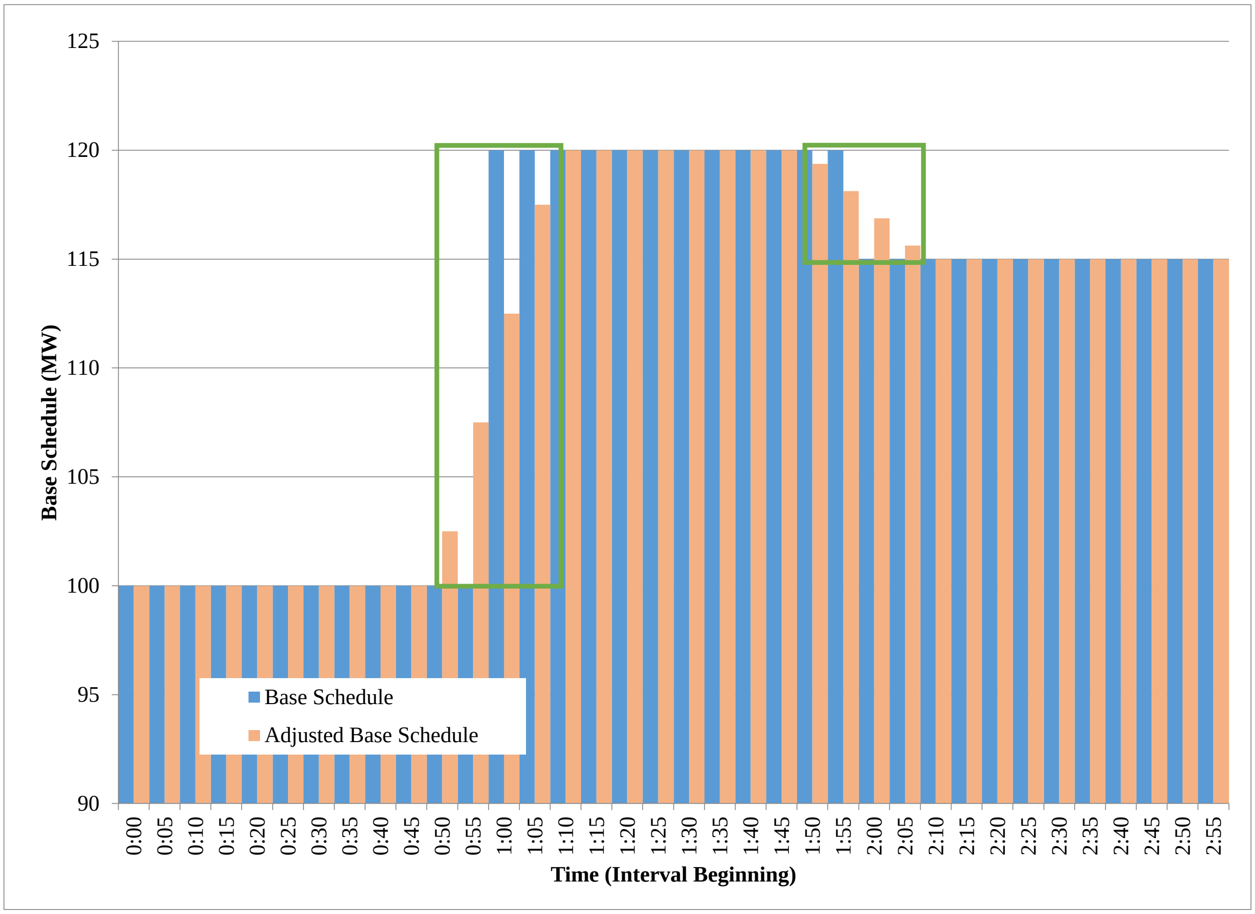
Figure F.2 - Proxy Load Base Schedule



Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.3 below illustrates the hourly base schedule and the ramping adjustment. The same calculation applies to all base schedules: Load, Wind, Non-VERs, and the combined portfolio.

Figure F.3 - Base Schedule Ramping Adjustment



Data Corrections

The raw data extracted from PacifiCorp's systems for Load, Wind, and Non-VERs was reviewed to identify potentially spurious data points prior to performing the regulation reserve requirement calculations contained in the next section. Hourly intervals of data were excluded from the FRS results if any five-minute interval within that hour suffered from at least one of the data anomalies that are described further below:

Load:

- Stuck meter/flat meter reading
- Telemetry spike/poor connection to meter

Wind and Non-VERs:

- Deviations missing in CAISO database
- Base schedules missing in CAISO database
- Generator trip events
- Wind curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system ("EMS") load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported. For instance, in one observed example, PACW BAA load remained stuck at a single level for two days beginning at 2:00 PM on January 6, 2015. The change in load relative to the prior interval was calculated for the entire test period and instances where multiple successive intervals showed no change in load were excluded from the analysis since they are not indicative of actual operating conditions.

Similarly, rapid spikes in load either up or down are also unlikely to be a result of conditions which require deployment of regulation reserve, particularly when they are transient. For example, a 637 MW drop in PACE BAA load occurred over one five-minute interval on May 15, 2015. Roughly one hour later, PACE BAA load increased by 849 MW over two five-minute intervals. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. A similar spike on March 23, 2015, spanned just one five-minute interval, and was likely a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they don't reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis.

The available Wind and Non-VER data also includes some data irregularities. PacifiCorp evaluated these irregularities and in some cases removed data that appears to be inaccurate. For instance, PACW wind deviation data is missing in 36 five-minute intervals out of the 105,108 intervals in the study. Deviations are directly tied to regulation reserve requirements, so the hours in which deviation data is missing are excluded from the analysis. Base schedules for PACE Non-VERs are missing in 75 hours, while the other wind and Non-VER categories have smaller amounts of missing data. While Wind base schedules are directly linked to the regulation requirement forecast, missing base schedule data in PacifiCorp's database may be indicative of inconsistencies in deviation results, which may be calculated off of a stale or erroneous base. Given the limited frequency of such events, PacifiCorp has excluded from the analysis intervals where deviations or base schedules are missing.

As with Load, certain Wind and Non-VER deviations are more likely to be a result of conditions that allow for the deployment of contingency reserve, rather than regulation reserve. In particular, contingency reserve can be deployed to compensate for unexpected generator outages. For Non-VERs, these are relatively straightforward—namely, periods when generation drops to zero despite base schedules indicating otherwise. Certain Wind outages also qualify as contingency events. Notably, wind generators can be curtailed when wind speed exceeds the maximum rating of the equipment (sometimes referred to as "high speed cutout"). In such instances, generation is curtailed until wind speeds drop back into a safe operating range in order to protect the equipment. When wind speed oscillates above and below the cut-off point, generation may ramp down and up repeatedly. Because events which qualify for deployment of contingency reserve do not require deployment of regulation reserve they have been excluded from the analysis.

As the regulation reserve requirements are calculated using a rolling thirty-minute timeline, data from the prior hour is necessary during the first several five-minute intervals of the next hour. An error in one hour thus results in the need to remove the following hour. This is relevant to error adjustments for both Wind and Non-VERs.

For load, an hour of spurious data will prevent the calculation of the base schedule for the next hour, since the actual load at T-55 is not available. The spurious data also impacts the same two hours in the following week as the expected load change used to determine the base schedule for those hours utilizes the hour in question. For example, if the hour beginning at midnight on February 1, 2015, is found to be spurious, four hours are removed from the Study Term: the spurious hour (the hour ending midnight, February 1, 2015); the hour following the spurious hour (the hour ending 1:00 AM, February 1, 2015), which relies on the spurious hour to inform the regulation forecast; and the two corresponding hours in the following week (the hour ending at midnight, February 8, 2015 and the hour ending at 1:00 AM, February 8, 2015), each of which no longer has a valid prior-week hour from which to develop a proxy load base schedule. The description of "Load Base Schedule Development" above contains further discussion about this relationship and development of the base schedule.

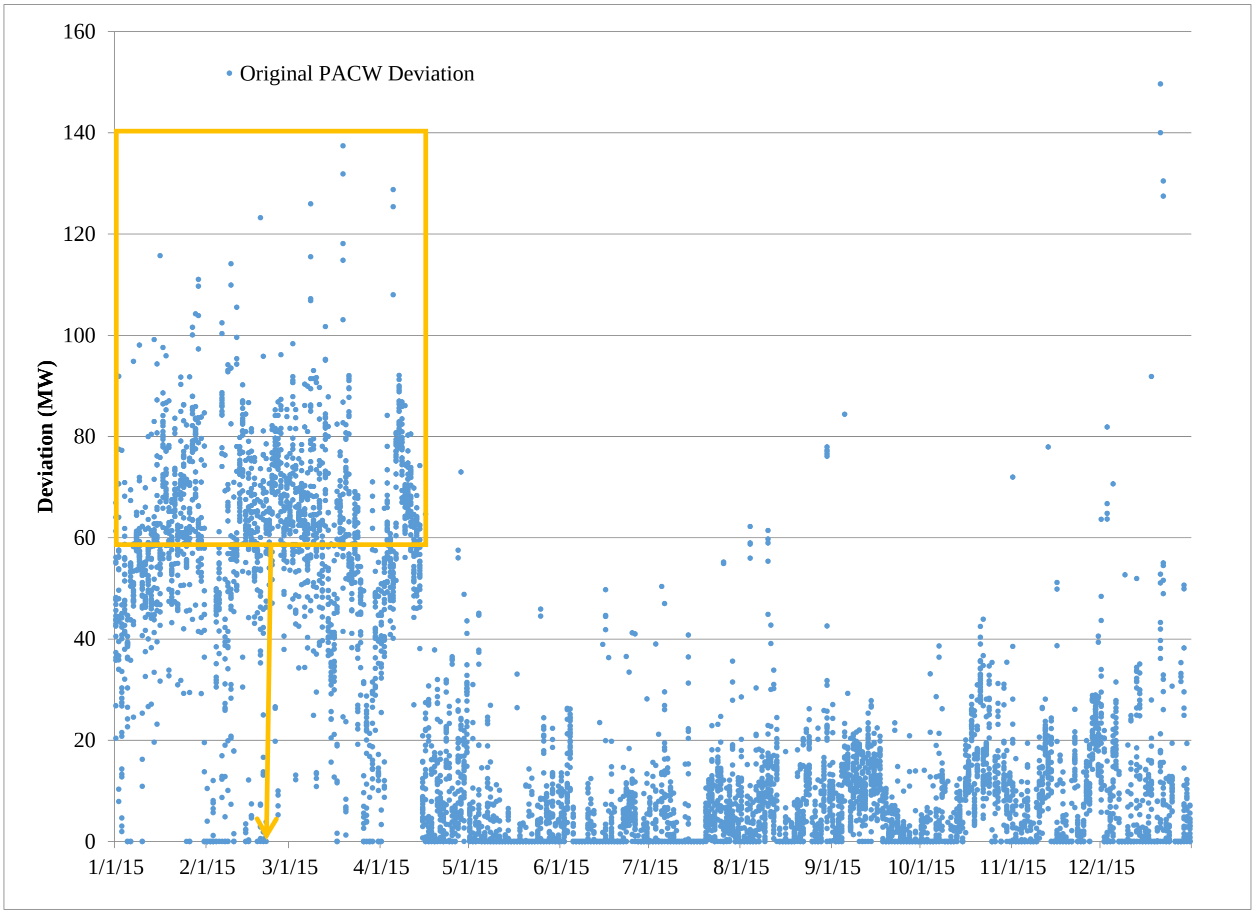
After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals in the Study Term, only 5.9 percent and 3.6 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 9.1 percent, slightly lower than the sum of the PACW and PACE rates due to coincident hours. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective. By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp actually experiences, including the impact on regulation reserve requirements of weather events experienced during the Study Term.

Non-VER Deviation Adjustment

The deviations associated with the Non-VER class show a clear anomaly between January 2015 and April 14, 2015. The abrupt change is evident in the hourly data for PACW shown in Figure 4 below and a comparable anomaly was seen over the same time frame for PACE (not shown). The anomaly ends abruptly at midnight on April 14, 2015, in both BAAs. PacifiCorp has concluded that this issue is a result of errors in base schedule submission rather than an actual deviation. During the early stages of the EIM there were differences between the CAISO's EIM model and PacifiCorp's EMS. The modeling of Colstrip generation was one of those differences. Within the PacifiCorp EMS, 100 percent of Colstrip generation output is pseudo-tied into the PACW BAA. However, the EIM modeled 50 percent of Colstrip generation as being in the PACW BAA and the other 50 percent of Colstrip generation as modeled in the PACE BAA. This mismatch between the two systems resulted in the measured deviation.

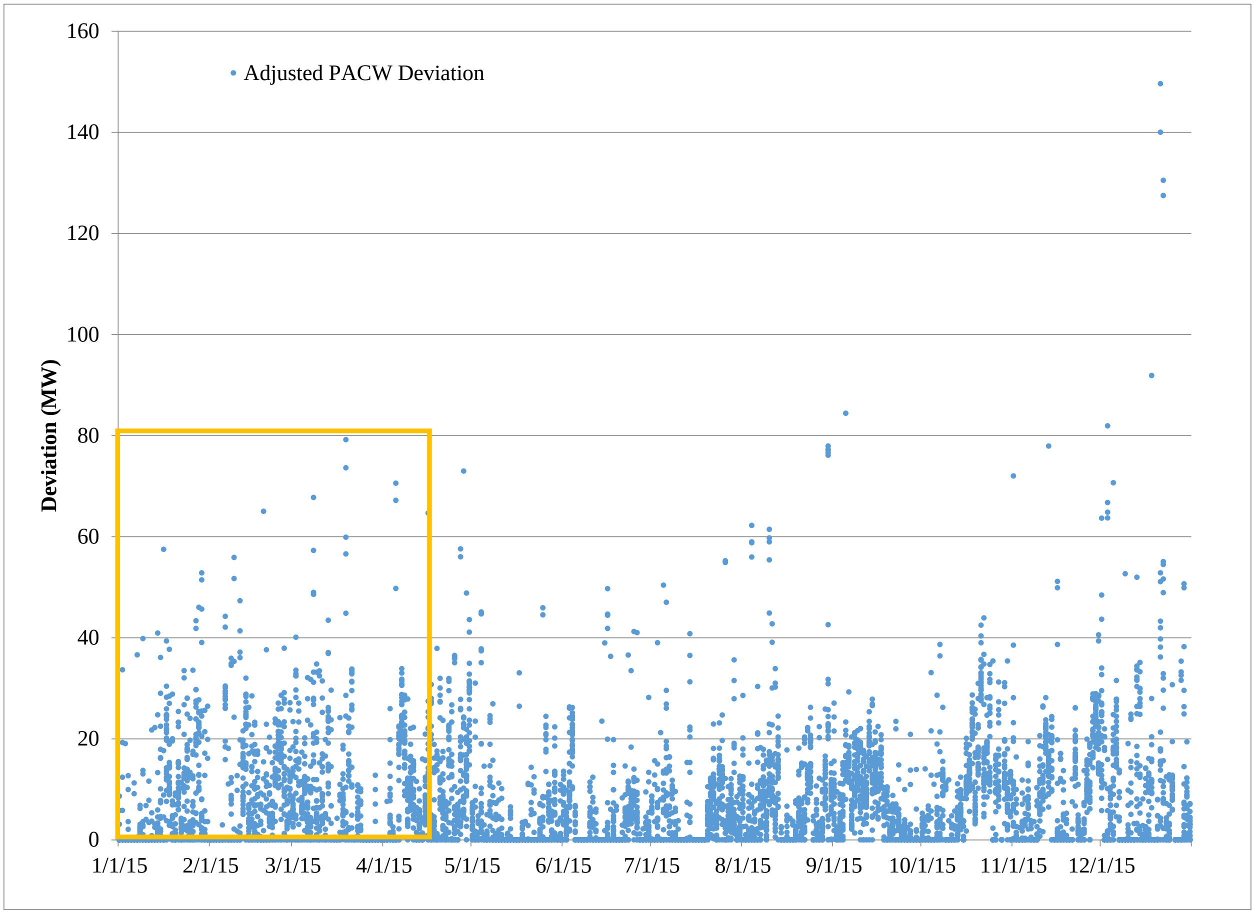
The Colstrip EIM base schedule of 50 percent to PACE and 50 percent to PACW was compared to the EMS output of 100 percent to PACW to determine the deviation. This resulted in a positive deviation to base schedule for PACW. When the EIM model mismatch was discovered it was corrected to align to PacifiCorp's EMS system. This eliminated the persistent deviation on April 14, 2015. For the purposes of the FRS, the regulation reserve requirement for this period was reduced by 58 MW such that the average requirement during this period is equal to the average in the remainder of 2015. The box in Figures F.4 and F.5 below shows the affected data before and after the adjustment is applied.

Figure F.4 - Original PACW Non-VER Deviations



The adjusted regulation reserve requirement is shown in Figure F.5 below.

Figure F.5 - Adjusted PACW Non-VER Deviations



Methodology to Determine Initial Regulation Reserve Requirement

Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and
- Uses data available at time of EIM base schedule submission at T-55.[15]

The components of the methodology are described below, and include:

- Operating Reserve: Reserve Categories;
- Calculation of Regulation Reserve Need;
- Balancing Authority ACE Limit: Allowed Deviations;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and

[15] *See* footnote 11 above for explanation of PacifiCorp's use of the T-55 base schedule time point in the FRS.

- Regulation Reserve Forecast: Amount Held.

Following the explanation below of the components of the methodology, the next section details the forecasted amount of regulation reserve for:

- Wind;
- Non-VERs; and
- Load.

Components of Operating Reserve Methodology

Operating Reserve: Reserve Categories

Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. These requirements must be met by resources that are incremental to those needed to meet firm system demand. The purpose of the FRS is to determine the regulation reserve requirement. The contingency reserve requirement is defined formulaically by a regional reliability standard.

Of the three categories of reserve referenced above, the FRS is primarily focused on the requirements associated with regulation reserve. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output. Because deviations caused by contingency events are covered by contingency reserve rather than regulation reserve, they are excluded from the determination of the regulation reserve requirements. On the other hand, frequency response reserve can be considered a subset of the regulation reserve obligation, though it requires faster responding resources than those contemplated in the FRS. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the FRS analysis. The types of operating reserve and relationship between them are further defined in in the Flexible Resource Requirements section above.

Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulation reserve incremental to contingency reserve to maintain reliability.[16] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

The BAL-001-2 standard became effective as of July 1, 2016 and, upon its effectiveness, officially replaced the BAL-001-1 standard. The new BAL-001-2 standard is a fundamentally different

[16] NERC Standard BAL-001-2, http://www.nerc.com/files/BAL-001-2.pdf

requirement than the prior standard, BAL-001-1, though it is intended to achieve a similar result. BAL-001-1 required ten-minute average ACE to be within the static L_{10} limit in at least 90 percent of non-overlapping ten-minute intervals in a month.[17] The new BAL-001-2 standard requires average ACE to be within a dynamic limit for at least one minute in 100 percent of all rolling thirty-minute intervals. PacifiCorp has been operating under BAL-001-2 since March 1, 2010, as part of a NERC Reliability-Based Control field trial in the Western Interconnection, so PacifiCorp has experience operating under the new standard, even though it did not become effective until July 1, 2016.

PacifiCorp's 2012, 2013, and 2014 studies were all based on compliance with BAL-001-1. These studies utilized deviations over ten-minute intervals and allowed deviations up to the fixed L_{10} value.[18,19] While these studies all used a 99.7 percent confidence interval, they did not necessarily achieve 99.7 percent compliance with the BAL-001-1 standard. For instance, the 2014 Wind Integration Study had a failure rate of 1.4 percent for PACE and 2.0 percent for PACW.[20] This is higher than the 90 percent compliance requirement under BAL-001-1, but significantly lower than the 100 percent compliance requirement under BAL-001-2. In addition, prior studies separately distinguished between three categories of regulation reserve, all of which were intended to capture the total potential deviation over the ten-minute interval relevant under BAL-001-1:

- Ramping – flexibility required to follow the change in actual net system Load from hour to hour;
- Regulating – flexibility required to manage forecast uncertainty over ten-minute intervals; and
- Following – flexibility required to manage forecast uncertainty over sixty-minute intervals.

The FRS fundamentally differs from the 2012, 2013, and 2014 studies because it is based on compliance with BAL-001-2. The impacts of the changes in three key elements of the new BAL-001-2 standard relative to the old standard are summarized in Table F.3 below. The three key elements shown in Table F.3 include: (1) the length of time (or "interval") used to measure compliance under the old versus new BAL standard; (2) the change in compliance threshold between the two standards, which represents the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used under each standard to determine whether an interval is considered out of compliance. These changes are discussed in further detail below.

[17] BAL-001-1 (R2) stated: Each Balancing Authority shall operate such that its average ACE for at least 90 percent of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

[18] L_{10} represents a bandwidth of acceptable deviation under BAL-001-1 prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.

[19] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf

[20] *See* Redacted Rebuttal Testimony of Brian S. Dickman, Wyoming Public Service Commission Docket No. 20000-469-ER-15 at p. 46:1-6 (filed Sept. 16, 2015).

Table F.3 - BAL-001-1 vs BAL-001-2

	Interval (minutes)	Compliance %	Allowed Variance
BAL-001-1	10	90%	Fixed: L_{10}
BAL-001-2	30	100%	Dynamic: BAAL
Impact on Requirement	Down	Up	Varies

The first change in Table F.3 is related to the length of time used to measure compliance. Under the prior standard, BAL-001-1, compliance was measured over six, non-overlapping ten-minute intervals within each hour. If ACE was within the allowed limits for all ten minutes of an interval, that interval was in compliance, and only the maximum deviation in that interval was considered in determining compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with sixty overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If ACE is within the allowed limits at least once in a thirty-minute interval, that interval was in compliance, and only the minimum deviation in each thirty-minute interval is considered in determining compliance. This change reduces regulation reserve requirements because PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second change in Table F.3 above is related to the compliance percentage, or the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-1 required 90 percent compliance, that is, 10 percent of ten minute intervals were allowed to have deviations in excess of the requirement in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals. Under the old standard, overall compliance could be achieved despite shortfalls in the intervals with the largest deviations. Because shortfalls are not permitted when the compliance requirement is 100 percent, this change increases regulation reserve requirements.

The third change in Table F.3 is related to the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-1, the acceptable deviation for each BAA was set at a fixed value in all intervals, referred to as L_{10}.[21] Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. The impact of this change is mixed as the limits under BAL-001-2 are generally higher, but at times can be lower than the limits under BAL-001-1.

In addition, the FRS identifies a single category of flexible capacity, rather than the three categories used in the prior studies performed in compliance with the old standard. Because deviations over ten-minute intervals are only relevant to the extent they exacerbate deviations over longer time

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[21] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf .

frames, measuring three separate categories does not provide an accurate depiction of the requirements under BAL-001-2. In addition, while the following and regulating requirements in prior studies were statistically uncorrelated over the course of the year, the root sum square methodology used in the prior studies fails to account for the few random intervals when these components both show large requirements. Because the root sum square methodology underestimates the frequency of outlier events, it underestimates the capacity needed to cover them. The FRS eliminates complexity and distortion associated with combining multiple requirements by directly calculating a single component that allows for compliance with the BAL-001-2 standard.

Calculation of Regulation Reserve Need

The next step of the operating reserve methodology is to calculate the amount of regulation reserve required to be held under BAL-001-2. Regulation reserve requirements were calculated from five-minute EIM deviation data in a manner that emulates the requirements of the BAL-001-2 standard. The same calculation applies to all types of imbalances: Load, Wind, Non-VERs, and the combined portfolio.

First, the minimum five-minute imbalance was calculated for each thirty-minute rolling period in the Study Term. Second, for each hour, the maximum five-minute imbalance was selected from the values identified in the first step. An example is provided in the Table 2 and Figure 6 below.

In the example in Table F.4 below, the minimum five-minute imbalance in the thirty minutes beginning at 0:15 is 40 MW. This is also the maximum five-minute imbalance in any thirty-minute period in this hour. Assuming 40 MW of regulation reserve was available in this hour and the allowable ACE deviation was zero, this hour would still be compliant with the BAL-001-2 requirement—even though the imbalance exceeds the regulation reserve available for five consecutive, five-minute intervals—because the allowable ACE deviation was exceeded for less than 30 minutes.

Table F.4 - Deviation and Regulation Reserve Requirement Example

Interval	Base Schedule	Actual	5-Minute Deviation	30-Minute Deviation	Reserve Requirement
0:00	2500	2510	10	10	40
0:05		2520	20	10	40
0:10		2530	30	10	40
0:15		2540	**40**	10	40
0:20		2550	50	10	40
0:25		2560	60	10	40
0:30		2570	70	20	40
0:35		2560	60	30	40
0:40		2550	50	**40**	40
0:45		2540	40	40	40
0:50		2530	30	30	40
0:55		2520	20	20	40

As shown in Figure F.6 below, if the ACE deviations were only allowed for a ten minute interval, the requirement would be higher.

Figure F.6 - Deviation and Regulation Reserve Requirement Example

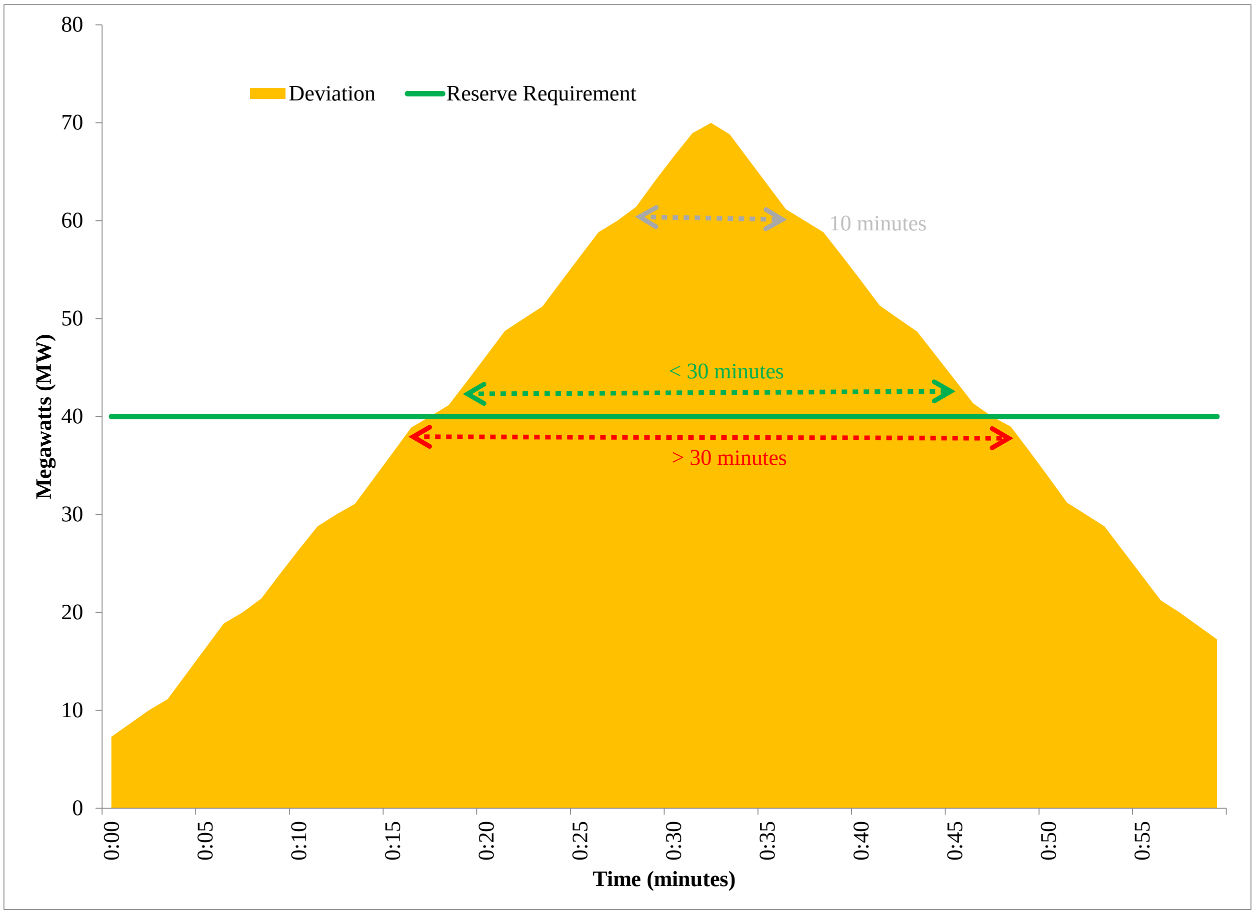
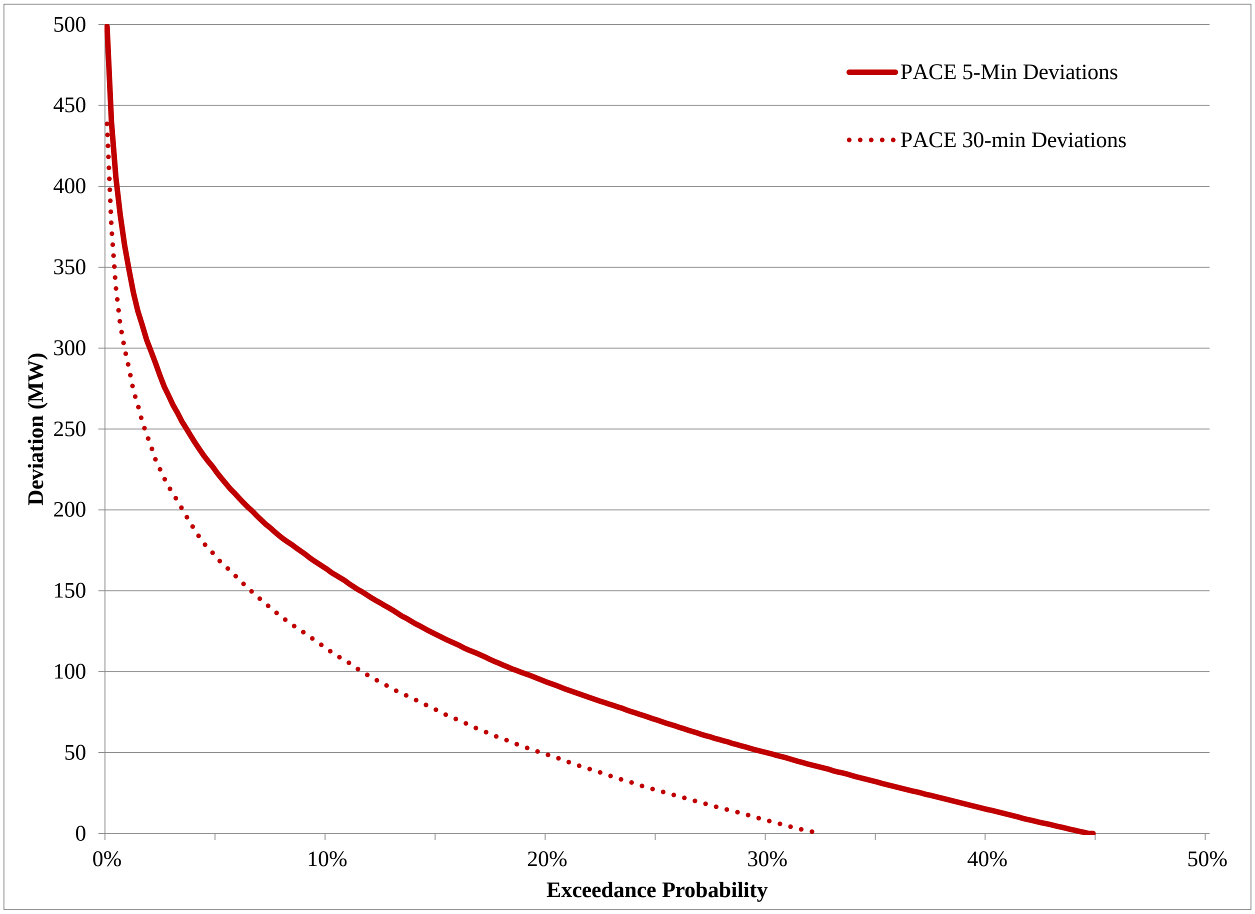


Figure F.7 below illustrates the distribution of the combined five-minute deviations for Load, Wind, and Non-VERs in PACE during 2015, as well as the distribution of thirty-minute sustained deviations relevant to the BAL-001-2 standard. The effect for PACW was comparable (not shown). The thirty-minute window for compliance reduces the regulation reserve need. The thirty-minute window can be particularly helpful with deviations in the last few intervals of each hour. This period has the longest forecast horizon (*i.e.*, the furthest out from T-55), so the potential deviations are expected to be larger. However, if the change resulting in the deviation is reflected in the base schedule for the next hour, PacifiCorp's ACE will return to zero on its own a few minutes later. Thus, so long as the duration of the deviation is less than 30 minutes, the size of the deviation in the last few intervals is irrelevant for compliance with BAL-001-2.

Figure F.7 - Probability Distribution of PACE Combined Portfolio Deviations



Balancing Authority ACE Limit: Allowed Deviations

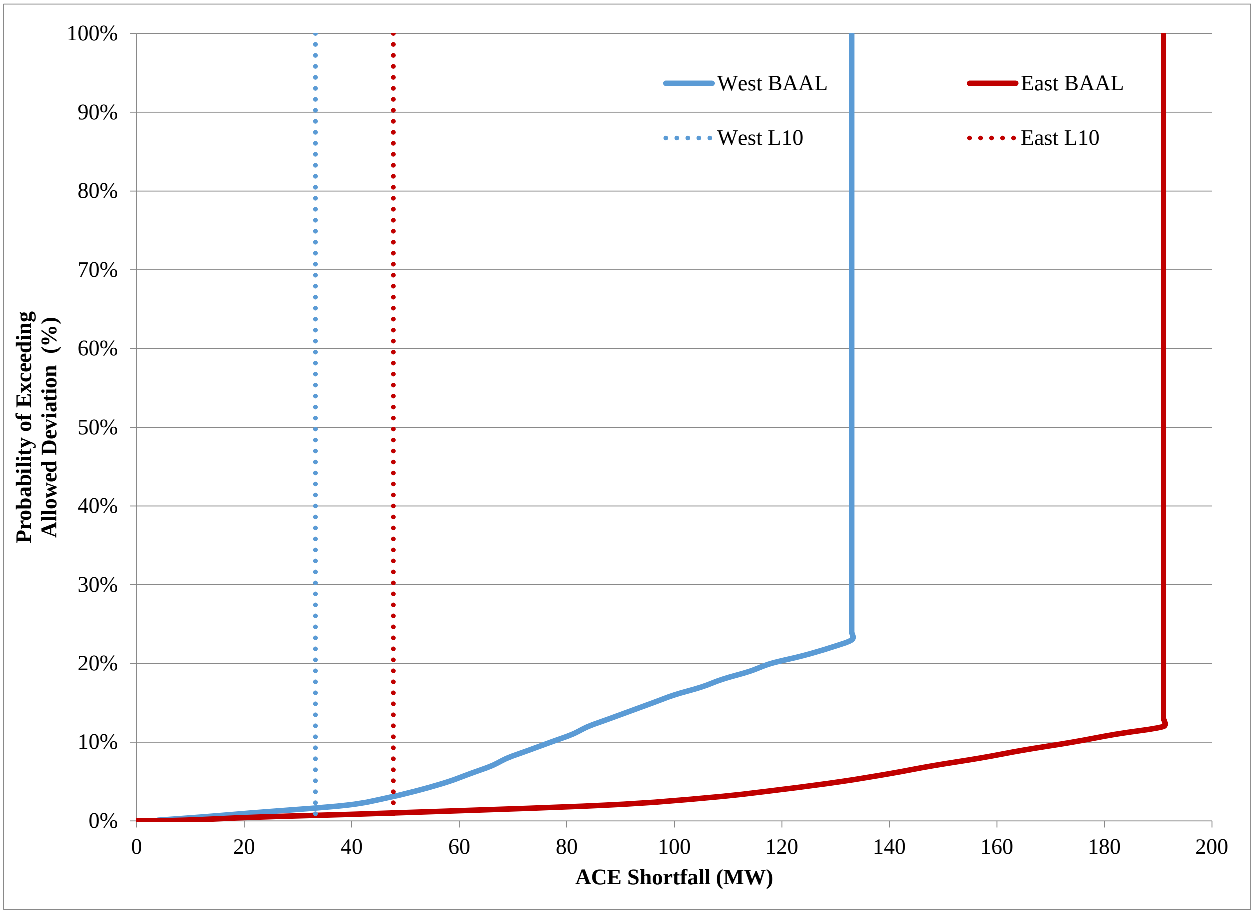
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, *i.e.* those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it doesn't have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure 8 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. The fixed value under the prior BAL-001-1 standard for L_{10} is also plotted for comparison. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE

Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[22,23] This cap is reflected in Figure F.8.

Figure F.8 - Probability of Exceeding Allowed Deviation



In 2015, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

[22] "Regional Industry Initiatives Assessment." NWPP MC Phase 3 Operations Integration Work Group. Dec. 31, 2014. Pg. 14. Available at: http://www.nwpp.org/documents/MC-Public/NWPP-MC-Phase-3-Regional-Industry-Initiatives-Assessment12-31-2014.pdf

[23] "NERC Reliability-Based Control Field Trial Draft Report." Western Electricity Coordinating Council. Mar. 25, 2015. Available at: https://www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

Planning Reliability Target: Loss of Load Probability

When conducting resource planning, it is common to use a reliability target that assumes a specified LOLP. In effect, this is a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

PacifiCorp's 2015 Integrated Resource Plan ("IRP") utilized a planning reserve margin of 13 percent, which is intended to achieve 0.88 loss of load hours per year.[24] This FRS assumes that 0.88 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution. As the magnitude of the shortfall increases, the probability of exceeding the Balancing Authority ACE Limit increases. For instance, as indicated above, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. A one percent probability of failing to meet the Balancing Authority ACE Limit in one hour is 0.01 loss of Load hours per year. A one percent probability of failing to meet the Balancing Authority ACE Limit in eighty-eight hours would be 0.88 loss of load hours per year and corresponds to the targeted level of reliability.

Regulation Reserve Forecast: Amount Held

As previously shown in Figure 7, the instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. As described above, the regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast should achieve a cumulative LOLP that corresponds to the annual reliability target.

PacifiCorp submits balanced base schedules to CAISO for its load and resources by T-55.[25] Operating reserve is intended to cover demand in excess of the balanced load and resources submitted in base schedules. Capacity to be used as operating reserve needs to be identified and

[24] 2015 IRP, Appendix I, Table I.3

[25] *See* footnote 9 for explanation of PacifiCorp's use of the T-55 base schedule time point in the Regulation Reserve Study.

set aside so that it is not utilized in the base schedule submission. Likewise, the regulation reserve forecast identifying the quantity of operating reserve to be set aside for the upcoming hour needs to be finalized by T-55.

The base schedule itself reflects the best, most up-to-date information about conditions in the upcoming hour. The next section describes how the information available can be used to forecast regulation reserve requirements for each of the regulation reserve classes while maintaining reliability. The portfolio regulation reserve requirement forecast incorporates each of the resource/load class forecasts and accounts for the reduced requirements resulting from diversity between the classes. All of these calculations are prepared separately for each of the PacifiCorp BAAs.

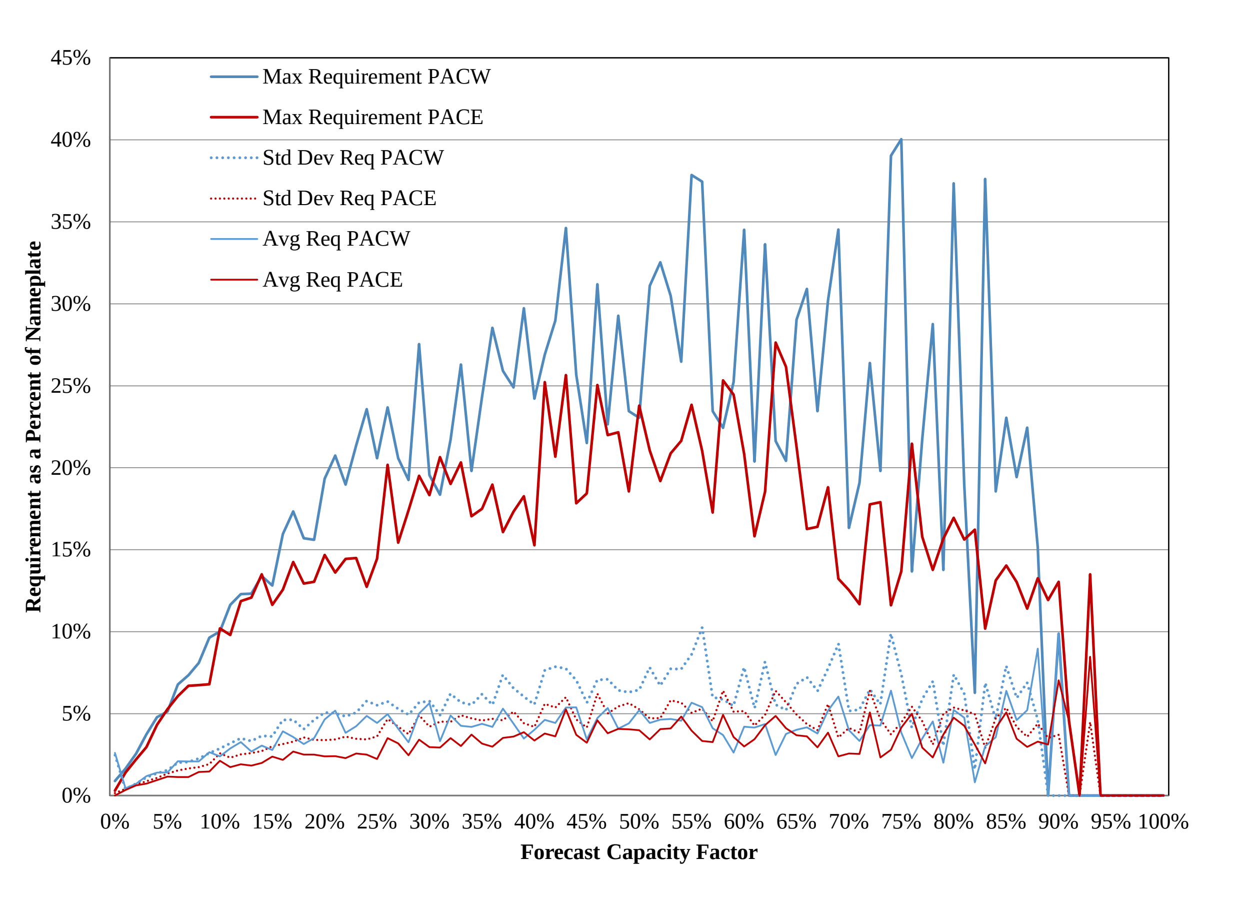
2015 Regulation Reserve Forecast

Wind

Figure F.9 illustrates the relationship between the observed regulation reserve requirements for wind during 2015 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate wind capacity).

Three distinct patterns are apparent in the figure. First, for capacity factors from zero percent to approximately 20 percent, the regulation reserve requirement increases linearly. The linear relationship in this first range reflects the fact that the largest possible deviation is equal to the base schedule and a very small amount of negative generation (station service). Second, for capacity factors from approximately 20 percent to approximately 80 percent, the maximum requirement varies somewhat widely and does not exhibit significant trends. Third, as capacity factors increase above approximately 80 percent, the observed maximum requirement declines.

Figure F.9 - Wind Regulation Reserve Requirements by Forecast Capacity Factor



When evaluating the distribution of maximum requirements above an approximately 20 percent capacity factor, it is important to consider the characteristics of an observed maximum within a sample. The mean of a sample may be higher or lower than the mean of the population from which it is drawn, but it is not expected to vary systematically with sample size. This is not the case for the maximum of a sample, which will always be less than or equal to the maximum of the population from which it is drawn. In addition, the expected value of the sample maximum increases as the sample size increases.

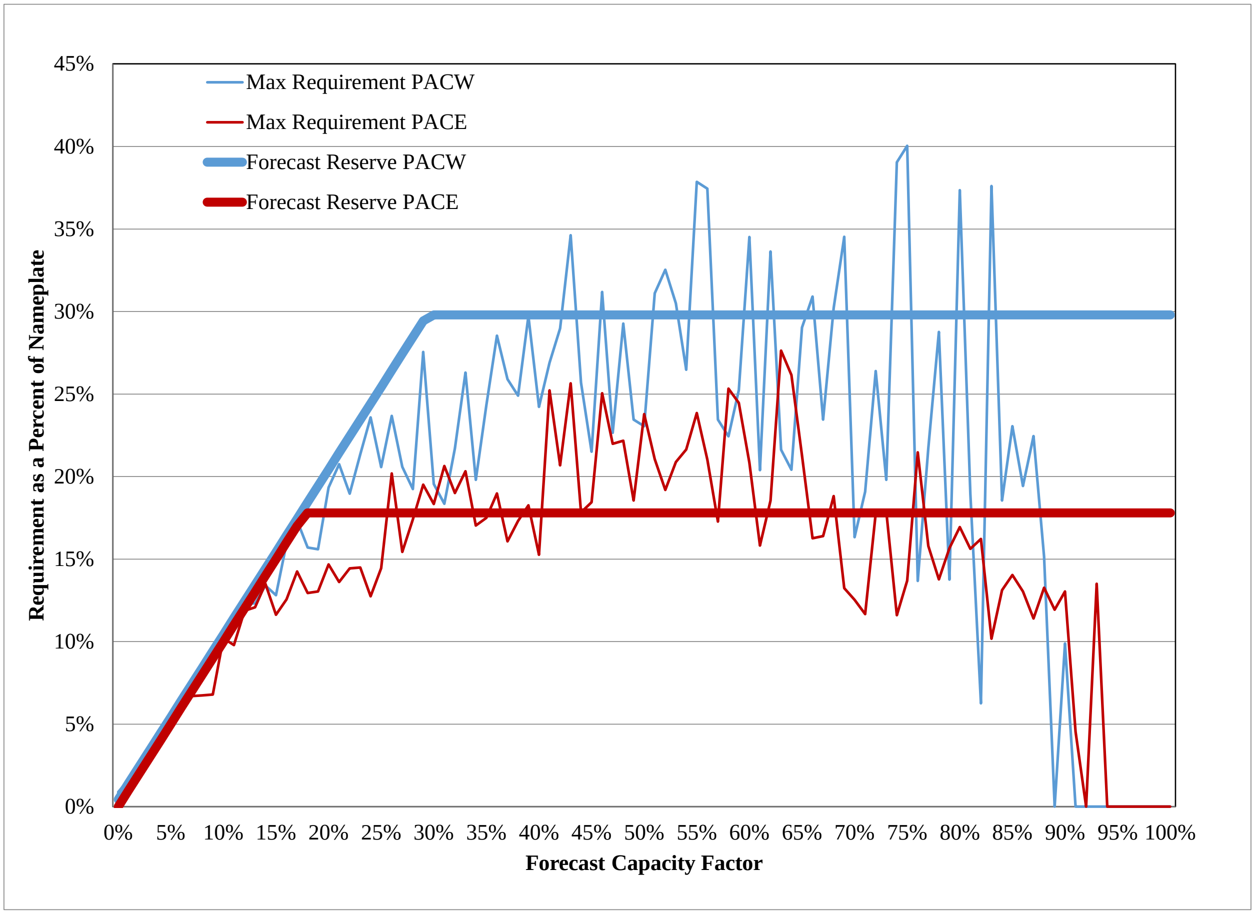
The sample size of each forecasted capacity factor varies, with very high capacity factors occurring less frequently. With this consideration in mind, the decline in observed maximum requirements at high capacity factors can be viewed as an artifact of the sample rather than a real trend related to the behavior of wind under those specific conditions. This view is reinforced by the fact that the average and standard deviation of the requirements are relatively constant at forecasted capacity factors above roughly 20 percent. Because the probability of a large deviation doesn't vary for capacity factors above roughly 20 percent, a single regulation reserve requirement is a reasonable forecast for that range.

Figure F.10 below presents the regulation reserve forecast for PACE and PACW wind, incorporating the two trends described above: (1) the linear increase in requirements at low capacity factors (*i.e.*, below 20 percent); and (2) a uniform requirement at higher capacity factors (*i.e.*, from 20 percent to 100 percent). As illustrated in Figure 10, PACW had 888 hours with forecasted capacity factors between 41 percent and 55 percent, while PACE had 1,115 hours in that range. PACW only had 64 hours with forecasted capacity factors of 85 percent or more, while PACE only had 109 hours in that range.

The wind regulation reserve forecast is a fixed percentage of the wind nameplate capacity, but never more than the difference between minimum actual output and the base schedule. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The forecast resulted in the possibility of reliability violations in roughly one percent of the hours. While the forecast does not result in any potential reliability violations at high capacity factors, this is likely due to the small number of observations in this range, as described above.

Using a forecast based on the hour-ahead base schedule results in a 2015 stand-alone regulation reserve requirement for wind of 384 MW, or approximately 14.8 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the reserve requirements for wind with the requirements of other classes. Diversity benefits are discussed later on in the study.

Figure F.10 - Stand-alone Wind Regulation Reserve Forecast



Non-VERs

Figure F.11 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate Non-VERs capacity). For Non-VERs, the forecasted capacity factors during 2015 fall within limited ranges and do not approach either zero or 100 percent. Since the distribution of errors appears to be essentially random, the base schedule provides limited forecasting value for Non-VERs, resulting in a single reserve value applied in all hours.

Figure F.11 - Non-VER Regulation Reserve Requirements by Forecast Capacity Factor

Figure F.12 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of hour of the day. The average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods. While an overall diurnal pattern is noticeable, significant volatility in the observed maximum requirements is apparent from hour to hour. For example, consider the significant drop in the observed maximum requirement for PACW in hour 19 relative to hours 18 and 20. The average and standard deviation do not indicate that hour 19 is significantly different from hours 18 and 20. As a result, this drop is more likely to be from randomness in the sample, rather than a specific characteristic of hour 19 itself.

Figure F.12 - Non-VER Regulation Reserve Requirements by Hour of the Day

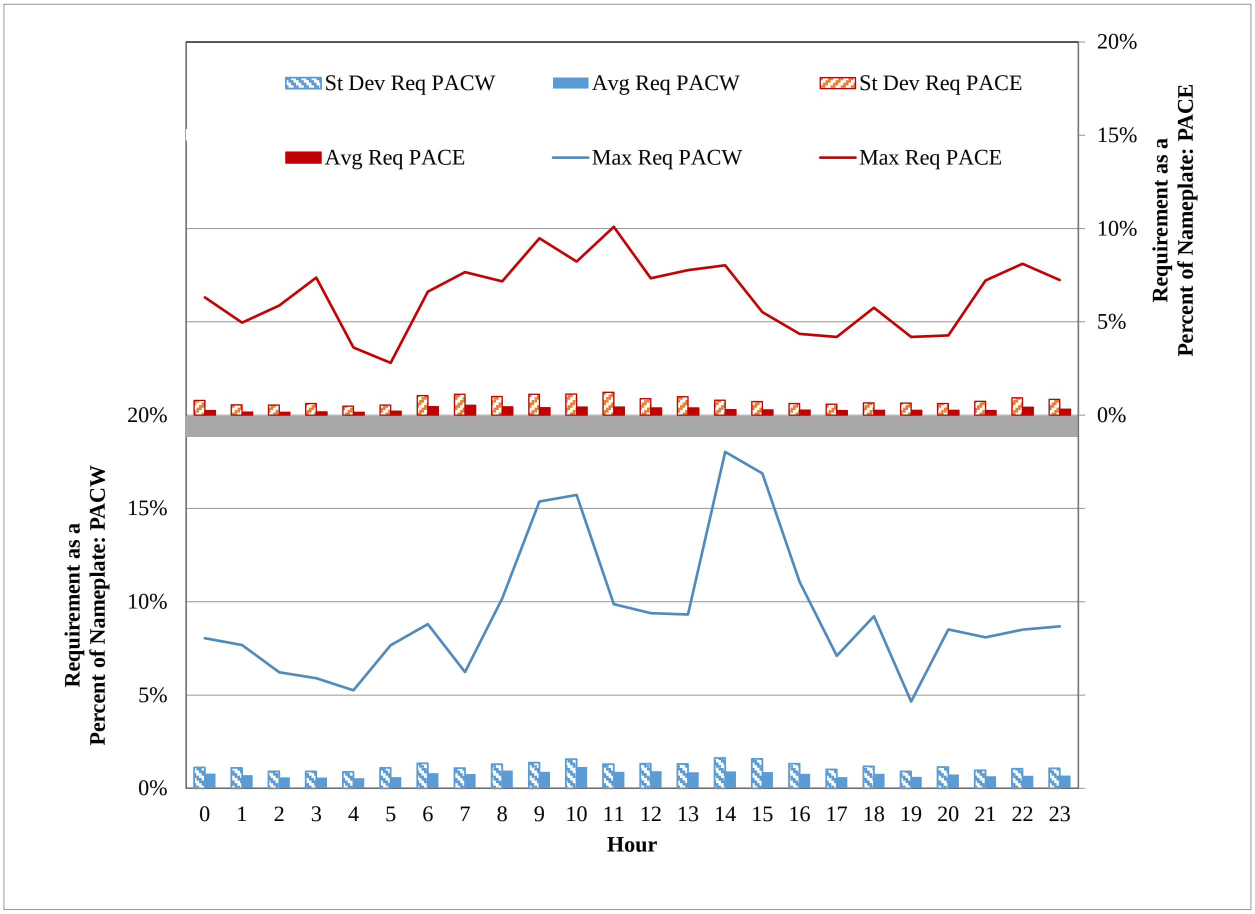
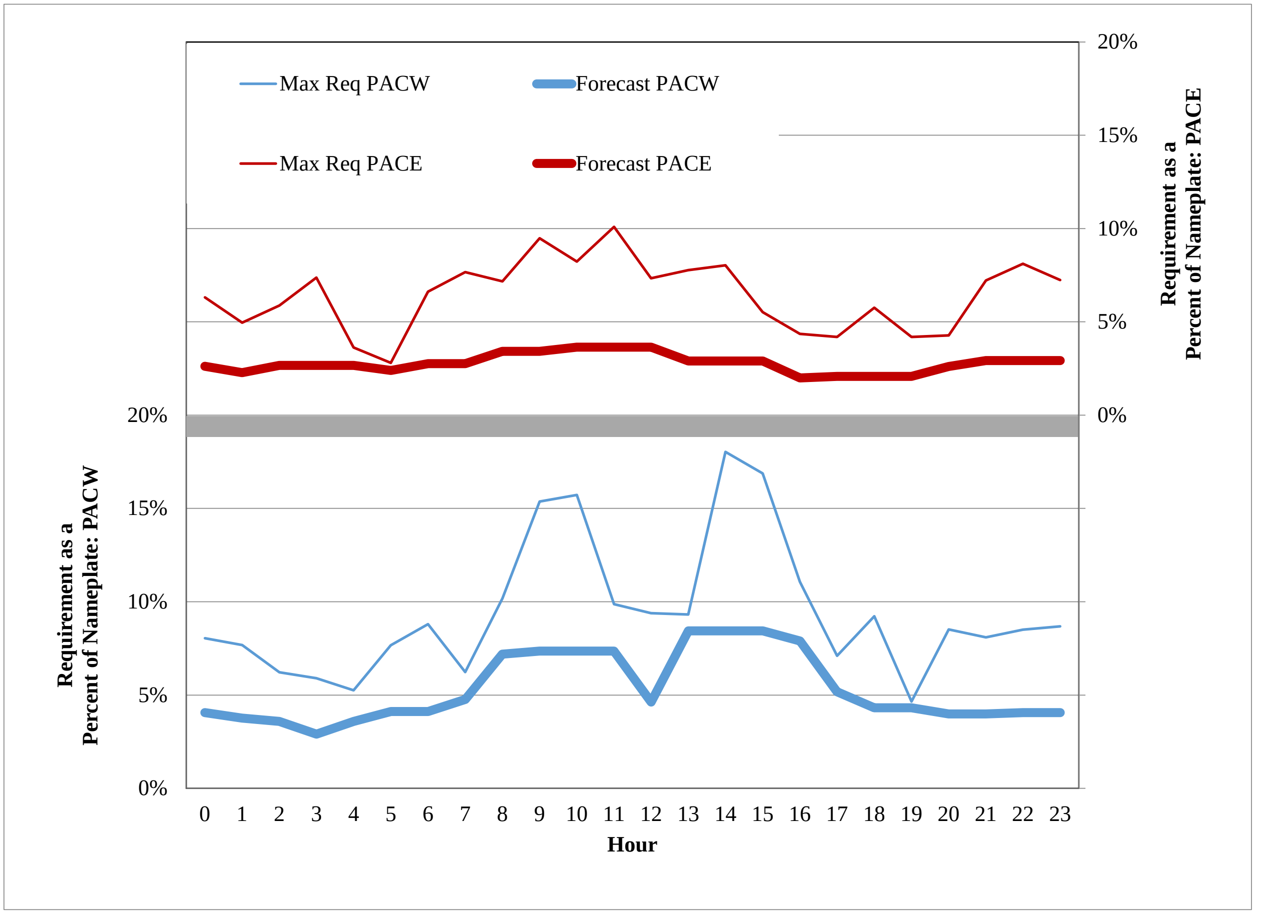


Figure F.13 below presents the regulation reserve forecast for each hour of the day for PACE and PACW Non-VERs. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 1.1 percent of the time on PACW, and 2.6 percent of the time on PACE. Due to the lower probability of a reliability violation in each hour for PACE Non-VERs, more hours of potential violations are aggregated to reach the reliability target of 0.88 loss of load hours per year. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for Non-VERs of 83 MW, or approximately 3.7 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the regulation reserve requirements for Non-VERs with the requirements of other classes.

Figure F.13 - Stand-alone Non-VER Regulation Reserve Forecast



Load

Figure F.14 below illustrates the relationship between the observed regulation reserve requirements for load during 2015 and hour of the day. Similar to the results for Non-VERs, the average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods.

Figure F.14 - Stand-alone Load Regulation Reserve Requirements by Hour of the Day

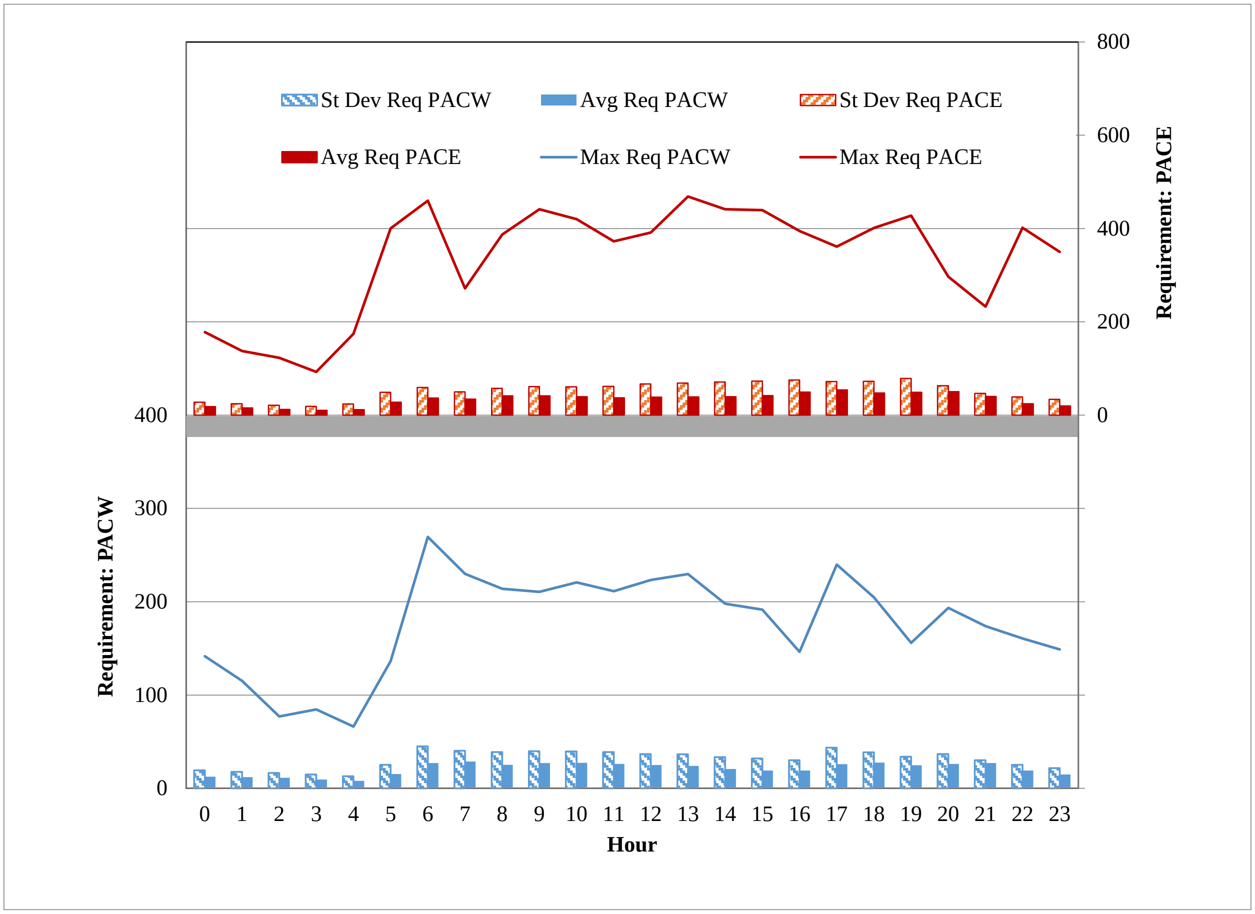
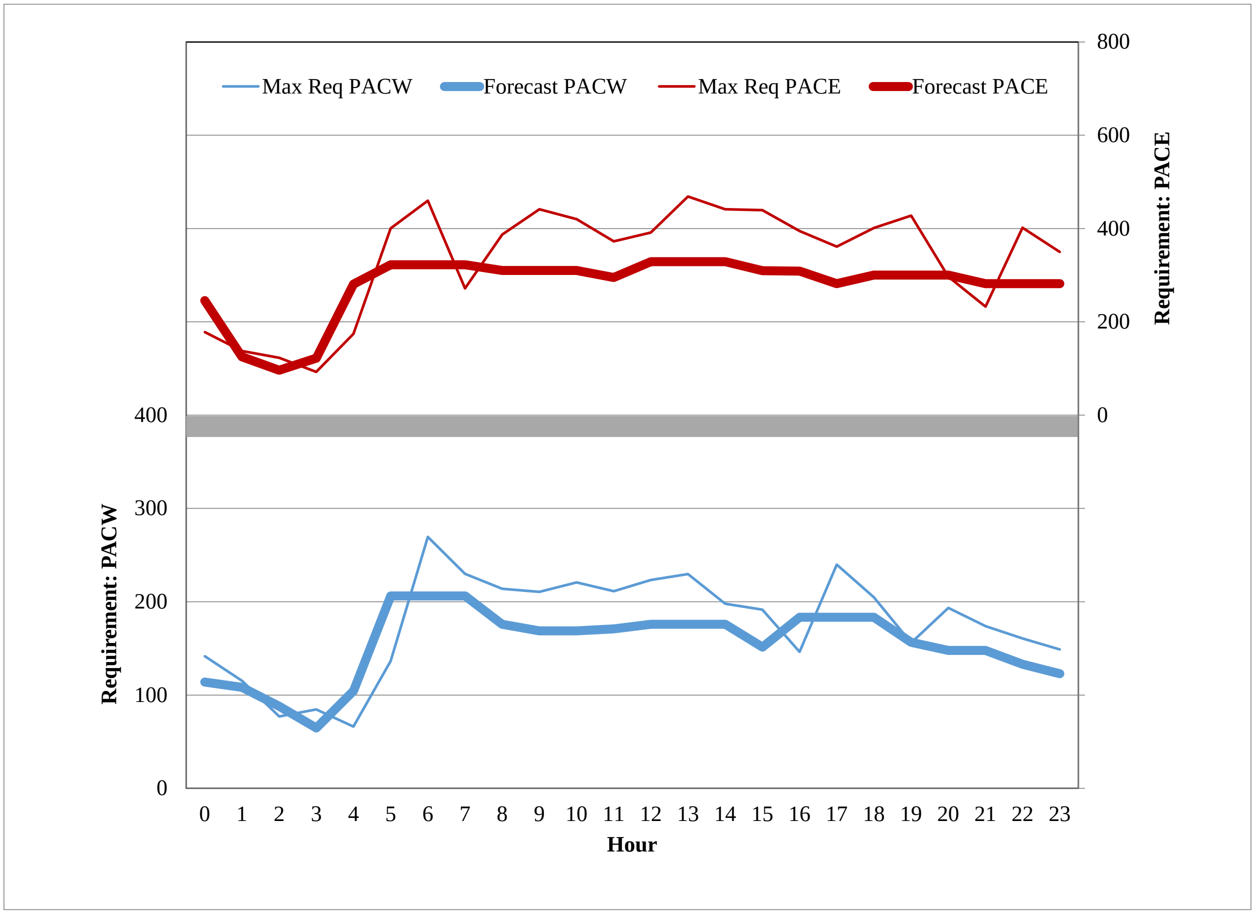


Figure F.15 below presents the regulation reserve forecast for each hour of the day for PACE and PACW load. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 0.7 percent of the time in both PACW and PACE. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for load of 433 MW, or approximately 4.5 percent of the 12CP. This forecast does not account for any diversity benefit from combining the reserve requirements for load with the requirements of other classes.

Figure F.15 - Stand-alone Load Regulation Reserve Forecast



2015 PacifiCorp System Diversity and EIM Diversity Benefits

PacifiCorp System-Wide Portfolio Diversity Benefit

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen minutes, dispatching the least-cost resources every five minutes.

PacifiCorp began full EIM operation on November 1, 2014. NV Energy began full operation in EIM on December 1, 2015. Puget Sound Energy and Arizona Public Service Company commenced EIM participation on October 1, 2016. Additionally, several other entities have announced their intention to begin participating over the next few years. PacifiCorp's participation in the EIM results in improved power production forecasting and optimized intra-hour resource dispatch. This brings important benefits including reduced energy dispatch costs through automatic dispatch, enhanced reliability with improved situational awareness, better integration of renewable energy resources, and reduced curtailment of renewable energy resources

EIM also direct effects related to regulation reserve requirements. First, as a result of EIM participation, PacifiCorp has improved granularity for data used in the analysis contained in this FRS. The data and control provided EIM allow PacifiCorp to achieve the portfolio diversity benefits described in this section. Second, the EIM's intra-hour capabilities across the broader EIM footprint provide the opportunity to reduce the amount of regulation reserve necessary for PacifiCorp to hold, as further explained in the next section.

The regulation reserve forecasts described above (384 MW for Wind, 83 MW for Non-VERs, and 433 MW for Load) independently ensure that the probability of a reliability violation for each class remains within the reliability target; however, the largest deviations in each class tend not to occur simultaneously, and in some cases deviations will occur in offsetting directions. Because the deviations are not occurring at the same time, the regulation reserve held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserve is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserve to cover deviations in Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target.

As shown in Table F.5 below, the sum of the stand-alone forecasts for each class results in a cumulative LOLP of 0.03 hours per year. This is significantly less than the target of 0.88 hours per year as a result of the diversity among the different classes. PacifiCorp then calculated the proportional reduction to the standalone requirement—the diversity benefit shown in the second column of values in Table 3—that could be applied such that the PacifiCorp system just achieves the reliability target for the Study Term. A total portfolio requirement of 654 MW is sufficient to achieve the reliability target, resulting in diversity benefits equal to 118 MW for Load, 105 MW for Wind, and 23 MW for Non-VERs. The last column of Table 3 shows the regulation requirements for each class that incorporates the proportional allocation of portfolio diversity benefits. The diversity benefits result in a 27 percent reduction from the total standalone requirement of 900 MW.

Table F.5 - Results with PacifiCorp Portfolio Diversity

Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	83	(23)	60
Load	433	(118)	315
VER - Wind	384	(105)	279
Total	900	(246)	654
Portfolio LOLP (hours/year)	0.03		0.88

EIM Intra-Hour Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint—such as NV Energy, Puget Sound Energy, and Arizona Public Service Company—provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load, wind, and solar output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM intra-hour benefit by first calculating a flexible reserve requirement for each individual EIM BAA and then by comparing the sum of those requirements to the flexible reserve requirement for the entire EIM area. The latter amount is expected to be less than the sum of the flexible reserve requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the intra-hour benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's share of the intra-hour benefits associated with EIM, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Under the current EIM operational structure, the calculated EIM intra-hour benefit is not known to PacifiCorp prior to its base schedule submission at T-55. The CAISO does not finalize the intra-hour benefit until T-40, therefore making it too late to incorporate any of the benefit into PacifiCorp's base schedule.

Table F.6 below provides a numeric example of flexible reserve requirements for each EIM participating BAA and application of the calculated intra-hour benefit.

Table F.6 - EIM Flexible Reserve Diversity Benefit Application Example

Interval	CAISO req't. before benefit (MW)	NEVP req't. before benefit (MW)	PACE req't. before benefit (MW)	PACW req't. before benefit (MW)	Total req't. before benefit (MW)	Total req't. after benefit (MW)	Total diversity benefit (MW)	PACE share (%)	PACE benefit (MW)	PACE req't. after benefit (MW)
15-minute Interval 1	550	110	165	100	925	583	342	17.8%	61	104
15-minute Interval 2	600	110	165	100	975	636	339	16.9%	57	108
15-minute Interval 3	650	110	165	110	1,035	689	346	15.9%	55	110
15-minute Interval 4	667	120	180	113	1,080	742	338	16.7%	56	124

While the intra-hour benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. PacifiCorp proposes crediting its regulation reserve forecast with a probability distribution of calculated EIM intra-hour benefits based on historical results. When a potential regulation shortfall occurs, the probability that the EIM intra-hour benefit would have exceeded that level can be calculated, and the LOLP associated with that event goes down. As a result, PacifiCorp's regulation reserve requirements can be reduced until the reliability target is again just achieved. While this FRS considers regulation reserve requirements in 2015, the participation of NV Energy in the EIM starting in December 2015 has resulted in increased intra-hour benefits. To capture these additional benefits for this analysis, PacifiCorp has applied the probability distribution of EIM intra-hour benefits from January 2016 through June 2016 because it is a more reasonable representation of actual operations going forward than the 2015 results. Relatively small incremental EIM diversity benefits are expected going forward as additional entities participate in EIM; however, operational data on new participants was not available at the time the study was prepared.

The inclusion of EIM intra-hour benefits in the 2015 regulation reserve analysis reduces the probability of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced until the PacifiCorp system just achieves the reliability target for the 2015 Study Term. As shown in Table F.7 below, the resulting regulation reserve requirement is 562 MW, a 38 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 92 MW relative to the PacifiCorp portfolio reserve requirement without the EIM intra-hour benefit.

Table F.7 - 2015 Results with PacifiCorp Portfolio Diversity and EIM Intra-Hour Benefit

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast with EIM (aMW)	Portfolio Rate with EIM (%)	2015 Capacity (MW)	Rate Determinant
Non-VER	83	3.7%	52	2.3%	2,228	Nameplate
Load	433	4.4%	271	2.7%	9,852	12 CP
VER - Wind	384	14.8%	240	9.2%	2,588	Nameplate
Total	**900**		**562**			
Portfolio LOLP (hours/year)	0.03		0.88			
Diversity Savings (%)			38%			

Incremental Wind Regulation Reserve Requirements

Since 2015, 153 MW of wind resources have been added to PacifiCorp's system. Furthermore, the IRP portfolio optimization process contemplates the addition of new wind capacity as part of its selection of future resources. As PacifiCorp's portfolio of resources grows, the diversity of that portfolio is also expected to increase. As a result, incremental regulation reserve requirements are expected to be lower than the average requirement for a given portfolio.

The need to develop realistic deviation data for a period during which resources did not exist makes measuring an incremental diversity effect a difficult proposition. Instead, PacifiCorp's FRS evaluated the decremental diversity associated with reducing the size of PacifiCorp's wind portfolio. Removing specific resources produces a similar change in the size of PacifiCorp's portfolio without requiring the creation of any data points. Specifically, the PacifiCorp system-wide results described above were recalculated using only 90 percent of the available wind resources, by removing approximately 10 percent of the wind capacity from each geographic location.

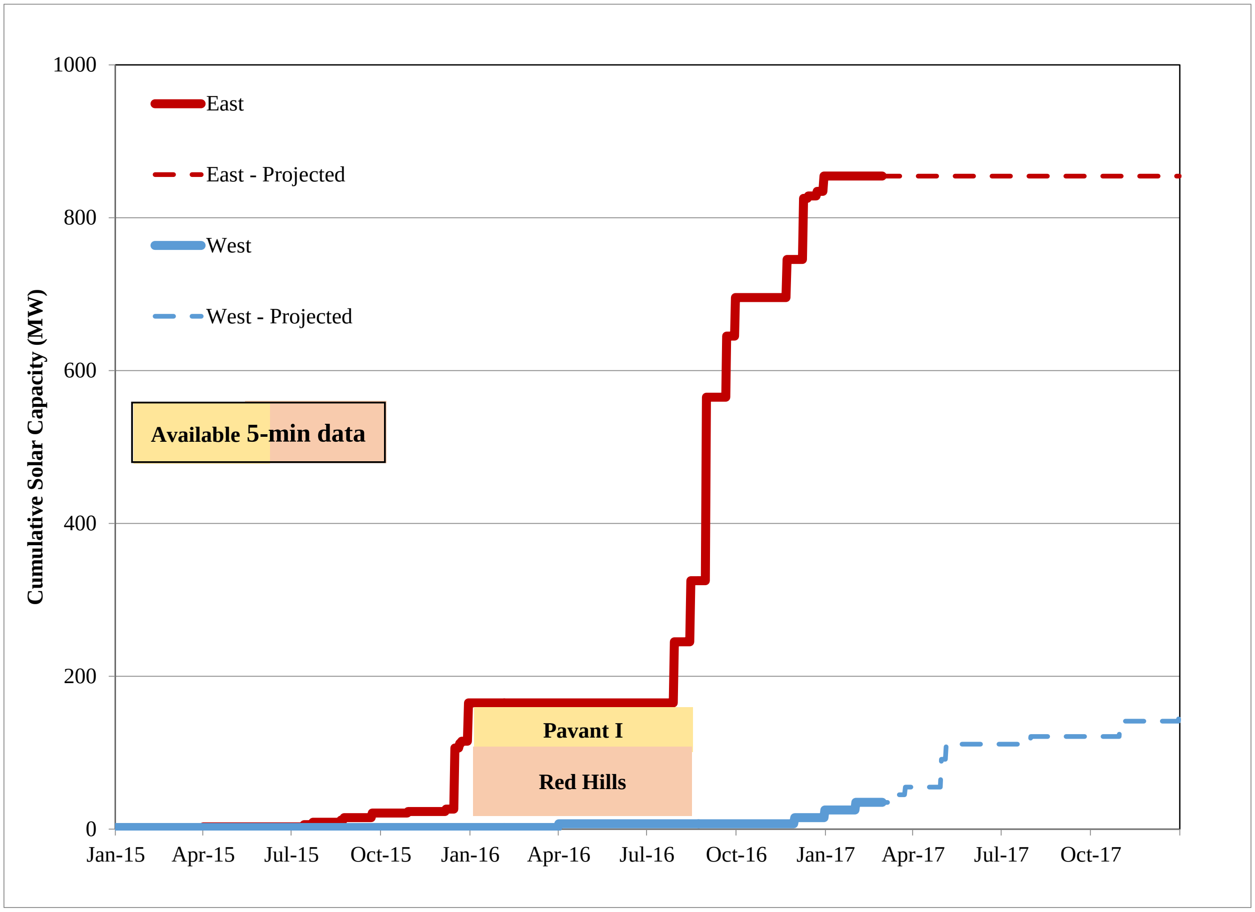
Regulation reserve requirements for PacifiCorp's system-wide portfolio dropped by 6.1percent of the wind capacity removed. This is lower than the average requirement of 9.2 percent in the 2015 portfolio results shown in Table F.7 above. This indicates that diversity is increasing as the pool of requirements increases, as expected. These incremental wind regulation requirement results are incorporated in the forecasted portfolio regulation results discussed later on in the study.

Solar Regulation Reserve Requirements

Overview

At the start of 2015, PacifiCorp had less than three megawatts of utility-scale solar generating capacity on its system. Over the course of 2015, an additional 165 MW was added but the majority was from two large resources which only came online in the second half of December. As shown in Figure F.16, solar capacity has increased rapidly in both PACE and PACW and by the end of 2017 is expected to total over 1,000 MW. Reference Table F.25 on page 64 contains the list of solar resources included in the study. Because solar resources have only recently been added to PacifiCorp's system, the 2015 study period used for the regulation reserve requirements for load, wind, and Non-VERs does not have data suitable predict current and future solar regulation reserve requirements.

Figure F.16 - Solar Capacity Additions



Five-minute solar data was collected from PacifiCorp's Ranger PI system for Jan. 1, 2016 through Aug. 23rd, 2016 for two large solar resources in southern Utah totaling 130 MW.[26] PacifiCorp's solar forecast service provider, DNV GL, provided generation forecasts for these resources during this timeframe, which were submitted to EIM. While EIM deviation data is available for a portion of this period, certain meteorological monitoring equipment was not in place for the entire timeframe, and the limited availability of historical results are expected to make the forecasts for these resources less accurate than what will be possible going forward. Instead, proxy solar base schedules were developed for these two resources, as described in the next section. To make the results easier to compare and apply elsewhere, the actual output of the resources was normalized by their capacity. The calculations described below were all carried out on a capacity factor basis.

Proxy Solar Base Schedule Development

Solar resource output is primarily a function of two attributes: the position of the sun, and the amount of cloud cover. The position of the sun is comparable from day to day at a given time, though over the course of weeks it changes by meaningful amounts. To estimate the maximum possible output for a particular date and time, the maximum output at that time from two weeks prior to two weeks following is calculated. The four week span helps ensure that at least one data point is likely to have very little cloud cover and maximum output, while limiting the effect of

[26] Pavant I, 50 MW and Utah Red Hills, 80 MW.

seasonal changes in the position of the sun. Identifying the maximum possible output for each interval allows the forecast to account for changes in output as the sun rises and sets. The following calculations were carried out independently for the two solar resources.

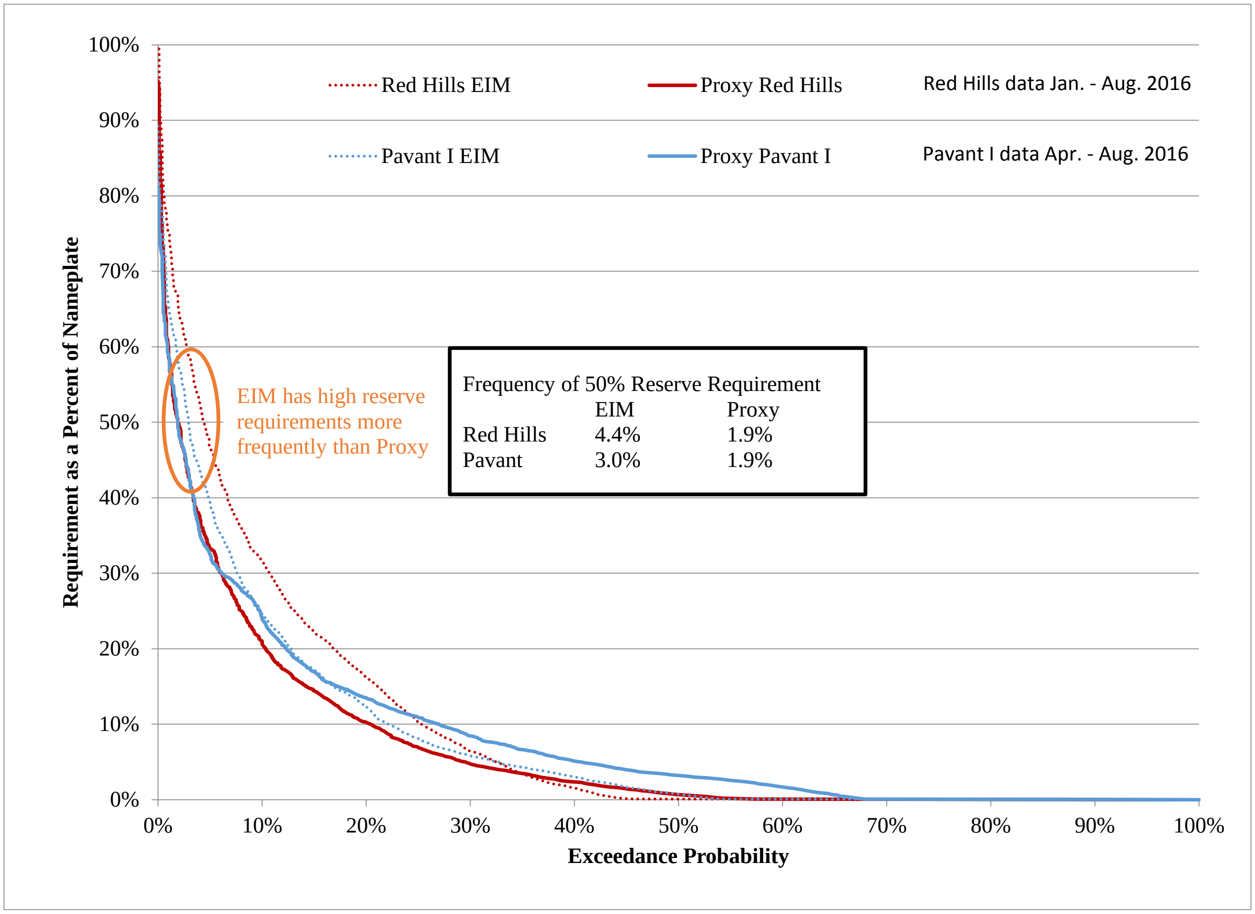
To estimate the amount of cloud cover, the solar availability is calculated by dividing the actual output in each five-minute interval by the maximum output for that interval, as identified above. This removes the effect of the position of the sun, and the changes that remain should primarily be primarily associated with cloud cover. From day to day, cloud cover is expected to vary widely, but from T-55 when the solar resource forecast is submitted as an hourly base schedule to EIM through the course of that upcoming hour, it is reasonable to assume the prevailing cloud conditions will continue. To improve further upon the cloud cover forecast using the available data, the trend in cloud conditions leading up to the time of forecast submission was also accounted for. If it is less cloudy at T-55 than it was twenty minutes earlier, that trend is also extrapolated forward to the forecast period. The weighting of the trend versus the final measurement before the forecast is submitted was set to maximize the correlation between the actual solar output and the forecasted hourly base schedule, i.e. to produce the best achievable forecast. Due to the absence of generation output, cloud cover can't be estimated from intervals prior to sunrise, so the forecasted output during the first hours after sunrise is set at the monthly average for those intervals.

The proxy solar base schedules incorporate cloud cover data and solar position data as follows. The cloud cover measurement is the primary component in the forecast for the upcoming hour. The cloud cover trend over the preceding intervals, and the cloud cover in the last interval are locked in at the values measured just prior to base schedule submission. On the other hand the position of the sun, embedded in the maximum output for each interval, is assumed to be fixed and known in advance. The base schedule submission looks forward in time to the forecast hour and incorporate the expected solar position changes over each five-minute interval in the hour.

While the forecast is created with a five-minute granularity, the base schedule submission to EIM at T-55 reflects an hourly average value in accordance with EIM operating procedures. The difference between this hourly average and the five-minute actual resource output (i.e. the original source data) is the deviation of the solar resource. Once base schedule and deviation data were prepared for the two solar resources, those deviations were applied in the same template used to calculate hourly regulation reserve requirements for load, wind, and Non-VERs, including the base schedule ramping adjustment described previously. This identifies the minimum hourly regulation reserve needed to guarantee compliance with BAL-001-2 with the resource in question viewed in isolation.

As shown in Figure F.17, the proxy solar forecasts have less frequent large deviations, and thus produce fewer instances of large regulation reserve requirements than the available EIM deviation data from the same period. Note that while Pavant I become operational in 2015, EIM deviations only became available starting April 1, 2016. For comparability, the proxy and EIM results for each generator are shown for the overlapping time period only. Regulation reserve requirements in excess of approximately 15 percent of nameplate capacity occurred more frequently in the EIM data than the proxy data. Because the largest errors are most likely to cause a BAAL violation, they drive the majority of the reserve requirement. Future results will show whether the forecast accuracy that can be achieved in actual practice is higher or lower than that in the proxy data used in this analysis.

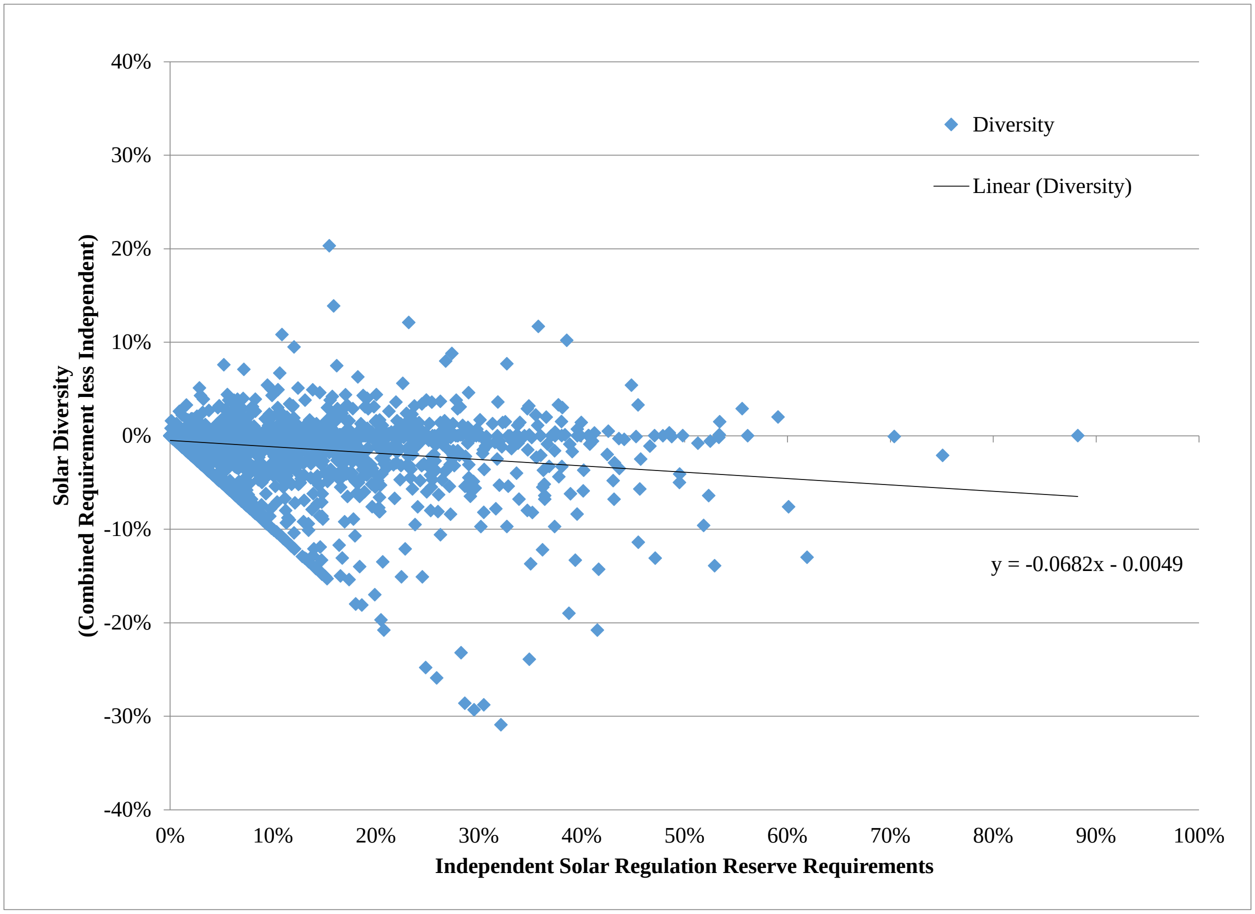
Figure F.17 - Solar Regulation Reserve Requirements: Proxy vs EIM



Solar Diversity

When the hourly regulation reserve requirements of the two solar resources are measured independently, as described above, the results do not capture any of the potential for diversity in the intra-hour requirements. To identify the potential diversity between the two solar resources, the average of their base schedules and actual output was used in the hourly regulation reserve calculation. The difference between the requirements when measured independently and the requirements when measured in aggregate is the result of diversity. The results of this diversity measurement are shown in Figure F.18.

Figure F.18 - Solar Diversity



As shown in Figure F.18, diversity is not guaranteed to reduce hourly regulation reserve requirements. While this is not intuitive, it is a direct result of the 30 minute maximum time limit for deviations under BAL-001-2. If two resources each have deviations that are only 20 minutes long, the regulation reserve requirement is zero. If the deviations both started at the same time, then viewed together they will overlap perfectly, and the length of the deviation remains just 20 minutes with a regulation reserve requirement of zero. However, if one resource's deviation starts 15 minutes earlier than the other, the length of the aggregate deviation will be 35 minutes, and the regulation reserve requirement will be greater than zero to ensure compliance with BAL-001-2.

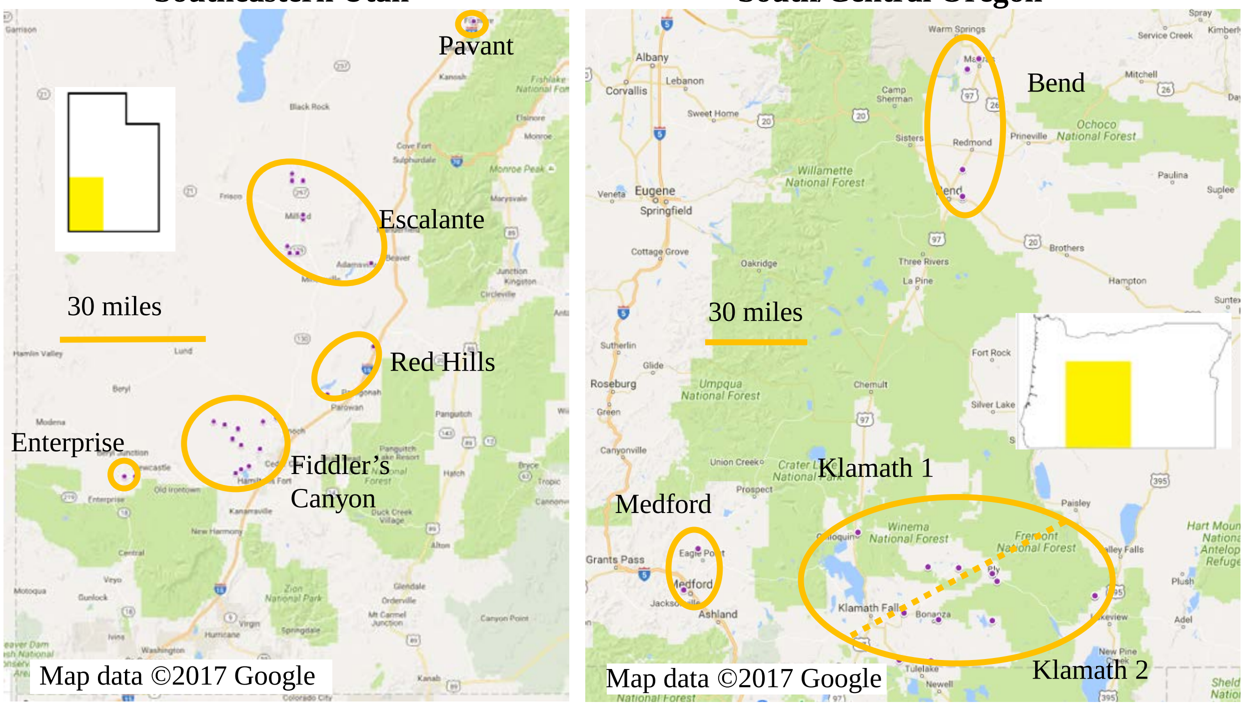
Despite the potential for increased aggregate requirements in some instances, on average the aggregate requirements are lower as a result of diversity. Because the regulation requirements are bounded by zero, the diversity benefit is limited to the size of the independent requirement.
As a result, the diversity benefits increase as the independent requirements increase.

Solar Locations

The solar facilities on PacifiCorp's system are concentrated in southeastern Utah and southern and central Oregon. As shown in Figure F.19, within these areas multiple facilities are also clustered within relatively close proximity. Five clusters were identified in Utah, while three were identified in Oregon. Because one of the Oregon clusters is relatively dispersed, it is treated as two independent clusters.

Figure F.19 - Solar Resource Locations

Southeastern Utah **South/Central Oregon**



While all of the clusters identified are in close enough proximity to experience most of the same passing weather systems, different clusters experience different cloud cover at the time of forecast submission, and different cloud cover over the course of the operating hour. These differences are in turn reflected in their actual output and deviations. On the other hand, due to their proximity, facilities within a given cluster are expected to reflect more closely-related weather conditions in their forecasts and deviations. As a result, the aggregate capacity within a given cluster is not expected to experience offsetting deviations, i.e. diversity benefits, whereas the effect of capacity spread among multiple clusters should create opportunities for offsetting deviations.

The IRP is focused not just on regulation reserve requirements for existing solar resources, but also on the requirements associated with incremental solar resources added in the future. Tables F.8 and F.9 present the solar capacity on PacifiCorp's system in three scenarios. The base scenario reflects the contracted solar resources scheduled to be online in 2017, while two incremental scenarios reflect the addition of 500 MW and 1000 MW of new solar resources. The incremental solar capacity is split between the PACE and PACW BAAs, and among existing and new clusters.

Table F.8 - East Solar Clusters by Scenario

East Cluster	Base	Incr. Solar 1	Incr. Solar 2
Enterprise	83	+17	+17
Fiddler's Canyon	311	+62	+62
Escalante	257	+51	+51
Red Hills	83	+17	+17
Pavant	120	+24	+24
New Cluster 1		+229	
New Cluster 2			+229
Total	**855**	**1,255**	**1,655**
% Change vs Base		47%	94%

Table F.9 - West Solar Clusters by Scenario

West Cluster	Base	Incr. Solar 1	Incr. Solar 2
Bend	50	+31	+6
Medford	20	+12	+2
Klamath 1	47	+29	+6
Klamath 2	47	+29	+6
New Cluster 1			+80
Total	**163**	**263**	**363**
% Change vs Base		61%	123%

Solar Portfolio Data

Red Hills and Pavant have proxy base schedules, hourly regulation reserve requirements, and diversity based on actual generation. It is reasonable to assume other solar resources within those two clusters would experience comparable conditions and results. Therefore, the Red Hills and Pavant results are scaled up to reflect any additional capacity within the cluster.

At the time the study was prepared, actual data for the other clusters in PACE and all of the clusters in PACW was unavailable. While the varying geographic locations of these clusters impact the timing of weather conditions, they are all relatively sunny locations, and it is reasonable to assume that the likelihood of over-forecasting resource output, resulting in a regulation reserve requirement, is similar in all of the clusters. With this in mind, all of the hourly regulation reserve requirements for Red Hills and Pavant (measured independently) were taken as a single data set and hourly regulation reserve requirements for the other clusters were assigned randomly from this distribution. While the resulting hourly regulation reserve requirements vary from 0 percent to 95 percent of the solar nameplate capacity, 18.7 percent of the regulation reserve requirements are zero, and half of the regulation reserve requirements are less than 2 percent of the solar nameplate. Despite being predominantly random, there is a relatively small positive correlation (+0.2638) between the hourly regulation reserve requirements for Red Hills and Pavant. This may reflect weather conditions that occur at the same time over a broad area, such as afternoon thundercloud formation, rather than as a result of passing weather fronts. This relationship is assumed to be real effect and is reflected in each of the calculated clusters by blending a random regulation requirement and the simultaneous requirement for one of the two source clusters. The weighting of the blend was set such that the average correlation between the new clusters and the existing clusters matches the correlation measured between the existing clusters.

Because the hourly regulation reserve requirements described above reflect the independent regulation reserve requirements for Red Hills and Pavant, they do not capture the diversity between different clusters of solar resources. As discussed above, diversity is partly a linear function of the independent hourly regulation reserve requirements – the greater the requirement, the greater the diversity credit. However, much of the variation in diversity values appears to be unpredictable, i.e. largely random. In a similar manner to the regulation reserve requirements described above, the diversity results for Red Hills and Pavant were taken as a single data set and assigned randomly to each of the clusters. A weighted average diversity value was then calculated that takes into account the number of clusters since diversity requires two or more. In addition, because diversity benefits are bounded by a zero regulation reserve requirement, they may be truncated in manner that under-represents the potential diversity available. Instances when diversity leads to higher requirements are not bounded in this manner in the sample. With more than two clusters, it may be possible to utilize additional diversity benefits before hitting the zero bound. To help reflect this, whenever the sampled diversity components indicated an increase in requirements, the increase was reduced by half.

The random assignment of regulation reserve requirements described above disregards the hour of the day, and can overstate requirements when little output is expected such as during the morning ramp. To compensate, the aggregate regulation reserve requirements are reduced during the morning ramp to align with the requirements seen for Pavant and Red Hills.

Solar Regulation Reserve Forecast

The solar regulation reserve forecast is comparable to that developed for wind, representing a fixed percentage of the solar nameplate capacity, but never more than the maximum output in that hour, including a portion of the ramp up across the hour in the morning and down across the hour in the afternoon. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The reserve requirement necessary to achieve the reliability target varies in PACE and PACW, and with changes in total solar capacity.

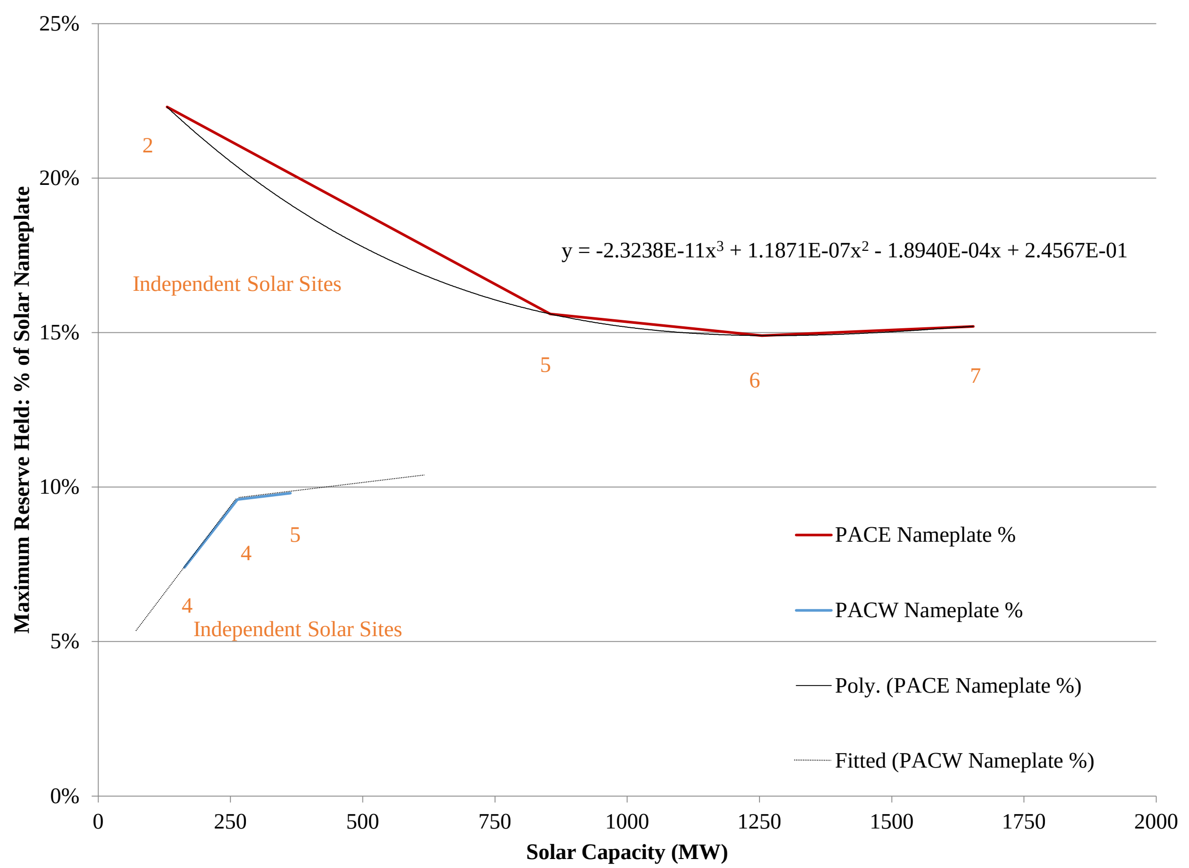
The results of the solar regulation requirements in the various scenarios is shown in Table F.10 below, with the wind results shown for comparison. Note that while the fixed percentage of nameplate capacity (i.e. the maximum reserve held) for solar and wind in PACE is similar, ranging from 14.9 percent to 18.6 percent of nameplate capacity, the average requirement for solar is significantly lower than that for wind. This is because solar output is zero for half of the hours in the year, whereas PACE wind output drops below the maximum reserve held infrequently. PACW wind output is more strongly correlated and drops to zero more frequently than PACE wind.

Table F.10 - Solar and Wind Stand-alone Regulation Requirements, as Percentage of Nameplate Capacity

Scenario	Average Reserve Held East	Average Reserve Held West	Max Reserve Held East	Max Reserve Held West
No Solar	12.3%	n/a	22.3%	n/a
Base Solar	8.8%	4.2%	15.6%	7.4%
Incr. Solar 1	8.5%	5.3%	14.9%	9.6%
Incr. Solar 2	8.6%	5.4%	15.2%	9.8%
90% Wind	15.1%	15.8%	18.6%	32.3%
Base Wind	14.6%	15.2%	17.8%	29.8%

For solar, the fixed percentage of nameplate in the reserve requirement calculation varies with the size of the solar capacity. There are two offsetting trends related to increasing solar capacity. First, more diverse solar resources (i.e. more clusters) have lower requirements, but the incremental benefit declines as more diversity is added. Second, spreading the fixed allowable BAAL variation across more capacity increases requirements, and the incremental impact increases as capacity increases. Figure F.20 shows these relationships as well as fitted curves used to project the solar regulation reserve requirements as a function of capacity for PACE and PACW. The solar regulation reserve requirement in PACE is assumed to be related to capacity using a third-order polynomial. The solar regulation reserve requirement in PACW is assumed to be related to capacity using two linear extrapolations.

Figure F.20 - Stand-alone Solar Regulation Reserve Requirements, by capacity



Portfolio Regulation Reserve Requirements

Overview

A single pool of regulation reserve is held to cover deviations by load, wind, solar, and non-dispatchable generation. Simultaneous large deviations by all classes are unlikely – as a result, this pool of regulation reserve can be smaller than what these classes would require on their own. The reduction in regulation reserve is a result of the diversity of the portfolio of requirements. While the diversity of load, wind, and Non-VER generation was measured using 2015 data, the solar deviations are from 2016 and are extrapolated from a very limited sample. As such, it is not currently possible to measure the diversity of the PacifiCorp system, inclusive of requirements for solar. Instead, several characteristics of the diversity of PacifiCorp's system were used to produce an estimate of the relationship between the amount of diversity and the portfolio of regulation requirements. These characteristics are discussed below.

Methodology

The most important element in PacifiCorp's portfolio diversity estimate is the system diversity, including EIM benefits, associated with load, wind, and Non-VERs during 2015. The diversity in the 2015 portfolio reduced reserve requirements by 37.51 percent. This captures the vast majority of the regulation reserve requirements both today and in likely future scenarios over the near term. For example, approximately 1000 MW of solar capacity is expected to be on the PacifiCorp system in 2017, and no solar was included in the 2015 results. However, this additional solar increases the stand-alone regulation reserve requirement (before accounting for diversity) by less than 10 percent. Since diversity only occurs in intervals when two or more regulation reserve requirements exist, changes in diversity in 10 percent of the intervals will have relatively limited effects.

In a portfolio without solar capacity, incremental wind generation was calculated to have reserve requirements of 6.1 percent of nameplate, after accounting for portfolio diversity, compared to an average requirement of 9.2 percent for the entire wind fleet. Much of the benefits are captured within the wind class – its stand-alone requirements increase by a limited amount; however, the diversity of the entire portfolio increases slightly when the reserve requirements for the incremental wind are added. This relationship between stand-alone reserve requirements and portfolio diversity is assumed to be linear - a small increase in diversity as the reserve requirements of the existing classes grows.

As a starting point, solar regulation reserve requirements are assumed to create equivalent amounts of diversity as the components of the pre-solar portfolio, including the linear increase as requirements grow. In addition, incremental diversity as a result of solar is assumed to occur in relation to the size of the stand-alone solar regulation requirements. When the solar requirements are equivalent in size to the requirements for load, wind, and Non-VERs, the incremental diversity benefits are assumed to be maximized at 20 percent of the solar requirement. At lower levels of solar requirements (i.e. for less solar capacity), the incremental diversity benefits are smaller and are assumed to proportional to the size of the solar requirements relative to the other regulation requirements. With four categories of requirements (load, wind, solar, Non-VER), solar requirements would need to be 25 percent of the total to achieve the maximum level of diversity. In the base scenario, solar requirements are 81 MW out of 998 MW total, and result in incremental diversity benefits of 5.3 MW, on top of approximately 30 MW of benefits based on the diversity in the pre-solar portfolio.[27]

Based on the above, hourly regulation requirements for PACE and PACW are calculated as a function of: wind and solar nameplate capacity, forecasted wind output and month/hour as a proxy for expected solar output, and static hourly regulation reserve requirements for load and non-VER generation. Diversity is a function of the total requirements and is calculated dynamically as described above.

Results

Table F.11 presents the portfolio regulation requirement results from the various scenarios described above. As the wind and solar capacity on PacifiCorp's system increases, regulation requirements increase, but those requirements are partially offset by the increasing diversity of the portfolio. The 2017 Base Case regulation reserve requirements are 617 MW. By comparison, PacifiCorp's 2014 Wind Integration Study identified requirements of 626 MW for a smaller amount of wind, and without any requirements for solar or Non-VERs.

Table F.11 - Portfolio Regulation Requirement Results, by Scenario

Scenario	Wind capacity (MW)	Solar capacity (MW)	Stand-alone regulation requirement (MW)	Portfolio diversity credit (%)	Regulation requirement with diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

There are a significant number of changes between the PacifiCorp's 2014 Wind Integration Study and the current study. First, the specific requirements of the BAL-001-2 standard are being applied, as previously discussed. Second, the updated requirements are based on an expanded portfolio of resources, including solar, Non-VERs, and additional wind capacity. Finally, diversity benefits are now shared among all requirements, rather than being allocated solely to wind resources as was done in the 2014 Study. Table F.12 presents a comparison of the regulation reserve requirement results in the current study and prior studies.

[27] 81 MW solar requirement / (998 MW total requirement / 4 classes) * 20% incremental diversity = 5.3 MW.

81 MW solar requirement * 37.6% pre-solar portfolio diversity = ~30 MW

Table F.12 - Portfolio Regulation Requirement Results, Percent of Nameplate Capacity

Study	Load	Wind	Non-VER	Solar	Method
2012 WIS: 2011	4.0%	8.7%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2012	4.1%	8.1%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2013	4.5%	7.3%	n/a	n/a	Load -> Incr Wind
2016 FRS	2.8%	8.9%	2.4%	4.6%	Portfolio Diversity (Base)
2016 FRS	n/a	5.8%	n/a	n/a	Base -> Incr Wind
2016 FRS	n/a	n/a	n/a	3.6%	Base -> Incr Solar 1
2016 FRS	n/a	n/a	n/a	3.8%	Incr Solar 1 -> Incr Solar 2

The 2012 and 2014 Wind Integration Studies calculated the regulation reserve requirement for load only, then the incremental requirement for the entire wind fleet, allocating all diversity to wind. The FRS calculates the regulation reserve requirement for the 2017 resource mix, allocating the diversity among all components. As compared to prior studies, the diversity allocation decreases the load requirement and increases the wind requirement, the changes in standards and methodology notwithstanding. In an additional step, the FRS also calculates incremental requirements for wind and solar which are more closely aligned with the obligations resulting from new resource additions contemplated in the IRP. While these requirements are lower than the average requirements in the base case, they will call on higher cost resources, as the least-cost regulation reserve resources are dispatched first. The cost of the regulation reserve obligation is discussed in more detail in the next section.

Regulation Reserve Cost

A series of PaR scenarios were prepared to isolate the regulation reserve cost associated with wind and solar generation. The scenarios are shown in Table F.13. These scenarios were based on 2017 and included the existing resources in the 2015 IRP Update. In the 2014 Wind Integration Study reserve requirements were modeled on both an hourly and monthly basis to reflect the timing differences of reserve requirements. While the requirements are calculated on an hourly basis, due to difficulties incorporating those requirements in the PaR model at that granularity, monthly requirements were used to calculate regulation reserve costs discussed herein. Where possible, it is recommended that hourly regulation requirements be modeled that are consistent with the resource capacity and generation profiles of the specific portfolio under evaluation.

Table F.13 - Regulation Reserve PaR Scenarios

#	Scenario	Resources	Regulation requirement
B.1	Base No Reserve	1/1/17 wind and solar	None
B.2	Base With Reserve	1/1/17 wind and solar	1/1/17 wind and solar
W.1	Incr. Wind, Base Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar
W.2	Incr. Wind + Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar + 250MW wind
S1.1	Incr. Solar 1, Base Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar
S1.2	Incr. Solar 1 + Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar + 500MW solar
S2.1	Incr. Solar 2, Base Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar
S2.2	Incr. Solar 2 + Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar + 1000MW solar

The regulation reserve cost results are shown in Table F.14. The 2014 Wind Integration Study identified regulation reserve costs for wind generation of $2.35/MWh. This value measured the incremental cost when regulation reserve for the existing wind fleet were added to the regulation reserve for load. The most comparable wind reserve cost from the FRS is $0.30/MWh. This represents the cost of the regulation reserve for existing wind, load, solar, and Non-VERs, relative to a scenario with no regulation reserve. The result is adjusted to account for the wind regulation reserve requirement relative to the total regulation reserve requirement.

Table F.14 - Regulation Reserve Cost Calculations

#	Value	Calculation	Units	Results
a	Base regulation reserve cost	[Study B.2] - [Study B.1]	$	5,936,990
b	Wind reserve requirement	[Wind req.] / [Total req.]	%	40%
c	Wind generation	[Study B.1]	MWh	7,802,061
	Base wind reserve rate	**[a] x [b] / [c]**	**$/MWh**	**$0.30**
a'	Incremental regulation reserve cost	[Study W.2] - [Study W.1]	$	$389,890
b'	Incremental wind generation	[Study W.1] - [Study B.1]	MWh	909,050
	Incremental wind reserve rate	**[a'] / [b']**	**$/MWh**	**$0.43**
a"	Incremental regulation reserve cost	[Study S2.2] - [Study S2.1]	$	$1,221,610
b"	Incremental solar generation	[Study S2.1] - [Study B.1]	MWh	2,667,200
	Incremental solar reserve rate	**[a"] / [b"]**	**$/MWh**	**$0.46**

The change in regulation reserve costs is primarily attributable to the following factors: lower market prices, transmission congestion, and 30-minute regulation reserve capability. Assuming sufficient regulating capability is available within PacifiCorp's portfolio, the cost of regulation reserve reflects the lost margin on resources that can provide the service, i.e. the difference between the market price or alternative generation cost and their fuel cost. Since the prior study, market prices have declined, which reduces this margin, and a 10 percent drop in market price can reduce the margin by more than 10 percent. In addition, transmission congestion has increased, primarily as a result of substantial additions of solar, which has reduced the ability of resources to get to market. If regulation-capable resources are already backed down due to transmission congestion there is no additional cost to count that capacity as regulation reserve. Finally, in the prior study the entire regulation reserve requirement was included in the spinning reserve category, which is limited to capacity available within 10 minutes. The FRS assumes that dispatchable capacity available within 30-minutes can be counted toward the regulation reserve requirement. This increases the supply of regulation resources and reduces costs when 30-minute capacity from the unit with the lowest-cost reserve can be used instead of being limited to only the 10-minute capacity of that unit.

While the Base wind reserve rate is helpful for comparison with the 2014 Wind Integration Study, it is not representative of the incremental cost of regulation reserve for new wind resources. Instead, PacifiCorp's FRS calculates regulation reserve requirements specific to the incremental resource additions contemplated in the IRP. As shown in Table F.14 above, the addition of 250 MW of wind capacity results in incremental regulation reserve costs of $0.43/MWh, while the addition of 1000 MW of solar capacity results in incremental regulation reserve costs of $0.46/MWh. It should be noted that the difference in reserve costs for wind and solar reflects timing differences. Per MWh of generation, the wind reserve obligation is 16 percent higher than the solar obligation; however, the solar obligation is higher during the summer and during the day, when market prices and marginal reserve costs are higher.

While incremental reserve costs generally increase with volume, the 500 MW solar scenario had a slightly higher cost than the 1000 MW scenario, likely due to lower transmission congestion. For simplicity, the 1000 MW result was used where a specific dollar value was required in the IRP. The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios. Ideally, the hourly regulation reserve requirements should be used to determine costs specific to the requirements of the resource and portfolio under consideration. This ensures regulation reserve costs reflect changes in market prices and fuel costs, transmission congestion, and regulation reserve capability relative to the IRP analysis. The corollary of a more accurate estimate of incremental regulation reserve cost is a more accurate estimate of the value of resources that supply regulation reserve, including energy storage and direct load control.

Day-ahead System Balancing Costs

In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate the costs associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of load and wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time. The methodology is comparable to that used in the 2014 Wind Integration Study, with modifications to account for solar and the allocation of costs between load, wind, and solar.

The PaR model simulates production costs of a system by committing and dispatching resources to meet system load. For this study, PacifiCorp developed nine different PaR simulations as summarized in Table F.15. These simulations isolate the system balancing costs of load, wind, and solar, plus the system balancing costs of the overall portfolio. These simulations were run assuming operation in the 2017 calendar year, applying 2015 load, wind, and solar data collected from PacifiCorp's wind forecast service provider, DNV GL. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis, as well as the current resource portfolio.[28] PacifiCorp resources used in the simulations are based upon its existing resource portfolio.

[28] The Study uses the October 12, 2016 official forward price curve (OFPC).

Table F.15 - System Balancing Cost Simulations in PaR

#	Load	Wind profile	Solar profile	Commitment	Day-ahead forecast error
1	Day-ahead	Day-ahead	Day-ahead	Study 1	n/a
2	Actual	Actual	Actual	Study 2	None
3	Actual	Actual	Actual	***Study 1***	For Load/Wind/Solar
4	Day-ahead	Actual	Actual	Study 4	n/a
5	Actual	Day-ahead	Actual	Study 5	n/a
6	Actual	Actual	Day-ahead	Study 6	n/a
7	Actual	Actual	Actual	***Study 4***	For Load
8	Actual	Actual	Actual	***Study 5***	For Wind
9	Actual	Actual	Actual	***Study 6***	For Solar

Simulation 1 identifies the unit commitment using day-ahead forecasts of load, wind, and solar. Simulation 2 identifies the unit commitment using actual load, wind, and solar, and represents the optimal dispatch of the system. Simulation 3 uses the unit commitment from Simulation 1, along with the actual load, wind, and solar from Simulation 2. Since Simulation 2 and 3 both have identical load, wind, and solar, differences between them are solely due to unit commitment and Simulation 3 represents the achievable optimization of unit commitment using the information available on a day-ahead basis when unit commitment occurs. The difference in cost between Simulation 3 and Simulation 2 is the system balancing cost associated with changes between day-ahead load, wind, and solar forecasts and actual output.

Simulations 4-9 isolate the total day-ahead forecast cost of the individual components. Simulations 4-6 each calculate unit commitment using one day-ahead forecast and two actual results. Simulations 7-9 calculate the costs of those day-ahead unit commitment decisions under actual output. The relative costs of Simulations 7-9 are used to determine the relative allocation of the portfolio among the individual components. The simulation results and day-ahead balancing cost for each category is shown in Table F.16.

Table F.16 - Day-ahead Forecast System Balancing Cost Results

#	Value	Cost calculation	Cost ($)	Diversity calculation	Rate w/ diversity ($/MWh)
a	Total Combined	[Study 3] - [Study 2]	$6,208,760		
b	Load Only	[Study 7] - [Study 2]	$6,132,860	[b] * ([a] / [e]) / [Actual Load MWh]	**$0.09**
c	Wind Only	[Study 8] - [Study 2]	$1,053,530	[c] * ([a] / [e]) / [Actual Wind MWh]	**$0.14**
d	Solar Only	[Adjusted]	$31,111	[Set equal to wind result]	**$0.14**
e	Total One-off	[b] + [c] + [d]	$7,217,501		

As indicated in the Regulation Reserve section above, the actual solar on PacifiCorp's system in 2015 was very limited, and the available solar generation averages just 21 megawatts, or roughly 3 percent of the available wind generation. Because unit commitment changes have low granularity (a unit is either on or off), small differences can sometimes have a large effect, and this appears to be the case for the solar results, which were far out of proportion with the measured volumes. In light of the limited solar data set, it is unlikely those results would scale up to the current level of solar on PacifiCorp's system. In light of this, the day-ahead forecast cost for solar generation has been reduced to the level calculated for wind generation.[29]

Table F.16 above has been modified from what was presented in the 2014 Wind Integration Study. In that study, day-ahead system balancing costs associated with load were calculated first, and incremental day-ahead system balancing costs associated with wind were calculated second. In this analysis, the total day-ahead system balancing costs are calculated for the portfolio and are allocated among the components based on their individual contributions. This attributes diversity in the requirements to all of the components and avoids differences related to the order the studies are conducted. A comparison of the day-ahead system balancing costs in the FRS and 2014 Wind Integration Study is shown in Table F.17.

Table F.17 - Day-Ahead System Balancing Cost Comparison

	2014 WIS (2014$/MWh)	2017 FRS (2016$/MWh)
Load	$0.01	$0.09
Wind	$0.71	$0.14
Solar	n/a	$0.14

The increase in the day-ahead system balancing costs associated with load do not appear to be a result of the portfolio allocation methodology, as load was previously calculated on a stand-alone basis, and the portfolio adjustment reduces the stand-alone day-ahead system balancing costs by 14 percent. Instead the difference appears to be related to market prices and the composition of the PacifiCorp's system. Market prices influence the relative costs of PacifiCorp's gas resources and determine how close they are to being economic or uneconomic. Resources generally only are faced with commitment changes when they have low margins. Because falling market prices have reduced margins, this occurs more frequently. In addition, transmission congestion has reduced the ability of resources to get to market. When resources are committed in anticipation of high load or low resources, there may not be sufficient transmission to get them to market if load is lower than expected or resources are higher. The costs of backing down economic resources due to transmission constraints is higher than the cost of forgone market sales, and thus contributes to higher day-ahead system balancing costs.

Technical Review Committee

As was done for its prior Wind Integration Studies, PacifiCorp engaged a Technical Review Committee (TRC) to review the study results from the FRS. PacifiCorp thanks each of the TRC members, identified below, for their participation and professional feedback. The members of the TRC are:

- **Andrea Coon** - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- **Michael Milligan** - Principal Analyst at the National Renewable Energy Laboratory (NREL)
- **J. Charles Smith** - Executive Director, Utility Variable-Generation Integration Group (UVIG)

[29] The calculated Solar Only Day-Ahead Forecast Cost, [Study 9] – [Study 2], was $805k, or over $4/MWh.

- **Robert Zavadil** - Executive Vice President, EnerNex LLC

In its technical review[30] of PacifiCorp's FRS, the TRC provided comments and questions on specific aspects of the analysis.

Table F.18 - FRS TRC Recommendations

2016 FRS TRC Recommendations	Response to TRC Recommendations
The TRC feels that it might be useful to state the role of key assumptions generally - but specifically how key requirements of the EIM may have an impact on reserves (don't study it, just point out key issues).	EIM operating processes underlie PacifiCorp's regulation reserve requirements and the calculations in the FRS. Specific details on the EIM market process are available in the FRS, specifically in footnote 11.
On Slide page 8 of the presentation provided to the TRC, below the table: should that be 70 MW instead of 40 MW?	This references Figure F.6 in the FRS. The presentation stated: 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour. This is more accurately stated as: <u>When the minimum imbalances in every rolling thirty-minute period are compared,</u> 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour.
Would be helpful to include a few sentences about the ACE cap of 4L10?	This is addressed in the FRS in the section entitled "Balancing Authority ACE Limit: Allowed Deviations."
The use of what has traditionally been a resource adequacy metric – LOLH – use in long term capacity planning as a key criterion for estimating regulation reserve requirements is both interesting and a departure from previous studies – by Pacificorp as well as the general wind integration community in the U.S. This approach has been employed in a few recent integration analyses, but given the uniqueness, it would be good if it were more clearly called out/highlighted in the description of the analytical methodology. The discussion of 0.88 LOLH was helpful on the call. It would be useful to have a similar explanation in the report - something along the lines that the RA target resulted in 0.88 LOLH/year and that was judged to be an acceptable reliability level. Using the same target for operations, there are different drivers, but assuming resource adequacy is not the constraint, the 0.88 LOLH may instead result from UC errors that result in too little regulation being available when needed.	This is addressed in the FRS in the section entitled "Planning Reliability Target: Loss of Load Probability." The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The 0.88 LOLH in the FRS assumes that resources are available to provide the identified hourly regulation requirements. To the extent resources are not available to meet the identified requirements, LOLH would increase. PacifiCorp's Flexible Resource Needs Assessment in the FRS assesses the availability of resources to meet its reserve requirements over the long term. In addition, over the short term, maintaining adequate reserve can be dependent on the availability of hourly market balancing opportunities. While a single unit can provide reserve in each hour of for a multi-hour ramp, it can only do so to the extent alternate resources can be procured so that it can ramp back to its starting point. Potential market balancing constraints are an area for future work.

[30] PacifiCorp 2016 Wind Integration Study Technical Review, Dec. 12, 2016. Available at: http://www.pacificorp.com/es/irp/irpsupport.html

2016 FRS TRC Recommendations	Response to TRC Recommendations
Would be useful to have discussion of how wind (and solar) are treated in the study - do they respond to AGC or dispatch or both? Impact of lost RECs vs. operational flexibility etc.	The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The ability of wind or solar to provide "up" regulation reserve would impact the cost of meeting that need. Generally, the opportunity cost of foregone renewable resource output is higher than the variable cost of PacifiCorp's regulation reserve resources. When considered relative to the cost of adding flexible resource capacity, in some circumstances providing regulation reserve with wind or solar resources may be economic.
Is there a reference to the method used by the CAISO to allocate the diversity benefits for each EIM participant?	This is addressed in the FRS in the section entitled "EIM Intra-hour Benefit."
There is some remaining confusion on the part of the TRC regarding the assumptions and utilization of forecasting into the production simulations for calculating integration cost. Specifically, the forecast lead time is nearly one hour prior to the operating hour. The disconnect on the part of the TRC is likely driven by current operation in some larger RTOs, where very short term persistence forecasts (5 minutes ahead) are used to dispatch generators participating in the sub-hourly energy markets, which substantially reduces the remaining requirement for generators providing regulation.	While the EIM uses forecasts up to 7.5 minutes prior to the start of an interval, it can only dispatch the resources made available by participants. Because of EIM operating timelines, balanced load and resource schedules with regulation reserve capacity identified have to be submitted by 55 minutes prior to the hour. Once a resource is deployed, for instance to cover increasing load or decreasing wind, PacifiCorp cannot restore that regulating capacity to its original levels without buying additional resources from a third party. Bilateral hourly markets in the West have historically been liquid enough for this purpose, whereas sub-hourly markets, other than EIM, have not. Because EIM is an *Energy* Imbalance Market, each participant is independently responsible for meeting its reliability obligations and it is inappropriate to rely upon the availability of resources from other participants, though they will be deployed in the EIM if it is economic to do so. As discussed in the section entitled "EIM Intra-hour Benefit", the FRS incorporates benefits associated with the diversity of the EIM as whole, rather than the resources of other participants.
The use of actual high temporal resolution operating data, especially for wind generation (rather than synthesized data from numerical weather simulations) has been a key feature of the Pacificorp integration studies dating back to 2012. Going forward, the TRC feels that future Pacificorp integration studies could benefit greatly by a thorough comparison of "study results vs. real world", especially since a current year baseline is part of the analysis. This would provide perhaps the strongest validation of the analytical methodology or otherwise give strong clues to adjustments that may be needed.	PacifiCorp agrees that the performance of the regulation reserve forecast developed in the FRS against future regulation reserve requirements would provide valuable feedback. This is an area for future work.

Flexible Resource Needs Assessment

Overview

In its Order No. 12013 issued on January 19, 2012 in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options including the use of electric vehicles (EVs), on a consistent and comparable basis.

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2017 through 2036, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from stochastic simulations run using the Planning and Risk (PaR) model. The regulating reserve requirements are part of the inputs to the PaR model, and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2017 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.19 below.

Table F.19 - Reserve Requirements (MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2017	195	195	387	88	88	229
2018	197	197	387	89	89	229
2019	198	198	390	91	91	231
2020	200	200	390	91	91	231
2021	203	203	454	92	92	230
2022	205	205	454	92	92	230
2023	207	207	454	93	93	230
2024	209	209	454	93	93	230
2025	212	212	454	94	94	230
2026	211	211	454	95	95	230
2027	213	213	454	95	95	230
2028	215	215	390	96	96	232
2029	218	218	390	96	96	235
2030	219	219	390	97	97	235
2031	222	222	398	97	97	233
2032	225	225	396	98	98	234
2033	227	227	398	98	98	232
2034	228	228	392	98	98	231
2035	231	231	401	99	99	231
2036	235	235	436	99	99	230

Flexible Resource Supply Forecast

Requirements by NERC and the WECC dictate the types of resources that can be used to serve the reserve requirements.

- **10-minute spinning reserve** can only be provided by resources currently online and synchronized to the transmission grid;

- **10-minute non-spinning reserve** may be served by fast-start resources that are capable of being online and synchronized to the transmission grid within ten minutes. Interruptible load can only provide non-spinning reserve. Non-spinning reserve may be provided by resources that are capable of providing spinning reserve.

- **30-minute regulation reserve** can be provided by unused spinning or non-spinning reserve. Incremental 30-minute ramping capability beyond the 10-minute capability captured in the categories above also counts toward this requirement.

The resources that PacifiCorp employs to serve its reserve requirements include owned hydro resources that have storage, owned thermal resources, and purchased power contracts that provide reserve capability.

Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as contracted generation from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.

Table F.20 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas. All the resources included in the calculation are capable of providing all types of reserve. The non-spinning reserve resources under third party contracts are excluded in the calculations. The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

Table F.20 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-minute)	West Supply (10-minute)	East Supply (30-minute)	West Supply (30-minute)
2017	1,340	745	1,975	1,009
2018	1,340	751	1,975	1,015
2019	1,290	700	1,875	964
2020	1,290	743	1,875	1,007
2021	1,250	724	1,755	988
2022	1,250	684	1,755	948
2023	1,250	725	1,755	989
2024	1,250	725	1,755	989
2025	1,250	725	1,755	989
2026	1,250	724	1,755	988
2027	1,250	725	1,755	989
2028	1,169	726	1,675	990
2029	1,281	692	1,786	890
2030	1,231	968	1,656	1,166
2031	1,231	969	1,656	1,167
2032	1,231	970	1,657	1,168
2033	1,469	936	1,832	1,068
2034	1,469	935	1,832	1,067
2035	1,469	936	1,832	1,068
2036	1,469	937	1,833	1,069

Figure F.21 and Figure F.22 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.21 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

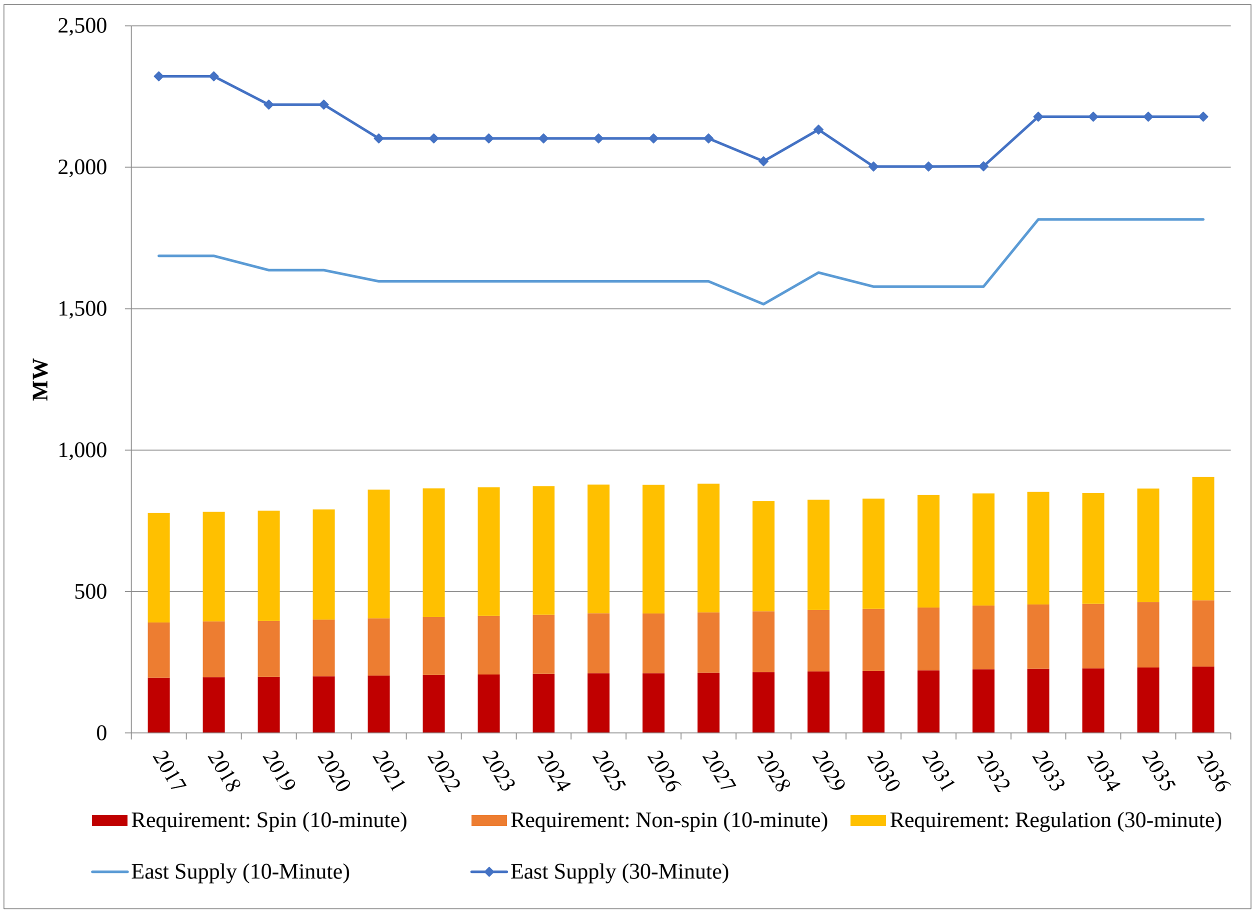
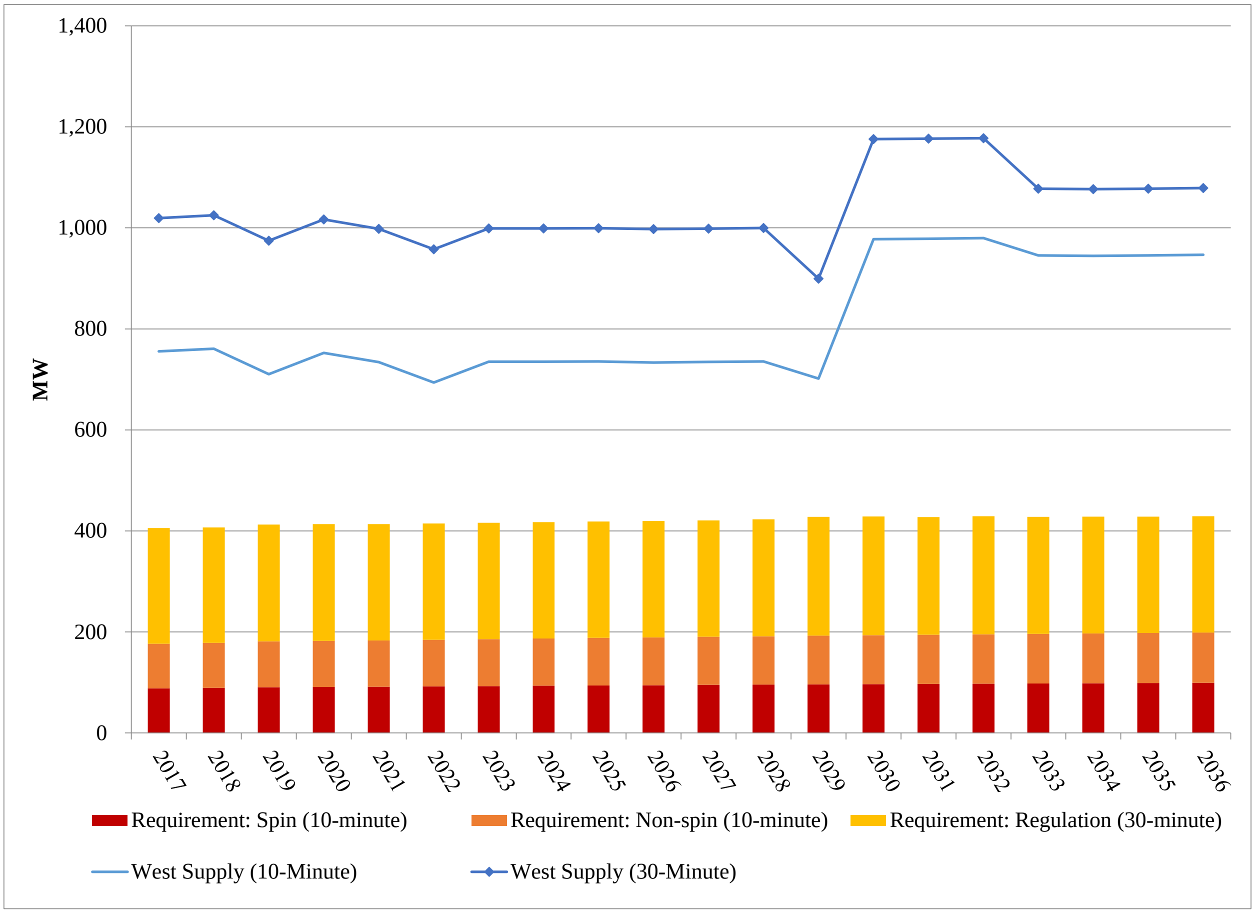


Figure F.22 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation has since expanded to include NV Energy, Arizona Public Service, and Puget Sound Energy, with several additional participants scheduled for entry between 2017 and 2019. By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour benefit reflects offsetting variability and lower combined uncertainty. PacifiCorp's regulation reserve forecast includes a credit to account for the diversity benefits associated with its participation in EIM.

As indicated in the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, the electric vehicle technology and market have not developed sufficiently to provide data for the current study. Since this analysis shows no gap between forecasted demand and supply of flexible resources over the IRP planning horizon, this IRP does not include whether electric vehicles could be used to meet future flexible resource needs.

Summary

The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

PacifiCorp incorporated a revised methodology in the FRS compared to its 2014 Wind Integration Study. The FRS now estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and flexibility reserve benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in the analysis and in the 2014 Wind Integration Study are shown in Table F.21.

Table F.21 – Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.22 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for comparison.

Table F.22 – 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2015$)	**Wind 2017 FRS** (2017$)	**Solar 2017 FRS** (2017$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

Reference Tables

Table F.23 - Wind

Resource ID	Nameplate Capacity (MW)	BAA	Grouping
DUNLAP_6_UNIT	111	PACE	Wind
FOOTECRE_7_UNITS	133.6	PACE	Wind
FREEZOUT_6_UNIT	118.5	PACE	Wind
GLENROCW_6_UNIT	138	PACE	Wind
HINSHAW_7_UNITS	144	PACE	Wind
HIPLAINS_7_UNITS	127.5	PACE	Wind
HORSEBU_7_UNIT	57.6	PACE	Wind
JOLLYHIL_1_GOSHEN	124.5	PACE	Wind
LATIGO_6_UNIT	99	PACE	Wind
MEADOWCR_6_UNIT	119.7	PACE	Wind
MOONSHIN_7_UNITS	45	PACE	Wind
MTWNDCOL_7_UNITS	140.7	PACE	Wind
RAWHIDE_6_UNIT	16.5	PACE	Wind
ROLLHILL_6_UNIT	99	PACE	Wind
SPNFKWND_7_UNIT	18.9	PACE	Wind
TOPWORLD_7_UNITS	200.2	PACE	Wind
WOLVERIN_7_UNITS	64.5	PACE	Wind
CAMPCOL_6_UNIT	98.9	PACW	Wind
COMBINEH_6_UNIT	41	PACW	Wind
DALREED_7_WIND	9.9	PACW	Wind
GOODNOEH_7_UNIT	94	PACW	Wind
HINKLE_6_UNIT	64.55	PACW	Wind
LEANJNPR_7_UNIT	100.5	PACW	Wind
MARENGO_6_UNITS	210.6	PACW	Wind
NINEMIL_7_UNIT 1	210	PACW	Wind
Total	**2587.65**		

Table F.24 – Non-VERs

Resource ID	Nameplate Capacity (MW)	BAA	Class
BONANZA_7_UNIT	458	PACE	Non-VER
DALTONU_7_UNIT	4.6	PACE	Non-VER
EXXON_7_UNITS	107.4	PACE	Non-VER
GEMSTATE_1_UNIT	23.4	PACE	Non-VER
MILLCRK_7_UNIT 1	40	PACE	Non-VER

MILLCRK_7_UNIT 2	40	PACE	Non-VER
NEBOPS_7_UNITS	140	PACE	Non-VER
PALISADI_7_UNIT 1	44	PACE	Non-VER
PALISADI_7_UNIT 2	44	PACE	Non-VER
PALISADI_7_UNIT 3	44	PACE	Non-VER
PALISADI_7_UNIT 4	44	PACE	Non-VER
SLENERGY_7_UNIT	3.2	PACE	Non-VER
SUNNYSIU_6_UNIT	53	PACE	Non-VER
TESORO_7_UNITS	25	PACE	Non-VER
USBRGATE_7_UNIT	4.5	PACE	Non-VER
WESTVALL_7_UNIT 1	40	PACE	Non-VER
WESTVALL_7_UNIT 2	40	PACE	Non-VER
WESTVALL_7_UNIT 3	40	PACE	Non-VER
WESTVALL_7_UNIT 4	40	PACE	Non-VER
WESTVALL_7_UNIT 5	40	PACE	Non-VER
BIOMAS_7_PACW	32.5	PACW	Non-VER
CAMASMI_7_UNIT	61.5	PACW	Non-VER
CLEARWA1_7_UNIT	17.9	PACW	Non-VER
CLEARWA2_7_UNIT	31	PACW	Non-VER
COID_7_UNITS	6	PACW	Non-VER
COLSTR_5_PACE	74	PACW	Non-VER
COLSTR_5_PACW	74	PACW	Non-VER
COPCO1_7_UNIT 1	14	PACW	Non-VER
COPCO1_7_UNIT 2	14	PACW	Non-VER
COPCO2_7_UNIT 1	17	PACW	Non-VER
COPCO2_7_UNIT 2	17	PACW	Non-VER
DALREED_7_BIO	4.8	PACW	Non-VER
EVERGBIO_6_BIO	10	PACW	Non-VER
FALLCREE_7_UNIT	2	PACW	Non-VER
FARMERS_6_UNIT	4.15	PACW	Non-VER
FISHCREO_7_UNIT	10.4	PACW	Non-VER
GRACE_7_UNIT 3	11	PACW	Non-VER
GRACE_7_UNIT 4	11	PACW	Non-VER
GRACE_7_UNIT 5	11	PACW	Non-VER
IRONGATE_7_UNIT	18.8	PACW	Non-VER
JCBOYLE_7_UNIT 1	40	PACW	Non-VER
JCBOYLE_7_UNIT 2	43	PACW	Non-VER
LEMOLO1_7_UNIT	32	PACW	Non-VER
LEMOLO2_7_UNIT	38.5	PACW	Non-VER
MERWIN_7_UNITS	150	PACW	Non-VER
OPALSPRI_7_UNIT	4.3	PACW	Non-VER

PELTONRE_7_UNIT	19.6	PACW	Non-VER
PENSTOCK_6_UNIT	5	PACW	Non-VER
PROSPEC2_7_UNIT 1	18	PACW	Non-VER
PROSPEC2_7_UNIT 2	18	PACW	Non-VER
PROSPEC3_7_UNIT	7.7	PACW	Non-VER
RFP_6_UNIT	10	PACW	Non-VER
ROSEBURL_7_LUMB	20	PACW	Non-VER
SLIDECRE_7_UNIT	18	PACW	Non-VER
SODA_7_UNIT 1	7	PACW	Non-VER
SODA_7_UNIT 2	7	PACW	Non-VER
SODASPRI_7_UNIT	11.6	PACW	Non-VER
TIETONHY_6_UNIT	13.8	PACW	Non-VER
TOKETEE_7_UNIT 1	15	PACW	Non-VER
TOKETEE_7_UNIT 2	15	PACW	Non-VER
TOKETEE_7_UNIT 3	15	PACW	Non-VER
WEBER_7_UNIT	2	PACW	Non-VER
Total	**2227.65**		

Table F.25 - Solar

Resource	Nameplate Capacity (MW)	BAA	Class
Beryl Solar	3	PACE	Solar
Buckhorn	3	PACE	Solar
Cedar Valley	3	PACE	Solar
Enterprise Solar I QF	80	PACE	Solar
Escalante Solar I QF	80	PACE	Solar
Escalante Solar II QF	80	PACE	Solar
Escalante Solar III QF	80	PACE	Solar
Fiddler's Canyon 1	3	PACE	Solar
Fiddler's Canyon 2	3	PACE	Solar
Fiddler's Canyon 3	3	PACE	Solar
Granite Mountain East Solar QF	80	PACE	Solar
Granite Mountain West Solar QF	50.4	PACE	Solar
Granite Peak	3	PACE	Solar
Greenville	2.2	PACE	Solar
Iron Springs Solar QF	80	PACE	Solar
Laho #1	3	PACE	Solar
Milford 2	2.97	PACE	Solar
Milford Flat	3	PACE	Solar

Pavant II Solar QF	50	PACE	Solar
Pavant III Solar	20	PACE	Solar
Quichapa 1	3	PACE	Solar
Quichapa 2	3	PACE	Solar
Quichapa 3	3	PACE	Solar
South Milford	2.93	PACE	Solar
Three Peaks Solar QF	80	PACE	Solar
Utah Pavant Solar QF	50	PACE	Solar
Utah Red Hills Solar QF	80	PACE	Solar
Adams Solar Center LLC	10	PACW	Solar
Beatty Solar	5	PACW	Solar
Black Cap	2	PACW	Solar
Black Cap II LLC	8	PACW	Solar
Bly Solar Center LLC	8.5	PACW	Solar
Chiloquin Solar	9.9	PACW	Solar
Collier Solar	9.9	PACW	Solar
Elbe Solar Center LLC	10	PACW	Solar
Ivory Pine Solar	10	PACW	Solar
Norwest Energy 2 LLC (Neff)	10	PACW	Solar
Old Mill Solar	5	PACW	Solar
OR Solar 2 (Agate Bay Solar)	10	PACW	Solar
OR Solar 3 (Turkey Hill Solar)	10	PACW	Solar
OR Solar 5 (Merrill)	8	PACW	Solar
OR Solar 6 (Lakeview)	10	PACW	Solar
OR Solar 7 (Jacksonville)	10	PACW	Solar
OR Solar 8 (Dairy)	10	PACW	Solar
Sprague River Solar	7	PACW	Solar
Tumbleweed Solar	9.9	PACW	Solar
Total	**1017.7**		

APPENDIX G – PLANT WATER CONSUMPTION

The information provide in this appendix is for PacifiCorp owned plants. Total water consumption and generation includes all owners for jointly-owned facilities

Table G.1 – Plant Water Consumption with Acre-Feet Per Year

			Acre-Feet Per Year					MWhs Per Year				4-year Average	
Plant Name	Zero Discharge	Cooling Media	2012	2013	2014 *	2015 *	4-year Average	2012	2013	2014	2015	Gals/ MWH	GPM/ MW
Chehalis		Air	55	86	150	93	96	849,938	1,674,194	2,543,785	1,095,433	20	0.3
Currant Creek	Yes	Air	90	84	92	78	86	2,132,523	2,359,924	2,498,058	2,257,106	12	0.2
Dave Johnston		Water	7,721	8,941	9,474	9,736	8,968	4,906,422	5,295,081	5,183,347	5,140,970	569	9.5
Gadsby		Water	1,059	610	367	1,022	764	214,739	339,592	325,677	123,795	993	16.5
Hunter	Yes	Water	18,266	17,001	16,662	16,386	17,079	9,118,876	9,546,313	9,098,918	9,630,419	595	9.9
Huntington	Yes	Water	10,423	10,643	10,240	9,888	10,299	6,744,160	6,768,625	6,300,558	5,988,318	520	8.7
Jim Bridger	Yes	Water	23,977	25,059	23,936	22,493	23,866	13,625,135	14,817,041	14,016,315	13,439,341	557	9.3
Lake Side ***		Water	1,693	1,361	2,960	4,533	3,746	2,890,938	2,508,960	4,351,182	4,550,871	274	4.6
Naughton ****	Yes	Water	8,745	9,622	7,484	9,160	8,753	5,056,959	5,533,895	4,958,589	4,899,321	558	9.3
Wyodak	Yes	Air	322	319	332	228	300	2,526,307	2,518,120	2,625,183	2,563,421	38	0.6
TOTAL			**72,351**	**73,726**	**71,695**	**73,616**	**72,591**	**48,065,997**	**51,361,745**	**51,901,612**	**49,688,995**	**472**	**7.9**

* Beginning in 2014, net water consumed reflects "Raw Water Consumed" instead of "Raw Water Diversion."

** Gadsby includes a mix of both Rankine steam units and peaking gas turbines.

*** Lake Side 2 went commercial in May 30, 2014. The averages for Lake Side 2 are based only on 2014 and 2015 numbers.

**** Naughton Unit 3 was rerated in September 2015 from 330 MW to 280 MW. The averages remain as 4-year averages.

1 acre-foot of water is equivalent to 325,851 Gallons or 43,560 Cubic Feet

Table G.2 – Plant Water Consumption by State (acre-feet)

UTAH PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Currant Creek	82	78	90	84	92	78
Gadsby	893	864	1,059	610	367	1,022
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Lake Side	1,533	1,154	1,693	1,361	2,960	4,533
TOTAL	**30,998**	**28,125**	**31,531**	**29,699**	**30,320**	**31,906**

Percent of total water consumption = 41.9%

WYOMING PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Dave Johnston	6,604	7,233	7,721	8,941	9,474	9,736
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Wyodak	396	367	322	319	332	228
TOTAL	**41111**	**44039**	**40765**	**43941**	**41225**	**41617**

Percent of total water consumption = 58.1%

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Dave Johnston	6,604	7,233	7,721	8,941	9,474	9,736
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Wyodak	396	367	322	319	332	228
TOTAL	**69,601**	**70,069**	**69,454**	**71,585**	**68,127**	**67,891**

Percent of total water consumption = 95.7%

NATURAL GAS FIRED PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Currant Creek	82	78	90	84	92	78
Chehalis	24	43	55	86	150	93
Gadsby	893	864	1,059	610	367	1,022
Lake side	1,533	1,154	1,693	1,361	2,960	4,533
Total	**2,532**	**2,139**	**2,897**	**2,141**	**3,569**	**5,726**

Percent of total water consumption = 4.4%

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2010	2011	2012	2013	2014	2015
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
TOTAL	**62,601**	**62,469**	**61,411**	**62,325**	**58,322**	**57,927**

Percent of total water consumption = 83.9%

APPENDIX H – STOCHASTIC PARAMETERS

For this IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2015 IRP for use in the Planning and Risk (PaR) model runs.

PaR, as used by PacifiCorp, develops portfolio cost scenarios via computational finance in concert with production simulation. The model stochastically shocks the case-specific underlying electricity price forecast as well as the corresponding case-specific key drivers (e.g., natural gas, loads, and hydro) and dispatches accordingly. Using exogenously calculated parameters (i.e., volatilities, mean reversions, and correlations), PaR develops scenarios that bracket the uncertainty surrounding a driver; statistical sampling techniques are then employed to limit the number of representative scenarios to 50. The stochastic model used in PaR is a two-factor (short- and long-run) short run mean reverting model.

PacifiCorp used short-run stochastic parameters for this IRP; long-run parameters were set to zero since PaR cannot re-optimize its capacity expansion plan. This inability to re-optimize or add capacity can create a problem when dispatching to meet extreme load and/or fuel price excursions, as often seen in long-term stochastic modeling. Such extreme out-year price and load excursions can influence portfolio costs disproportionately while not reflecting plausible outcome. Thus, since long-term volatility is the year-on-year growth rate, only the expected yearly price and/or load growth is simulated over the forecast horizon[1].

Key drivers that significantly affect the determination of prices tend to fall into two categories: loads and fuels. Targeting only key variables from each category simplifies the analysis while effectively capturing sensitivities on a larger number of individual variables. For instance, load uncertainty can encompass the sensitivities of weather, transmission availability, unit outages, and evolving end-uses. Depending on the region, fuel price uncertainty (especially that of natural gas) can encompass the sensitivities of weather, load growth, emissions, and hydro availability. The following sections summarize the development of stochastic process parameters and describe how these uncertain variables evolve over time.

[1]Mean reversion is assumed to be zero in the long run.

Introduction

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[2].

Volatility

The standard measure of uncertainty for a stochastic variable is volatility:

$$Volatility = \frac{Standard\ Deviation}{\sqrt{Time}}$$

The standard deviation[3] is a measure of how widely values are dispersed from the average value:

$$Standard\ Deviation = \sqrt{\frac{\sum_{i=1}^{n}(x_i - average)^2}{(n-1)}}$$

Volatility incorporates a time component so a variable with constant volatility has a larger spread of possible outcomes two years in the future than one year in the future. Volatilities are typically quoted on an annual basis but can be specified for any desired time period. Suppose the annual volatility of load in Idaho is two percent. This implies that the standard deviation of the range of possible loads in Idaho a year from now is two percent, while the standard deviation four years from now is four percent.

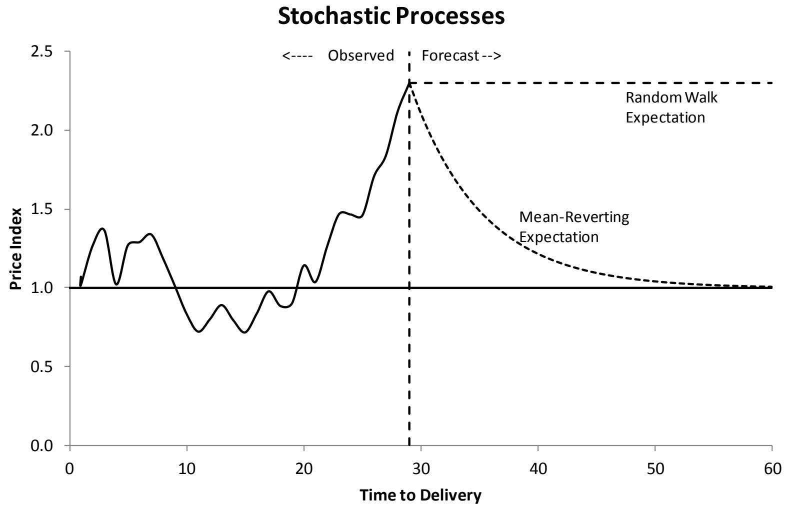
Mean Reversion

If volatility were constant over the forecast period, then the standard deviation would increase linearly with the square root of time. This is described as a "Random Walk" process and often provides a reasonable assumption for long-term uncertainty. However, for energy commodities as well as many other variables in the short-term, this is not typically the case. Excepting seasonal effects, the standard deviation increases less quickly with longer forecast time. This is called a mean reverting process - variable outcomes tend to revert back towards a long-term mean after experiencing a shock:

[2] A stochastic or random process is the counterpart to a deterministic process. Instead of dealing with only one possible reality of how the variables might evolve over time, there is some indeterminacy in the future evolution described by probability distributions.

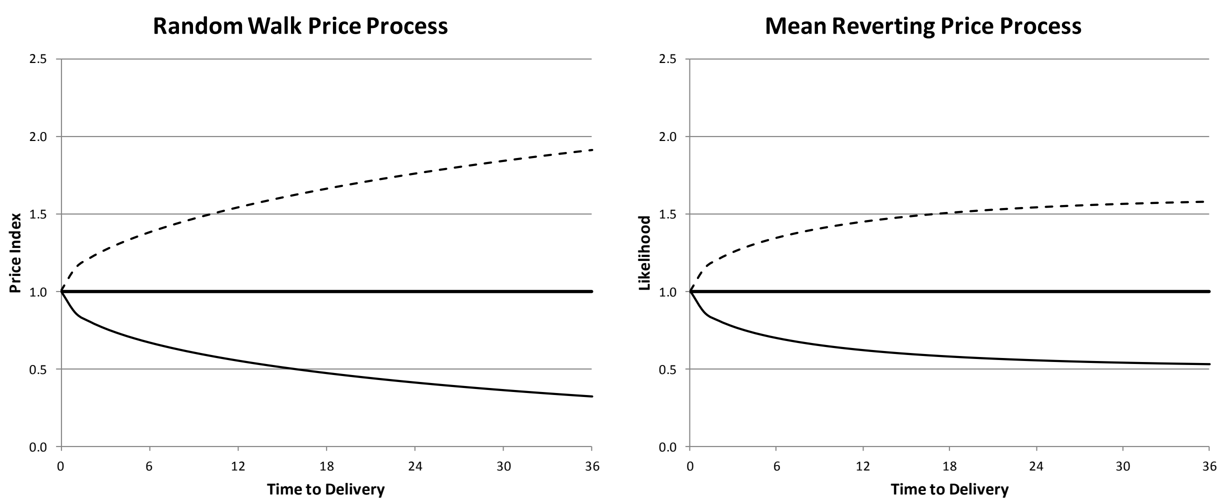
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

Figure H.1 – Stochastic Processes



For a random walk process, the distribution of possible future outcomes continues to increase indefinitely. While for a mean reverting process, the distribution of possible outcomes reaches a steady-state. Actual observed outcomes will continue to vary within the distribution, but the distribution across all possible outcomes does not increase:

Figure H.2 – Random Walk Price Process and Mean Reverting Process



The volatility and mean reversion rate parameters combine to provide a compact description of the distribution of possible variable outcomes over time. The volatility describes the size of a typical shock or deviation for a particular variable and the mean reversion rate describes how quickly the variable moves back towards the long-run mean after experiencing a shock.

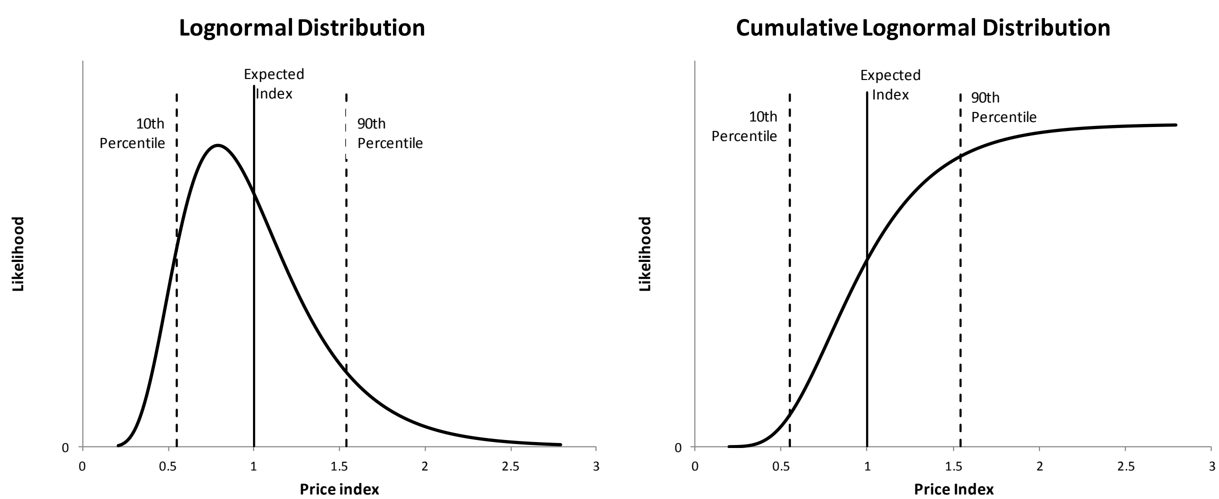
Estimating Short-term Process Parameters

Short-term uncertainty can best be described as a mean reverting process. The factors that drive uncertainty in the short-term are generally short-lived, decaying back to long-run average levels. Short-term uncertainty is mainly driven by weather (temperature, windiness, rainfall) but can also be driven by short-term economic factors, congestion, outages, etc. The process for estimating short-term uncertainty parameters is similar for most variables of interest. However, each of PacifiCorp's variables have characteristics that make their processes slightly different. The process for estimating short-term uncertainty parameters is described in detail below for the most straightforward variable -- natural gas prices. Each of the other variables is then discussed in terms of how they differ from the standard natural gas price parameter estimation process.

Stochastic Process Description

The first step in developing process parameter estimates for any uncertain variable is to determine the form of the distribution and time step for uncertainty. In the case of natural gas, and prices in general, the lognormal distribution is a good representation of possible future outcomes. A lognormal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed[4]. The lognormal distribution is often used to describe prices because it is bounded on the bottom by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average:

Figure H.3 – Lognormal Distribution and Cumulative Lognormal Distribution



The time step for calculating uncertainty parameters depends on how quickly a variable can experience a significant change. Natural gas prices can change substantially from day to day and are reported on a daily basis, so the time step for analysis will be one day.

[4] A normal distribution is the most common continuous distribution represented by a bell-shaped curve that is symmetrical about the mean, or average, value.

All short-term parameters were calculated on a seasonal basis to reflect the different dynamics present during different seasons of the year. For instance, the volatility of gas prices is higher in the winter and lower in the spring and summer. Seasons were defined as follows:

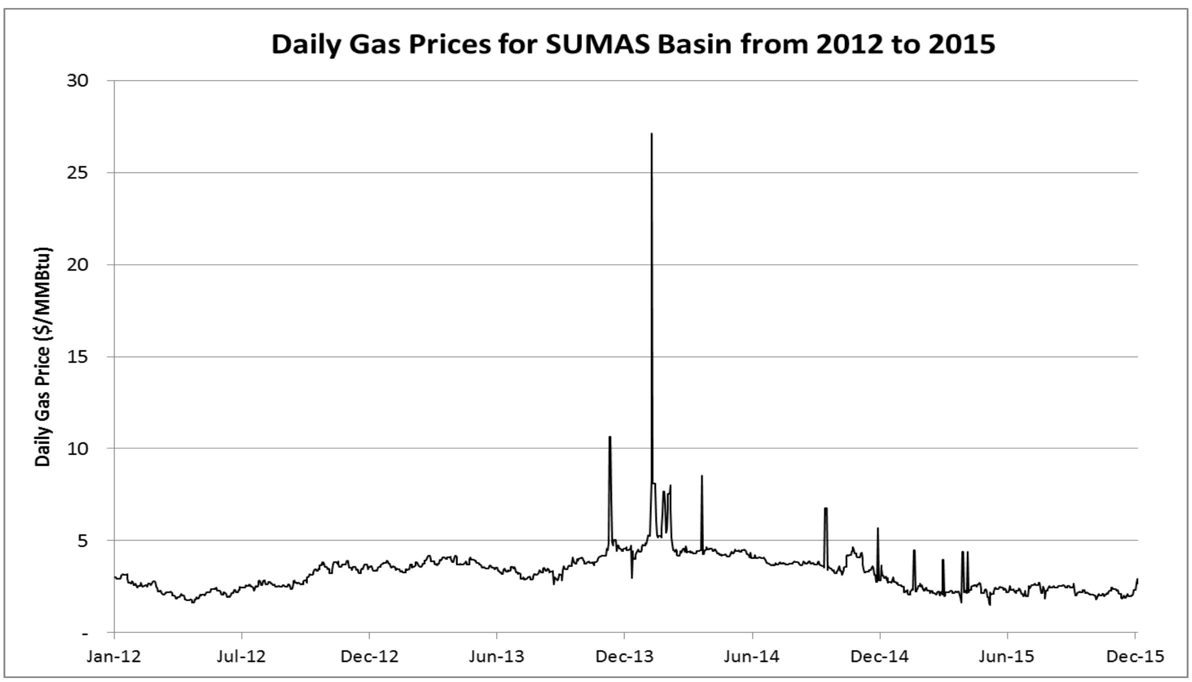
Table H.1 - Seasonal Definition

Winter	December, January, and February
Spring	March, April, and May
Summer	June, July, and August

Data Development

Basic Data Set:
The natural gas price data were organized into a consistent dataset with one natural gas price for each gas delivery point reported for each delivery day. The data were checked to make sure that there were no missing or duplicate dates. If no price is reported for a particular date, the date is included but left blank to maintain a consistent 24 hour time step between all observed prices. Four years of daily data from 2012 to 2015 was used for this short-term parameter analysis. The following chart shows the resulting data set for the Sumas gas basin:

Figure H.4 – Daily Gas Prices for SUMAS Basin



Development of Price Index:
Uncertainty parameters are estimated by looking at the movement, or deviation, in prices from one day to the next. However, some of this movement is due to expected factors, not uncertainty. For instance, gas prices are expected to be higher during winter or as we move towards winter. This expectation is already included in the gas price forecast and should not be considered a shock, or random event. In order to capture only the random or uncertain portion of price

movements, a price index is developed that takes into account the expected portion of price movements. There are three categories of price expectations that are calculated:

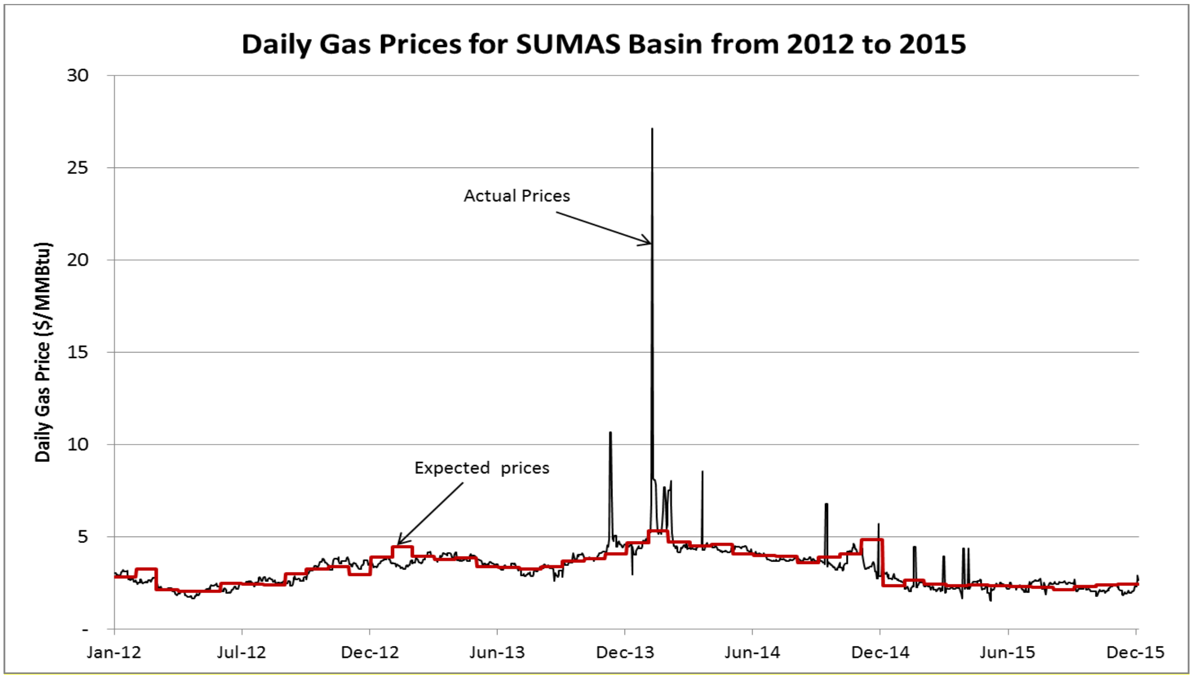
> Seasonal Average: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. In order to account for this possible difference in the level of gas prices, the average gas price for each season and year is calculated. For example, Sumas prices in the winter of 2012 average \$3.02/MMBtu.
>
> Monthly Average: Within a season, there are different expected prices by month. For instance, within the fall season, November gas prices are expected to be much higher than September and October prices as winter is just around the corner. A monthly factor representing the ratio of monthly prices to the seasonal average price is calculated. For example, February prices in Sumas are 108 percent of the winter average price.
>
> Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated but found to be insignificant (expected variation by weekday did not exceed two percent of the weekly average).

These three components: seasonal average, monthly shape, and weekly shape, combine to form an expected price for each day. For example, the expected price of gas in Sumas in January of 2012 was \$2.84/MMBtu, the product of the seasonal average and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Avg.Price * Monthly\ Shape\ within\ the\ Season$$

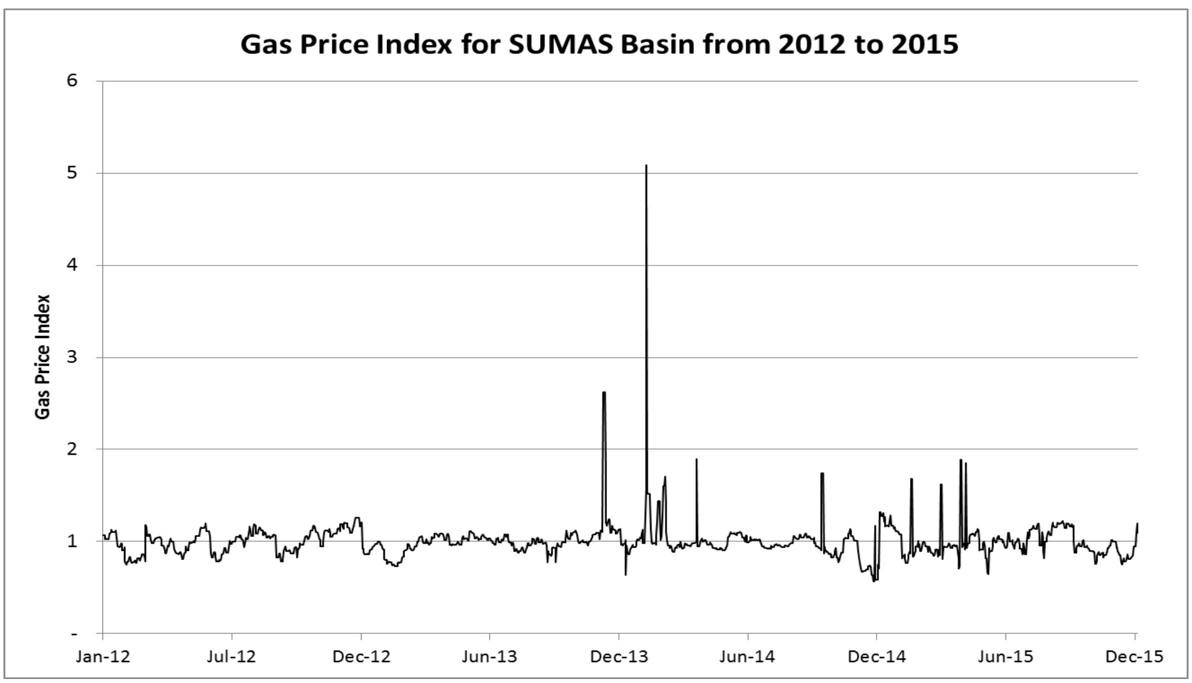
The chart below shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices



Dividing the actual gas prices by the expected prices forms a price index that averages one. This index captures only the random component of price movements—the portion not explained by expected seasonal, monthly, and weekly shape.

Figure H.6 – Gas Price Index for SUMAS Basin



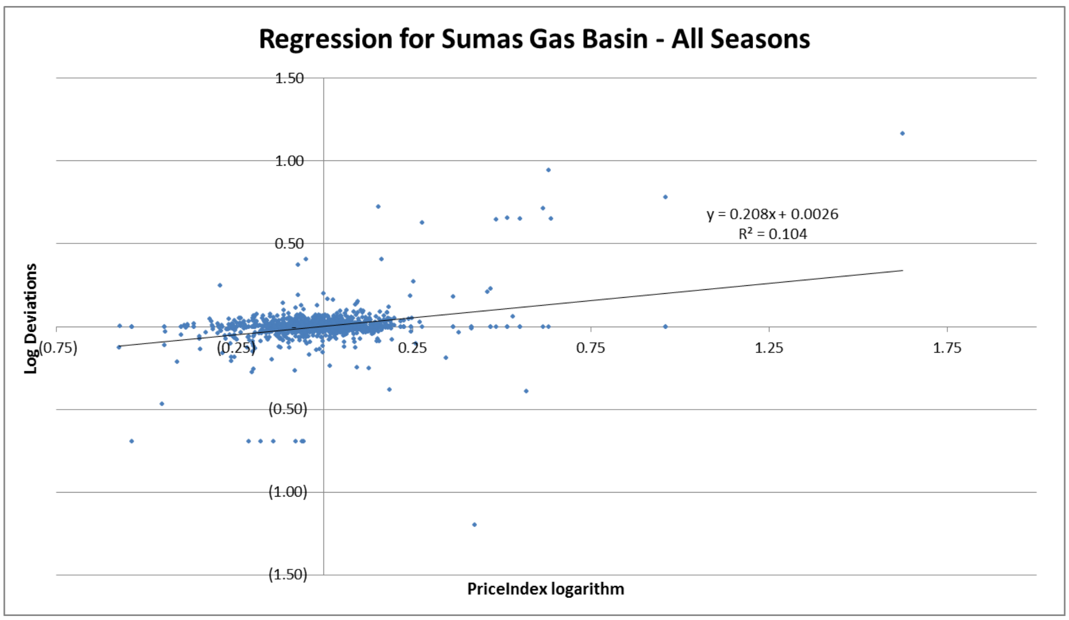
Parameter Estimation – Autoregressive Model

Uncertainty parameters are calculated for each variable by regressing the movement of each regions price index compared to the previous day's index.

Step 1 - Calculate Log Deviation of Price Index
Since gas prices are log normally distributed, the regression analysis is performed on the natural log of prices and their log deviations. The log deviations are simply the differences between the natural log of one day's price index and the natural log of the previous day's price index.

Step 2 - Perform Regression
The log deviations of price index are regressed against the previous day's logarithm of price index for each season as well as for the entire data set. The following chart shows the log of the price index versus the log deviations for Sumas gas for all seasons and the resulting regression equation:

Figure H.7 – Regression for SUMAS Gas Basin



Step 3 - Interpret the Results
The INTERCEPT of the regression represents the log of the long-run mean. So in this case, the intercept is approximately zero, implying that the long-run mean is equal to one. This is consistent with the way in which the price index is formulated.

The *SLOPE* of the regression is related to the auto correlation and mean reversion rate:

$$auto\ correlation = \emptyset = 1 + slope$$
$$Mean\ Reversion\ Rate\ \ \alpha = \ -\ln(\emptyset)$$

The autocorrelation measures how much of the price shock from the previous time period remains in the next time period. For instance, if the autocorrelation is 0.4 and gas prices yesterday experienced a 10 percent jump over the norm, today's expected price would be four percent higher than normal. In addition, today's gas price will experience a shock today that may result in prices higher or lower than this expectation. The mean reversion rate expresses the same thing in a different manner. The higher the mean reversion rate, the faster prices revert to the long-run mean.

The last component of the regression analysis is the *STANDARD ERROR* or *STEYX*. This measures the portion of the price movements not explained by mean reversion and is the estimate of the variable's volatility.
Both the mean reversion rate and volatility calculated with this process are daily parameters and can be applied directly to daily movements in gas prices.

Step 4 - Results
The natural gas price parameters derived through this process are reported in the table below.

Table H.2 - Uncertainty Parameters for Natural Gas

	Winter	Spring	Summer	Fall
KERN OPAL				
Daily Volatility	13.2%	10.4%	2.7%	2.8%
Daily Mean Reversion Rate	0.219	0.652	0.068	0.060
SUMAS				
Daily Volatility	14.0%	10.0%	4.2%	6.0%
Daily Mean Reversion Rate	0.197	0.537	0.125	0.157

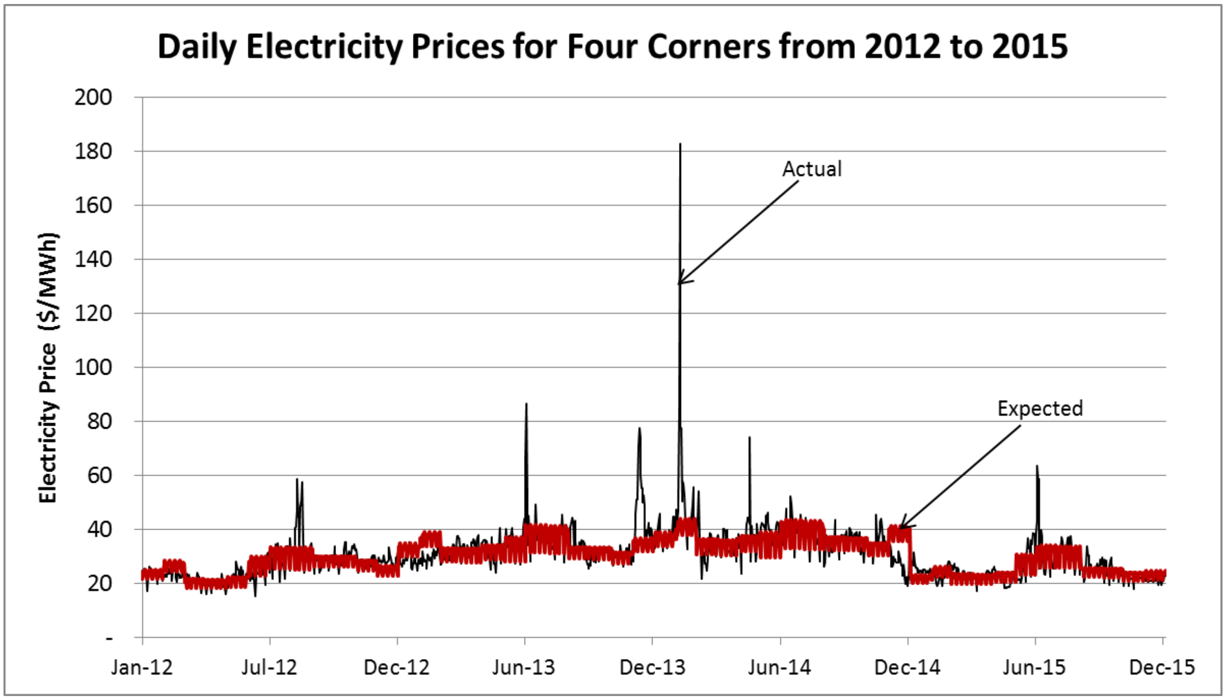
Electricity Price Process

For the most part, electricity prices behave very similar to natural gas prices. The lognormal distribution is generally a good assumption for electricity. While electricity prices do occasionally go below zero, this is not common enough to be worth using the Normal distribution assumption. And the distribution of electricity prices is often skewed upwards. In fact, even the lognormal assumption is sometimes inadequate for capturing the tail of the electricity price distribution. Similar to gas prices, electricity price can experience substantial change from one day to the next so a daily time step should be used.

Basic Data Set:
The electricity price data were organized into a consistent dataset with one price for each region reported for each delivery day similar to gas prices. Data covers the 2012 through 2015 time period. However, electricity prices are reported for "High Load Level" periods (16 hours for six days a week) and "Low Load Level" periods (eight hours for six days a week and 24 hours on Sunday & NERC holidays). In order to have a consistent price definition, a composite price calculated based on 16 hours of peak and eight hours of off-peak prices is used for Monday through Saturday. The Low Load Level price was used for Sundays since that already reflects the 24 hour price. Missing and duplicate data is handled in a fashion similar to gas prices. Illiquid delivery point prices are filled using liquid hub prices as reference. Mid-C is the most liquid market in PACW, so missing prices for COB are filled using latest available spread between COB and Mid-C markets. Similarly, Four Corner prices are filled using Palo Verde prices.

Development of Price Index:
As with gas prices, an electricity price index was developed which accounts for the expected components of price movements. The "expected" electricity price incorporates all three possible adjustments: seasonal average, monthly shape and weekly shape. For instance, the expected price for January 2, 2012 in the Four Corners region was $24.28/MWh. This price incorporates the 2012 winter average price of $25.26/MWh times the monthly shape factor for January of 94 percent and the weekday index for Monday of 102 percent. The following chart shows the Four Corners actual and expected electricity prices over the analysis time period.

Figure H.8 – Daily Electricity Prices for Four Corners



Electricity Price Uncertainty Parameters
Uncertainty parameters are calculated for each electric region similar to the process for gas prices. The electricity price parameters derived through this process are reported in the table below.

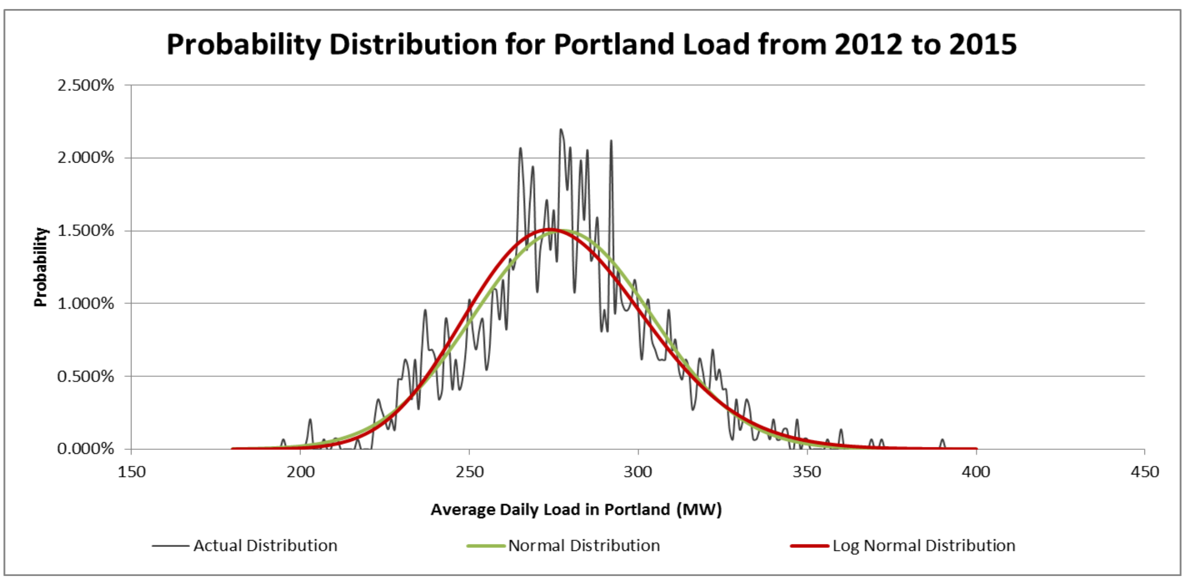
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	10.57%	8.68%	10.51%	6.55%
Daily Mean Reversion Rate	0.129	0.466	0.270	0.372
CA-OR Border				
Daily Volatility	13.61%	22.88%	23.51%	7.35%
Daily Mean Reversion Rate	0.135	0.435	0.390	0.227
Mid-Columbia				
Daily Volatility	16.18%	41.99%	38.34%	7.93%
Daily Mean Reversion Rate	0.138	0.510	0.910	0.188
Palo Verde				
Daily Volatility	10.59%	5.82%	8.78%	5.01%
Daily Mean Reversion Rate	0.160	0.308	0.252	0.247

Regional Load Process

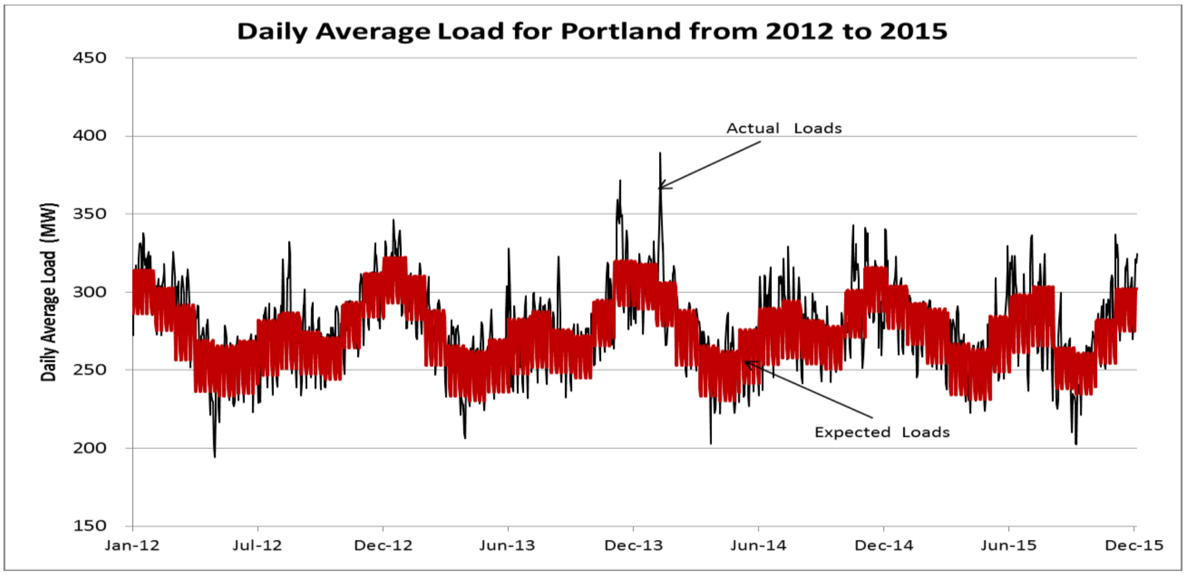
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution. And, similar to electricity prices, loads have a significant expected shape across the week. The chart below shows the distribution of historical load outcomes for the Portland area as well as normal and lognormal distribution functions representing load possibilities. Both distributions do a reasonable job of representing the spread of possible load outcomes but the tail of the lognormal distribution implies the possibility of higher loads than is supported by the historical data.

Figure H.9 – Probability Distribution for Portland Load



Development of Load Index:
As with electricity prices, a load index was developed which accounts for the expected components of load movements incorporating all three possible adjustments. For instance, the expected load for January 2, 2012 in Portland was 314 MW. This load incorporates the 2012 winter average load of 302 MW times the monthly shape factor for January of 101 percent and the weekday index for Monday of 102 percent. The following chart shows the Portland actual and expected loads over the analysis time period.

Figure H.10 – Daily Average Load for Portland



Load Uncertainty Parameters
Uncertainty parameters are calculated for each load region similar to the process for gas and electricity prices. Since loads are modeled as normally, rather than log-normally distributed, deviations are simply calculated as the difference between the load index and the previous day's index.

The uncertainty parameters for regional loads derived through this process are reported in the table below.

Table H.4 - Uncertainty Parameters for Load Regions

	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.5%	4.1%	3.6%	4.8%
Daily Mean Reversion Rate	0.268	0.263	0.156	0.296
Idaho				
Daily Volatility	3.1%	5.2%	4.8%	4.9%
Daily Mean Reversion Rate	0.175	0.097	0.101	0.210
Portland				
Daily Volatility	3.3%	2.9%	3.9%	3.4%
Daily Mean Reversion Rate	0.237	0.204	0.294	0.268
Oregon Other				
Daily Volatility	4.4%	3.4%	3.8%	4.1%
Daily Mean Reversion Rate	0.206	0.279	0.200	0.212
Utah				
Daily Volatility	2.2%	2.9%	4.5%	3.3%
Daily Mean Reversion Rate	0.400	0.398	0.211	0.287
Washington				
Daily Volatility	4.9%	3.8%	4.8%	4.4%
Daily Mean Reversion Rate	0.202	0.250	0.184	0.184
Wyoming				
Daily Volatility	1.7%	1.6%	1.6%	1.7%
Daily Mean Reversion Rate	0.263	0.271	0.316	0.192

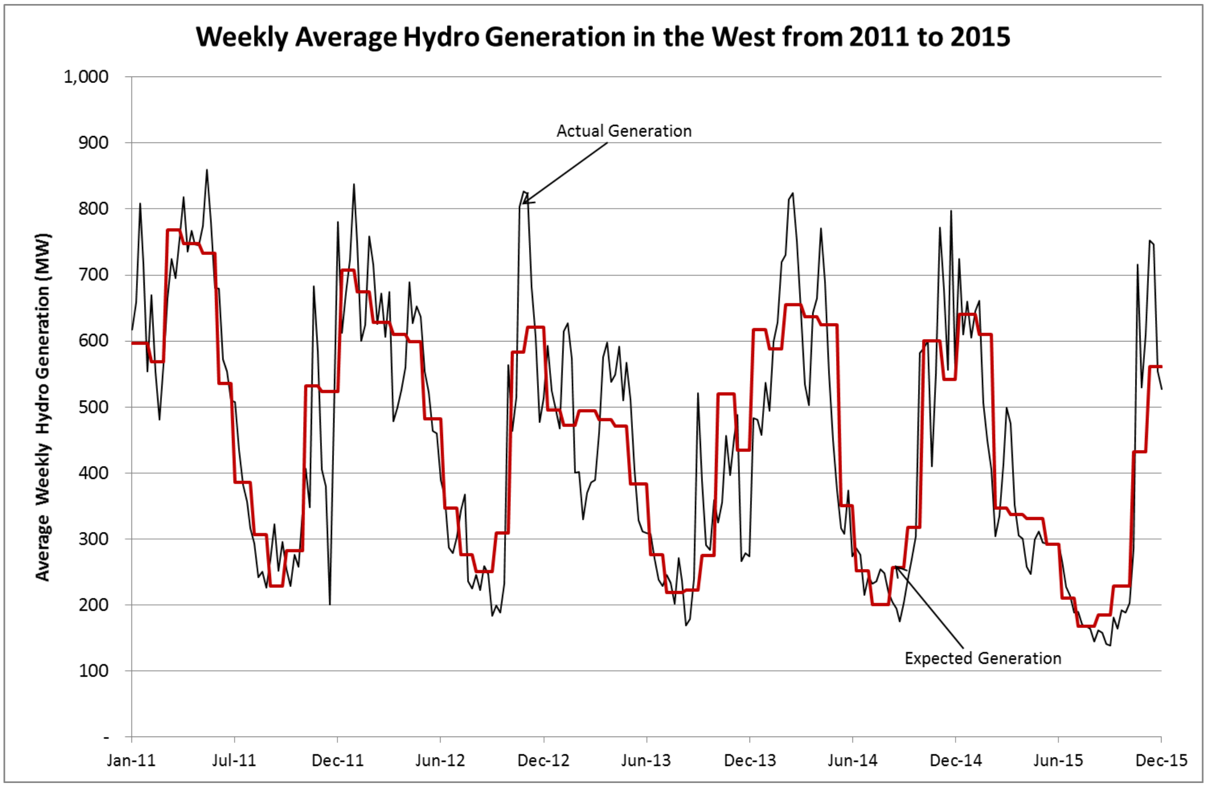
Hydro Generation Process

There are two differences between the uncertainty analysis for hydro generation and natural gas prices. Hydro generation varies on a slower time frame than other variables analyzed. As such, average hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the average hourly generation across the 168 hour in a week. In addition, an extra year of data was analyzed for hydro generation. The hydro analysis covers the 2011 through 2015 time period.

Development of Hydro Index:

A hydro generation index was developed which accounts for the expected components of hydro movements incorporating seasonal and monthly adjustments. For instance, the expected hydro generation for the week of January 1, 2011 through January 7, 2011 in the Western Region was 596 MW. This generation incorporates the 2011 winter average generation of 562 MW times the monthly shape factor for January of 106 percent. The following chart shows the western hydro actual and expected generation over the analysis time period.

Figure H.11 – Weekly Average Hydro Generation in the West



Hydro Generation Uncertainty Parameters
Uncertainty parameters are calculated for each hydro region similar to the process for gas and electricity prices. The uncertainty parameters for hydro generation derived through this process are reported in the table below.

Table H.5 - Uncertainty Parameters for Hydro Generation

	Winter	Spring	Summer	Fall
Daily Volatility	20.83%	13.38%	14.89%	27.98%
Daily Mean Reversion Rate	0.81	0.37	1.44	1.06

Short-term Correlation Estimation

Correlation is a measure of how much the random component of variables tend to move together. After the uncertainty analysis has been performed, the process for estimating correlations is relatively straight-forward.

Step 1 - Calculate Residual Errors

Calculate the residual errors of the regression analysis for all of the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each time period as the difference between the actual value and the value predicted by the linear regression equation:

$$Error = Actual\ Deviation - (Slope * Previous\ Deviation + Intercept)$$

All of the residual errors are compiled by delivery date.

Step 2 - Calculate Correlations

Correlate the residual errors of each pair of variables:

$$Correlation(X,Y) = \frac{\sum_i^n[(x_i - x_{avg.}) * (y_i - y_{avg.})]}{\sqrt{\sum_i^n(x_i - x_{avg.})^2 * \sum_i^n(y_i - y_{avg.})^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same time period is being compared for both variables. So for instance, weekly hydro deviations cannot be compared to daily gas price deviations. Thus, a daily regression analysis was performed for the hydro variables.

Also note that what is being correlated is the residual errors of the regression—only the uncertain portion of the variable movements. Variables may exhibit similar expected shapes—both loads and electricity prices are higher during the week than on the weekend. This coincidence is captured in the expected weekly shapes input into the planning model. The correlation calculated here captures the extent to which the shocks experienced by two different variables tend to have similar direction and magnitude. The resulting short-term correlations by season are reported below:

Table H.6 - Short-term Correlations by Season

SHORT-TERM WINTER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	92%	53%	27%	27%	52%	-4%	7%	14%	6%	2%	13%	6%	1%
SUMAS	92%	100%	46%	28%	28%	45%	-2%	9%	17%	10%	3%	16%	9%	-1%
4C	53%	46%	100%	54%	53%	78%	11%	21%	35%	27%	25%	34%	22%	6%
COB	27%	28%	54%	100%	96%	71%	14%	17%	35%	37%	18%	45%	22%	7%
Mid-C	27%	28%	53%	96%	100%	68%	14%	18%	36%	37%	18%	46%	23%	5%
PV	52%	45%	78%	71%	68%	100%	10%	16%	30%	25%	22%	31%	16%	9%
CA	-4%	-2%	11%	14%	14%	10%	100%	27%	40%	73%	32%	37%	18%	6%
ID	7%	9%	21%	17%	18%	16%	27%	100%	31%	33%	34%	37%	31%	-6%
Portland	14%	17%	35%	35%	36%	30%	40%	31%	100%	70%	51%	66%	35%	6%
OR Other	6%	10%	27%	37%	37%	25%	73%	33%	70%	100%	43%	65%	33%	8%
UT	2%	3%	25%	18%	18%	22%	32%	34%	51%	43%	100%	44%	48%	0%
WA	13%	16%	34%	45%	46%	31%	37%	37%	66%	65%	44%	100%	33%	15%
WY	6%	9%	22%	22%	23%	16%	18%	31%	35%	33%	48%	33%	100%	5%
Hydro	1%	-1%	6%	7%	5%	9%	6%	-6%	6%	8%	0%	15%	5%	100%

SHORT-TERM SPRING CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	87%	13%	9%	6%	18%	-1%	-1%	-2%	0%	-3%	-6%	3%	-2%
SUMAS	87%	100%	12%	9%	6%	14%	-2%	-2%	2%	1%	-3%	-1%	6%	-3%
4C	13%	12%	100%	42%	35%	64%	9%	9%	12%	10%	20%	11%	5%	-2%
COB	9%	9%	42%	100%	86%	46%	14%	2%	30%	28%	15%	33%	13%	3%
Mid-C	6%	6%	35%	86%	100%	33%	16%	7%	28%	26%	22%	30%	9%	0%
PV	18%	14%	64%	46%	33%	100%	12%	13%	24%	19%	30%	19%	9%	1%
CA	-1%	-2%	9%	14%	16%	12%	100%	23%	25%	45%	16%	31%	4%	3%
ID	-1%	-2%	9%	2%	7%	13%	23%	100%	9%	16%	47%	14%	12%	-11%
Portland	-2%	2%	12%	30%	28%	24%	25%	9%	100%	73%	29%	63%	24%	10%
OR Other	0%	1%	10%	28%	26%	19%	45%	16%	73%	100%	33%	69%	19%	11%
UT	-3%	-3%	20%	15%	22%	30%	16%	47%	29%	33%	100%	27%	35%	-11%
WA	-6%	-1%	11%	33%	30%	19%	31%	14%	63%	69%	27%	100%	19%	22%
WY	3%	6%	5%	13%	9%	9%	4%	12%	24%	19%	35%	19%	100%	2%
Hydro	-2%	-3%	-2%	3%	0%	1%	3%	-11%	10%	11%	-11%	22%	2%	100%

SHORT-TERM SUMMER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	56%	7%	10%	5%	11%	-4%	8%	12%	12%	4%	11%	-1%	0%
SUMAS	56%	100%	10%	13%	5%	13%	-1%	3%	16%	12%	-8%	11%	-6%	3%
4C	7%	10%	100%	45%	34%	84%	21%	8%	19%	20%	25%	12%	10%	5%
COB	10%	13%	45%	100%	66%	53%	16%	15%	35%	34%	12%	27%	-1%	24%
Mid-C	5%	5%	34%	66%	100%	37%	19%	9%	35%	34%	16%	30%	2%	8%
PV	11%	13%	84%	53%	37%	100%	16%	6%	19%	21%	20%	10%	11%	12%
CA	-4%	-1%	21%	16%	19%	16%	100%	30%	26%	49%	24%	37%	9%	4%
ID	8%	3%	8%	15%	9%	6%	30%	100%	14%	19%	38%	21%	20%	9%
Portland	12%	16%	19%	35%	35%	19%	26%	14%	100%	78%	18%	63%	-4%	22%
OR Other	12%	12%	20%	34%	34%	21%	49%	19%	78%	100%	27%	75%	-2%	19%
UT	4%	-8%	25%	12%	16%	20%	24%	38%	18%	27%	100%	26%	43%	2%
WA	11%	11%	12%	27%	30%	10%	37%	21%	63%	75%	26%	100%	-1%	15%
WY	-1%	-6%	10%	-1%	2%	11%	9%	20%	-4%	-2%	43%	-1%	100%	-3%
Hydro	0%	3%	5%	24%	8%	12%	4%	9%	22%	19%	2%	15%	-3%	100%

SHORT-TERM FALL CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	35%	14%	7%	4%	17%	9%	11%	8%	14%	8%	10%	8%	12%
SUMAS	35%	100%	6%	3%	4%	1%	7%	7%	9%	16%	6%	11%	17%	7%
4C	14%	6%	100%	45%	38%	73%	16%	13%	22%	24%	28%	23%	10%	-18%
COB	7%	3%	45%	100%	85%	50%	7%	6%	21%	22%	20%	24%	1%	-12%
Mid-C	4%	4%	38%	85%	100%	37%	9%	9%	24%	25%	13%	26%	0%	-10%
PV	17%	1%	73%	50%	37%	100%	12%	14%	20%	20%	26%	19%	8%	-16%
CA	9%	7%	16%	7%	9%	12%	100%	26%	43%	66%	27%	54%	19%	5%
ID	11%	7%	13%	6%	9%	14%	26%	100%	22%	27%	35%	24%	7%	-11%
Portland	8%	9%	22%	21%	24%	20%	43%	22%	100%	77%	40%	71%	32%	9%
OR Other	14%	16%	24%	22%	25%	20%	66%	27%	77%	100%	37%	82%	31%	8%
UT	8%	6%	28%	20%	13%	26%	27%	35%	40%	37%	100%	36%	37%	-2%
WA	10%	11%	23%	24%	26%	19%	54%	24%	71%	82%	36%	100%	31%	9%
WY	8%	17%	10%	1%	0%	8%	19%	7%	32%	31%	37%	31%	100%	13%
Hydro	12%	7%	-18%	-12%	-10%	-16%	5%	-11%	9%	8%	-2%	9%	13%	100%

Conclusion

For the continuous, stochastic variables that drive PacifiCorp's electricity environment short-term volatility and mean reversion, complete with corresponding correlations, provide a robust picture of the spread of future outcome. The standard parameters developed here can be used within the PaR model to develop PacifiCorp's Integrated Resource Plan.

APPENDIX I - PLANNING RESERVE MARGIN STUDY

Introduction

The planning reserve margin (PRM), measured as a percentage of coincident system peak load, is a parameter used in resource planning to ensure there are adequate resources to meet forecasted load over time. PacifiCorp selects a PRM for use in its resource planning by studying the relationship between cost and reliability among ten different PRM levels, accounting for variability and uncertainty in load and generation resources.[1] Costs include capital and run-rate fixed costs for new resources required to achieve ten different PRM levels, ranging from 11 percent to 20 percent, along with system production costs (fuel and non-fuel variable operating costs, contract costs, and market purchases). In analyzing reliability, PacifiCorp performed a stochastic loss of load study using the Planning and Risk (PaR) production cost simulation model to calculate the following reliability metrics for each PRM level:

- Expected Unserved Energy (EUE): Measured in gigawatt-hours (GWh), EUE reports the expected (mean) amount of load that exceeds available resources over the course of a given year. EUE measures the magnitude of reliability events, but does not measure frequency or duration.
- Loss of Load Hours (LOLH): LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. A LOLH of 2.4 hours per year equates to one day in 10 years, a common reliability target in the industry. LOLH measurs the duration of reliability events, but does not measure frequency or magnitude.
- Loss of Load Events (LOLE): LOLE is a count of the expected (mean) number of reliability events over the course of a given year. A LOLE of 0.1 events per year equates to one event in 10 years, a common reliability target in the industry. LOLE measures the frequency of reliability events, but does not measure magnitude or duration.

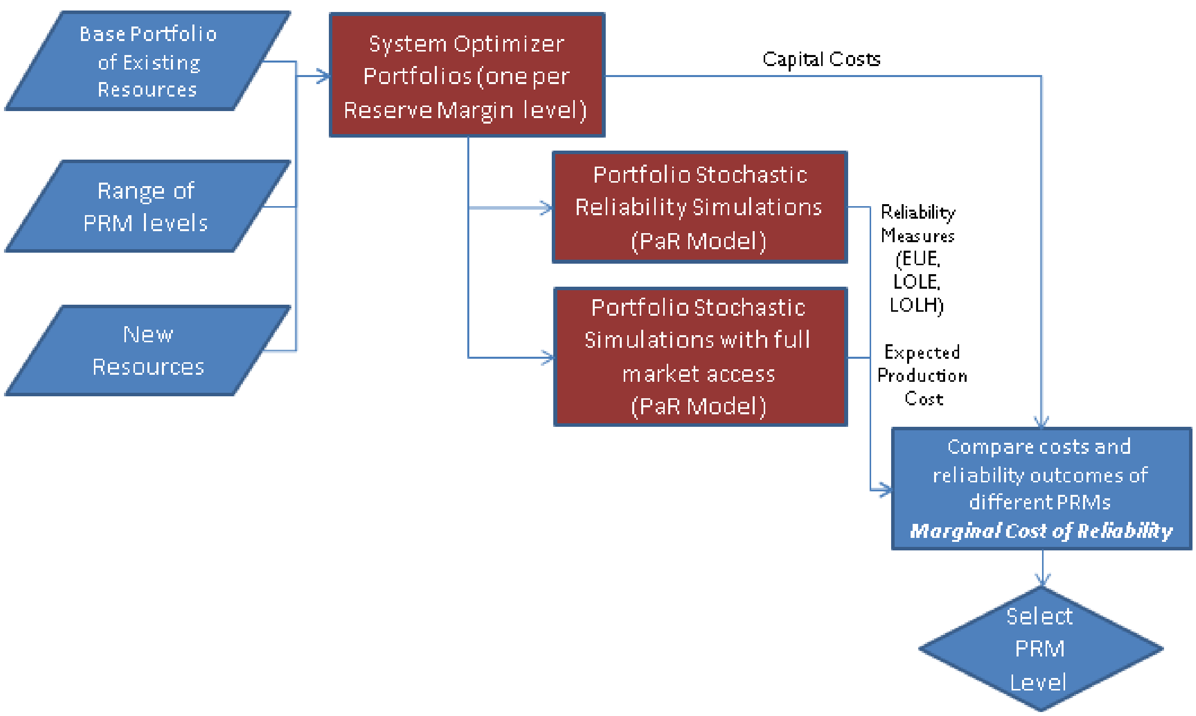
PacifiCorp’s loss of load study results reflect its participation in the Northwest Power Pool (NWPP) reserve sharing agreement. This agreement allows a participant to receive energy from other participants within the first hour of a contingency event, defined as an event when there is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. PacifiCorp’s participation in the NWPP reserve sharing agreement improves reliability at a given PRM level. Upon evaluating the relationship between cost and reliability in its PRM study, PacifiCorp will continue to use a 13 percent target PRM in its resource planning.

[1] Costs and reliability metrics are calculated for eleven different PRM levels, ranging from 10 percent to 20 percent. Comparative analysis among each PRM is performed for 10 different PRM levels by comparing the cost and reliability results from PRM levels ranging between 11 percent and 20 percent to those from the 10 percent PRM.

Methodology

Figure I.1 shows the workflow used in PacifiCorp's PRM study. The four basic modeling steps in the workflow include: (1) using the System Optimizer (SO) model, produce resource portfolios among eleven different PRM levels ranging between 10 percent and 20 percent; (2) using the Planning and Risk model (PaR), produce reliability metrics for each resource portfolio; (3) using PaR, produce system stochastic variable production costs with full market access for each resource portfolio; (4) produce the marginal cost of reliability using outcomes of different PRM levels, (5) select PRM level.

Figure I.1 - Workflow for Planning Reserve Margin Study



Development of Resource Portfolios

The SO model is used to produce resource portoflios assuming PRM levels ranging between 10 percent and 20 percent. The SO model optimizes expansion resources over a 20-year planning horizon to meet peak load inclusive of the PRM applicable to each case. An improvement was made in the study to meet the PRM in both summer and winter. As the PRM level is increased from 10 percent to 20 percent, additional resources are added to the portfolio. Resource options used in this step of the workflow include demand side management (DSM), gas-fired combined cycle combustion turbines (CCCT), gas-fired simple cycle combustion turbines (SCCT), renewable resources and front office transactions (FOTs).

FOTs are considered as a resource expansion option in this phase of the workflow. FOTs are proxy resources used in the IRP portfolio development process that represent firm forward short-term market purchases for summer and winter on-peak delivery, which coincides with the time of year and time of day in which PacifiCorp observes its coincident system peak load. These proxy resources are a reasonable representation of firm market purchases when performing comparative analysis of different resource portfolios to arrive at a preferred portfolio in the IRP.

Upfront capital and run-rate fixed costs from each portfolio are recorded and used later in the workflow where the relationship between cost and reliability is analyzed. Resources from each portfolio are used in the subsequent workflow steps where reliability metrics and production costs are produced in PaR.

Development of Reliability Metrics

PaR is used to produce reliability metrics for each of the resource portfolios developed assuming PRM levels ranging between 10 percent and 20 percent. PaR is a production cost simulation model, configured to represent PacifiCorp's integrated system, that uses Monte Carlo random sampling of stochastic variables to produce a distribution of system operation. For this step in the workflow, reliability metrics are produced from a 500-iteration PaR simulation with Monte Carlo draws of stochastic variables that affect system reliability—load, hydro generation, and thermal unit outages. As discussed above, system balancing hourly purchases are enabled to capture the contribution of firm market purchases to system reliability. The PaR reliability studies are used to report instances where load exceeds available resources, including system balancing hourly purchases. Reported EUE measures the stochastic mean volume of instances where load exceeds available resources, and is mesasured in GWh. EUE measures the magnitude of reliability events. Reported LOLH is a count of the stochastic mean hours in which load exceeds available resources. LOLH measures the duration of reliability events. Reported LOLE is a count of the stochastic mean events in which load exceeds available resources. LOLE is a measure of the frequency of reliability events.

Each of the reliability metrics described above is adjusted to account for PacifiCorp's participation in the NWPP reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. The NWPP adjustments are made to EUE by reducing the stochastic mean volume of instances where load exceeds available resources for the first hour of a reliability event. For example, if the stochastic mean volume of EUE for a reliability event is 120 MWh, equal to 40 MWh in three consecutive hours, then the adjusted EUE is 80 MWh after removing the first hour of the event. Using this same example, LOLH would be adjusted from three to two hours, and LOLE would not be adjusted. The LOLE is only adjusted inasmuch as a given reliability event has a one hour duration.

For PaR, the contribution of firm market purchases are removed and instead include system balancing hourly purchases that cover the firm market purchases, limited by transmission and market depth limits, for the reliability metrics.

Development of System Variable Production Costs

In addition to using PaR to develop reliability metrics, PaR is also used to produce system variable production operating costs for each of the resource portfolios developed assuming PRM levels ranging between 10 percent and 20 percent. For PaR's system variable production cost runs, its Monte Carlo sampling of stochastic variables is expanded to include natural gas and wholesale market prices in addition to load, hydro generation, and thermal unit outages. At this step, the stochastic treatment of market prices is key given its influence on the economic dispatch of system resources, cost of system balancing purchases, and revenues from system balancing sales. In this step, full market access is included for the simulation. The stochastic mean of system variable costs is added to the upfront capital and run-rate fixed costs from each portfolio so that total portfolio costs are captured for each PRM level.

Marginal Cost of Reliability The marginal cost of reliability compares costs and reliabability outcomes across different PRM levels for 2020 through 2030. The use of a 10-year test period was an improvement to that of earlier IRPs which used a one-year test period. The marginal cost of reliability for each PRM, vis-a-vis that of the 10-percent PRM, is calculated as the difference in total production costs divided by the change in EUE. Correspondingly, for a 10 year period, the average marginal cost of reliability is the 10-year nominal levelized cost of yearly marginal reliability costs. The average ten-year marginal cost of reliability is calculated for all PRM levels ranging between 11 percent and 20 percent.

Selection of PRM Level

Using the marginal cost of reliability analysis, the PRM level is selected for use in the 2017 IRP.

Results

Resource Portfolios

Table I.1 shows new resources added to the portfolio for the summer at PRM levels ranging between 10 and 20 percent. Each portfolio includes high load hour (HLH) front office transactions (FOTs) ranging from 550 to 1,136 MWs and flat FOTs of 176 MW in all PRMs. A 454 MW CCCT is added for the 19 percent and 20 percent PRM studies. DSM resource additions range between 374 MW and 431 MW. An improvement, to prior IRPs, was the inclusion of DSM Class 1 to the resource selection. As the PRM increases, system capacity is largely met with FOTs. Because new CCCT resources are added in blocks indicative of a typical plant size (i.e. the model cannot add a 2 MW CCCT plant), the addition of new DSM resources does not always follow an increase in the PRM.

Table I.1 - Expansion Resource Additions by PRM for Summer

PRM (%)	Summer						
	DSM Capacity at System Peak	DSM Class 1	FOT	FOT Flat	SCCT	CCCT	Total
10	380	0	550	176	0	0	1,107
11	374	0	651	176	0	0	1,201
12	380	0	738	176	0	0	1,294
13	384	0	828	176	0	0	1,388
14	394	0	912	175	0	0	1,481
15	400	0	1,000	175	0	0	1,575
16	382	0	1,112	176	0	0	1,670
17	425	25	1,134	174	0	0	1,759
18	431	113	1,136	172	0	0	1,852
19	396	0	982	175	0	454	2,007
20	380	0	1,093	176	0	454	2,103

Table I.2 shows new resources added to the portfolio for the winter at PRM levels ranging between 10 percent and 20 percent. The winter resource rating are difference from summer due to temperative variations and contribution to system peak.

Table I.2 - Expansion Resource Additions by PRM for Winter

PRM (%)	Winter						
	DSM Capacity at System Peak	DSM Class 1	FOT	FOT Flat	SCCT	CCCT	Total
10	240	0	26	176	0	0	442
11	237	0	34	176	0	0	447
12	240	0	41	176	0	0	456
13	243	0	48	176	0	0	467
14	250	0	55	175	0	0	480
15	253	0	70	175	0	0	497
16	241	0	86	176	0	0	502
17	259	25	101	174	0	0	559
18	266	113	93	172	0	0	643
19	248	0	133	175	0	454	1,010
20	239	0	149	176	0	454	1,018

Reliability Metrics

Table I.3 shows EUE, LOLH, and LOLE reliability results before and after adjusting these reliability metrics for PacifiCorp's participation in the NWPP reserve sharing agreement. Each of the reliability metrics generally improve as the PRM increases and after accounting for benefits associated with PacifiCorp's participation in the NWPP reserve sharing agreement. After accounting for its participation in the NWPP reserve sharing agreement, all PRM levels meet a one day in ten year planning criteria (LOLH at or below 2.4), and PRM levels of between 19 and 20 percent meet a one event in ten year planning criteria (LOLE at or above 0.1).

Table I.3 - Expected Reliability Metrics by PRM

PRM (%)	Before NWPP Adjustment			After NWPP Adjustment		
	Simulated Energy Not Served (GWh)	LOLH (<2.4 target year) (Hour)	Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
10	79	0.94	0.69	21	0.25	0.15
11	80	0.93	0.68	21	0.25	0.15
12	79	0.94	0.69	21	0.25	0.15
13	78	0.92	0.68	20	0.24	0.15
14	76	0.90	0.66	20	0.24	0.15
15	75	0.90	0.66	20	0.24	0.15
16	78	0.94	0.69	21	0.25	0.15
17	72	0.92	0.68	19	0.24	0.15
18	71	0.91	0.68	18	0.23	0.14
19	33	0.78	0.60	8	0.18	0.10
20	34	0.76	0.58	8	0.19	0.10

The reliability metrics do not montonically improve with each incremental increase in the PRM. This is influenced by the physical location of new resources within PacifiCorp's system at varying PRM levels and the ability of these resources to serve load in all load pockets when Monte Carlo sampling is applied to load, hydro generation, and thermal unit outages. Considering that the reliability metrics are measuring very small magnitudes of change among the different PRM levels, the PaR outputs are fit to a logarithmic function to report the overall trend in reliability improvements as the PRM level increases. Table I.4 shows the fitted EUE LOLH, and LOLE results. Figure I.2, Figure I.3 and Figure I.4 show a plot of the fitted trend for EUE, LOLH, and LOLE, respectively, after accounting for PacifiCorp's participation in the NWPP reserve sharing agreement.

Table I.4 - Fitted Reliability Metrics by PRM

PRM (%)	Before NWPP Adjustment			After NWPP Adjustment		
	EUE (GWh)	LOLH (<2.4 target year) (Hour)	Modeled Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
10	91	0.97	0.71	24	0.26	0.16
11	81	0.94	0.69	22	0.25	0.15
12	76	0.92	0.68	20	0.24	0.15
13	72	0.90	0.67	19	0.23	0.14
14	68	0.89	0.66	18	0.23	0.14
15	66	0.88	0.66	17	0.23	0.14
16	64	0.87	0.65	16	0.22	0.14
17	62	0.87	0.65	16	0.22	0.13
18	60	0.86	0.65	15	0.22	0.13
19	58	0.86	0.64	15	0.22	0.13
20	57	0.85	0.64	14	0.21	0.13

Figure I.2 - Expected and Fitted Relationship of EUE to PRM

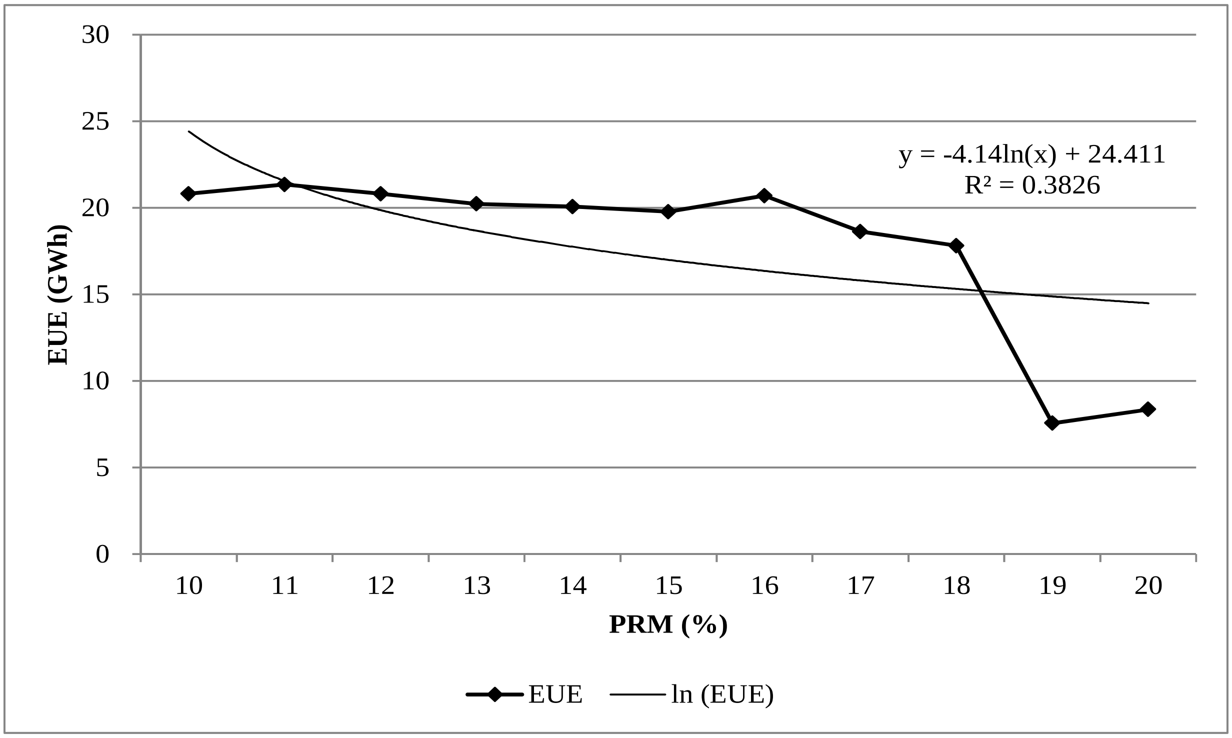


Figure I.3 - Expected and Fitted Relationship of LOLH to PRM

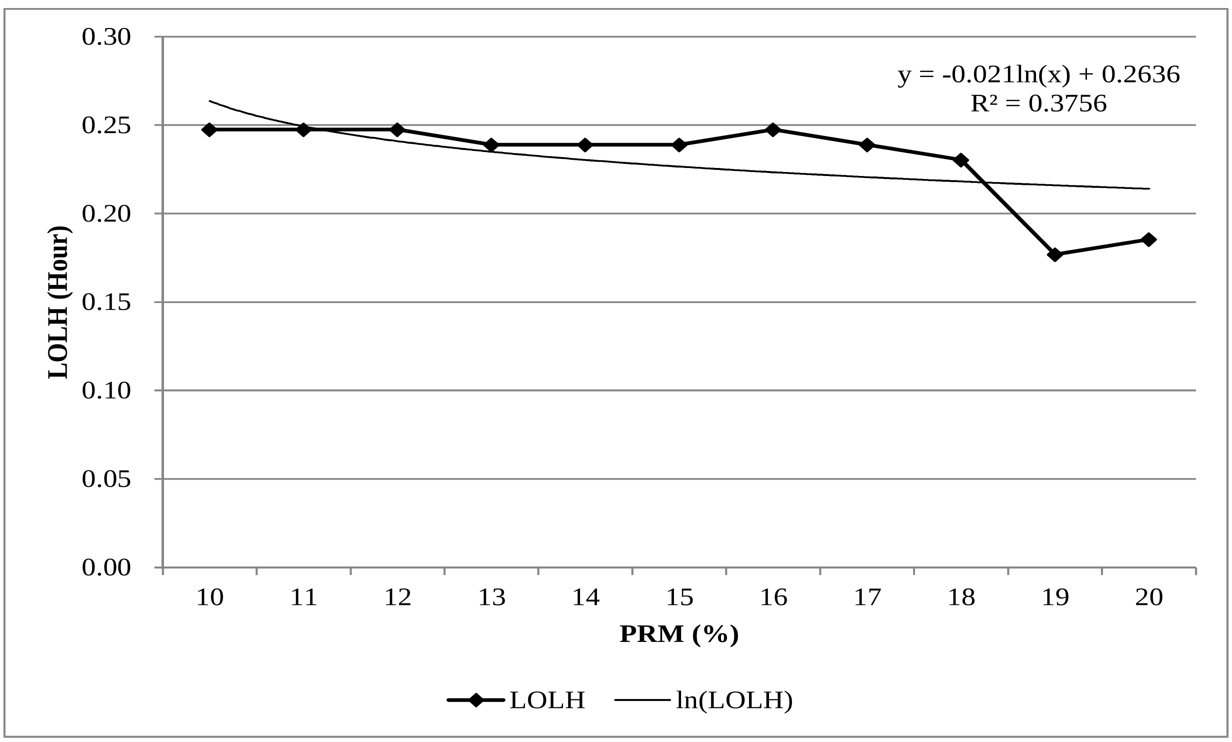
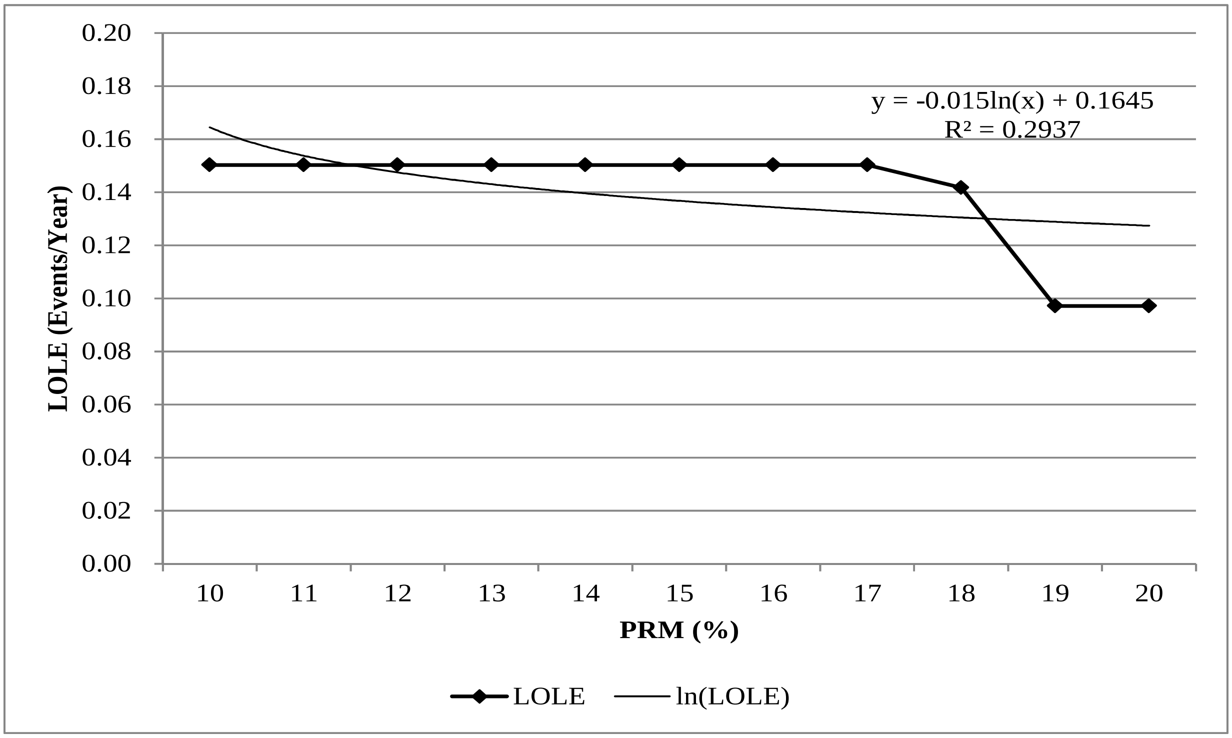


Figure I.4 - Simulated Relationship of Loss of Load Episode to PRM



System Costs

For the 2020 reference year, Table I.5 shows the stochastic mean of system variable production costs and the upfront capital and run-rate fixed costs, including the cost of new DSM resources, for each portfolio developed at PRM levels ranging between 10 percent and 20 percent. The fixed costs associated with these new resource additions drive total costs higher as PRM levels increase. DSM run-rate costs vary depending on resource additions for DSM Class 1 and new resources where a CCCT was added in 19 percent and 20 percent.

Table I.5 – System Variable, Up-front Capital, and Run-rate Fixed Costs by PRM

PRM (%)	System Production Costs ($m)	Class 2 DSM ($m)	Class 1 DSM ($m)	Existing Resource Fixed Costs ($m)	New Resource Fixed Cost ($m)	Total Costs ($m)
10	10,969	437	0	6,093	183	$17,681
11	11,003	404	0	6,093	197	$17,698
12	10,966	437	2	6,093	203	$17,701
13	10,958	463	9	6,093	193	$17,715
14	10,906	514	12	6,093	198	$17,723
15	10,892	553	28	6,093	181	$17,747
16	10,923	440	2	6,093	382	$17,840
17	10,882	522	18	6,093	354	$17,869
18	10,865	535	63	6,093	371	$17,927
19	10,835	527	26	6,093	581	$18,061
20	10,870	429	7	6,093	745	$18,144

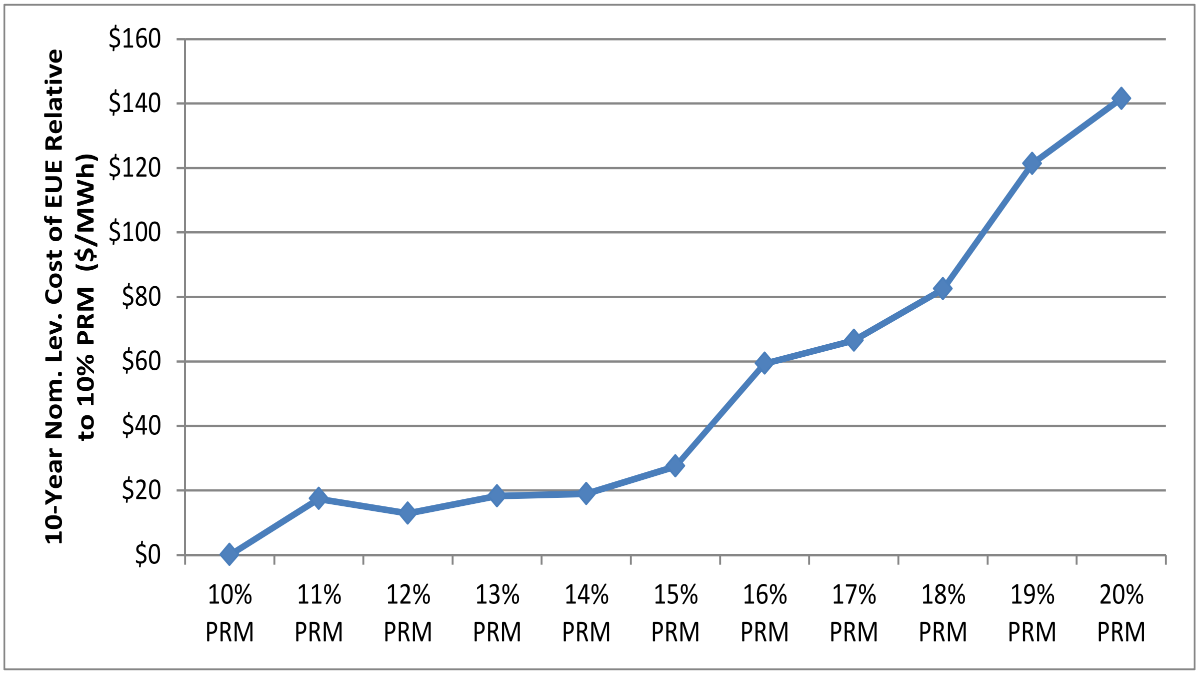
Incremental Cost of Reliability

Table I.6 shows the incremental cost of reliability, stated as the 10-year nominal levelized cost of EUE relative to 10 percent PRM, at PRM levels ranging between 11 percent and 20 percent. Figure I.5 depicts this same information graphically. The incremental cost of reliability rises modestly at the 14 percent to 15 percent PRM, then rises dramatically as PRM levels increase from 16 percent to 20 percent.

Table I.6 - 10-year nominal levelized cost of EUE relative to 10 percent PRM

PRM	Reduction in EUE Reliability from 10% PRM (GWh)	Reduction in Total Cost from 10% PRM ($ Million)	$/MWh
10	-	-	$0
11	930	16	$17
12	1,475	19	$13
13	1,861	34	$18
14	2,160	41	$19
15	2,405	66	$27
16	2,612	155	$59
17	2,791	185	$66
18	2,949	243	$82
19	3,091	375	$121
20	3,219	455	$141

Figure I.5 - Incremental Cost of Reliability by PRM



Conclusion

PacifiCorp will continue to use a 13 percent target PRM in its resource planning after evaluating the relationship between cost and reliability in the PRM study. A PRM below 13 percent would not sufficiently cover the need to carry short-term operating reserve needs (contingency and regulating margin) and longer-term uncertainties such as extended outages and changes in customer load.[2] A PRM above 15 percent improves reliability above a one event in ten year planning level, though with a 300 percent to 700 percent increase in the incremental cost per megawatt-hour of reduced EUE when compared to a 13 percent PRM. With these considerations, the selected 13 percent PRM level ensures PacifiCorp can reliably meet customer loads while maintaining operating reserves, with a planning criteria that meets one day in 10 year planning targets, at the lowest reasonable cost.

[2] PacifiCorp must hold approximately six percent of its resources in reserve to meet contingency reserve requirements and an estimated additional 4.5 percent to 5.5 percent of its resources in reserve, depending upon system conditions at the time of peak load, as regulating margin. This sums to 10.5 percent to 11.5 percent of operating reserves before even considering longer-term uncertainties such as extended outages (transmission or generation) and customer load growth.

APPENDIX J – WESTERN RESOURCE ADEQUACY EVALUATION

Introduction

The Public Service Commission of Utah, in its 2008 IRP Order, directed the Company to conduct two analyses pertaining to the Company's ability to support reliance on market purchases:

> *Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.*[1]

To fulfill the first requirement, PacifiCorp evaluated the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) reports to glean trends and conclusions from the supporting analysis. This evaluation, along with a discussion on risk allocation associated with reliance on market purchases, is provided below. As part of this evaluation, the Company also reviewed the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

Western Electricity Coordinating Council Resource Adequacy Assessment

The WECC 2016 PSA, issued in December 2016, shows a planning reserve margin (PRM) calculated as a percentage of resources (generation and transfers) and load, and is the percentage of capacity greater than demand. The PRM indicates that there are sufficient resources when the PRM is equal to or greater than the target planning reserve margin. The 2016 PSA shows WECC in total not needing additional resources throughout the entire period of the study, which ends in 2026 (see Figure J.1).

In WECC's PSAs, the region and sub-region target planning reserve margins are calculated using a building block methodology established by WECC. As such, they do not reflect a criteria-based margin determination process and do not reflect any balancing authority area or load serving entity level requirements that may have been established through other processes (e.g., state regulatory authorities). They are not intended to supplant any of those requirements.

[1] Public Service Commission of Utah, PacifiCorp 2008 Integrated Resource Plan, Report and Order, Docket No. 09-2035-01, p. 30.

The WECC building block methodology is comprised of four elements[2]:

1. Contingency Reserves – An amount of operating reserves sufficient to reduce area control error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency.

2. Regulating Reserves – The amount of spinning reserves responsive to automatic generation control that is sufficient to provide the normal regulating margin. The regulating component of this guideline was calculated using data provided in WECC's annual loads and resources data request responses.

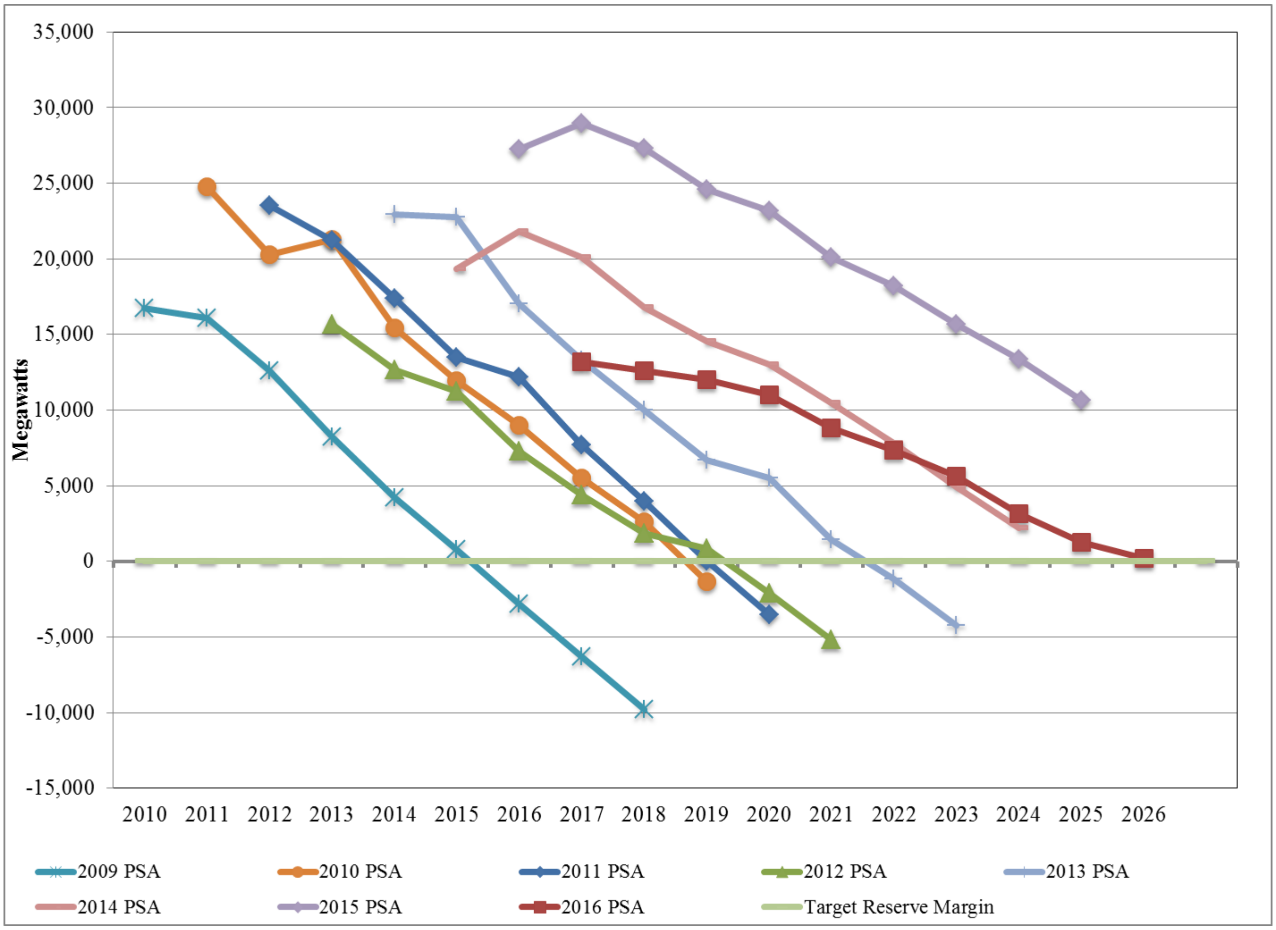
3. Reserves for Generation Forced Outages – The capacity lost to forced outages for both the summer (July) and winter (December) is added by sub-region and divided by the total capacity reported for each sub-region. The seasonal forced out rates are then averaged across five years to give the forced outage portion of the reserve margin.

4. Temperature Adders – a MW/degree Celsius coefficient is determined by WECC staff based on five years of daily peak demand regressed on daily maximum temperature for every weekday in the season. Fifty years of seasonal extremes in daily peak temperature are used to estimate the difference between a 1-in-2 and 1-in-10 observation. The MW/degree Celsius number is multiplied by the 1-in-10 temperature to yield a 90/10 extreme weather demand forecast.

As seen in Figure J.1, the 2016 PSA shows the WECC as having a positive summer power supply margin (PSM) in all years. The PSM is a measure of a region's ability to meet total load requirements, including its target reserve margin. As such, a PSM of zero or more indicates that demand plus the target reserve margin was met.

[2] Further details of building block elements can be found on the WECC website at the following location: https://www.wecc.biz/Reliability/2016LAR_MethodsAssumptions%20(002).pdf

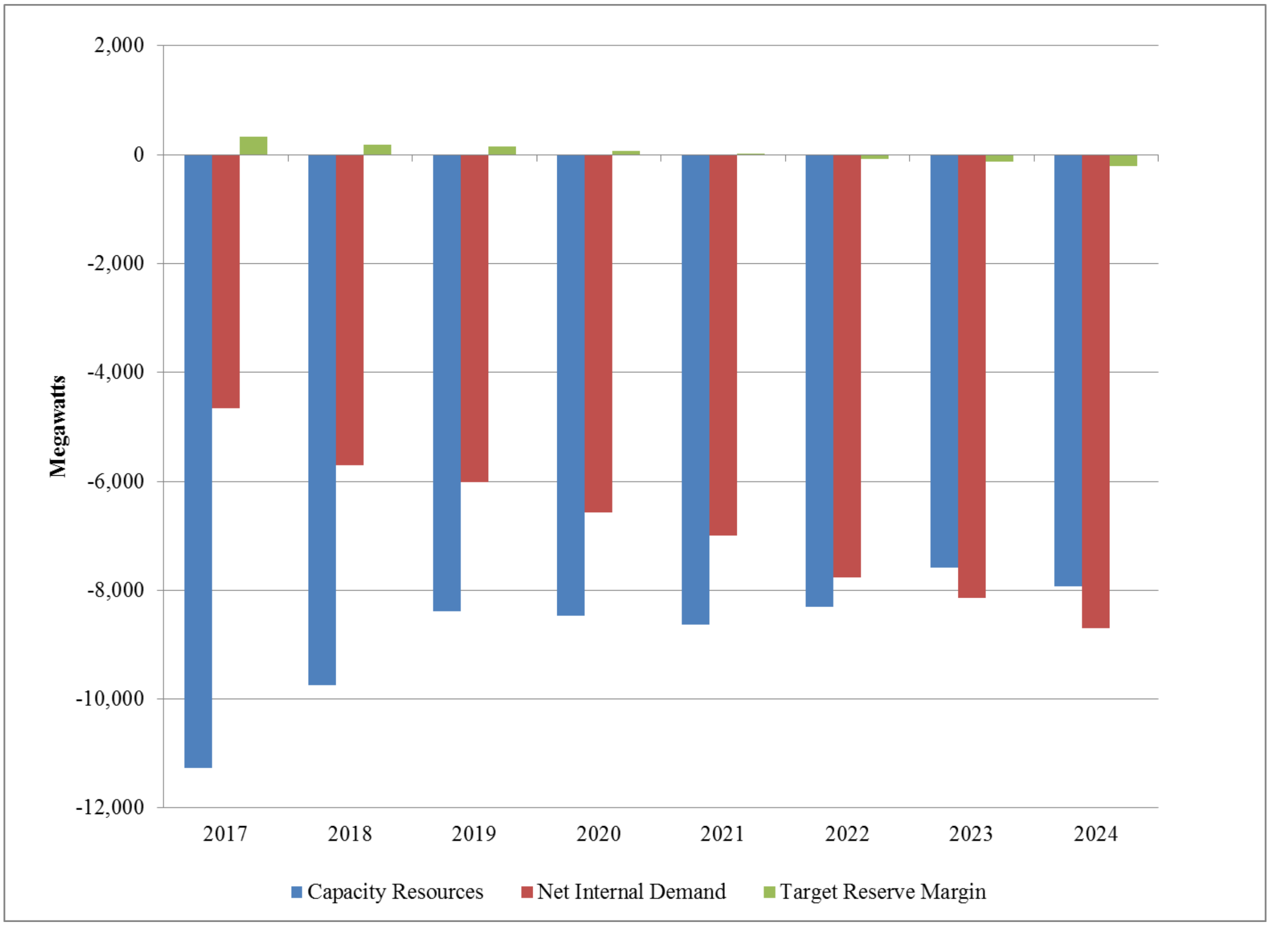
Figure J.1 - WECC Forecasted Power Supply Margins, Issued 2009 to 2016 (Summer)



Note: WECC Power Supply Assessments include Class 1 Planned Resources Only

The 2016 PSA shows no deficit for the study period. Figure J.2 shows the difference between the 2016 and 2014 PSA studies. For all years the load forecasts (net internal demand) and capacity resources decreased. The target reserve margins change from year to year, though for the most part are not a major contributor to the PSA deviations between the 2016 and 2014 PSAs.

Figure J.2 - 2016 less 2014 WECC PSA (for Summer Periods)



Tables J.1 and J.2 show both the target summer and winter planning reserve margins calculated in the 2016 WECC PSA report, along with the forecasted yearly results. These results are based on the following elements:

- Monthly and annual peak demand and energy forecasts:
- Expected generation availability;
- Annual energy for energy limited resources;
- Coincident hourly-shaping data for loads and energy-limited resources; and
- A simplified transmission configuration that reflects nominal power transfer capability limits.

Table J.1 - 2016 WECC Forecasted Planning Reserve Margins (Summer)

Planning Reserve Margin											
Subregion	Target Reserve Margin	2017 (S)	2018 (S)	2019 (S)	2020 (S)	2021 (S)	2022 (S)	2023 (S)	2024 (S)	2025 (S)	2026 (S)
NWPP	**15.20%**	27.7%	26.5%	28.3%	27.9%	26.6%	25.4%	24.7%	22.8%	20.0%	18.9%
RMRG	**14.14%**	27.0%	24.3%	22.1%	20.1%	19.7%	19.7%	19.6%	16.7%	16.5%	16.5%
SRSG	**15.82%**	23.4%	21.2%	21.1%	17.6%	17.5%	17.5%	17.4%	17.4%	17.4%	17.3%
CA/MX	**16.16%**	19.1%	20.3%	20.1%	21.3%	19.7%	18.8%	17.4%	16.0%	16.0%	15.6%
WECC Total	**15.37%**	24.1%	23.6%	23.2%	22.5%	21.0%	20.0%	18.9%	17.3%	16.1%	15.5%

Table J.2 – 2016 WECC Forecasted Planning Reserve Margins (Winter)

Planning Reserve Margin											
Subregion	Target Reserve Margin	2017-18 (W)	2018-19 (W)	2019-20 (W)	2020-21 (W)	2021-22 (W)	2022-23 (W)	2023-24 (W)	2024-25 (W)	2025-26 (W)	2026-27 (W)
NWPP	**16.70%**	24.9%	24.9%	24.1%	23.1%	22.4%	21.3%	20.8%	19.9%	17.7%	17.1%
RMRG	**11.65%**	59.5%	51.8%	48.4%	44.6%	41.6%	39.5%	37.4%	35.1%	33.3%	31.2%
SRSG	**12.11%**	101.6%	101.0%	96.5%	94.2%	89.8%	85.0%	80.9%	77.1%	73.3%	69.7%
CA/MX	**13.50%**	19.3%	19.9%	20.8%	22.2%	18.8%	20.3%	19.6%	17.9%	18.2%	18.6%
WECC Total	**14.27%**	35.3%	34.9%	34.2%	33.5%	31.7%	29.9%	28.8%	27.5%	26.2%	25.3%

The 2016 WECC planning reserve margin results show that there is no resource need through 2026 on a WECC total basis. However, the planning reserve margin for the CA/MX sub-region falls below the target reserve margin beginning in summer period 2024.

Northwest Power Pool (NWPP) is a winter peaking WECC sub-region comprised of Washington, Oregon, Idaho, Montana, Nevada, Utah, western Wyoming, Alberta, British Columbia and the Balancing Authority of Northern California. The target summer reserve margin for this region is 15.2 percent, which is slightly below the WECC Total forecasted planning reserve margin for 2017-2026 (15.37 percent). The target winter reserve margin for this region is 16.70 percent, which is above the WECC Total forecasted planning reserve margin for 2017-2026 (14.27 percent).

Market depth refers to a market's ability to accept individual transactions without a perceptible change in market price. While different from market liquidity[3] the two are linked in that a deep market tends to be a liquid market. Electricity market depth is a function of the number of economic agents, market period, generating capacity, transmission capability, transparency, and institutional and/or physical constraints. Based on the 2016 PSA, WECC maintains a positive power supply margin (PSM) through 2026. All of the WECC's sub-regions also are forecasted to maintain sufficient PSM through 2026, with the exception of the CA/MX sub-region. In total, known market transactions, generation resources, load requirements, and the optimization of transfers within WECC show adequate market depth to maintain target reserve margins for several years.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

The Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were

[3] Market liquidity refers to having ready and willing buyers and sellers for large transactions.

subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. The Resource Adequacy Advisory Committee issued a Pacific Northwest Power Supply Adequacy Assessment for 2021 on August 10, 2016. [4] This assessment concluded that power supply is expected to be adequate through 2020. However, with the planned retirements of four Northwest coal plants by July of 2022, 1,400 megawatts of new capacity will be needed to maintain the Council's adequacy standard. [5] In 2021, with the loss of 1,330 megawatts of capacity from the retirements of the Boardman and Centralia 1 coal plants, the likelihood of a power supply shortfall (also referred to as the loss of load probability) rises to 10 percent. In this scenario, the region will need more than 1,000 megawatts of new capacity to maintain adequacy. Northwest utilities show about 550 megawatts of planned generating capacity for 2021, yet this capacity was not included in the August 10, 2016 assessment because it was not yet sited and licensed.

Customer versus Shareholder Risk Allocation

Market purchase costs are reflected in rates. Consequently, customers bear the price risk of the Company's reliance on a given level of market purchases. However, customers also bear the cost impact of the Company's decision to build or acquire resources if those resources exceed market alternatives and result in an increase in rates. These offsetting risks stress the need for robust IRP analysis, efficient RFPs and ability to capture opportunistic procurement opportunities when they arise.

Market Purchases

As described in Volume I, Chapter 6 (Resource Options), PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp models front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the Company cover short positions.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

[4] Pacific Northwest Power Supply Adequacy Assessment for 2021, at https://www.nwcouncil.org/media/7150504/2021-adequacy-assessment-final-aug_9_2016.pdf
[5] The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall is higher than 5 percent.

In developing FOT limits for the 2017 IRP, PacifiCorp reviewed the studies described in the sections above as part of its assessment of western resource adequacy in addition to consideration of its active participation in wholesale power markets, its view of physical delivery constraints, and market liquidity and market depth. For the 2017 IRP, PacifiCorp held its FOT limits consistent with the prior IRP as shown in Table J.3.

Table J.3 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017 - 2036
July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	375 MW, 2017 - 2036
California Oregon Border (COB) Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017- 2036
Southern Oregon / Northern California (NOB) July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	100 MW, 2017- 2036
Mona July, Heavy Load Hour (6x16) December, Heavy Load Hour ("6x16")	300 MW, 2017-2036

In determining FOT limits for the 2017 IRP planning cycle, PacifiCorp reviewed historical market purchases from 2009 to 2015 in both the summer peak and winter peak periods. As shown in Figures J.3 and J.4 below, PacifiCorp reviewed its hourly purchases during peak load times in the summer and in the winter when market purchases may be more likely to be constrained by market depth or physical delivery constraints. The review showed that in 34 percent of summer hours and 17 percent of winter hours, PacifiCorp purchased more than its IRP FOT limit of 1,575 MW.

Figure J.3 - PacifiCorp Summer Peak Market Purchases 2009-2015

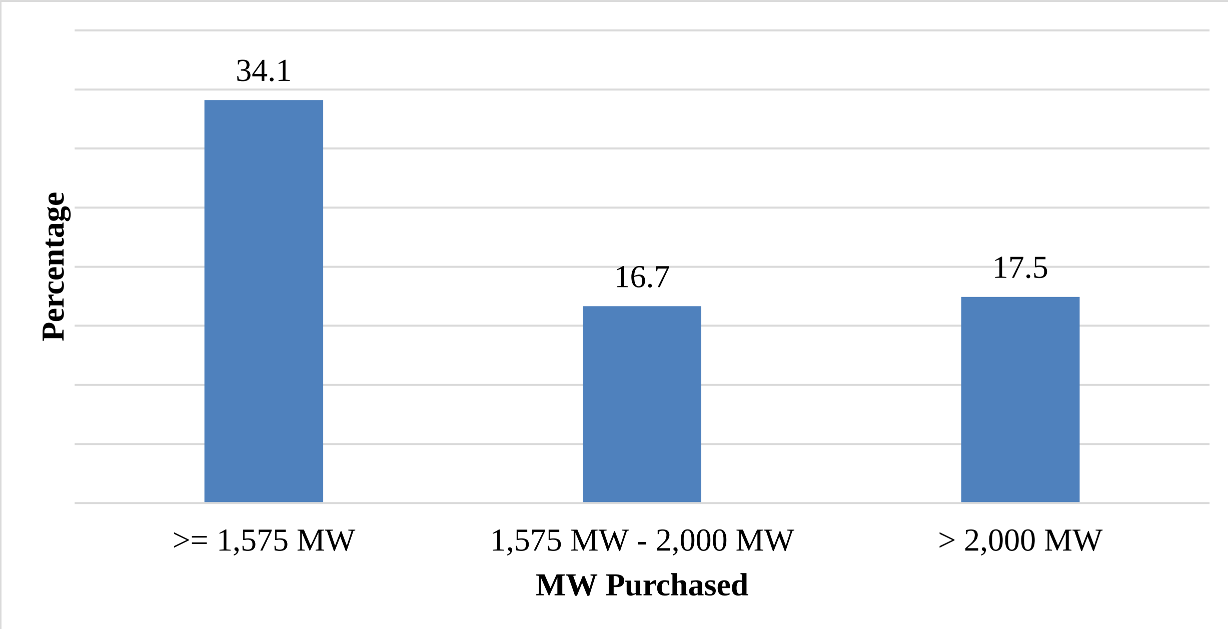
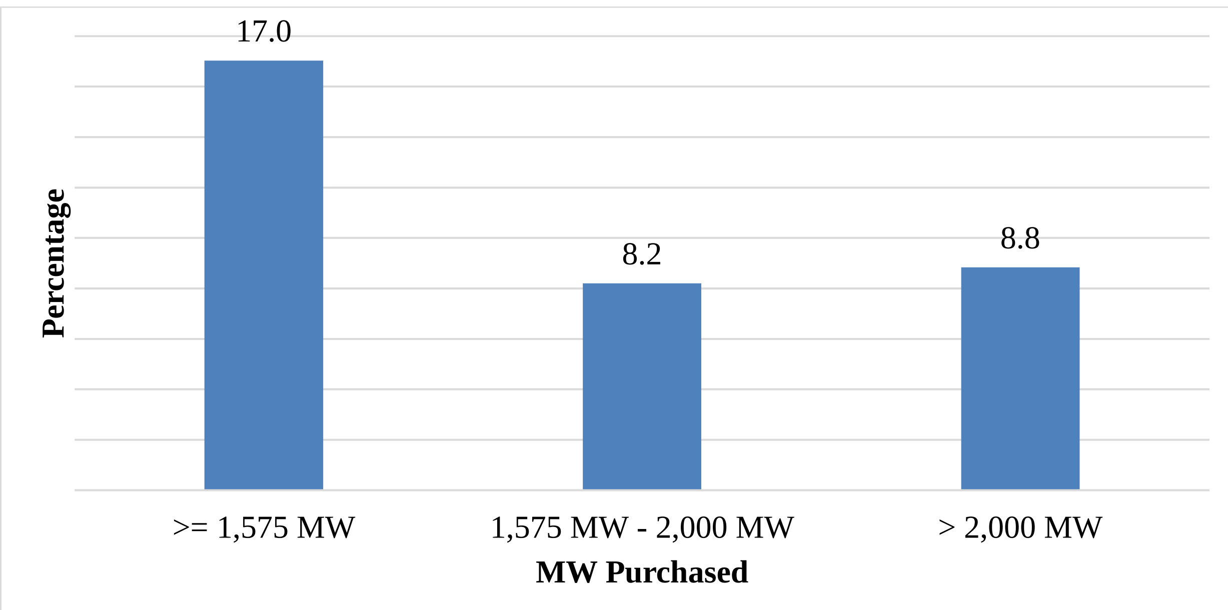


Figure J.4 - PacifiCorp Winter Peak Market Purchases 2009-2015



PacifiCorp believes based on its historical market transactions and review of western resource adequacy discussed above that its FOT limits for the 2017 IRP, unchanged from the 2015 IRP, continue to be a reasonable assumption.

APPENDIX K – CAPACITY EXPANSION RESULTS DETAIL

Portfolio Case Build Tables

This section provides the System Optimizer portfolio build tables for each of the case scenarios as described in the portfolio development section of Chapter 7. There are seven Regional Haze cases, eleven core cases, twenty sensitivity cases, and four final cases.

Table K.1 – Regional Haze Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR. ($m)
Ref.	Reference Case	-	Base	Base	Mass Cap B	Base	None	2032	$24,219
RH-1	Regional Haze 1	-	Base	Base	Mass Cap B	Base	None	2030	$23,159
RH-2	Regional Haze 2	-	Base	Base	Mass Cap B	Base	None	2029	$23,482
RH-3	Regional Haze 3	-	Base	Base	Mass Cap B	Base	None	2029	$23,398
RH-4	Regional Haze 4	-	Base	Base	Mass Cap B	Base	None	2030	$23,663
RH-5	Regional Haze 5	-	Base	Base	Mass Cap B	Base	None	2029	$23,177
RH-6	Regional Haze 6	-	Base	Base	Mass Cap B	Base	None	2028	$23,986

Table K.2 – Core Case Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR ($m)
OP-1	Optimized Portfolio	RH5	Base	Base	Mass Cap B	Base	None	2029	$23,177
OP-NT3	Optimized Naughton 3	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,052
OP-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,984
OP-GW4	Energy Gateway + Repower	OP-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,123
FR-1	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$23,585
FR-2	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$24,319
RE-1a	OR RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,082
RE-1b	WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,091
RE-1c	OR & WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,154
RE-2	OR RPS Early	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,098
DLC1	Direct Load Control	OP-NT3	Base	Base	Mass Cap B	Base	None	2030	$23,103

Table K.3 – Sensitivity Case Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/ Trans. ($m)
RH2a	Regional Haze	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,404
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None	2029	$23,364
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None	2030	$21,567
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None	2028	$24,818
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None	2029	$23,304
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None	2030	$22,899
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None	2029	$23,268
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None	2029	$23,102
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None	2029	$23,347
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None	2030	$26,401
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None	2028	$22,891
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None	2030	$23,198
GW1	Gateway 1	OP-NT3	Base	Base	Mass Cap B	Base	Segment D	2029	$23,593
GW2	Gateway 2	OP-NT3	Base	Base	Mass Cap B	Base	Segment F	2029	$24,054
GW3	Gateway 3	OP-NT3	Base	Base	Mass Cap B	Base	Segment D&F	2029	$24,627
GW4	Gateway 4	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,159
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,162
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,121
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,542
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,557

Table K.4 – Final Case Study Reference Guide

	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR ($m)
FS-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,042
FS-GW4	Gateway 4	FS-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,990
FS-1c	OR & WA RPS Just in Time	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,006
FS-2	OR RPS Early	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,995

Table K.5 – East Side Resource Name and Description

Resource List	Detailed Description
CCCT - DJohns - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Dave Johnston Brownfield
CCCT - Utah-S - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Utah South
CCCT - Utah-S - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Utah South
IC Aero UN	Inter-cooled Simple Cycle Combustion Turbine Aero - Utah North
SCCT Aero UN	Simple Cycle Combustion Turbine Aero - Utah North
SCCT Frame DJ	Simple Cycle Combustion Turbine Frame - Dave Johnston Brownfield
SCCT Frame UTN	Simple Cycle Combustion Turbine Frame - Utah North
SCCT Frame UTS	Simple Cycle Combustion Turbine Frame - Utah North
Battery Storage - East	Battery Storage – East
CAES - East	Compressed Air Energy Storage
Wind, DJohnston	Wind, Wyoming After DJ Retirement
Wind, GO	Wind, Goshen Idaho
Wind, UT	Wind, Utah
Wind, WYAE	Wind, Wyoming Aeolus
Utility Solar - PV - Utah-S	Utility Solar - Photovoltaic - Utah South
DSM, Class 1, ID-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Idaho
DSM, Class 1, ID-Curtail	Curtailment - Idaho
DSM, Class 1, ID-Irrigate	Direct Load Control-Irrigation -Idaho
DSM, Class 1, UT-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Utah
DSM, Class 1, UT-Curtail	Curtailment - Utah
DSM, Class 1, UT-ICE storage	Ice Energy Storage - Utah
DSM, Class 1, UT-Irrigate	Direct Load Control-Irrigation -Utah
DSM, Class 1, UT-Smart APPl	Direct Load Control-Smart Appliance-Residential - Utah
DSM, Class 1, UT-Thermostat	Direct Load Control-Smart Thermostat-Residential - Utah
DSM, Class 1, WY-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Wyoming
DSM, Class 1, WY-Curtail	Curtailment - Wyoming
DSM, Class 1, WY-Irrigate	Direct Load Control-Irrigation -Wyoming
DSM, Class 2, ID	DSM, Class 2 - Idaho
DSM, Class 2, UT	DSM, Class 2 - Utah
DSM, Class 2, WY	DSM, Class 2 - Wyoming
FOT Mona - SMR	Front Office Transaction - Summer HLH Product - Mona

Table K.6 – West-Side Resource Name and Description

Resource List	Detailed Description
CCCT - SOregonCal - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Southern Oregon
CCCT - WillamValcc - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - WillamValcc - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - Yakima - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Yakima, Washington
IC Aero PO	Inter-cooled Simple Cycle Combustion Turbine Aero - Portland-North Coast, Oregon
IC Aero SO	Inter-cooled Simple Cycle Combustion Turbine Aero - Southern Oregon
IC Aero WV	Inter-cooled Simple Cycle Combustion Turbine Aero - Willamette Valley, Oregon
IC Aero WW	Inter-cooled Simple Cycle Combustion Turbine Aero - Walla Walla, Washington
SCCT Frame SO	Simple Cycle Combustion Turbine Frame - Southern Oregon
Battery Storage - West	Battery Storage – West
Wind, SO	Wind, Southern Oregon
Wind, YK	Wind, Yakima, Washington
Utility Solar - PV - S-Oregon	Utility Solar - Photovoltaic - Southern Oregon
Utility Solar - PV - Yakima	Utility Solar - Photovoltaic - Yakima, Washington
Geothermal, Greenfield - West	Geothermal, Greenfield - West
DSM, Class 1, CA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - California
DSM, Class 1, CA-Curtail	Curtailment - California
DSM, Class 1, CA-Irrigate	Direct Load Control-Irrigation -California
DSM, Class 1, OR-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Oregon
DSM, Class 1, OR-Curtail	Curtailment - Oregon
DSM, Class 1, OR-Irrigate	Direct Load Control-Irrigation -Oregon
DSM, Class 1, OR-Thermostat	Direct Load Control-Smart Thermostat-Residential - Oregon
DSM, Class 1, WA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Washington
DSM, Class 1, WA-Curtail	Curtailment - Washington
DSM, Class 1, WA-Irrigate	Direct Load Control-Irrigation -Washington
DSM, Class 1, WA-Thermostat	Direct Load Control-Smart Thermostat-Residential - Washington
DSM, Class 2, CA	DSM, Class 2 - California

Table K.6 – West-Side Resource Name and Description (Continued)

Resource List	Detailed Description
DSM, Class 2, OR	DSM, Class 2 - Oregon
DSM, Class 2, WA	DSM, Class 2 - Washington
FOT COB - SMR	Front Office Transaction - Summer HLH Product - California Oregon Border
FOT COB - WTR	Front Office Transaction - Winter HLH Product - California Oregon Border
FOT MidColumbia - SMR	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - SMR - 2	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - WTR	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT MidColumbia - WTR2	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT NOB - SMR	Front Office Transaction - Summer HLH Product - Nevada Oregon Border
FOT NOB - WTR	Front Office Transaction - Winter HLH Product - Nevada Oregon Border

Table K.7 – Regional Haze Cases, Detailed Capacity Expansion Portfolios

	REF	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_AZ - Gas RePower	-	-	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-	-	-	-	387	387
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	617	145	-	-	-	-	-	-	762
	Wind, WYAE	-	-	-	-	299	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	299	300
	Total Wind	-	-	-	-	299	-	-	-	-	-	-	-	-	617	145	-	1	-	-	-	299	1,062
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	155	-	381
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	219.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	4	4	4	3	3	2	2	54	92
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	57	57	57	56	47	42	35	33	33	627	1,106
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	10	10	10	9	8	7	7	7	119	210
	DSM, Class 2 Total	97	73	74	75	78	77	76	85	82	84	78	73	72	72	71	60	53	45	42	42	801	1,409
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	29	98	300	300	248	300	300	300	300	-	109
West	**Expansion Resources**																						
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	-	295	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	344	55	73	-	-	471
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	118.1	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	24	23	23	22	22	20	19	19	19	409	626
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400	-	180
	FOT MidColumbia - SMR	399	400	400	400	378	400	360	341	400	400	400	400	400	400	400	400	400	400	400	400	388	394
	FOT MidColumbia - SMR - 2	-	276	112	46	-	23	-	-	64	-	65	375	375	375	375	375	375	375	375	375	52	198
	FOT NOB - SMR	100	100	100	100	-	9	7	67	100	100	100	100	100	100	100	100	100	100	100	100	68	84
	FOT MidColumbia - WTR	281	-	275	-	323	311	309	-	-	300	-	292	-	400	46	-	395	400	62	384	180	189
	FOT MidColumbia - WTR2	-	331	-	310	-	-	-	290	298	-	292	-	301	57	375	319	-	35	375	375	123	168
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	15	100	100	97	100	100	100	100	11	42
	Existing Plant Retirements/Conversions	-	-	5	-	-	-	-	-	-	(82)	-	(762)	-	(642)	(78)	-	(358)	-	(82)	-		
	Annual Additions, Long Term Resources	154	126	126	122	418	114	109	117	112	111	105	97	95	1,080	350	284	716	122	364	228		
	Annual Additions, Short Term Resources	779	1,107	887	856	701	743	676	698	915	854	865	1,606	1,689	2,132	2,096	1,939	2,070	2,110	2,112	2,434		
	Total Annual Additions	933	1,234	1,013	978	1,119	857	784	815	1,027	965	970	1,703	1,784	3,212	2,447	2,224	2,786	2,232	2,476	2,662		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

RH-1	Capacity (MW)																				Resource Totals 1/	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
Coal Ret_WY - Gas RePower	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expansion Resources																						
CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	165	86	-	-	-	-	285
Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	35	-	-	165	86	-	-	-	300	585
Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	41	291	46	-	699
DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	57	58	49	44	37	34	35	656	1,152
DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	122	218
DSM, Class 2 Total	97	74	79	75	81	86	85	86	89	84	82	78	73	73	73	62	55	47	43	44	835	1,465
FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	108	195	300	300	300	300	300	3	123
West																						
Existing Plant Retirements/Conversions																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	(354)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	(359)
Expansion Resources																						
CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	217	7	-	-	-	224
DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	-	39.4
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	93.5	24.7	-	3.3	-	-	-	-	-	-	121.5
DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	22	20	19	19	18	412	630
Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
FOT COB - SMR	-	-	-	-	-	-	-	-	279	188	249	400	400	400	400	400	400	400	400	364	47	214
FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia - SMR - 2	-	275	375	310	56	167	95	135	375	375	375	375	375	375	375	375	375	375	375	375	216	296
FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia - WTR	281	331	275	-	-	310	-	289	297	-	-	400	91	249	290	352	-	16	394	400	178	199
FOT MidColumbia - WTR2	-	-	-	310	322	-	308	-	-	299	290	21	375	-	-	-	351	375	-	251	124	145
FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	86	97	100	100	100	100	100	11	50
Existing Plant Retirements/Conversions	-	(280)	-	-	-	-	-	-	(387)	(82)	-	(762)	-	(357)	(78)	-	(712)	-	(82)	(359)		
Annual Additions, Long Term Resources	154	128	131	122	423	123	118	119	118	112	109	417	195	737	98	252	1,178	117	356	597		
Annual Additions, Short Term Resources	779	1,106	1,150	1,119	877	976	903	924	1,503	1,442	1,449	2,096	2,141	1,717	1,857	2,027	2,026	2,066	2,069	2,290		
Total Annual Additions	933	1,234	1,281	1,241	1,300	1,100	1,021	1,042	1,621	1,554	1,558	2,513	2,336	2,454	1,955	2,278	3,204	2,184	2,425	2,887		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RH-2	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	(269)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_CO - Gas RePower	-	-	-	-	-	-	82	-	-	-	-	-	-	-	-	-	-	-	(82)	-	82	-
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477	389	-	-	-	-	1,342
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	593	-	593
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	85	-	-	-	-	593	300	979
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	383	48	315	54	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	68.4	140.6	10.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	4	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	64	66	66	68	65	65	61	57	57	58	47	44	37	34	35	653	1,146
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	10	10	11	8	8	7	7	7	122	215
	DSM, Class 2 Total	97	74	79	75	81	83	85	86	89	84	82	78	72	72	73	59	55	47	43	44	832	1,457
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	71	272	300	279	300	300	300	300	-	121
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	-	-	-	-	-	-	54
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244	-	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	11.4	17.7	3.3	-	-	-	-	-	-	32.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	93.5	17.7	3.3	-	-	-	-	-	-	114.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	FOT COB - SMR	-	-	-	-	-	-	-	-	347	283	344	400	400	400	400	400	400	400	400	367	63	227
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	107	41	153	266	194	234	375	375	375	375	375	375	375	375	375	375	375	375	202	288
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	-	-	-	290	298	-	-	-	300	375	368	-	-	317	319	400	114	161
	FOT MidColumbia - WTR2	-	331	-	310	323	311	309	-	-	300	292	291	-	-	-	306	276	-	-	210	188	163
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	-	100	100	45	100	100	100	100	11	38
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	(354)	-	-	(432)	(359)	(642)	(78)	(687)	(688)	-	(164)	-		
	Annual Additions, Long Term Resources	154	128	131	122	421	120	118	119	118	111	109	171	765	599	237	960	1,094	117	381	721		
	Annual Additions, Short Term Resources	779	1,106	882	851	975	1,077	1,003	1,024	1,572	1,512	1,520	1,876	1,647	2,022	2,043	1,904	1,951	1,992	1,994	2,252		
	Total Annual Additions	933	1,234	1,013	973	1,397	1,196	1,122	1,143	1,690	1,623	1,628	2,047	2,412	2,621	2,280	2,864	3,046	2,108	2,375	2,974		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RH-3	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	-	-	800
	Wind, WYAE	-	-	-	-	235	-	-	-	-	-	-	-	-	-	-	-	65	-	-	-	235	300
	Total Wind	-	-	-	-	235	-	-	-	-	-	-	-	-	-	-	-	151	-	800	-	235	1,185
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	712	33	60	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	-	-	7.3	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	-	4.8	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	-	-	-	14.0	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	6	6	6	6	6	5	5	5	5	5	4	4	3	3	2	58	98
	DSM, Class 2, UT	84	62	62	59	70	68	66	67	72	69	65	65	57	60	59	51	45	40	48	24	679	1,192
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	13	13	12	11	11	10	9	8	9	5	125	227
	DSM, Class 2 Total	97	78	79	77	89	87	86	88	92	88	83	83	74	76	75	65	58	51	60	31	862	1,517
	Battery Storage - East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.0	-	-	-	8
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	127	91	188	300	300	300	300	272	3	112
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	286	13	19	-	-	318
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.8	-	-	-	9.2	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	108.9	-	-	-	12.6	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	9	9	9	9	8	8	7	6	5	5	5	4	3	3	2	2	88	130
	DSM, Class 2 Total	57	54	52	46	41	37	34	33	29	27	26	25	23	22	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	17	-	-	-	-	-	311	221	286	400	400	400	400	400	400	400	400	360	55	220
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	4	284	375	330	83	196	126	166	375	375	375	375	375	375	375	375	375	375	375	375	231	303
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	322	311	-	290	298	-	-	42	-	-	292	306	292	-	-	400	211	172
	FOT MidColumbia - WTR2	-	-	-	310	-	-	309	-	-	301	292	375	301	251	-	-	-	327	330	152	92	147
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	55	10	100	9	-	-	76	100	100	100	100	11	35
	Existing Plant Retirements/Conversions	-	(280)	-	-	-	-	-	-	(387)	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	365	124	120	121	122	115	110	455	733	575	96	113	1,429	128	960	249		
	Annual Additions, Short Term Resources	784	1,115	1,167	1,139	906	1,007	934	956	1,538	1,479	1,490	2,092	1,711	1,617	1,756	1,957	1,967	2,002	2,005	2,160		
	Total Annual Additions	938	1,247	1,299	1,263	1,271	1,131	1,054	1,077	1,659	1,594	1,599	2,547	2,443	2,192	1,852	2,070	3,396	2,130	2,966	2,409		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RH-4	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	364	-	364
	Wind, WYAE	-	-	-	-	288	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	288	300
	Total Wind	-	-	-	-	288	-	-	-	-	-	-	-	-	-	-	297	-	-	-	364	288	950
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	347	41	291	121	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	61.9	6.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	61.9	31.0	126.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	58	49	44	37	34	35	647	1,141
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	11	11	9	8	7	7	7	122	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	73	73	62	55	47	43	44	826	1,453
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	24	298	300	140	228	300	300	300	300	300	-	124
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	(354)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	213	7	-	-	-	246
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	24	23	22	22	20	19	19	18	410	626
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	25	-	-	400	400	400	400	400	400	400	400	364	2	179
	FOT MidColumbia - SMR	399	400	400	400	378	400	359	340	400	400	400	400	400	400	400	400	400	400	400	400	388	394
	FOT MidColumbia - SMR - 2	-	276	107	41	-	23	-	-	375	336	375	375	375	375	375	375	375	375	375	375	116	245
	FOT NOB - SMR	100	100	100	100	-	-	-	40	100	100	100	100	100	100	100	100	100	100	100	100	64	82
	FOT MidColumbia - WTR	281	-	275	-	-	311	-	290	-	-	-	291	300	264	-	349	-	388	15	400	116	158
	FOT MidColumbia - WTR2	-	331	-	310	323	-	309	-	298	300	292	-	-	-	316	-	348	-	375	277	187	174
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	54	100	100	100	100	100	100	100	11	44
	Existing Plant Retirements/Conversions	-	-	5	-	-	-	-	-	(387)	(82)	-	(762)	-	(642)	(78)	-	(712)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	410	114	118	119	117	111	107	163	160	973	98	409	1,115	117	356	560		
	Annual Additions, Short Term Resources	779	1,106	882	851	701	734	668	671	1,250	1,190	1,199	1,875	1,929	1,779	1,918	2,024	2,023	2,063	2,065	2,316		
	Total Annual Additions	933	1,234	1,013	973	1,110	848	787	789	1,368	1,301	1,306	2,038	2,090	2,752	2,016	2,433	3,137	2,180	2,422	2,876		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RH-5	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	485	-	485
	Wind, WYAE	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	51	20	-	-	-	229	300
	Total Wind	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	137	20	-	-	485	229	871
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	654	44	-	85	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	65.2	3.2	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	4.8	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	21.7	-	-	19.0	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	65.2	130.0	-	-	27.1	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	2	3	56	94
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	33	35	647	1,138
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	9	10	9	8	7	6	7	122	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	71	71	62	55	47	41	44	826	1,446
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	299	173	260	300	300	300	300	300	-	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.0	-	-	-	7.4	-	-	-	-	11.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	73.0	-	-	-	7.4	-	-	-	-	80.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	9	8	9	8	9	9	8	8	7	6	6	5	4	4	3	3	2	2	85	126
	DSM, Class 2 Total	57	50	52	46	41	35	33	33	29	27	26	24	23	22	21	21	19	18	18	18	404	616
	FOT COB - SMR	-	-	-	-	-	-	-	-	30	-	29	400	400	357	362	398	398	400	400	366	3	177
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	277	108	43	165	282	210	250	375	341	375	375	375	375	375	375	375	375	375	375	205	290
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	293	8	-	-	-	-	-	314	224	118	101
	FOT MidColumbia - WTR2	-	331	-	310	-	312	310	291	299	-	293	-	375	253	294	308	310	320	-	375	185	219
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	12	100	1	13	59	68	100	95	100	11	33
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	124	131	122	350	113	118	119	117	111	106	166	515	1,005	92	263	1,159	113	244	644		
	Annual Additions, Short Term Resources	779	1,108	884	853	988	1,094	1,021	1,042	1,258	1,198	1,207	1,880	2,057	1,658	1,804	1,941	1,951	1,995	1,984	2,239		
	Total Annual Additions	933	1,232	1,015	974	1,338	1,206	1,139	1,160	1,375	1,309	1,313	2,046	2,572	2,664	1,896	2,204	3,109	2,108	2,228	2,883		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RH-6	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526	-	526
	Wind, WYAE	-	-	-	-	179	-	-	-	-	-	-	-	-	-	-	-	121	-	-	-	179	300
	Total Wind	-	-	-	-	179	-	-	-	-	-	-	-	-	-	-	-	407	-	-	526	179	1,111
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	391	41	291	78	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	-	-	4.8	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	164.3	46.6	-	-	3.4	11.2	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	62	61	57	56	56	49	44	37	34	35	642	1,132
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	9	10	9	8	7	7	7	121	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	80	77	73	70	71	62	55	47	44	45	819	1,441
	FOT Mona - SMR	-	-	-	-	-	-	-	-	264	200	264	300	300	261	171	300	300	300	300	300	46	163
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	7	-	-	-	117
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	7.4	-	-	-	32.0	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	20.4	-	-	-	32.0	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	22	22	21	20	19	19	18	409	624
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	173	101	142	400	400	400	400	400	400	400	400	400	400	400	364	122	259
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	375	310	90	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	293	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	323	311	309	290	298	-	-	321	399	-	-	319	-	9	11	298	242	189
	FOT MidColumbia - WTR2	-	-	-	310	-	-	-	-	-	300	292	-	-	327	341	-	343	375	375	375	61	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	-	55	100	100	100	100	11	43
	Existing Plant Retirements/Conversions	-	(280)	-	-	-	(356)	-	-	(387)	(82)	-	(762)	-	(357)	(78)	-	(358)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	300	114	118	118	112	111	106	843	163	569	292	87	1,055	117	356	678		
	Annual Additions, Short Term Resources	779	1,106	1,150	1,120	913	1,359	1,286	1,307	1,890	1,830	1,839	1,996	2,074	1,963	1,787	1,949	2,018	2,059	2,061	2,312		
	Total Annual Additions	933	1,234	1,281	1,242	1,213	1,473	1,404	1,425	2,002	1,941	1,945	2,839	2,237	2,532	2,079	2,036	3,073	2,176	2,418	2,990		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.8 – Core Cases, Detailed Capacity Expansion Portfolio

OP-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	485	-	485
	Wind, WYAE	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	51	20	-	-	-	229	300
	Total Wind	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	137	20	-	-	485	229	871
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	654	44	-	85	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	65.2	3.2	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	4.8	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	21.7	-	-	19.0	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	65.2	130.0	-	-	27.1	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	2	3	56	94
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	33	35	647	1,138
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	9	10	9	8	7	6	7	122	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	71	71	62	55	47	41	44	826	1,446
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	299	173	260	300	300	300	300	300	-	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.0	-	-	-	7.4	-	-	-	-	11.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	73.0	-	-	-	7.4	-	-	-	-	80.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	9	8	9	8	9	9	8	8	7	6	6	5	4	4	3	3	2	2	85	126
	DSM, Class 2 Total	57	50	52	46	41	35	33	33	29	27	26	24	23	22	21	21	19	18	18	18	404	616
	FOT COB - SMR	-	-	-	-	-	-	-	-	30	-	29	400	400	357	362	398	398	400	400	366	3	177
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	277	108	43	165	282	210	250	375	341	375	375	375	375	375	375	375	375	375	375	205	290
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	293	8	-	-	-	-	-	314	224	118	101
	FOT MidColumbia - WTR2	-	331	-	310	-	312	310	291	299	-	293	-	375	253	294	308	310	320	-	375	185	219
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	12	100	1	13	59	68	100	95	100	11	33
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	124	131	122	350	113	118	119	117	111	106	166	515	1,005	92	263	1,159	113	244	644		
	Annual Additions, Short Term Resources	779	1,108	884	853	988	1,094	1,021	1,042	1,258	1,198	1,207	1,880	2,057	1,658	1,804	1,941	1,951	1,995	1,984	2,239		
	Total Annual Additions	933	1,232	1,015	974	1,338	1,206	1,139	1,160	1,375	1,309	1,313	2,046	2,572	2,664	1,896	2,204	3,109	2,108	2,228	2,883		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

OP-NT3	Capacity (MW)																				Resource Totals 1/	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
Expansion Resources																						
CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	-	3.4	-	3.1	-	-	21.3
DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	-	14.0	-	-	6.5	3.7	3.1	11.6	-	243.8
DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	236	300	300	252	300	300	300	300	3	132
West																						
Existing Plant Retirements/Conversions																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
Expansion Resources																						
CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	76	3	-	31	7	13	-	-	130
DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.0	-	32.1	3.3	-	-	-	-	-	-	39.4
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	73.0	-	45.1	3.3	-	-	-	-	-	-	121.5
DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
FOT COB - SMR	-	-	-	-	19	130	58	95	249	156	217	400	400	400	400	400	400	400	400	357	71	224
FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia - WTR	281	331	275	310	-	311	-	290	298	-	-	27	317	400	17	-	-	378	380	286	210	195
FOT MidColumbia - WTR2	-	-	-	-	323	-	309	-	-	300	292	375	-	27	375	287	337	-	-	375	93	150
FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
Annual Additions, Long Term Resources	154	132	131	124	572	123	119	124	118	115	109	382	605	577	253	280	998	117	657	933		
Annual Additions, Short Term Resources	779	839	1,148	1,115	1,217	1,316	1,242	1,260	1,475	1,412	1,420	2,075	1,928	2,102	2,067	1,914	2,012	2,053	2,055	2,293		
Total Annual Additions	933	971	1,279	1,239	1,789	1,440	1,361	1,385	1,593	1,527	1,528	2,457	2,533	2,679	2,320	2,195	3,010	2,170	2,712	3,226		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	OP-REP	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	128	-	-	-	-	-	-	-	-	-	-	-	-	-	516	-	128	644
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	428	-	-	-	-	-	-	-	-	-	-	-	85	-	516	-	428	1,030
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	617	40	142	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	2	57	95
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	67	65	61	57	57	58	49	44	37	34	24	658	1,144
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	10	10	11	9	8	7	7	5	122	214
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	86	82	78	72	72	73	62	55	47	44	31	838	1,453
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	282	236	300	300	300	300	300	29	3	120
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	247	37	8	13	-	-	357
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	-	-	-	3.3	-	-	-	-	-	14.7
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	80.5	13.0	-	-	3.3	-	-	-	-	-	96.8
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	22	20	19	19	18	410	627
	FOT COB - SMR	-	-	-	-	24	135	64	103	258	165	227	400	400	400	400	400	400	400	400	342	75	226
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	307	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	273	307	-	308	-	287	295	-	-	35	397	-	348	312	314	-	357	-	208	192
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	375	-	323	-	-	-	355	-	308	92	129
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	550	123	118	119	118	113	109	388	553	576	148	337	1,217	117	737	526		
	Annual Additions, Short Term Resources	779	842	1,148	1,115	1,219	1,318	1,245	1,266	1,480	1,418	1,425	2,085	2,053	1,934	2,023	1,987	1,989	2,030	2,032	1,654		
	Total Annual Additions	933	970	1,279	1,236	1,769	1,441	1,363	1,384	1,598	1,532	1,535	2,473	2,607	2,510	2,171	2,325	3,206	2,147	2,770	2,180		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

OP-GW4	Capacity (MW)																				Resource Totals 1/	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
Expansion Resources																						
CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	9	5	-	-	-	85
Wind, WYAE	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,200	1,200
Total Wind	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	72	-	9	5	-	-	1,200	1,285
Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	59	167	208	40	279	-	-	752
DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	817	1,448
FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	293	300	291	300	300	300	300	300	263	3	135
West																						
Existing Plant Retirements/Conversions																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
Expansion Resources																						
CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	82	-	64	70	16	8	13	-	-	253
DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
FOT COB - SMR	-	-	-	-	-	27	-	-	154	63	124	400	400	400	400	400	400	400	400	357	24	196
FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia - SMR - 2	-	11	375	307	286	375	331	372	375	375	375	375	375	375	375	375	375	375	375	375	281	328
FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia - WTR	281	331	273	307	-	-	-	287	295	-	-	-	400	41	390	351	-	377	4	236	177	179
FOT MidColumbia - WTR2	-	-	-	-	319	308	306	-	-	297	289	305	51	375	-	-	337	-	375	375	123	167
FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
Annual Additions, Long Term Resources	154	128	131	122	1,321	114	118	118	112	111	109	295	548	536	296	323	986	121	358	256		
Annual Additions, Short Term Resources	779	842	1,148	1,115	1,105	1,210	1,137	1,159	1,376	1,316	1,323	1,973	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,206		
Total Annual Additions	933	970	1,279	1,236	2,426	1,324	1,255	1,276	1,488	1,427	1,432	2,267	2,674	2,618	2,361	2,349	2,998	2,173	2,412	2,462		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	FR-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	52	234	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	401	399	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	455	-	455
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	52	234	-	-	-	401	853	450	1,990
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	534	41	173	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15.0	65.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	103.2	115.7	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	5	4	3	3	3	3	56	96
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	65	61	57	60	59	49	44	37	34	35	647	1,148
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	218
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	82	78	74	76	74	62	55	47	44	44	826	1,462
	Battery Storage - East	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	67	296	300	300	300	300	300	300	300	-	123
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	IC Aero SO	-	-	-	-	393	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	393	393
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	163	-	-	-	-	-	247
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	8	13	-	-	36
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	24.7	11.4	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	27.3	7.7	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.8	9.1	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4.7	4.4	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	66.5	51.6	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	24	23	22	22	20	19	19	18	410	627
	Battery Storage - West	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	357	-	178
	FOT MidColumbia - SMR	399	400	400	400	378	400	359	355	400	400	400	400	400	400	400	400	400	400	400	400	389	395
	FOT MidColumbia - SMR - 2	-	11	375	310	-	23	-	-	109	45	106	375	375	375	375	375	375	375	375	375	87	218
	FOT NOB - SMR	100	100	100	100	-	63	56	100	100	100	100	100	100	100	100	100	100	100	100	100	82	91
	FOT MidColumbia - WTR	281	331	275	310	-	-	309	290	298	300	-	291	300	400	5	-	339	5	382	400	239	226
	FOT MidColumbia - WTR2	-	-	-	-	323	311	-	-	-	-	292	-	-	15	375	340	-	375	-	263	63	115
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	57	100	100	100	100	100	100	100	-	38
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,150	114	118	119	117	112	109	103	267	548	417	303	1,105	117	653	933		
	Annual Additions, Short Term Resources	779	842	1,150	1,120	701	798	724	745	907	845	898	1,633	1,928	2,090	2,055	2,015	2,014	2,055	2,057	2,295		
	Total Annual Additions	933	970	1,281	1,242	1,851	912	842	863	1,024	957	1,007	1,735	2,195	2,637	2,472	2,318	3,119	2,172	2,710	3,228		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

FR-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	182
	SCCT Aero UN	-	-	-	-	121	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	121
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	39	-	-	247	-	-	-	-	285
	Wind, GO	-	-	-	-	46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	46	846
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	346	-	-	-	-	-	-	-	-	39	-	-	247	-	-	800	346	1,432
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	41	279	19	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	217.1	-	3.4	5.0	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	5	4	4	3	3	3	3	54	93
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	57	57	57	56	47	44	37	34	35	627	1,112
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	10	10	10	9	8	7	7	7	119	211
	DSM, Class 2 Total	97	73	74	75	78	77	76	85	82	84	78	73	72	72	71	60	55	47	43	44	801	1,415
	Battery Storage - East	-	-	-	-	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	-	140	300	204	300	300	300	300	300	-	107
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	IC Aero PO	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221
	IC Aero SO	-	-	-	-	196	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	196
	IC Aero WV	-	-	-	-	208	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	208	208
	IC Aero WW	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221
	DSM, Class 2, CA	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	12	18
	DSM, Class 2, OR	46	40	39	34	29	26	23	23	20	18	18	17	16	16	16	17	15	15	16	16	297	461
	DSM, Class 2, WA	10	7	7	8	8	8	7	7	7	7	6	6	5	5	4	3	3	2	2	2	76	114
	DSM, Class 2 Total	57	48	47	43	38	35	32	31	27	27	25	23	22	22	21	21	19	18	18	18	384	592
	Battery Storage - West	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	FOT COB - SMR	-	-	11	-	-	-	-	-	-	-	-	-	251	261	270	303	311	316	322	279	1	116
	FOT MidColumbia - SMR	399	400	400	400	138	117	116	97	97	97	97	400	400	400	400	400	400	400	400	400	226	298
	FOT MidColumbia - SMR - 2	-	15	375	322	-	-	-	-	-	-	-	363	375	375	372	375	375	375	375	375	71	204
	FOT NOB - SMR	100	100	100	100	-	-	-	-	25	-	26	100	100	100	100	100	100	100	100	100	43	68
	FOT MidColumbia - WTR	281	332	278	313	108	98	97	79	70	68	83	83	92	124	-	-	100	127	-	400	172	137
	FOT MidColumbia - WTR2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	98	-	-	136	16	-	17
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	74	82	100	100	100	-	28
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	121	120	118	1,620	113	107	115	110	110	104	96	94	349	292	83	1,268	109	344	894		
	Annual Additions, Short Term Resources	779	847	1,164	1,135	246	215	213	176	192	165	206	945	1,358	1,660	1,431	1,650	1,669	1,718	1,733	1,971		
	Total Annual Additions	933	968	1,284	1,253	1,867	327	320	292	302	275	310	1,042	1,452	2,010	1,722	1,734	2,936	1,826	2,078	2,864		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RE-1a	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	200	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	200	-	-	-	407	853	450	1,996
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	-	14.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	265	300	257	300	300	300	300	287	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	153	-	-	-	-	-	-	153
	Total Wind	-	-	-	-	1	-	-	-	-	-	-	-	-	-	153	-	-	-	-	-	1	154
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	305	-	-	56	-	-	-	-	361
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	126	3	166	235	7	13	-	-	550
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.0	-	32.1	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	73.0	-	45.1	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	19	130	58	95	249	156	217	400	400	400	400	400	400	400	400	370	71	225
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	290	-	-	292	400	-	67	361	-	370	400	400	318	149	205
	FOT MidColumbia - WTR2	-	-	-	-	323	311	309	-	298	300	-	-	348	375	-	367	-	10	13	375	154	151
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	573	123	119	124	118	115	109	382	573	732	602	253	1,160	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,217	1,316	1,242	1,260	1,475	1,412	1,419	2,074	1,988	2,117	1,993	2,042	2,045	2,085	2,088	2,325		
	Total Annual Additions	933	971	1,279	1,239	1,789	1,439	1,361	1,384	1,592	1,527	1,528	2,455	2,561	2,849	2,595	2,295	3,205	2,203	2,744	3,258		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

RE-1b		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	37.6	3.1	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	201.9	12.3	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	289	156	160	105	300	300	300	300	3	113
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	Total Wind	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	76	3	-	245	7	13	-	-	344
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	-	-	-	-	-	3.3
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	67.8	-	-	-	3.3	-	-	-	-	-	71.2
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	10	121	50	86	241	147	208	400	400	400	400	400	400	400	400	357	66	221
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	3	-	-	257	290	-	333	238	148	164
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	375	219	242	-	-	330	-	375	150	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	42	-	100	100	100	100	11	43
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	651	123	119	124	118	115	109	373	545	799	250	287	932	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,199	1,299	1,225	1,243	1,457	1,394	1,402	2,066	2,042	1,751	1,720	1,636	1,965	2,005	2,008	2,245		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,422	1,343	1,367	1,575	1,509	1,510	2,440	2,588	2,550	1,969	1,923	2,897	2,123	2,664	3,178		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RE-1c	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	279	6	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	279	6	-	-	-	407	853	450	1,996
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	37.6	-	3.1	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	201.9	-	15.1	-	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	297	263	300	258	300	287	287	287	287	3	131
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, YK	-	-	-	-	81	-	-	-	-	-	-	-	-	-	186	-	-	-	39	-	81	306
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	212	-	-	-	-	-	-	212
	Total Wind	-	-	-	-	81	-	-	-	-	-	-	-	-	-	398	-	-	-	39	-	81	518
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	105	3	124	31	7	13	-	-	282
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	14.8	-	24.6	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	-	27.9	-	24.6	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	10	121	49	86	240	147	208	400	400	400	400	400	335	335	331	288	65	208
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	-	31	-	-	-	-	-	209	148	120
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	339	375	326	354	265	306	304	375	150	207
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	652	123	119	124	118	115	109	374	573	783	654	234	1,136	117	696	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,199	1,298	1,224	1,242	1,457	1,394	1,402	2,065	1,978	2,081	1,959	2,029	1,863	1,903	1,897	2,134		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,422	1,343	1,367	1,575	1,509	1,510	2,439	2,551	2,864	2,614	2,263	2,998	2,020	2,593	3,067		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	RE-2	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	71.3	4.0	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	160.4	53.9	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	198	300	300	-	300	300	300	300	3	118
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	296	296
	Total Wind	-	-	-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	296	296
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	24	-	16	-	-	-	-	-	-	-	41
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	92	10	-	31	7	13	-	-	153
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	-	-	-	-	-	-	36.1
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	-	-	-	-	-	-	-	118.1
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	97	25	62	216	123	184	400	400	400	400	396	400	400	400	357	52	213
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	361	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	292	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	257	-	-	259	354	-	56	392	221	338	3	381	400	145	193
	FOT MidColumbia - WTR2	-	-	-	-	290	278	276	-	265	267	-	-	339	375	-	-	-	375	-	261	138	136
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	-	100	100	100	100	11	46
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	867	123	119	124	118	115	109	357	636	555	257	560	718	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,151	1,250	1,177	1,195	1,409	1,346	1,354	2,029	1,912	2,106	2,067	1,491	2,013	2,053	2,056	2,293		
	Total Annual Additions	933	971	1,279	1,239	2,019	1,374	1,295	1,319	1,527	1,461	1,462	2,386	2,548	2,661	2,325	2,052	2,731	2,171	2,712	3,226		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	DLC-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	-	-	-	-	121
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	460	-	473
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	285	-	-	13	-	407	853	450	2,008
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	3.4	-	-	-	-	-	-	-	11.5	-	-	3.4	-	-	3.1	-	3.4	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	45.8	-	-	-	-	-	-	-	22.5	-	-	-	-	-	-	-	45.8	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	71.3	-	-	-	-	-	-	-	4.0	4.8	-	-	-	3.7	-	2.2	71.3	85.9
	DSM, Class 1, UT-ICE storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	-	-	-	-	3.3
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, UT-Smart APPl	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5	-	-	-	-	4.5
	DSM, Class 1, UT-Thermostat	-	-	-	-	23.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.4	23.4
	DSM, Class 1, WY-Cool/WH	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.9	4.8	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	37.6	-	-	-	-	-	-	-	3.1	-	-	-	3.1	-	-	2.0	37.6	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	186.4	-	-	-	-	-	-	-	51.3	4.8	-	3.4	10.8	3.7	3.1	11.6	186.4	274.9
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	Battery Storage - East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	10
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	281	300	300	300	300	300	300	300	300	-	134
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	81
	Total Wind	-	-	-	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	81
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	405	-	-	-	-	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	101	254	3	41	94	7	13	-	-	514
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	24.7	-	-	-	-	-	-	-	11.4	-	3.3	-	-	-	-	-	24.7	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	9.1	-	-	-	-	-	-	-	3.8	-	-	-	-	-	-	-	9.1	12.8
	DSM, Class 1, OR-Thermostat	-	-	-	-	4.4	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	4.4	9.6
	DSM, Class 1, WA-Cool/WH	-	-	-	-	8.9	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	8.9	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	DSM, Class 1, WA-Thermostat	-	-	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.5	3.5
	DSM, Class 1 Total	-	-	-	-	103.1	-	-	-	-	-	-	-	28.1	-	3.3	-	-	-	-	-	103.1	134.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	357	-	178
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	96	207	135	172	326	259	321	375	375	375	375	375	375	375	375	375	188	279
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	130	119	85	36	400	400	400	366	148	205
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	375	375	375	375	18	59	61	375	150	175
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	942	123	119	124	118	115	109	103	682	900	253	246	1,088	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	910	1,009	935	953	1,168	1,105	1,112	2,048	2,180	2,169	2,135	2,086	2,093	2,134	2,136	2,373		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,132	1,054	1,077	1,285	1,220	1,221	2,152	2,862	3,070	2,388	2,332	3,182	2,251	2,793	3,306		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.9 – Sensitivity Cases, Detailed Capacity Expansion Portfolios

	RH2a	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	(269)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	389	-	-	-	-	865
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	-	121
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	152	314	-	-	555
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	85	-	-	88	152	314	-	300	940
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	122	150	219	309	-	-	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	3.9	6.7	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	6	6	6	6	6	5	5	5	5	5	4	4	3	3	2	58	97
	DSM, Class 2, UT	84	62	62	59	70	68	66	71	70	69	65	64	60	60	59	49	44	37	34	24	681	1,178
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	14	13	12	11	11	9	8	7	7	5	125	222
	DSM, Class 2 Total	97	78	79	77	89	87	86	92	91	88	84	82	77	76	75	62	55	47	43	31	864	1,497
	FOT Mona - SMR	-	-	-	-	-	-	-	-	197	130	191	300	300	300	300	300	300	300	300	267	33	159
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	1	121	2	58	8	-	-	-	-	190
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	7	13	-	-	26
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	21.8	-	14.2	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	8.9	-	4.1	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	99.8	-	18.3	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	22	20	19	19	18	412	630
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	35	146	74	110	400	400	400	400	400	400	400	400	400	400	400	357	117	256
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	320	347
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	322	310	308	-	-	299	290	400	52	62	400	-	-	-	348	400	212	204
	FOT MidColumbia - WTR2	-	-	-	310	-	-	-	289	297	-	-	38	375	375	-	320	313	353	-	167	90	142
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	(280)	-	-	(387)	-	-	-	(354)	(82)	-	(432)	(359)	(357)	(78)	(687)	(688)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	432	124	120	125	120	116	110	415	542	683	253	1,041	1,060	229	513	249		
	Annual Additions, Short Term Resources	779	1,103	1,147	1,114	1,232	1,331	1,256	1,274	1,821	1,758	1,764	2,113	2,102	2,112	2,075	1,995	1,988	2,028	2,023	2,166		
	Total Annual Additions	933	1,235	1,278	1,238	1,664	1,455	1,376	1,399	1,941	1,873	1,874	2,529	2,644	2,794	2,328	3,036	3,048	2,258	2,536	2,416		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	LD-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	695	-	695
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	85	-	-	-	-	695	300	1,080
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	179	216	41	297	47	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	49	44	37	34	35	670	1,170
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	124	220
	DSM, Class 2 Total	97	78	79	77	81	87	85	92	89	88	82	79	73	76	74	62	55	47	44	44	852	1,488
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	84	300	300	300	300	300	300	300	3	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	151	-	16	130	70	16	8	-	-	-	391
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	7.9	5.1	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	88.3	29.8	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	412	629
	FOT COB - SMR	-	209	44	-	96	210	138	177	334	244	311	400	400	400	400	400	400	400	400	364	145	266
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	306	375	375	354	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	366	371
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	1
	FOT MidColumbia - WTR	380	71	400	120	400	76	74	60	312	400	203	400	383	400	400	400	92	400	127	400	229	275
	FOT MidColumbia - WTR2	-	375	7	375	59	375	375	375	375	287	375	193	-	180	176	85	375	106	375	375	260	242
	FOT NOB - WTR	-	3	-	45	88	86	91	77	100	100	100	100	100	100	100	100	100	100	100	100	59	79
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	423	123	119	125	118	116	109	548	772	596	335	336	987	118	363	816		
	Annual Additions, Short Term Resources	1,186	1,532	1,325	1,394	1,518	1,623	1,553	1,564	1,996	1,933	1,891	2,268	1,842	2,255	2,251	2,160	2,142	2,181	2,177	2,425		
	Total Annual Additions	1,340	1,664	1,456	1,518	1,941	1,746	1,671	1,688	2,114	2,048	2,000	2,816	2,614	2,852	2,585	2,496	3,128	2,298	2,540	3,241		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

LD-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	285
	Wind, WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	102	162	-	-	300
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	102	162	-	-	585
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	209	83	-	292
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	219.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	4	4	4	3	3	2	2	53	91
	DSM, Class 2, UT	84	58	56	53	62	58	57	57	63	60	61	57	57	57	56	47	43	36	33	34	607	1,088
	DSM, Class 2, WY	8	10	11	10	11	11	14	14	14	14	12	11	10	10	10	9	8	7	7	7	116	208
	DSM, Class 2 Total	97	73	74	69	78	75	76	76	81	79	78	73	72	72	71	60	54	46	42	43	777	1,387
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	27	276	144	194	298	300	300	300	300	-	107
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76	-	-	-	-	76
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	118.1	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	18	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	8	8	9	9	9	8	8	8	7	6	6	5	5	4	3	3	2	2	86	129
	DSM, Class 2 Total	57	50	52	46	41	37	33	32	29	27	26	24	23	23	22	21	20	19	19	18	404	619
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	276	400	400	400	400	400	400	400	400	-	174
	FOT MidColumbia - SMR	280	400	400	368	369	400	349	329	400	330	377	400	400	400	400	400	400	400	400	400	362	380
	FOT MidColumbia - SMR - 2	-	69	15	-	-	13	-	-	14	-	-	375	375	375	375	375	375	375	375	375	11	174
	FOT NOB - SMR	61	100	-	-	18	62	26	50	100	100	100	100	100	100	100	100	100	100	100	100	52	76
	FOT MidColumbia - WTR	280	-	274	-	321	-	-	-	-	291	-	289	-	290	-	-	377	393	400	353	116	163
	FOT MidColumbia - WTR2	-	329	-	308	-	309	307	288	289	-	289	-	334	-	310	372	-	-	2	375	183	176
	FOT NOB - WTR	-	-	-	-	-	-	-	-	42	42	-	-	100	100	100	100	100	100	100	100	8	44
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	123	126	115	119	112	109	108	110	105	104	97	95	898	96	84	1,151	170	436	156		
	Annual Additions, Short Term Resources	621	898	688	676	707	783	682	667	845	763	767	1,467	1,985	1,809	1,879	2,045	2,052	2,068	2,077	2,403		
	Total Annual Additions	774	1,021	814	791	827	895	790	775	956	868	870	1,564	2,079	2,707	1,975	2,129	3,202	2,238	2,513	2,559		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	LD-3	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	630	-	-	630
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	85	-	-	-	-	-	-	630	-	300	1,015
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	238	270	62	155	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	-	10.6	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	66	68	66	71	68	69	65	61	57	60	59	49	44	37	34	35	674	1,174
	DSM, Class 2, WY	8	12	13	12	14	14	15	15	15	16	14	14	13	11	11	9	8	7	7	7	134	234
	DSM, Class 2 Total	97	80	81	77	85	87	86	92	89	90	84	79	74	76	74	62	55	47	44	45	865	1,506
	FOT Mona - SMR	-	-	-	-	-	-	-	-	22	-	52	300	252	300	300	300	300	300	300	265	2	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	21	55	48	-	-	-	-	-	124
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	18	11	18	-	-	62
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	118.1	-	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	10	9	9	8	8	7	7	6	6	5	4	3	3	2	2	90	135
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	30	27	27	25	23	23	22	22	20	19	19	18	413	631
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	95	-	-	66	215	162	223	400	371	400	400	400	400	400	400	400	400	400	360	153	275
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	151	375	341	297	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	341	358
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	282	-	277	-	324	-	-	-	-	308	-	400	-	359	351	322	-	319	-	400	119	167
	FOT MidColumbia - WTR2	-	332	-	312	-	312	310	292	305	-	294	25	359	-	-	-	318	-	316	140	186	166
	FOT NOB - WTR	-	-	-	-	-	-	-	-	63	65	27	100	100	100	93	70	51	89	97	100	13	48
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	134	133	124	427	125	120	125	119	117	111	716	606	807	258	388	1,024	143	870	275		
	Annual Additions, Short Term Resources	932	1,302	1,118	1,109	1,264	1,402	1,347	1,390	1,666	1,620	1,648	2,100	1,986	2,034	2,019	1,967	1,944	1,983	1,988	2,140		
	Total Annual Additions	1,086	1,436	1,251	1,232	1,692	1,527	1,467	1,515	1,785	1,737	1,759	2,816	2,592	2,841	2,277	2,355	2,969	2,126	2,857	2,415		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	PG-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83	3	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	212	-	526	-	800
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	347	-	347
	Wind, WYAE	-	-	-	-	211	-	-	-	-	-	-	-	-	-	-	-	89	-	-	-	211	300
	Total Wind	-	-	-	-	211	-	-	-	-	-	-	-	-	-	83	3	152	212	-	873	211	1,532
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	-	-	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.5	40.5	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	82.4	-	10.6	39.5	88.0	5.0	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	34	35	647	1,140
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	214
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	88	84	80	77	72	72	71	62	55	47	44	44	825	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	296	249	300	300	300	300	300	300	300	-	132
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	141	14	16	-	-	186
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	23.7	-	1.2	44.1	52.4	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	409	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	54	-	64	400	400	400	400	400	400	400	400	365	5	184
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	281	115	50	178	298	228	270	375	372	375	375	375	375	375	375	375	375	375	375	217	296
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	292	-	-	334	313	259	291	-	180	118	142
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	291	298	-	293	-	301	269	-	-	-	-	274	375	185	168
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	9	11	-	-	-	38	100	100	100	100	11	28
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	332	114	118	118	117	111	107	208	603	783	275	227	1,403	295	264	952		
	Annual Additions, Short Term Resources	780	1,112	891	860	1,001	1,109	1,037	1,061	1,281	1,227	1,240	1,874	1,825	1,844	1,909	1,926	1,934	1,966	1,949	2,194		
	Total Annual Additions	934	1,240	1,022	982	1,333	1,223	1,155	1,178	1,398	1,338	1,347	2,082	2,428	2,627	2,185	2,153	3,337	2,262	2,213	3,146		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	PG-2	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	503	297	-	800
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	463	-	463
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	503	760	300	1,849
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	150	502	-	115	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	209.0	10.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	58	49	44	37	34	35	647	1,141
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	88	84	80	77	73	73	73	62	55	47	44	44	825	1,452
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	249	300	300	300	300	300	299	300	300	-	132
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	12
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	28	5	17	33	-	-	-	-	-	82
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	93.5	24.7	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	2	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	18	19	18	409	624
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	353	-	178
	FOT MidColumbia - SMR	395	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	268	97	27	133	245	172	207	354	281	320	375	375	375	375	375	375	375	375	375	178	274
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86	-	4
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	300	-	291	144	400	121	400	400	400	198	400	118	197
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	290	298	-	292	-	375	121	375	78	95	154	375	375	185	204
	FOT NOB - WTR	-	-	-	-	-	-	-	-	52	53	4	5	100	100	100	100	100	100	100	100	10	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	422	114	118	118	117	111	107	101	439	801	431	272	1,056	68	684	839		
	Annual Additions, Short Term Resources	776	1,099	873	837	955	1,056	981	997	1,204	1,133	1,116	1,820	2,194	2,196	2,171	2,153	2,170	2,228	2,248	2,489		
	Total Annual Additions	930	1,227	1,004	959	1,377	1,170	1,099	1,115	1,321	1,245	1,223	1,921	2,632	2,997	2,602	2,425	3,226	2,296	2,932	3,328		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	CPP-C	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	300	585
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	49	293	212	-	750
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	37.6	3.1	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	68.4	-	142.3	6.4	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	2	2	56	94
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	61	57	57	56	48	43	36	33	34	627	1,114
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	213
	DSM, Class 2 Total	97	74	74	75	81	77	76	85	82	84	78	77	72	72	71	61	54	46	42	43	805	1,421
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	299	284	298	300	300	300	300	300	300	-	134
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - Yakima - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	458
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	458
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	124	27	-	-	-	-	171
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.7	24.7	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	69.1	27.8	24.7	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	8	8	8	8	8	7	6	5	5	5	4	3	2	2	2	83	123
	DSM, Class 2 Total	57	53	52	46	41	35	32	31	29	27	26	24	23	22	22	21	19	18	19	18	406	617
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	31	-	32	400	400	400	400	400	400	400	400	368	3	182
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	111	45	157	274	208	249	375	342	375	375	375	375	375	375	375	375	375	375	204	289
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	303	-	294	-	343	341	-	-	-	-	271	118	122
	FOT MidColumbia - WTR2	-	331	-	310	-	312	311	293	301	-	295	-	147	-	-	328	313	354	356	375	186	201
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	100	100	100	100	100	100	100	100	11	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	126	122	422	113	108	116	112	111	105	169	552	782	432	265	976	117	357	285		
	Annual Additions, Short Term Resources	779	1,106	886	855	979	1,085	1,019	1,042	1,259	1,199	1,209	1,879	1,806	2,016	2,016	2,003	1,988	2,029	2,031	2,289		
	Total Annual Additions	933	1,234	1,012	977	1,401	1,198	1,127	1,158	1,371	1,310	1,314	2,048	2,359	2,798	2,448	2,268	2,965	2,145	2,387	2,574		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

CPP-D		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	768	-	-	768
	Wind, WYAE	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	291	-	-	-	9	300
	Total Wind	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	377	-	768	-	9	1,154
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	684	40	75	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	-	3.4	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	18.6	22.1	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	82.4	-	109.3	27.4	-	6.5	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	56	59	62	58	66	66	63	65	63	61	57	57	58	47	44	37	34	35	637	1,128
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	215
	DSM, Class 2 Total	97	74	74	75	81	77	85	85	82	84	80	77	72	72	73	60	55	47	44	44	814	1,438
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	4	27	300	267	300	281	233	300	300	300	263	0	129
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	98	8	13	-	-	130
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	18.9	-	50.1	52.4	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	409	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	68	-	40	400	400	400	400	400	400	400	400	357	7	183
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	111	45	200	316	245	286	375	375	375	375	375	375	375	375	375	375	375	375	223	299
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	300	-	292	-	325	-	313	329	370	-	228	118	152
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	290	298	-	292	-	301	-	349	-	-	-	372	375	185	177
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	28	15	100	100	31	100	100	100	100	11	39
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	126	122	130	114	118	118	112	111	107	203	571	775	204	281	1,440	117	923	256		
	Annual Additions, Short Term Resources	779	1,106	886	855	1,023	1,127	1,054	1,076	1,294	1,233	1,243	1,894	1,858	2,000	2,005	1,852	2,004	2,045	2,047	2,198		
	Total Annual Additions	933	1,234	1,012	977	1,153	1,241	1,172	1,194	1,405	1,345	1,349	2,097	2,429	2,775	2,210	2,133	3,444	2,162	2,970	2,454		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	FOT-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387	-	387
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	-	387	300	973
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	115	535	40	-	111	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	210.3	3.9	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	60	60	59	49	44	37	34	35	670	1,174
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	12	13	12	11	11	9	8	7	7	7	125	222
	DSM, Class 2 Total	97	78	79	77	81	87	86	92	89	88	82	79	77	76	74	62	55	47	44	44	853	1,493
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	115	24	173	-	-	-	-	-	-	-	311
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	225	86	127	16	7	-	-	-	462
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	118.1	-	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	21	20	19	19	18	412	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	101	34	96	400	400	400	400	400	400	400	398	364	14	190
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	103	36	247	358	285	322	375	375	375	375	375	375	375	375	375	375	375	375	237	306
	FOT NOB - SMR	100	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	20
	FOT MidColumbia - WTR	281	-	275	-	322	310	-	289	349	-	298	289	298	-	180	-	91	-	98	-	182	154
	FOT MidColumbia - WTR2	-	331	-	310	-	-	308	-	-	353	-	-	-	151	-	94	-	93	-	358	130	100
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	423	123	120	125	118	116	109	577	544	978	471	329	1,105	117	247	572		
	Annual Additions, Short Term Resources	779	1,103	878	846	968	1,068	993	1,011	1,225	1,162	1,169	1,464	1,473	1,326	1,355	1,269	1,266	1,268	1,270	1,497		
	Total Annual Additions	933	1,235	1,009	969	1,391	1,191	1,113	1,135	1,343	1,277	1,278	2,041	2,017	2,304	1,826	1,598	2,371	1,385	1,518	2,069		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	$C0_2$-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	477	-	-	865
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	366	396	-	-	-	-	-	-	-	762
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	673	57	-	-	-	-	800
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	366	396	70	673	57	-	-	-	300	1,862
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	628	40	-	-	-	717
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.3	65.0	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	8.1	206.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	98
	DSM, Class 2, UT	84	62	62	59	70	68	66	71	70	69	65	61	60	60	59	49	44	37	34	37	681	1,187
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	15	14	13	12	11	11	9	8	8	7	8	126	226
	DSM, Class 2 Total	97	78	79	77	89	87	86	92	90	89	84	80	77	76	74	62	56	47	43	48	865	1,511
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	300	300	300	300	300	300	86	149	-	117
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	33
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	241	33	-	-	-	533
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	405	-	-	-	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	272	149	-	-	-	-	-	-	421
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	4.7	4.4	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	12.4	105.7	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	19	16	21	310	483
	DSM, Class 2, WA	10	9	9	8	10	10	9	9	8	8	7	7	6	6	5	4	3	3	2	2	90	135
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	30	27	27	25	24	23	22	22	20	22	19	24	413	640
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	342	363	-	175
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	103	36	142	252	180	216	369	301	362	375	375	375	375	375	375	375	375	375	187	280
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	322	-	-	-	-	352	-	289	98	187	400	400	118	156	386	263	123	176
	FOT MidColumbia - WTR2	-	331	-	310	-	309	307	288	348	-	290	-	375	375	127	88	375	375	-	375	189	214
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	7	9	100	-	-	-	-	-	-	-	-	6
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	432	124	120	125	120	117	110	126	809	1,426	319	1,020	1,393	146	541	83		
	Annual Additions, Short Term Resources	779	1,103	878	846	963	1,062	987	1,005	1,217	1,153	1,159	1,873	2,148	2,137	2,102	2,063	2,068	2,106	1,690	2,025		
	Total Annual Additions	933	1,235	1,009	969	1,395	1,186	1,107	1,130	1,337	1,270	1,269	1,999	2,957	3,563	2,421	3,083	3,460	2,253	2,231	2,108		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	NO-CO_2	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	121
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	682	112	-	795
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	85	-	-	682	112	300	1,180
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	658	40	95	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	209.0	-	8.1	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	5	4	3	3	3	3	56	96
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	64	61	57	57	59	49	44	37	36	37	642	1,143
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	13	12	11	11	9	8	7	7	7	121	219
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	78	74	73	74	62	55	47	46	47	819	1,458
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	208	300	259	300	300	300	300	300	300	3	131
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - Yakima - G 1x1	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	-	458
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	-	458
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	159	13	6	11	-	-	192
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	14.8	-	10.3	14.2	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	96.9	-	10.3	14.2	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	471
	DSM, Class 2, WA	10	7	9	8	9	8	7	8	8	8	7	6	5	5	5	4	3	2	2	2	81	121
	DSM, Class 2 Total	57	49	52	46	41	35	32	31	29	27	26	24	23	22	22	21	19	18	19	18	400	613
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	49	166	95	136	293	202	264	400	400	400	400	400	400	400	400	357	94	238
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	14	375	312	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	295	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	276	311	-	-	-	294	302	-	-	-	36	337	-	336	338	3	382	280	180	175
	FOT MidColumbia - WTR2	-	-	-	-	324	313	312	-	-	304	296	-	375	-	359	-	-	375	-	375	125	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	99	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	123	131	122	422	113	116	116	112	111	108	560	403	571	147	353	1,149	116	857	310		
	Annual Additions, Short Term Resources	779	846	1,154	1,123	1,247	1,354	1,282	1,305	1,525	1,464	1,472	1,582	2,086	1,971	2,034	2,011	2,013	2,053	2,057	2,287		
	Total Annual Additions	933	969	1,285	1,245	1,669	1,466	1,399	1,422	1,636	1,575	1,580	2,142	2,488	2,542	2,181	2,364	3,162	2,169	2,913	2,597		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	BP	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	269	-	150	419
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	269	-	450	804
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	23	153	167	210	40	208	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.3	65.0	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	3.3	209.0	6.7	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	5	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	54	93
	DSM, Class 2, UT	84	86	80	59	62	58	66	66	68	65	65	61	57	58	58	49	44	37	34	35	694	1,191
	DSM, Class 2, WY	8	8	8	10	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	118	213
	DSM, Class 2 Total	97	99	94	75	81	77	85	86	89	84	82	78	73	73	73	62	55	47	44	44	865	1,497
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	275	300	300	300	300	300	300	300	29	-	120
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	87	22	-	-	-	-	-	-	-	109
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	70	16	7	13	-	-	109
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	29.1	7.0	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	111.1	7.0	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	50	46	41	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	315	479
	DSM, Class 2, WA	10	10	11	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	92	135
	DSM, Class 2 Total	62	58	55	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	421	637
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	321	-	176
	FOT MidColumbia - SMR	400	400	400	393	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	399	400
	FOT MidColumbia - SMR - 2	10	274	117	-	82	198	127	166	321	257	318	375	375	375	375	375	375	375	375	375	155	262
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	270	-	318	-	-	-	-	296	-	287	103	400	400	374	360	25	400	-	116	176
	FOT MidColumbia - WTR2	-	329	-	305	-	306	304	285	293	-	287	-	375	49	13	-	-	375	3	347	182	164
	FOT NOB - WTR	-	-	-	-	-	-	-	-	51	52	6	9	100	100	100	100	100	100	100	100	10	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	158	157	148	122	572	114	118	119	118	111	109	106	503	906	254	323	980	117	555	551		
	Annual Additions, Short Term Resources	791	1,103	887	798	899	1,004	931	952	1,165	1,104	1,112	1,845	2,153	2,124	2,088	2,049	2,035	2,075	2,078	1,673		
	Total Annual Additions	949	1,260	1,036	919	1,471	1,118	1,049	1,071	1,282	1,216	1,221	1,951	2,657	3,030	2,342	2,372	3,015	2,192	2,633	2,224		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	GW-1	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	46	152	-	602	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Wind, WYAE	-	-	-	-	300	440	-	-	-	-	-	-	-	-	-	-	-	-	-	-	740	740
	Total Wind	-	-	-	-	450	440	-	-	-	-	-	-	-	-	85	-	46	152	-	693	890	1,867
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	2	-	112	166	524	-	-	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	6.9	33.9	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	171.2	43.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	58	59	49	44	37	34	35	656	1,155
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	219
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	84	82	78	74	74	74	62	55	47	44	44	835	1,470
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	281	300	291	300	300	300	300	281	300	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	150	-	-	70	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	23	69	-	37	191	100	161	400	400	399	400	400	400	400	400	364	42	207
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	372	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	290	-	78	400	18	-	-	393	363	294	212	198
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	343	375	17	375	353	352	-	-	375	90	154
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	573	563	118	119	118	111	109	343	572	538	298	323	1,140	229	266	768		
	Annual Additions, Short Term Resources	779	842	1,150	1,119	1,220	1,253	1,180	1,201	1,415	1,355	1,362	2,000	2,128	2,082	2,068	2,028	2,027	2,068	2,019	2,307		
	Total Annual Additions	933	970	1,281	1,241	1,792	1,817	1,298	1,319	1,533	1,466	1,471	2,343	2,699	2,620	2,365	2,351	3,167	2,297	2,284	3,075		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	GW-2	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	46	152	-	602	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Wind, WYAE	-	-	-	-	300	-	440	-	-	-	-	-	-	-	-	-	-	-	-	-	740	740
	Total Wind	-	-	-	-	450	-	440	-	-	-	-	-	-	-	85	-	46	152	-	693	890	1,867
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	2	-	112	166	524	-	-	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	6.9	33.9	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	171.2	43.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	58	59	49	44	37	34	35	656	1,155
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	219
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	84	82	78	74	74	74	62	55	47	44	44	835	1,470
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	281	300	291	300	300	300	300	281	300	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	150	-	-	70	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	23	134	-	37	191	100	161	400	400	399	400	400	400	400	400	364	49	210
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	372	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	290	-	78	42	18	353	352	18	-	294	212	178
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	343	375	375	375	-	-	375	363	375	90	174
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	573	123	558	119	118	111	109	343	572	538	298	323	1,140	229	266	768		
	Annual Additions, Short Term Resources	779	842	1,150	1,119	1,220	1,319	1,180	1,201	1,415	1,355	1,362	2,000	2,128	2,082	2,068	2,028	2,027	2,068	2,019	2,307		
	Total Annual Additions	933	970	1,281	1,241	1,792	1,442	1,738	1,319	1,533	1,466	1,471	2,343	2,699	2,620	2,365	2,351	3,167	2,297	2,284	3,075		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

GW-3		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	376	-	376
	Wind, WYAE	-	-	-	-	300	440	760	-	-	-	-	-	-	-	-	-	-	-	-	-	1,500	1,500
	Total Wind	-	-	-	-	300	440	760	-	-	-	-	-	-	-	-	-	-	85	-	376	1,500	1,961
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	163	210	18	291	118	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	215
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	43	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	295	286	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	5	-	-	142	74	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	24.7	10.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	49.7	68.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	628
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	46	97	-	-	110	19	80	400	400	400	400	400	400	400	400	364	27	196
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	287	327	375	375	375	375	375	375	375	375	375	375	375	375	281	328
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	291	-	71	35	15	350	-	-	4	291	212	159
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	287	375	375	375	-	336	375	375	375	90	188
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	71	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	423	554	878	118	112	111	109	245	520	537	241	324	980	180	356	568		
	Annual Additions, Short Term Resources	779	842	1,150	1,120	1,243	1,282	1,095	1,116	1,334	1,274	1,281	1,933	2,116	2,071	2,065	2,025	2,011	2,050	2,054	2,305		
	Total Annual Additions	933	970	1,281	1,241	1,665	1,836	1,973	1,234	1,446	1,385	1,390	2,179	2,636	2,608	2,306	2,349	2,991	2,230	2,410	2,873		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

GW-4	Capacity (MW)																				Resource Totals 1/	
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
Expansion Resources																						
CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
Wind, WYAE	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,200	1,200
Total Wind	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	1,200	1,285
Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	167	210	41	279	-	-	749
DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	293	300	291	300	300	300	300	300	263	3	135
West																						
Existing Plant Retirements/Conversions																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
Expansion Resources																						
CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	83	-	68	70	16	7	13	-	-	257
DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	628
Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
FOT COB - SMR	-	-	-	-	-	28	-	-	154	63	125	400	400	400	400	400	400	400	400	357	25	196
FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia - SMR - 2	-	11	375	310	287	375	332	372	375	375	375	375	375	375	375	375	375	375	375	375	281	328
FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia - WTR	281	331	275	310	-	310	-	289	297	-	-	-	400	40	390	350	-	377	4	235	209	194
FOT MidColumbia - WTR2	-	-	-	-	322	-	308	-	-	299	291	305	50	375	-	-	336	-	375	375	93	152
FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
Annual Additions, Long Term Resources	154	128	131	122	1,323	114	118	118	112	111	109	295	549	537	306	323	980	117	358	256		
Annual Additions, Short Term Resources	779	842	1,150	1,120	1,108	1,213	1,139	1,161	1,379	1,319	1,326	1,974	2,125	2,081	2,065	2,025	2,011	2,052	2,054	2,205		
Total Annual Additions	933	970	1,281	1,241	2,431	1,327	1,258	1,279	1,491	1,430	1,435	2,268	2,675	2,617	2,371	2,349	2,991	2,169	2,412	2,461		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	Battery	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113	25	147	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	448	-	-	448
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	113	25	147	448	-	1,100	1,833
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	528	2	161	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	58	49	44	37	34	35	642	1,137
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
	DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	73	62	55	47	44	44	817	1,446
	Battery Storage - East	-	-	-	-	80.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	278	269	300	300	300	300	300	263	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	6	-	-	111	100	16	8	13	-	-	253
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	-	-	-	93	2	64	400	400	400	400	400	400	400	400	357	10	186
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	225	342	270	311	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	-	-	287	295	-	-	284	400	19	390	350	-	15	392	248	178	194
	FOT MidColumbia - WTR2	-	-	-	-	319	308	306	-	-	297	289	-	29	375	-	-	349	375	-	375	123	151
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	57	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,301	114	118	118	112	111	109	230	537	536	209	410	1,123	225	687	256		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,045	1,149	1,076	1,098	1,316	1,256	1,263	1,916	2,082	2,038	2,065	2,025	2,024	2,065	2,067	2,218		
	Total Annual Additions	935	981	1,282	1,236	2,345	1,264	1,194	1,216	1,428	1,367	1,372	2,146	2,619	2,574	2,273	2,435	3,147	2,290	2,754	2,474		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	CAES	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	28	107	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	447	-	-	447
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	151	28	107	447	-	1,100	1,833
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	527	12	161	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	58	49	44	37	34	35	642	1,137
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
	DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	73	62	55	47	44	44	817	1,446
	CAES - East	-	-	-	-	80.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	80.0
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	278	269	300	300	300	300	300	263	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	6	-	-	111	100	16	8	13	-	-	253
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	-	-	-	93	2	64	400	400	400	400	400	400	400	400	357	10	186
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	225	342	270	311	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	319	308	-	-	295	-	-	-	400	19	390	350	349	390	17	400	211	221
	FOT MidColumbia - WTR2	-	-	-	-	-	-	306	287	-	297	289	284	29	375	-	-	-	-	375	223	89	123
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	57	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,301	114	118	118	112	111	109	230	537	536	209	437	1,125	196	687	256		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,045	1,149	1,076	1,098	1,316	1,256	1,263	1,916	2,082	2,038	2,065	2,025	2,024	2,065	2,067	2,218		
	Total Annual Additions	935	981	1,282	1,236	2,345	1,264	1,194	1,216	1,427	1,367	1,372	2,146	2,619	2,574	2,273	2,462	3,149	2,261	2,754	2,474		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	WCA	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Expansion Resources**																						
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	7	7	8	9	8	7	7	7	8	7	6	5	5	4	3	3	2	2	2	77	116
	DSM, Class 2 Total	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	19	18	18	18	399	609
	FOT COB - SMR	-	-	-	-	-	58	180	193	182	188	207	206	400	400	400	400	333	340	348	250	80	204
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	162	160	306	204	368	375	170	164	198	182	177	187	338	345	352	359	375	375	375	375	229	277
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	241	-	238	390	305	267	400	400	400	400	400	400	242	189	87	214
	FOT MidColumbia - WTR	400	246	400	400	400	320	400	332	94	400	400	400	400	296	400	306	227	236	400	400	339	343
	FOT MidColumbia - WTR2	146	375	177	164	301	375	55	375	375	20	24	58	269	375	276	375	375	375	375	375	236	262
	FOT NOB - WTR	100	100	100	100	100	100	100	100	100	-	86	100	100	100	100	100	100	100	100	100	90	94
	Existing Plant Retirements/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	(359)	-	-	-		
	Annual Additions, Long Term Resources	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	455	18	18	518		
	Annual Additions, Short Term Resources	1,308	1,382	1,483	1,368	1,670	1,729	1,646	1,664	1,687	1,681	1,700	1,717	2,406	2,416	2,428	2,439	2,310	2,326	2,340	2,189		
	Total Annual Additions	1,365	1,434	1,533	1,414	1,711	1,764	1,678	1,695	1,714	1,708	1,725	1,741	2,429	2,438	2,449	2,460	2,765	2,343	2,359	2,708		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	WCA-RPS	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, YK	-	-	-	-	11	59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	Total Wind	-	-	-	-	11	59	-	-	-	-	-	-	-	-	-	-	-	-	-	500	70	570
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	7	7	8	9	8	7	7	7	7	7	6	5	5	4	3	3	2	2	2	77	116
	DSM, Class 2 Total	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	19	18	18	18	399	608
	FOT COB - SMR	-	-	-	-	-	51	180	193	182	188	207	206	400	400	400	400	325	332	341	242	79	202
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	162	160	306	204	367	375	162	156	190	175	169	179	330	338	345	351	375	375	375	375	226	273
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	241	-	238	390	291	267	400	400	400	400	400	400	235	182	87	212
	FOT MidColumbia - WTR	171	246	202	400	400	313	72	324	400	38	42	75	400	400	400	400	400	228	400	400	257	286
	FOT MidColumbia - WTR2	375	375	375	164	300	375	375	375	61	375	375	375	261	264	268	273	195	375	375	375	315	314
	FOT NOB - WTR	100	100	100	100	100	100	100	100	100	-	100	100	100	100	100	100	100	100	100	100	90	95
	Existing Plant Retirements/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	(359)	-	-	-		
	Annual Additions, Long Term Resources	57	52	50	46	52	94	32	31	27	27	26	24	22	22	21	21	455	18	18	518		
	Annual Additions, Short Term Resources	1,308	1,382	1,483	1,368	1,667	1,713	1,631	1,648	1,671	1,666	1,685	1,702	2,391	2,401	2,413	2,424	2,295	2,311	2,325	2,174		
	Total Annual Additions	1,365	1,434	1,533	1,414	1,719	1,807	1,662	1,679	1,699	1,692	1,710	1,726	2,414	2,423	2,434	2,445	2,750	2,328	2,344	2,693		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.10 – Final Screening Cases, Detailed Capacity Expansion Portfolios

	FS-REP	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	103	-	-	-	-	-	-	-	-	-	-	-	-	-	512	-	103	615
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	403	-	-	-	-	-	-	-	-	85	-	-	-	-	512	-	403	1,001
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	88	153	167	209	40	143	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	2	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	67	65	61	57	60	58	49	44	37	34	24	658	1,147
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	5	122	217
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	86	82	78	74	76	73	62	55	47	44	31	838	1,459
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	231	300	300	300	300	300	300	29	3	121
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Wind - Repower Existing resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	West Wind-Repower	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	36
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	101	10	62	16	8	13	-	-	210
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.8	9.2	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	84.2	33.9	-	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	22	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	28	139	67	107	261	169	230	400	400	400	400	400	400	400	400	342	77	227
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	295	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	38	-	54	15	-	340	381	383	334	208	181
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	375	371	375	375	354	-	-	-	-	92	153
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	526	123	118	119	118	113	109	392	606	613	258	319	980	117	734	526		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,222	1,322	1,248	1,269	1,484	1,422	1,429	2,088	1,977	2,104	2,065	2,029	2,015	2,056	2,058	1,680		
	Total Annual Additions	935	981	1,282	1,236	1,748	1,445	1,367	1,388	1,601	1,535	1,538	2,480	2,583	2,717	2,323	2,349	2,995	2,173	2,792	2,206		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	FS-GW4	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	FS-R1c	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	-	3.1	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	-	14.7	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	294	294	284	300	300	300	300	297	300	3	136
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	57	-	-	-	-	-	-	-	-	-	-	-	-	-	239	128	57	423
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	193	-	238
	Total Wind	-	-	-	-	57	-	-	-	-	-	-	-	-	-	-	-	-	-	284	322	57	662
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	34	-	3	161	70	131	400	400	400	394	394	394	394	369	290	27	192
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	293	375	338	375	375	375	375	375	375	375	375	375	375	375	375	375	283	329
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	313	301	-	-	288	-	282	306	69	34	9	-	330	371	342	218	210	203
	FOT MidColumbia - WTR2	-	-	-	-	-	-	300	281	-	291	-	-	375	375	375	344	-	-	-	375	87	136
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,280	114	118	118	112	111	109	306	563	536	303	323	980	117	637	1,186		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,106	1,211	1,137	1,159	1,377	1,317	1,324	1,975	2,113	2,069	2,053	2,013	1,999	2,039	1,982	2,158		
	Total Annual Additions	935	981	1,282	1,236	2,385	1,325	1,255	1,277	1,489	1,428	1,433	2,281	2,676	2,605	2,355	2,336	2,979	2,157	2,619	3,343		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

APPENDIX L – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

Introduction

This appendix reports additional results for the Monte Carlo production cost simulations conducted with the Planning and Risk (PaR) model for the core, sensitivity and final screening cases. These results supplement the data presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the IRP document. The results presented include the following:

- Statistics of the stochastic simulation results
- Components of portfolios' present value revenue requirements (PVRR)
- Energy-not-served
- Customer rate impact of portfolios in the final screen as compared with the preferred portfolio
- Loss of load probability of the preferred portfolio

There are seven Regional Haze cases, eleven core cases, twenty sensitivity cases, and four final screening cases.

Table L.1 – Stochastic Mean PVRR by Price Scenario, Regional Haze Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
Ref.	23,979	24,553	26,760	24,048	24,559	26,833
RH-1	22,840	23,453	25,654	22,931	23,477	25,827
RH-2	22,934	23,671	26,346	22,898	23,655	26,366
RH-3	22,953	23,593	25,956	22,981	23,593	26,046
RH-4	23,342	23,949	26,126	23,429	23,970	26,274
RH-5	22,762	23,446	26,088	22,730	23,430	26,059
RH-6	23,624	24,278	26,642	23,626	24,266	26,670

Table L.2 – Stochastic Mean PVRR by Price Scenario, Core Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
OP-1	22,763	23,444	25,988	22,730	23,430	26,020
OP-NT3	22,761	23,407	25,716	22,724	23,388	25,722
OP-REP	22,719	23,350	25,573	22,686	23,333	25,590
OP-GW4	23,069	23,608	25,400	23,035	23,584	25,413
FR-1	23,257	23,892	26,251	23,220	23,873	26,239
FR-2	23,820	24,485	27,003	23,783	24,467	26,995
RE-1a	22,819	23,431	25,651	22,783	23,449	25,656
RE-1b	22,772	23,395	25,632	22,737	23,413	25,650
RE-1c	22,868	23,462	25,613	22,832	23,444	25,627
RE-2	22,828	23,422	25,567	22,795	23,410	25,588
DLC-1	22,878	23,475	25,673	22,842	23,458	25,667

Table L.3 – Stochastic Mean PVRR by Price Scenario, Sensitivity Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
RH2a	22,842	23,558	26,149	22,806	23,542	26,167
CPP-C	22,813	23,513	26,274	22,777	23,505	26,490
CPP-D	22,699	23,364	25,667	22,661	23,330	25,663
FOT-1	23,048	23,681	26,061	23,011	23,663	26,067
CO2-1	23,791	24,306	25,620	23,748	24,261	25,667
GW1	23,321	23,890	25,841	23,283	23,867	25,846
GW2	23,667	24,236	26,194	23,629	24,212	26,199
GW3	24,214	24,723	26,440	24,176	24,696	26,449
GW4	23,055	23,611	25,480	23,020	23,587	25,489
WCA	6,767	7,090	8,261	6,739	7,066	8,225
WCA-RPS	6,789	7,102	8,241	6,762	7,079	8,207

Table L.4 – Stochastic Mean PVRR by Price Scenario, Final Screening Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
Ref.	23,979	24,553	26,760	24,048	24,559	26,833
RH-1	22,840	23,453	25,654	22,931	23,477	25,827
RH-2	22,934	23,671	26,346	22,898	23,655	26,366
RH-3	22,953	23,593	25,956	22,981	23,593	26,046
RH-4	23,342	23,949	26,126	23,429	23,970	26,274
RH-5	22,762	23,446	26,088	22,730	23,430	26,059
RH-6	23,624	24,278	26,642	23,626	24,266	26,670

Table L.5 – Stochastic Risk Results, Regional Haze Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	123	23,818	24,097	24,272	15,464
RH-1	118	22,688	22,959	23,134	15,584
RH-2	128	22,771	23,052	23,225	15,638
RH-3	119	22,809	23,107	23,244	15,646
RH-4	121	23,199	23,467	23,629	15,598
RH-5	119	22,614	22,882	23,051	15,681
RH-6	123	23,460	23,738	23,902	15,659

Table L.6 – Stochastic Risk Results, Regional Haze Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	138	24,375	24,682	24,869	16,086
RH-1	134	23,282	23,606	23,770	16,246
RH-2	145	23,482	23,804	23,987	16,421
RH-3	135	23,444	23,751	23,922	16,335
RH-4	136	23,784	24,086	24,262	16,253
RH-5	136	23,272	23,596	23,758	16,412
RH-6	140	24,119	24,425	24,605	16,386

Table L.7 – Stochastic Risk Results, Regional Haze Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	205	26,438	26,990	27,130	18,376
RH-1	197	25,383	25,882	26,036	18,562
RH-2	210	26,014	26,568	26,730	19,199
RH-3	201	25,703	26,193	26,380	18,822
RH-4	199	25,860	26,437	26,500	18,551
RH-5	199	25,790	26,259	26,478	19,161
RH-6	206	26,390	27,019	27,059	18,890

Table L.8 – Stochastic Risk Results, Regional Haze Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	123	23,893	24,174	24,347	15,525
RH-1	121	22,776	23,064	23,220	15,687
RH-2	127	22,737	23,007	23,188	15,598
RH-3	118	22,845	23,135	23,275	15,673
RH-4	123	23,287	23,576	23,721	15,697
RH-5	118	22,585	22,854	23,018	15,643
RH-6	121	23,487	23,755	23,921	15,675

Table L.9 – Stochastic Risk Results, Regional Haze Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	137	24,384	24,698	24,878	16,078
RH-1	132	23,315	23,622	23,818	16,260
RH-2	144	23,469	23,790	23,969	16,399
RH-3	134	23,432	23,758	23,936	16,329
RH-4	133	23,795	24,104	24,289	16,258
RH-5	135	23,259	23,571	23,743	16,393
RH-6	139	24,108	24,412	24,593	16,366

Table L.10 – Stochastic Risk Results, Regional Haze Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	195	26,517	27,168	27,220	18,424
RH-1	189	25,531	26,175	26,240	18,724
RH-2	208	26,094	26,577	26,751	19,219
RH-3	195	25,806	26,251	26,481	18,893
RH-4	190	26,002	26,597	26,674	18,676
RH-5	198	25,743	26,239	26,449	19,127
RH-6	202	26,435	26,929	27,091	18,912

Table L.11 – Stochastic Risk Results, Core Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	119	22,615	22,883	23,051	15,681
OP-NT3	121	22,606	22,885	23,054	15,557
OP-REP	118	22,573	22,843	23,002	15,395
OP-GW4	120	22,924	23,196	23,363	14,891
FR-1	119	23,107	23,391	23,547	15,528
FR-2	97	23,668	23,930	23,978	15,459
RE-1a	118	22,671	22,948	23,103	15,318
RE-1b	116	22,628	22,892	23,051	15,360
RE-1c	117	22,716	22,996	23,154	15,254
RE-2	117	22,680	22,955	23,108	15,246
DLC-1	122	22,715	23,014	23,169	15,318

Table L.12 – Stochastic Risk Results, Core Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	136	23,270	23,593	23,756	16,414
OP-NT3	137	23,234	23,558	23,730	16,255
OP-REP	133	23,185	23,500	23,659	16,074
OP-GW4	135	23,440	23,753	23,919	15,473
FR-1	135	23,721	24,037	24,203	16,211
FR-2	114	24,300	24,624	24,669	16,167
RE-1a	133	23,269	23,581	23,741	15,978
RE-1b	131	23,239	23,547	23,701	16,031
RE-1c	132	23,293	23,620	23,772	15,894
RE-2	132	23,255	23,577	23,728	15,888
DLC-1	138	23,292	23,624	23,787	15,964

Table L.13 – Stochastic Risk Results, Core Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	201	25,695	26,191	26,370	19,067
OP-NT3	201	25,419	25,933	26,104	18,678
OP-REP	195	25,266	25,776	25,943	18,414
OP-GW4	198	25,146	25,660	25,778	17,373
FR-1	198	25,971	26,474	26,627	18,677
FR-2	189	26,704	27,209	27,361	18,833
RE-1a	196	25,379	25,861	26,030	18,306
RE-1b	196	25,346	25,858	25,999	18,375
RE-1c	195	25,313	25,820	25,992	18,154
RE-2	195	25,294	25,776	25,938	18,144
DLC-1	203	25,388	25,880	26,059	18,273

Table L.14 – Stochastic Risk Results, Core Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	118	22,585	22,854	23,018	15,643
OP-NT3	119	22,575	22,842	23,016	15,516
OP-REP	116	22,535	22,810	22,967	15,357
OP-GW4	119	22,894	23,161	23,327	14,854
FR-1	118	23,068	23,346	23,507	15,487
FR-2	96	23,632	23,885	23,938	15,418
RE-1a	116	22,643	22,920	23,066	15,276
RE-1b	115	22,600	22,856	23,015	15,321
RE-1c	115	22,691	22,953	23,117	15,212
RE-2	115	22,655	22,927	23,072	15,207
DLC-1	121	22,684	22,977	23,131	15,278

Table L.15 – Stochastic Risk Results, Core Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	135	23,259	23,571	23,743	16,393
OP-NT3	136	23,219	23,538	23,709	16,226
OP-REP	132	23,164	23,470	23,641	16,053
OP-GW4	134	23,424	23,722	23,898	15,448
FR-1	134	23,696	24,017	24,188	16,187
FR-2	113	24,296	24,600	24,649	16,146
RE-1a	133	23,289	23,595	23,760	15,989
RE-1b	131	23,260	23,551	23,719	16,041
RE-1c	131	23,280	23,598	23,755	15,869
RE-2	131	23,248	23,557	23,714	15,868
DLC-1	138	23,283	23,606	23,773	15,943

Table L.16 – Stochastic Risk Results, Core Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	199	25,708	26,224	26,399	19,093
OP-NT3	197	25,410	25,934	26,104	18,666
OP-REP	191	25,329	25,790	25,957	18,408
OP-GW4	197	25,155	25,669	25,787	17,378
FR-1	196	25,952	26,447	26,608	18,663
FR-2	187	26,705	27,232	27,360	18,819
RE-1a	192	25,396	25,858	26,024	18,296
RE-1b	191	25,363	25,868	26,010	18,375
RE-1c	192	25,356	25,831	25,996	18,155
RE-2	192	25,306	25,793	25,959	18,149
DLC-1	201	25,389	25,874	26,044	18,265

Table L.17 – Stochastic Risk Results, Sensitivity Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	119	22,982	23,284	23,420	15,854
CPP-C	121	22,661	22,956	23,082	15,585
CPP-D	122	22,532	22,832	22,992	15,739
FOT-1	117	22,894	23,185	23,322	15,496
CO2-1	134	23,637	23,968	24,075	15,913
GW1	118	23,165	23,449	23,611	15,091
GW2	124	23,513	23,815	23,963	15,150
GW3	116	24,065	24,342	24,493	14,719
GW4	119	22,906	23,182	23,344	14,993
WCA	82	6,678	6,871	6,972	4,970
WCA-RPS	81	6,700	6,899	6,991	4,910

Table L.18 – Stochastic Risk Results, Sensitivity Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	136	24,015	24,352	24,499	16,954
CPP-C	139	23,332	23,652	23,808	16,333
CPP-D	138	23,186	23,505	23,679	16,449
FOT-1	133	23,502	23,844	23,990	16,177
CO2-1	138	24,167	24,472	24,584	16,422
GW1	133	23,721	24,050	24,202	15,689
GW2	140	24,058	24,400	24,561	15,737
GW3	130	24,554	24,878	25,022	15,258
GW4	134	23,439	23,766	23,928	15,523
WCA	95	6,981	7,220	7,300	5,312
WCA-RPS	94	6,996	7,231	7,309	5,241

Table L.19 – Stochastic Risk Results, Sensitivity Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	200	28,092	28,631	28,768	21,249
CPP-C	207	26,025	26,458	26,630	19,197
CPP-D	209	25,358	25,991	26,074	18,868
FOT-1	199	25,780	26,271	26,450	18,670
CO2-1	193	25,348	25,847	25,996	17,802
GW1	196	25,565	26,079	26,235	17,767
GW2	202	25,912	26,504	26,578	17,824
GW3	191	26,179	26,667	26,804	17,090
GW4	197	25,224	25,764	25,893	17,581
WCA	119	8,118	8,431	8,458	6,495
WCA-RPS	117	8,113	8,403	8,433	6,391

Table L.20 – Stochastic Risk Results, Sensitivity Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	118	22,985	23,275	23,415	15,847
CPP-C	120	22,584	22,872	22,992	15,489
CPP-D	120	22,496	22,789	22,951	15,698
FOT-1	116	22,858	23,141	23,283	15,455
CO2-1	134	23,526	23,848	23,960	15,796
GW1	117	23,134	23,413	23,571	15,051
GW2	123	23,481	23,769	23,921	15,108
GW3	115	24,034	24,309	24,453	14,679
GW4	118	22,876	23,148	23,307	14,956
WCA	82	6,644	6,841	6,944	4,941
WCA-RPS	81	6,688	6,870	6,965	4,882

Table L.21 – Stochastic Risk Results, Sensitivity Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	135	23,360	23,701	23,856	16,296
LD-1	133	23,534	23,827	23,997	16,270
LD-2	124	21,490	21,801	21,940	15,210
LD-3	146	25,016	25,382	25,559	17,690
PG-1	136	23,417	23,745	23,919	16,416
PG-2	133	22,985	23,300	23,458	16,042
CPP-C	138	23,276	23,576	23,739	16,253
CPP-D	137	23,146	23,476	23,654	16,418
FOT-1	132	23,489	23,822	23,972	16,155
CO2-1	138	24,046	24,344	24,472	16,309
NO-CO2	143	23,010	23,333	23,510	16,164
BP	140	23,316	23,643	23,816	16,407
GW1	132	23,696	24,021	24,182	15,677
GW2	139	24,041	24,376	24,540	15,730
GW3	129	24,532	24,850	24,995	15,244
GW4	133	23,422	23,740	23,911	15,567
Battery	132	23,322	23,629	23,795	15,344
CAES	131	23,274	23,598	23,749	15,334
WCA	93	6,961	7,178	7,279	5,285
WCA-RPS	92	6,997	7,197	7,289	5,215

Table L.22 – Stochastic Risk Results, Sensitivity Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	199	28,368	28,904	29,036	21,521
CPP-C	200	26,161	26,589	26,774	19,256
CPP-D	207	25,349	25,982	26,071	18,855
FOT-1	196	25,799	26,272	26,441	18,668
CO2-1	191	25,307	25,906	25,971	17,774
GW1	195	25,557	26,083	26,238	17,771
GW2	201	25,929	26,511	26,583	17,825
GW3	189	26,189	26,676	26,808	17,093
GW4	196	25,213	25,745	25,876	17,568
WCA	117	8,083	8,397	8,420	6,456
WCA-RPS	116	8,080	8,373	8,398	6,353

Table L.23 – Stochastic Risk Results, Final Screening Cases, Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	121	22,586	22,868	23,026	15,424
FS-GW4	121	22,671	22,964	23,107	14,852
FS-R1c	118	22,697	22,971	23,141	14,754
FS-R2	121	22,675	22,958	23,107	14,793

Table L.24 – Stochastic Risk Results, Final Screening Cases, Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	136	23,198	23,514	23,682	16,105
FS-GW4	136	23,182	23,510	23,660	15,433
FS-R1c	134	23,190	23,511	23,677	15,318
FS-R2	136	23,184	23,500	23,652	15,364

Table L.25 – Stochastic Risk Results, Final Screening Cases, High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	201	25,337	25,832	25,975	18,460
FS-GW4	199	24,865	25,388	25,524	17,323
FS-R1c	197	24,830	25,435	25,476	17,153
FS-R2	199	24,822	25,346	25,478	17,221

Table L.26 – Stochastic Risk Results, Final Screening Cases, Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	119	22,556	22,831	22,987	15,385
FS-GW4	120	22,642	22,919	23,070	14,816
FS-R1c	117	22,668	22,941	23,105	14,718
FS-R2	120	22,645	22,926	23,070	14,756

Table L.27 – Stochastic Risk Results, Final Screening Cases, Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	135	23,184	23,484	23,662	16,081
FS-GW4	136	23,164	23,486	23,639	15,409
FS-R1c	133	23,172	23,483	23,657	15,300
FS-R2	136	23,163	23,472	23,631	15,341

Table L.28 – Stochastic Risk Results, Final Screening Cases, High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	197	25,361	25,837	25,988	18,450
FS-GW4	198	24,876	25,391	25,532	17,326
FS-R1c	196	24,842	25,442	25,487	17,163
FS-R2	198	24,831	25,350	25,484	17,222

Table L.29 – Stochastic Risk Adjusted PVRR by Price Scenario, Regional Haze Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
Ref.	25,192	25,797	28,117	25,265	25,803	28,194
RH-1	23,997	24,642	26,956	24,092	24,668	27,139
RH-2	24,095	24,871	27,683	24,058	24,853	27,703
RH-3	24,116	24,789	27,275	24,145	24,789	27,370
RH-4	24,523	25,162	27,451	24,615	25,185	27,607
RH-5	23,915	24,634	27,412	23,881	24,618	27,382
RH-6	24,819	25,508	27,995	24,822	25,496	28,025

Table L.30 – Stochastic Risk Adjusted PVRR by Price Scenario, Core Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
OP-1	23,915	24,632	27,306	23,881	24,618	27,339
OP-NT3	23,913	24,593	27,021	23,875	24,573	27,028
OP-REP	23,870	24,533	26,870	23,834	24,515	26,888
OP-GW4	24,238	24,804	26,689	24,201	24,779	26,702
FR-1	24,434	25,103	27,582	24,395	25,083	27,570
FR-2	25,019	25,718	28,371	24,980	25,699	28,363
RE-1a	23,974	24,618	26,953	23,937	24,637	26,958
RE-1b	23,924	24,580	26,932	23,887	24,599	26,950
RE-1c	24,026	24,650	26,913	23,988	24,632	26,927
RE-2	23,984	24,609	26,864	23,948	24,595	26,886
DLC-1	24,036	24,664	26,976	23,998	24,647	26,969

Table L.31 – Stochastic Risk Adjusted PVRR by Price Scenario, Sensitivity Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
RH2a	24,013	24,783	27,588	23,976	24,735	27,619
LD-1					24,896	
LD-2					22,757	
LD-3					26,507	
PG-1					24,794	
PG-2					24,330	
CPP-C	23,967	24,703	27,605	23,926	24,691	27,829
CPP-D	23,848	24,548	26,971	23,809	24,513	26,966
FOT-1	24,215	24,881	27,384	24,176	24,862	27,389
CO2-1	24,994	25,535	26,919	24,946	25,484	26,966
NO-CO2					24,369	
BP					24,686	
GW1	24,501	25,100	27,153	24,462	25,076	27,158
GW2	24,865	25,464	27,523	24,825	25,439	27,528
GW3	25,439	25,974	27,780	25,399	25,946	27,789
GW4	24,223	24,808	26,775	24,185	24,783	26,782
Battery					24,672	
CAES					24,628	
WCA	7,116	7,456	8,684	7,087	7,430	8,646
WCA-RPS	7,139	7,468	8,662	7,110	7,443	8,627

Table L.32 – Stochastic Risk Adjusted PVRR by Price Scenario, Final Screening Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
FS-REP	23,892	24,556	26,915	23,854	24,536	26,928
FS-GW4	23,976	24,538	26,418	23,939	24,513	26,428
FS-R1c	24,005	24,549	26,369	23,969	24,525	26,383
FS-R2	23,977	24,531	26,372	23,940	24,506	26,383

Table L.33 – Carbon Dioxide Emissions by Price Scenario, Regional Haze Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
Ref.	777,629	792,139	822,316	746,112	771,917	807,893
RH-1	778,296	796,129	832,155	747,953	770,068	810,428
RH-2	740,349	760,516	789,876	731,639	746,202	782,057
RH-3	765,552	784,124	815,564	741,886	765,080	800,197
RH-4	778,761	797,502	833,982	748,802	772,180	814,146
RH-5	761,055	778,905	794,102	750,003	763,392	791,235
RH-6	769,111	790,454	823,815	750,212	774,962	815,909

Table L.34 – Carbon Dioxide Emissions by Price Scenario, Core Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
OP-1	761,704	779,805	807,022	750,003	763,392	797,073
OP-NT3	752,088	770,091	805,130	742,449	755,898	798,248
OP-REP	751,414	770,912	808,128	740,165	756,131	800,948
OP-GW4	729,100	754,628	799,689	720,898	742,897	796,752
FR-1	748,949	767,334	797,491	740,031	752,705	791,557
FR-2	758,938	776,901	803,494	749,934	761,926	796,269
RE-1a	744,406	762,430	795,949	734,788	748,177	789,525
RE-1b	752,346	771,202	806,636	742,328	756,734	799,467
RE-1c	747,267	766,006	800,317	737,728	751,818	793,791
RE-2	751,162	769,348	804,314	741,245	755,066	797,294
DLC-1	743,323	761,665	792,462	734,533	747,387	787,203

Table L.35 – Carbon Dioxide Emissions by Price Scenario, Sensitivity Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
RH2a	736,327	755,384	784,856	727,604	740,985	776,869
LD-1					761,575	
LD-2					753,141	
LD-3					768,550	
PG-1					760,451	
PG-2					756,276	
CPP-C	762,993	772,981	791,975	750,783	753,561	770,192
CPP-D	772,053	793,785	832,451	763,993	783,373	829,399
FOT-1	754,305	772,805	800,512	745,459	758,254	793,920
CO2-1	611,462	669,010	797,827	604,190	660,142	791,631
NO-CO2					790,322	
BP					767,893	
GW1	741,560	764,748	806,382	733,200	752,041	802,801
GW2	742,726	765,925	807,538	734,339	752,954	803,467
GW3	728,679	754,860	801,057	720,557	743,122	798,561
GW4	732,726	757,439	801,200	724,538	745,567	798,313
Battery					744,571	
CAES					744,830	
WCA	186,112	201,116	220,945	183,590	198,186	220,099
WCA-RPS	185,814	200,791	220,609	183,288	197,860	219,764

Table L.36 – Carbon Dioxide Emissions by Price Scenario, Final Screening Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
FS-REP	751,656	770,177	806,095	742,090	756,079	799,221
FS-GW4	731,108	756,103	800,457	722,965	744,328	797,681
FS-R1c	730,427	755,499	799,914	722,284	743,734	797,140
FS-R2	729,953	755,491	800,937	721,857	743,727	798,200

Table L.37 – Energy Not Served, Regional Haze Cases, Low Gas

GWh	Low Gas, MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	13.7	33.4	14.2	33.4
RH-1	11.5	31.2	12.4	32.4
RH-2	11.9	34.4	12.2	34.5
RH-3	11.2	30.5	11.4	30.3
RH-4	11.5	30.4	12.3	31.1
RH-5	11.5	30.2	11.7	30.3
RH-6	12.0	30.9	12.3	30.9

Table L.38 – Energy Not Served, Regional Haze Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	13.3	33.4	13.9	33.8
RH-1	11.1	31.0	11.6	31.3
RH-2	11.5	34.0	12.0	34.3
RH-3	10.8	30.2	11.3	30.6
RH-4	11.1	30.2	11.6	30.5
RH-5	11.1	30.1	11.6	30.5
RH-6	11.7	30.7	12.3	31.1

Table L.39 – Energy Not Served, Regional Haze Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	14.5	33.8	14.9	34.4
RH-1	12.3	31.6	12.5	31.8
RH-2	12.6	35.1	12.9	35.8
RH-3	11.9	30.8	12.1	30.9
RH-4	12.2	30.6	12.5	30.9
RH-5	12.2	30.7	12.4	30.8
RH-6	12.9	31.3	13.3	31.8

Table L.40 – Energy Not Served, Core Cases, Low Gas

GWh	Low Gas MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	11.5	30.2	11.7	30.3
OP-NT3	12.1	31.4	12.4	31.3
OP-REP	11.0	30.9	11.3	30.9
OP-GW4	11.0	30.3	11.3	30.5
FR-1	12.4	31.4	12.7	31.5
FR-2	2.8	8.2	3.0	8.3
RE-1a	12.1	31.2	12.4	31.4
RE-1b	10.9	29.8	11.2	29.9
RE-1c	11.2	30.6	11.5	30.5
RE-2	11.2	30.2	11.5	30.2
DLC-1	12.8	32.1	13.1	32.1

Table L.41 – Energy Not Served, Core Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	11.1	30.1	11.6	30.5
OP-NT3	11.8	31.0	12.3	31.4
OP-REP	10.7	30.7	11.2	31.0
OP-GW4	10.8	30.0	11.3	30.5
FR-1	12.0	31.1	12.6	31.5
FR-2	2.8	8.1	3.1	8.2
RE-1a	11.7	31.0	12.3	31.4
RE-1b	10.6	29.7	11.1	30.1
RE-1c	10.8	30.2	11.4	30.5
RE-2	10.8	29.9	11.4	30.3
DLC-1	12.5	31.7	13.0	32.1

Table L.42 – Energy Not Served, Core Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	12.2	30.7	12.4	30.8
OP-NT3	13.0	31.5	13.2	31.6
OP-REP	11.8	31.3	12.1	31.4
OP-GW4	12.0	30.7	12.2	30.8
FR-1	13.1	31.8	13.2	31.7
FR-2	3.1	8.4	3.1	8.5
RE-1a	12.9	31.7	13.1	32.0
RE-1b	11.7	30.1	12.0	30.3
RE-1c	12.0	30.7	12.2	30.8
RE-2	12.0	30.4	12.2	30.6
DLC-1	13.7	32.3	13.8	32.5

Table L.43 – Energy Not Served, Sensitivity Cases, Low Gas

GWh	Low Gas, MC A		Low Gas, MC B	
	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	11.2	30.5	11.5	30.5
CPP-C	13.3	32.0	13.4	32.0
CPP-D	12.3	31.9	12.6	31.9
FOT-1	11.9	30.9	12.2	31.0
CO2-1	14.8	38.4	14.8	38.4
GW1	11.2	30.4	11.5	30.5
GW2	11.7	30.6	11.9	30.9
GW3	10.9	30.3	11.2	30.6
GW4	11.0	31.0	11.3	31.3
WCA	15.6	39.2	15.9	39.4
WCA-RPS	15.6	39.2	15.9	39.4

Table L.44 – Energy Not Served, Sensitivity Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	10.8	30.1	11.4	30.5
LD-1			11.8	31.4
LD-2			9.9	27.5
LD-3			16.1	36.6
PG-1			13.3	32.9
PG-2			10.5	28.3
CPP-C	12.8	31.8	13.1	32.0
CPP-D	12.1	31.5	12.6	31.9
FOT-1	11.5	30.6	12.1	31.0
CO2-1	13.1	34.1	13.2	34.0
NO-CO2			9.9	29.2
BP			12.1	31.4
GW1	11.0	30.1	11.5	30.5
GW2	11.4	30.3	11.9	30.7
GW3	10.7	30.1	11.3	30.6
GW4	10.8	30.7	11.3	31.3
Battery			11.6	31.7
CAES			11.5	31.2
WCA	14.8	38.9	15.8	39.6
WCA-RPS	14.8	38.8	15.8	39.6

Table L.45 – Energy Not Served, Sensitivity Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	12.1	30.9	12.2	31.1
CPP-C	13.9	32.1	14.1	32.7
CPP-D	13.2	32.1	13.3	32.3
FOT-1	12.7	31.2	12.8	31.3
CO2-1	14.2	34.1	14.8	34.2
GW1	12.1	30.8	12.3	30.9
GW2	12.5	31.3	12.7	31.8
GW3	11.9	30.7	12.1	30.8
GW4	11.9	31.4	12.2	31.7
WCA	15.3	39.1	15.3	39.0
WCA-RPS	15.3	39.1	15.3	39.0

Table L.46 – Energy Not Served, Final Screening Cases, Low Gas

GWh	Low Gas MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	11.5	30.5	11.7	30.6
FS-GW4	11.3	30.0	11.6	30.3
FS-R1c	11.0	30.2	11.3	30.3
FS-R2	11.2	30.0	11.5	30.4

Table L.47 – Energy Not Served, Final Screening Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	11.1	30.3	11.6	30.5
FS-GW4	11.1	29.7	11.6	30.3
FS-R1c	10.7	29.8	11.3	30.3
FS-R2	11.0	29.7	11.5	30.3

Table L.48 – Energy Not Served, Final Screening Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	12.3	30.8	12.5	30.9
FS-GW4	12.2	30.5	12.4	30.7
FS-R1c	11.9	30.5	12.1	30.6
FS-R2	12.2	31.0	12.4	31.2

Table L.49 – PVRR Cost Components by Price Scenario, Regional Haze Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,256	479	428	2,510	857	(2,202)	1,804	8,847	23,979
RH-1	11,430	525	427	2,502	915	(2,096)	1,562	7,575	22,840
RH-2	11,193	505	428	2,486	904	(1,877)	1,631	7,665	22,934
RH-3	11,380	561	427	2,501	961	(2,094)	1,582	7,634	22,953
RH-4	11,435	517	427	2,500	899	(2,086)	1,574	8,076	23,342
RH-5	11,269	524	428	2,482	888	(1,892)	1,660	7,404	22,762
RH-6	11,408	578	428	2,489	886	(2,079)	1,625	8,289	23,624

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,862	524	434	2,510	857	(2,573)	2,093	8,847	24,553
RH-1	12,097	575	434	2,502	915	(2,448)	1,804	7,575	23,453
RH-2	11,995	553	435	2,486	904	(2,205)	1,840	7,665	23,671
RH-3	12,085	608	434	2,501	961	(2,449)	1,818	7,634	23,593
RH-4	12,105	563	434	2,500	899	(2,437)	1,809	8,076	23,949
RH-5	11,970	571	434	2,482	888	(2,195)	1,892	7,404	23,446
RH-6	12,151	631	435	2,489	886	(2,443)	1,840	8,289	24,278

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	13,626	587	457	2,510	857	(3,874)	3,750	8,847	26,760
RH-1	14,029	651	457	2,502	915	(3,606)	3,132	7,575	25,654
RH-2	14,222	627	455	2,486	904	(3,242)	3,230	7,665	26,346
RH-3	14,058	679	457	2,502	961	(3,573)	3,237	7,634	25,956
RH-4	14,017	631	457	2,500	899	(3,596)	3,141	8,076	26,126
RH-5	13,687	638	459	2,482	888	(3,107)	3,637	7,404	26,088
RH-6	14,215	716	458	2,489	886	(3,594)	3,183	8,289	26,642

Table L.50 – PVRR Cost Components by Price Scenario, Regional Haze Cases, MC B

	Stochastic PVRR ($ millions)								
Low Gas MC B	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	10,891	478	424	2,510	857	(2,055)	2,096	8,847	24,048
RH-1	11,080	526	424	2,502	915	(1,946)	1,857	7,575	22,931
RH-2	11,016	504	425	2,486	904	(1,801)	1,701	7,665	22,898
RH-3	11,077	558	423	2,501	961	(1,967)	1,792	7,634	22,981
RH-4	11,088	515	424	2,500	899	(1,937)	1,864	8,076	23,429
RH-5	11,074	522	424	2,482	888	(1,813)	1,749	7,404	22,730
RH-6	11,144	577	424	2,489	886	(1,968)	1,784	8,289	23,626

	Stochastic PVRR ($ millions)								
Medium Gas MC B	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,468	518	429	2,510	857	(2,388)	2,318	8,847	24,559
RH-1	11,649	568	429	2,502	915	(2,237)	2,077	7,575	23,477
RH-2	11,692	548	430	2,486	904	(2,059)	1,989	7,665	23,655
RH-3	11,711	603	429	2,501	961	(2,262)	2,014	7,634	23,593
RH-4	11,667	556	429	2,500	899	(2,229)	2,073	8,076	23,970
RH-5	11,654	564	429	2,482	888	(2,052)	2,061	7,404	23,430
RH-6	11,823	626	430	2,489	886	(2,276)	2,000	8,289	24,266

	Stochastic PVRR ($ millions)								
High Gas MC B	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	13,104	571	459	2,510	857	(3,639)	4,124	8,847	26,833
RH-1	13,445	634	458	2,502	915	(3,361)	3,659	7,575	25,827
RH-2	13,927	615	457	2,486	904	(3,112)	3,425	7,665	26,366
RH-3	13,581	664	458	2,502	961	(3,360)	3,605	7,634	26,046
RH-4	13,456	614	459	2,500	899	(3,367)	3,637	8,076	26,274
RH-5	13,475	626	459	2,482	888	(3,018)	3,743	7,404	26,059
RH-6	13,882	701	459	2,489	886	(3,451)	3,415	8,289	26,670

Table L.51 – PVRR Cost Components by Price Scenario, Core Cases, MC A

Low Gas MC A	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
	Stochastic PVRR ($ millions)								
OP-1	11,277	524	427	2,482	888	(1,893)	1,654	7,404	22,763
OP-NT3	11,103	545	427	2,497	937	(1,918)	1,636	7,534	22,761
OP-REP	11,145	544	426	2,489	911	(1,974)	1,535	7,643	22,719
OP-GW4	10,695	518	425	2,543	890	(1,991)	1,486	8,503	23,069
FR-1	10,974	492	427	2,506	906	(1,869)	1,777	8,045	23,257
FR-2	11,168	452	427	2,488	829	(1,909)	1,775	8,590	23,820
RE-1a	10,944	534	427	2,502	937	(1,946)	1,607	7,814	22,819
RE-1b	11,141	536	427	2,499	937	(1,990)	1,499	7,722	22,772
RE-1c	11,021	532	427	2,503	937	(2,020)	1,544	7,923	22,868
RE-2	11,088	530	427	2,503	937	(2,080)	1,525	7,898	22,828
DLC-1	10,867	505	427	2,506	937	(1,959)	1,709	7,886	22,878

Medium Gas MC A	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
	Stochastic PVRR ($ millions)								
OP-1	11,984	571	434	2,482	888	(2,199)	1,881	7,404	23,444
OP-NT3	11,772	598	433	2,497	937	(2,228)	1,864	7,534	23,407
OP-REP	11,837	594	433	2,489	911	(2,297)	1,741	7,643	23,350
OP-GW4	11,386	569	431	2,543	890	(2,342)	1,628	8,503	23,608
FR-1	11,647	541	433	2,506	906	(2,176)	1,991	8,045	23,892
FR-2	11,908	489	434	2,488	829	(2,234)	1,982	8,590	24,485
RE-1a	11,588	588	433	2,502	937	(2,260)	1,829	7,814	23,431
RE-1b	11,823	585	433	2,499	937	(2,315)	1,710	7,722	23,395
RE-1c	11,682	584	433	2,503	937	(2,349)	1,749	7,923	23,462
RE-2	11,755	580	433	2,503	937	(2,418)	1,734	7,898	23,422
DLC-1	11,510	557	433	2,506	937	(2,277)	1,923	7,886	23,475

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	13,936	641	455	2,482	888	(3,196)	3,377	7,404	25,988
OP-NT3	13,725	677	454	2,497	937	(3,290)	3,181	7,534	25,716
OP-REP	13,852	672	454	2,489	911	(3,407)	2,960	7,643	25,573
OP-GW4	13,354	648	452	2,543	890	(3,556)	2,567	8,503	25,400
FR-1	13,493	611	454	2,506	906	(3,200)	3,436	8,045	26,251
FR-2	13,817	529	454	2,488	829	(3,267)	3,562	8,590	27,003
RE-1a	13,456	670	454	2,503	937	(3,339)	3,155	7,814	25,651
RE-1b	13,804	661	454	2,499	937	(3,414)	2,969	7,722	25,632
RE-1c	13,598	662	454	2,504	937	(3,466)	3,002	7,923	25,613
RE-2	13,698	657	454	2,503	937	(3,551)	2,971	7,898	25,567
DLC-1	13,288	633	454	2,506	937	(3,345)	3,314	7,886	25,673

Table L.52 – PVRR Cost Components by Price Scenario, Core Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,074	522	424	2,482	888	(1,813)	1,749	7,404	22,730
OP-NT3	10,918	543	423	2,497	937	(1,841)	1,714	7,534	22,724
OP-REP	10,947	542	423	2,489	911	(1,893)	1,624	7,643	22,686
OP-GW4	10,528	516	421	2,543	890	(1,919)	1,552	8,503	23,035
FR-1	10,795	490	423	2,506	906	(1,796)	1,849	8,045	23,220
FR-2	10,988	451	424	2,488	829	(1,836)	1,849	8,590	23,783
RE-1a	10,758	532	423	2,502	937	(1,870)	1,685	7,814	22,783
RE-1b	10,952	534	423	2,499	937	(1,912)	1,581	7,722	22,737
RE-1c	10,837	531	423	2,503	937	(1,943)	1,621	7,923	22,832
RE-2	10,900	528	423	2,503	937	(1,999)	1,605	7,898	22,795
DLC-1	10,690	503	423	2,506	937	(1,885)	1,781	7,886	22,842

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,654	564	429	2,482	888	(2,052)	2,061	7,404	23,430
OP-NT3	11,476	591	428	2,497	937	(2,090)	2,014	7,534	23,388
OP-REP	11,533	587	428	2,489	911	(2,155)	1,898	7,643	23,333
OP-GW4	11,130	562	426	2,543	890	(2,216)	1,745	8,503	23,584
FR-1	11,347	536	429	2,506	906	(2,039)	2,143	8,045	23,873
FR-2	11,604	486	429	2,488	829	(2,097)	2,138	8,590	24,467
RE-1a	11,290	581	428	2,502	937	(2,121)	2,016	7,814	23,449
RE-1b	11,522	579	428	2,499	937	(2,173)	1,898	7,722	23,413
RE-1c	11,386	577	428	2,503	937	(2,208)	1,898	7,923	23,444
RE-2	11,458	574	428	2,503	937	(2,271)	1,882	7,898	23,410
DLC-1	11,212	550	428	2,506	937	(2,137)	2,074	7,886	23,458

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	13,590	627	457	2,482	888	(3,057)	3,629	7,404	26,020
OP-NT3	13,437	663	456	2,497	937	(3,174)	3,372	7,534	25,722
OP-REP	13,546	657	456	2,489	911	(3,283)	3,171	7,643	25,590
OP-GW4	13,194	637	452	2,543	890	(3,463)	2,657	8,503	25,413
FR-1	13,230	595	456	2,506	906	(3,095)	3,596	8,045	26,239
FR-2	13,507	512	457	2,488	829	(3,137)	3,749	8,590	26,995
RE-1a	13,171	656	456	2,503	937	(3,222)	3,341	7,814	25,656
RE-1b	13,503	647	456	2,499	937	(3,288)	3,174	7,722	25,650
RE-1c	13,309	648	456	2,504	937	(3,341)	3,192	7,923	25,627
RE-2	13,404	643	456	2,503	937	(3,416)	3,163	7,898	25,588
DLC-1	13,055	620	456	2,506	937	(3,239)	3,446	7,886	25,667

Table L.53 – PVRR Cost Components by Price Scenario, Sensitivity Cases, MC A

	Stochastic PVRR ($ millions)								
Low Gas MC A	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,004	514	427	2,501	964	(1,888)	1,710	7,610	22,842
CPP-C	11,337	535	427	2,496	864	(2,032)	1,626	7,560	22,813
CPP-D	11,432	542	427	2,486	878	(1,926)	1,575	7,287	22,699
FOT-1	11,138	478	427	2,509	948	(1,928)	1,617	7,861	23,048
CO2-1	9,890	508	426	2,520	966	(1,555)	2,759	8,276	23,791
GW1	10,864	525	426	2,524	916	(1,969)	1,472	8,546	23,305
GW2	10,894	527	426	2,523	916	(1,967)	1,479	8,850	23,648
GW3	10,632	515	425	2,549	896	(1,986)	1,372	9,799	24,202
GW4	10,746	519	426	2,543	896	(1,971)	1,448	8,380	22,986
WCA	2,989	353	(44)	70	225	(373)	1,514	2,034	6,767
WCA-RPS	2,983	351	(44)	71	225	(398)	1,489	2,112	6,789

	Stochastic PVRR ($ millions)								
Medium Gas MC A	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,758	570	433	2,501	964	(2,204)	1,925	7,610	23,558
CPP-C	11,975	583	434	2,496	864	(2,319)	1,921	7,560	23,513
CPP-D	12,183	589	433	2,486	878	(2,250)	1,760	7,287	23,364
FOT-1	11,827	513	433	2,509	948	(2,233)	1,823	7,861	23,681
CO2-1	10,879	555	431	2,520	966	(1,970)	2,649	8,276	24,306
GW1	11,549	578	431	2,524	916	(2,308)	1,637	8,546	23,874
GW2	11,582	579	432	2,523	916	(2,306)	1,640	8,850	24,217
GW3	11,311	565	430	2,549	896	(2,339)	1,499	9,799	24,710
GW4	11,438	570	431	2,543	896	(2,316)	1,599	8,380	23,542
WCA	3,359	436	(44)	70	225	(505)	1,515	2,034	7,090
WCA-RPS	3,352	433	(44)	71	225	(536)	1,488	2,112	7,102

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	13,856	659	454	2,502	964	(3,235)	3,341	7,610	26,149
CPP-C	13,962	656	455	2,496	864	(3,308)	3,590	7,560	26,274
CPP-D	14,377	663	455	2,486	878	(3,375)	2,898	7,287	25,667
FOT-1	13,737	566	455	2,510	948	(3,271)	3,257	7,861	26,061
CO2-1	13,326	621	453	2,521	966	(3,447)	2,903	8,276	25,620
GW1	13,507	659	452	2,525	916	(3,476)	2,698	8,546	25,826
GW2	13,539	660	452	2,523	916	(3,470)	2,704	8,850	26,176
GW3	13,270	645	451	2,549	896	(3,557)	2,376	9,799	26,429
GW4	13,405	650	452	2,544	896	(3,508)	2,594	8,380	25,412
WCA	4,095	584	(44)	70	225	(755)	2,053	2,034	8,261
WCA-RPS	4,086	580	(44)	71	225	(800)	2,010	2,112	8,240

Table L.54 – PVRR Cost Components by Price Scenario, Sensitivity Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	10,829	514	423	2,501	964	(1,815)	1,779	7,610	22,806
CPP-C	11,127	533	424	2,496	864	(1,945)	1,719	7,560	22,777
CPP-D	11,263	540	423	2,486	878	(1,855)	1,640	7,287	22,661
FOT-1	10,960	476	423	2,509	948	(1,855)	1,688	7,861	23,011
CO2-1	9,735	507	422	2,520	966	(1,487)	2,809	8,276	23,748
GW1	10,694	524	422	2,524	916	(1,898)	1,539	8,546	23,268
GW2	10,723	525	422	2,523	916	(1,895)	1,546	8,850	23,610
GW3	10,465	513	421	2,549	896	(1,915)	1,437	9,799	24,165
GW4	10,579	517	422	2,543	896	(1,900)	1,514	8,380	22,951
WCA	2,930	351	(44)	70	225	(364)	1,537	2,034	6,739
WCA-RPS	2,924	349	(44)	71	225	(389)	1,513	2,112	6,762

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,456	566	429	2,501	964	(2,063)	2,080	7,610	23,542
LD-1	11,681	667	429	2,487	943	(2,185)	1,889	7,787	23,696
LD-2	11,262	504	426	2,485	824	(2,189)	1,567	6,782	21,660
LD-3	11,994	641	432	2,498	973	(1,875)	2,648	7,917	25,229
PG-1	11,636	574	429	2,490	894	(2,047)	2,081	7,542	23,598
PG-2	11,459	564	429	2,503	896	(2,103)	1,931	7,478	23,157
CPP-C	11,623	577	430	2,496	864	(2,160)	2,115	7,560	23,505
CPP-D	11,931	583	427	2,486	878	(2,130)	1,869	7,287	23,330
FOT-1	11,527	506	429	2,509	948	(2,094)	1,978	7,861	23,663
CO2-1	10,663	550	425	2,520	966	(1,860)	2,720	8,276	24,261
NO-CO2	12,108	605	425	2,497	884	(2,395)	1,612	7,423	23,160
BP	11,690	556	429	2,502	1,003	(2,035)	1,842	7,476	23,464
GW1	11,278	571	427	2,524	916	(2,178)	1,766	8,546	23,850
GW2	11,305	573	428	2,523	916	(2,175)	1,773	8,850	24,193
GW3	11,054	559	426	2,549	896	(2,214)	1,614	9,799	24,683
GW4	11,178	564	427	2,543	896	(2,189)	1,719	8,380	23,517
Battery	11,154	558	426	2,541	889	(2,221)	1,618	8,499	23,464
CAES	11,156	558	427	2,541	889	(2,222)	1,613	8,461	23,423
WCA	3,262	432	(44)	70	225	(486)	1,573	2,034	7,066
WCA-RPS	3,255	429	(44)	71	225	(515)	1,545	2,112	7,078

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	13,572	646	457	2,502	964	(3,115)	3,532	7,610	26,167
CPP-C	13,473	642	457	2,496	864	(3,057)	4,056	7,560	26,490
CPP-D	14,194	651	455	2,486	878	(3,285)	2,997	7,287	25,663
FOT-1	13,464	554	457	2,509	948	(3,158)	3,432	7,861	26,067
CO2-1	13,077	609	453	2,521	966	(3,324)	3,090	8,276	25,667
GW1	13,322	646	455	2,525	916	(3,381)	2,803	8,546	25,831
GW2	13,343	648	456	2,523	916	(3,374)	2,819	8,850	26,181
GW3	13,120	634	451	2,549	896	(3,469)	2,458	9,799	26,438
GW4	13,244	638	452	2,544	896	(3,417)	2,684	8,380	25,420
WCA	4,065	575	(44)	70	225	(740)	2,041	2,034	8,225
WCA-RPS	4,056	571	(44)	71	225	(783)	1,998	2,112	8,206

Table L.55 – PVRR Cost Components by Price Scenario, Final Screening Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,102	536	427	2,504	916	(1,947)	1,560	7,643	22,741
FS-GW4	10,714	520	426	2,539	895	(1,989)	1,421	8,292	22,817
FS-R1c	10,703	517	426	2,541	895	(2,036)	1,390	8,410	22,844
FS-R2	10,698	519	425	2,540	878	(1,995)	1,400	8,352	22,818

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,777	589	433	2,504	916	(2,263)	1,774	7,643	23,372
FS-GW4	11,400	571	431	2,539	895	(2,338)	1,566	8,292	23,356
FS-R1c	11,387	567	431	2,541	895	(2,394)	1,528	8,410	23,366
FS-R2	11,387	571	431	2,540	878	(2,347)	1,538	8,352	23,349

High Gas MC A	Stochastic PVRR ($ millions) Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	13,739	668	454	2,505	916	(3,350)	3,042	7,643	25,616
FS-GW4	13,361	652	452	2,539	895	(3,544)	2,518	8,292	25,165
FS-R1c	13,342	646	452	2,541	895	(3,626)	2,458	8,410	25,119
FS-R2	13,351	651	451	2,541	878	(3,562)	2,459	8,352	25,122

Table L.56 – PVRR Cost Components by Price Scenario, Final Screening Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions) Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	10,917	535	423	2,504	916	(1,871)	1,637	7,643	22,705
FS-GW4	10,547	518	422	2,539	895	(1,918)	1,487	8,292	22,782
FS-R1c	10,537	515	422	2,541	895	(1,965)	1,456	8,410	22,810
FS-R2	10,533	518	421	2,540	878	(1,924)	1,465	8,352	22,783

Medium Gas MC B	Stochastic PVRR ($ millions) Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,482	582	428	2,504	916	(2,125)	1,922	7,643	23,353
FS-GW4	11,143	565	427	2,539	895	(2,212)	1,684	8,292	23,333
FS-R1c	11,130	561	427	2,541	895	(2,266)	1,646	8,410	23,343
FS-R2	11,130	564	426	2,540	878	(2,221)	1,655	8,352	23,326

High Gas MC B	Stochastic PVRR ($ millions) Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	13,453	654	456	2,505	916	(3,231)	3,233	7,643	25,629
FS-GW4	13,203	640	452	2,539	895	(3,452)	2,606	8,292	25,175
FS-R1c	13,185	635	452	2,541	895	(3,529)	2,545	8,410	25,133
FS-R2	13,194	639	451	2,541	878	(3,470)	2,547	8,352	25,133

Table L.57 – 10-year Average Incremental Customer Rate Impact, Final Screening Cases

	10-year Average Incremental Customer Rate Impact (2017 - 2026)							
	Low Gas, MC B		Medium Gas, MC B		High Gas, MC B		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
FS-GW4	0.0	3	0.0	3	0.0	3	0.0	3
FS-REP	4.3	4	12.6	4	43.6	4	20.2	4
FS-R1c	(0.1)	2	(0.3)	2	(0.7)	2	(0.4)	2
FS-R2	(0.4)	1	(0.6)	1	(1.2)	1	(0.7)	1

	10-year Average Incremental Customer Rate Impact (2017 - 2036)							
	Low Gas, MC B		Medium Gas, MC B		High Gas, MC B		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
FS-GW4	0.0	3	0.0	3	0.0	3	0.0	3
FS-REP	3.8	4	12.1	4	46.7	4	20.9	4
FS-R1c	(0.1)	2	(0.3)	2	(0.8)	2	(0.4)	2
FS-R2	(0.4)	1	(0.5)	1	(1.3)	1	(0.7)	1

Table L.58 – Loss of Load Probability, Major (> 25,000 MWh) July Event, Final Screening Cases, Medium Gas, MC B

Year	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
2017	0%	0%	0%	0%
2018	8%	8%	8%	8%
2019	0%	0%	0%	0%
2020	0%	0%	0%	0%
2021	2%	2%	2%	2%
2022	4%	4%	4%	4%
2023	0%	0%	0%	0%
2024	6%	6%	6%	6%
2025	4%	4%	4%	4%
2026	6%	6%	6%	6%
2027	4%	4%	4%	4%
2028	2%	2%	2%	2%
2029	4%	4%	4%	4%
2030	8%	6%	6%	8%
2031	2%	2%	2%	2%
2032	8%	8%	8%	8%
2033	14%	12%	12%	14%
2034	8%	10%	10%	8%
2035	4%	2%	2%	2%
2036	8%	8%	8%	8%

Table L.59 – Summer Peak, Average Loss of Load Probability, Final Screening Cases, Medium Gas, MC B

Event Size (MWh)	Average for operating years 2017 through 2026 (10 Year)			
	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
> 0	94%	94%	94%	94%
> 1,000	78%	78%	78%	78%
> 10,000	10%	10%	10%	10%
> 25,000	3%	3%	3%	3%
> 50,000	0%	0%	0%	0%
> 100,000	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%

Event Size (MWh)	Average for operating years 2017 through 2036 (20 Year)			
	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
> 0	96%	96%	96%	96%
> 1,000	82%	81%	81%	81%
> 10,000	12%	12%	12%	12%
> 25,000	5%	4%	4%	5%
> 50,000	1%	1%	1%	1%
> 100,000	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%

APPENDIX M – CASE STUDY FACT SHEETS

Case Fact Sheet Overview

This appendix documents the 2017 Integrated Resource Plan modeling assumptions used for the regional haze, core case, sensitivity and final screening studies.

Case Fact Sheets - Overview

Regional Haze Case Fact Sheets

The following Regional Haze Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. Similarly, in addition to the Regional Haze compliance requirements specified for each case, all cases include costs to meet known and assumed compliance obligations for Mercury and Air Toxics (MATS), coal combustion residuals (CCR) under subtitle D of the Resource Conservation and Recovery Act (RCRA), cooling water intake structures under §316(b) of the Clean Water Act, and effluent guidelines.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
Ref.	Reference Case	-	Base	Base	Mass Cap B	Base	None	2032	$24,156	$24,219
RH-1	Regional Haze 1	-	Base	Base	Mass Cap B	Base	None	2030	$23,066	$23,159
RH-2	Regional Haze 2	-	Base	Base	Mass Cap B	Base	None	2029	$23,313	$23,482
RH-3	Regional Haze 3	-	Base	Base	Mass Cap B	Base	None	2029	$23,315	$23,398
RH-4	Regional Haze 4	-	Base	Base	Mass Cap B	Base	None	2030	$23,582	$23,663
RH-5	Regional Haze 5	-	Base	Base	Mass Cap B	Base	None	2029	$23,081	$23,177
RH-6	Regional Haze 6	-	Base	Base	Mass Cap B	Base	None	2028	$23,891	$23,986

Core Case Fact Sheets

The following Core Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. As with the regional haze cases, all core cases comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
OP-1	Optimized Portfolio	RH5	Base	Base	Mass Cap B	Base	None	2029	$23,081	$23,177
OP-NT3	Optimized Naughton 3	OP-1	Base	Base	Mass Cap B	Base	None	2029	$22,913	$23,052
OP-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,890	$22,984
OP-GW4	Energy Gateway + Repower	OP-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,612	$23,123
FR-1	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$23,463	$23,585
FR-2	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$24,136	$24,319
RE-1a	OR RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,945	$23,082
RE-1b	WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,962	$23,091
RE-1c	OR & WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,016	$23,154
RE-2	OR RPS Early	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,967	$23,098
DLC-1	Direct Load Control	OP-NT3	Base	Base	Mass Cap B	Base	None	2030	$22,942	$23,103

Sensitivity Fact Sheets

The following Sensitivity Fact Sheets summarize key assumptions and portfolio results for each sensitivity being developed for the 2017 IRP. All sensitivities produce resource portfolios capable of meeting state renewable portfolio standard requirements. As with the regional haze cases, all sensitivities comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
RH2a	Regional Haze	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,237	$23,404
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None	2029	$23,207	$23,364
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None	2030	$21,512	$21,567
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None	2028	$24,629	$24,818
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None	2029	$23,203	$23,304
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None	2030	$22,782	$22,899
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None	2029	$23,129	$23,268
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None	2029	$23,010	$23,102
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None	2029	$23,189	$23,347
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None	2030	$26,222	$26,401
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None	2028	$22,787	$22,891
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None	2030	$23,053	$23,198
GW1	Gateway 1	OP-NT3	Base	Base	Mass Cap B	Base	Segment D	2029	$22,803	$23,593
GW2	Gateway 2	OP-NT3	Base	Base	Mass Cap B	Base	Segment F	2029	$22,841	$24,054
GW3	Gateway 3	OP-NT3	Base	Base	Mass Cap B	Base	Segment D&F	2029	$22,706	$24,627
GW4	Gateway 4	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,648	$23,159
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,735	$23,162
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,659	$23,121
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,539	$7,542
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,554	$7,557

Case Fact Sheets - Overview

Final Case Fact Sheets

The following Final Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. As with the regional haze cases, all final cases comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
FS-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,907	$23,042
FS-GW4	Gateway 4	FS-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,549	$22,990
FS-R1c	OR & WA RPS Just in Time	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,561	$23,006
FS-R2	OR RPS Early	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,554	$22,995

Master Fact Sheet

CASE ASSUMPTIONS - MASTER

Description

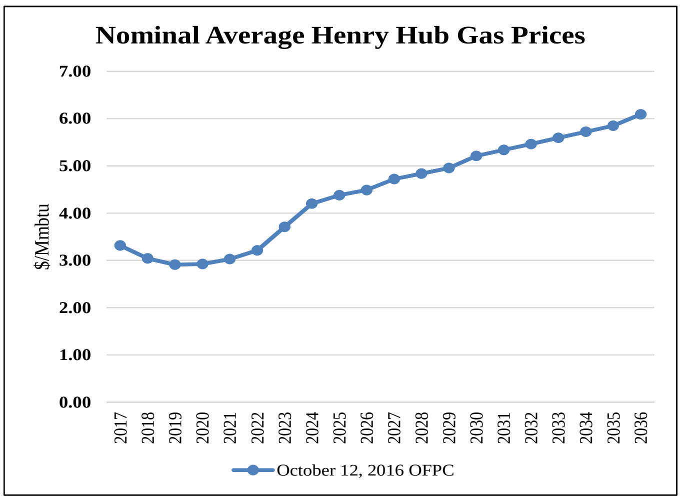
The following assumptions are applicable to all cases, except where otherwise specified.

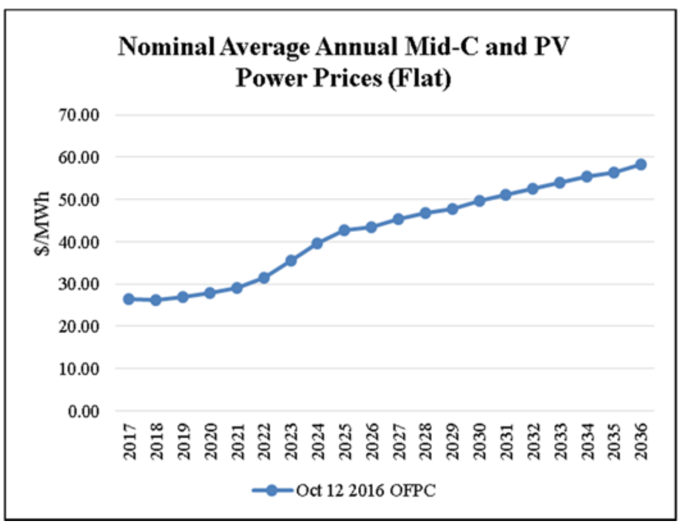
Federal CO_2 Policy/Price Signal

The Clean Power Plan is reflected in all Regional Haze, core cases, final selections and sensitivities, with the exception of the CO_2 Price and No CO_2 sensitivities.

Forward Price Curve

Gas and power prices utilize medium natural gas price assumptions consistent with the Company's October 12, 2016 OFPC through October 2022. After October 2022, prices are followed by a 12-month blend that segues into a pure fundamentals forecast. Prices reflect Mass Cap B total allocation cap.



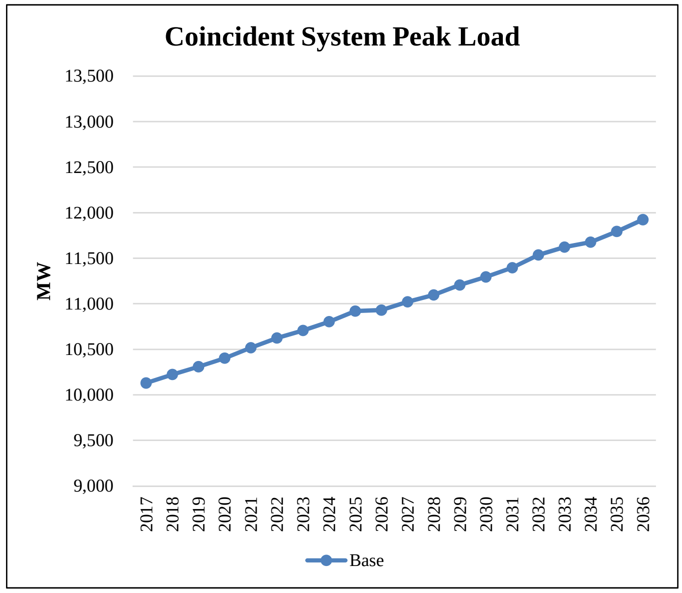


Federal Tax Incentives

- PTCs phase out beginning in 2017 and expire entirely end of 2019. To achieve the PTC, projects must be under construction by the end of 2019.
- ITC of 30 percent steps down to 26 percent in 2020 and 22 percent for 2021 through 2023, thereafter it continues in perpetuity at 10 percent.

Load Forecast

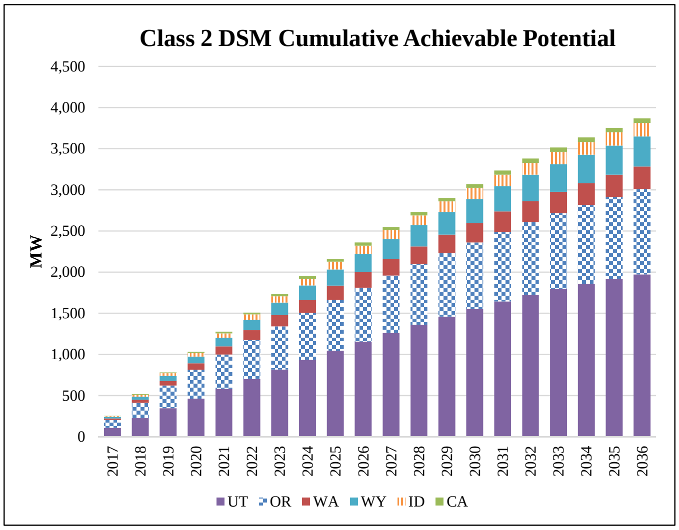
The figure below shows the base system coincident peak load forecast applicable to core cases before accounting for any potential contribution from DSM. Loads include private generation resources.



Master Fact Sheet

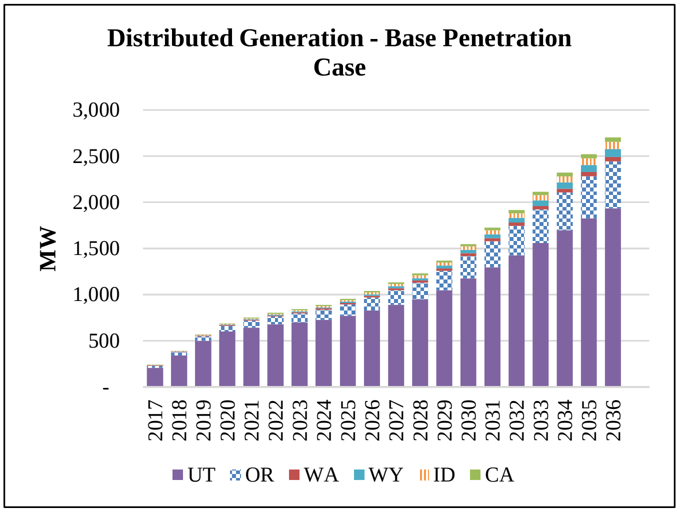
Energy Efficiency (Class 2 DSM)

Core case studies uses base supply curves with economic resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



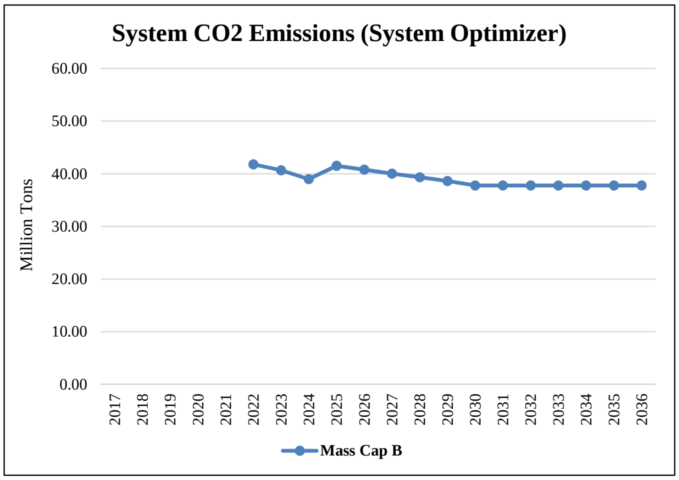
Private Generation

Base case private generation penetration by state and year are summarized in the following figure, which is included in the load forecast.



System CO_2 Emissions (System Optimizer)

System CO_2 emissions from System Optimizer are shown in the figure below. Emissions reflect Mass Cap B total allocation cap.



Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

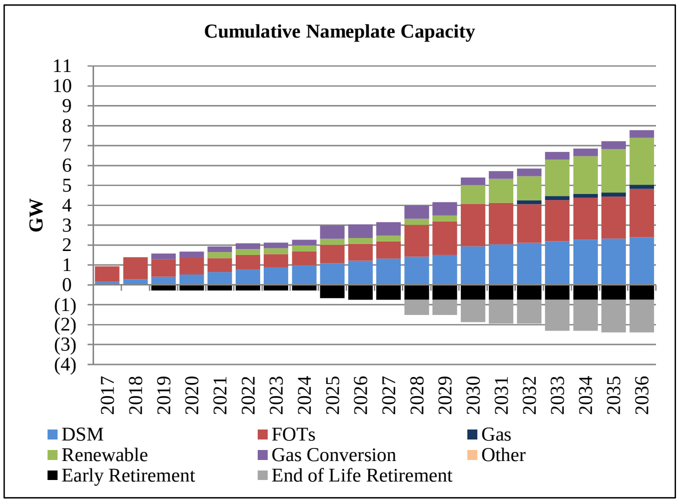
Description
Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,156
Transmission Integration	$51
Transmission Reinforcement	$12
Total Cost	$24,219

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze
Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Gas Conversion by Dec 2025, Retire Dec 2042
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by 2021, Retire Dec 2042
Hunter 2	SCR by 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	SCR by 2021, Retire Dec 2036
Huntington 2	SCR by 2021, Retire Dec 2036
Jim Bridger 1	SCR by 2022, Retire Dec 2037
Jim Bridger 2	SCR by 2021, Retire Dec 2037
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

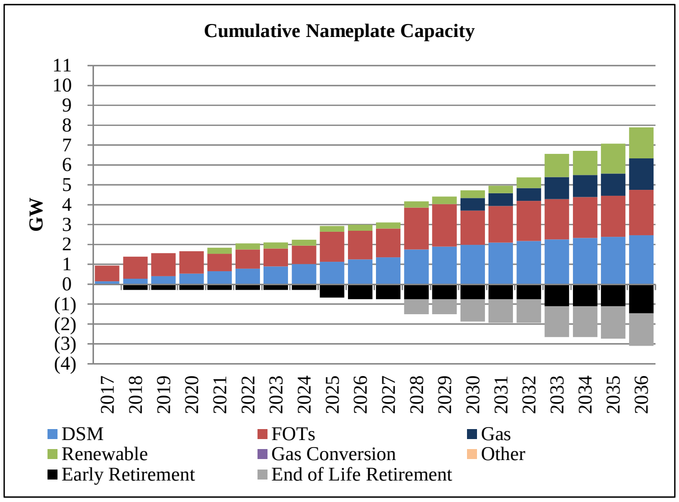
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,066
Transmission Integration	$81
Transmission Reinforcement	$12
Total Cost	$23,159

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by 2021, Retire Dec 2042
Hunter 2	NOx by 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2032
Jim Bridger 2	Retire Dec 2035
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction
NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

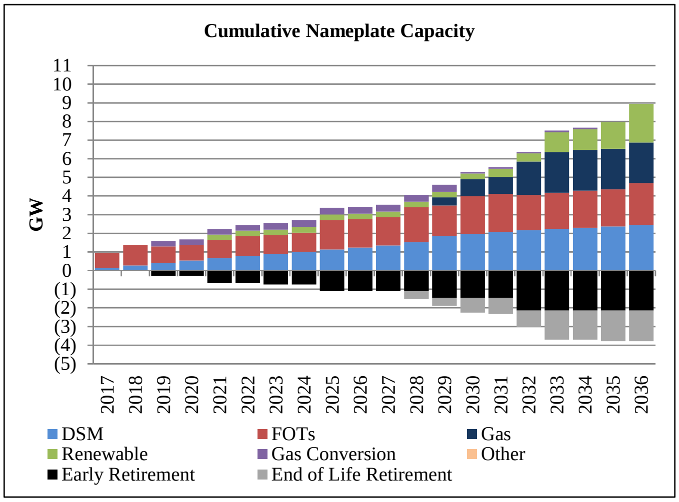
Description
Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,313
Transmission Integration	$157
Transmission Reinforcement	$12
Total Cost	$23,482

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze
Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Gas Conversion by Dec 2023, Retire Dec 2034
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2032
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	Retire Dec 2031
Hunter 2	Retire Dec 2031
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2024
Jim Bridger 2	Retire Dec 2028
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Regional Haze Case Fact Sheets

Case Assumptions

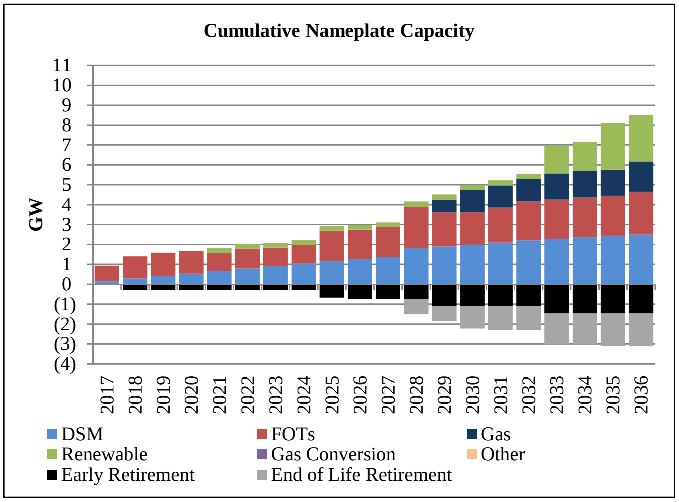
Description
Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

Portfolio Summary

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,315
Transmission Integration	$70
Transmission Reinforcement	$12
Total Cost	$23,398

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze
Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2026, Retire Dec 2042
Hunter 2	NOx by Dec 2027, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	NOx by Dec 2026, Retire Dec 2036
Huntington 2	NOx by Dec 2027, Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction
NOx = Low NOx burner

Regional Haze Case Fact Sheets

Case Assumptions

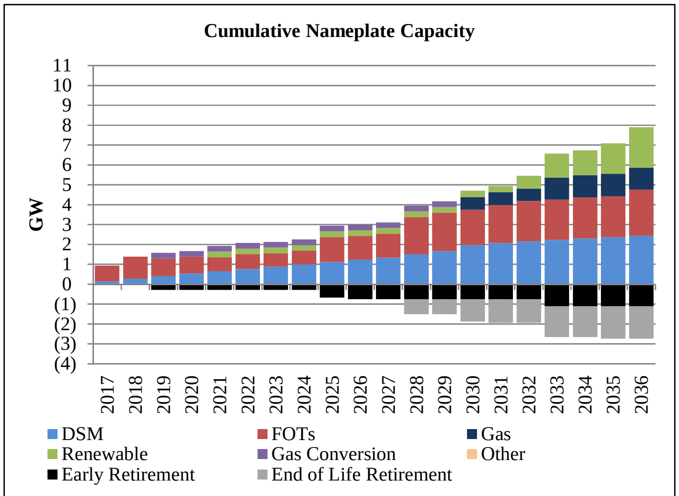
Description
Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

Portfolio Summary

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,582
Transmission Integration	$69
Transmission Reinforcement	$12
Total Cost	$23,663

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze
Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2027, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	SCR by Dec 2021, Retire Dec 2036
Huntington 2	NOx by Dec 2027, Retire Dec 2036
Jim Bridger 1	NOx by Dec 2022, Retire Dec 2032
Jim Bridger 2	SCR by Dec 2021, Retire Dec 2037
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions). This Regional Haze case became core case OP-1.

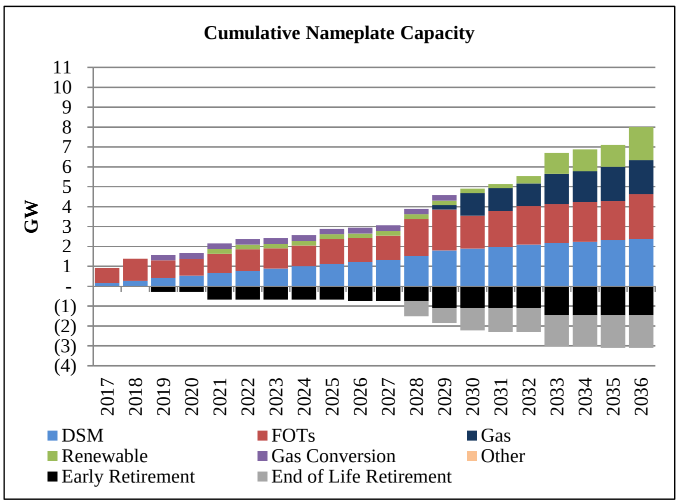
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,081
Transmission Integration	$84
Transmission Reinforcement	$12
Total Cost	$23,177

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-1 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

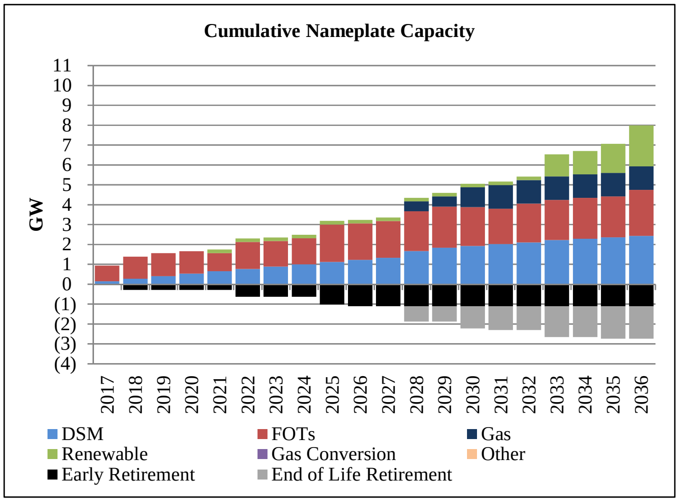
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,891
Transmission Integration	$83
Transmission Reinforcement	$12
Total Cost	$23,986

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by 8/4/2021 or Retire by 7/31/2021
Hunter 2	SCR by 8/4/2021 or Retire by 7/31/2021
Hunter 3	Retire Dec 2042
Huntington 1	SCR by 8/4/2021 or Retire by 7/31/2021
Huntington 2	SCR by 8/4/2021 or Retire by 7/31/2021
Jim Bridger 1	SCR by 12/31/2022 or Retire by 12/30/2022
Jim Bridger 2	SCR by 12/31/2022 or Retire by 12/30/2022
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Case: OP-1

Core Case Fact Sheets

CASE ASSUMPTIONS

Description

This case is the least-cost-least-risk Regional Haze case emerging from screening stage 1 (RH-5). The Regional Haze case with the best cost-risk metrics is promoted to become core case 1, and serves as the basis for further studies, including the remaining core cases and sensitivities. Therefore, as with the underlying Regional Haze case, all resources have been optimized (selected endogenously by System Optimizer), and valued in the Planning and Risk model.

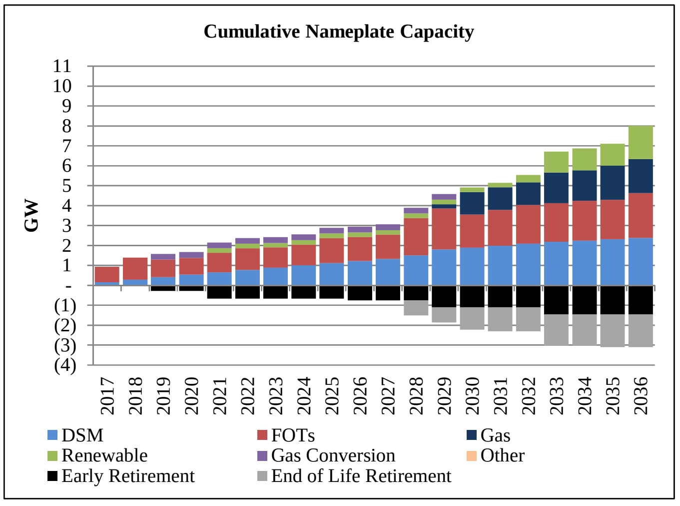
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,081
Transmission Integration	$84
Transmission Reinforcement	$12
Total Cost	$23,177

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-1 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Case: Optimized Naughton 3 (OP-NT3)

Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case OP-NT3 is the optimal Regional Haze case selected as core case 1 and includes enhancements of full PTC value and Naughton 3 retirement by December 31, 2018. All resources optimized (selected endogenously by System Optimizer), and valued in the Planning and Risk model. This case is a variant of core case OP-1.

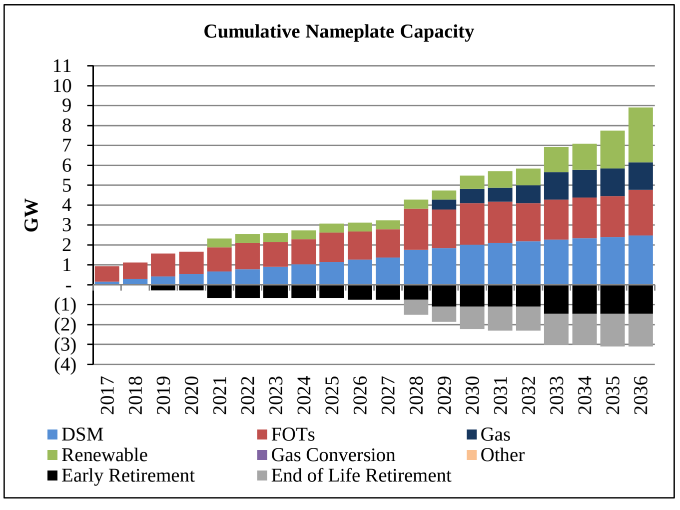
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,913
Transmission Integration	$127
Transmission Reinforcement	$12
Total Cost	$23,052

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-NT3 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Shut Down Dec 2042
Hunter 2	NOx by Dec 2021, Shut Down Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2018
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Core Case Fact Sheets

Case Assumptions

Description

Core case OP-REP assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo and Leaning Juniper). The repower projects provide significant customer benefits among all market price and Clean Power Plan scenarios. The 20-year planning horizon used for the IRP is insufficient to capture the incremental wind generation associated with the extended life of the repowered wind facilities: incremental annual energy production is in excess of 500 GWh over the existing life of the wind projects and incremental annual energy production beyond the current existing life exceeds 3,100 GWh. This case is a variant of core case OP-NT3.

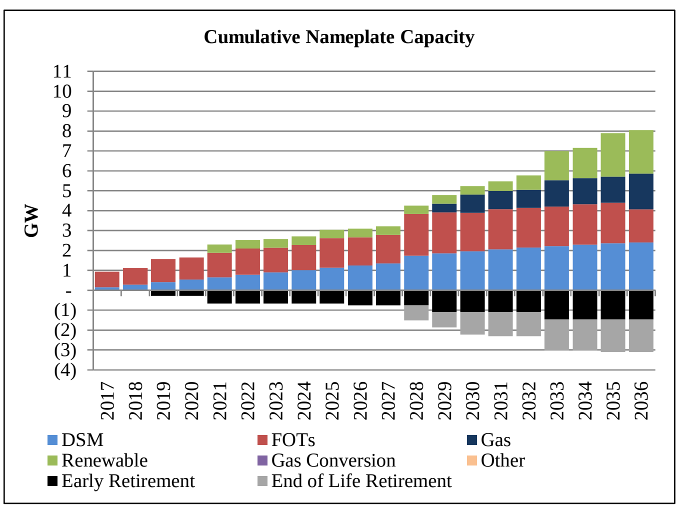
Portfolio Summary

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,890
Transmission Integration	$81
Transmission Reinforcement	$12
Total Cost	$22,984
Total Cost thru 2050	$22,638

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Core case OP-GW4 assumes 905 MW of existing wind resources are repowered by the end of 2020 and Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). This case is a variant of core case OP-REP.

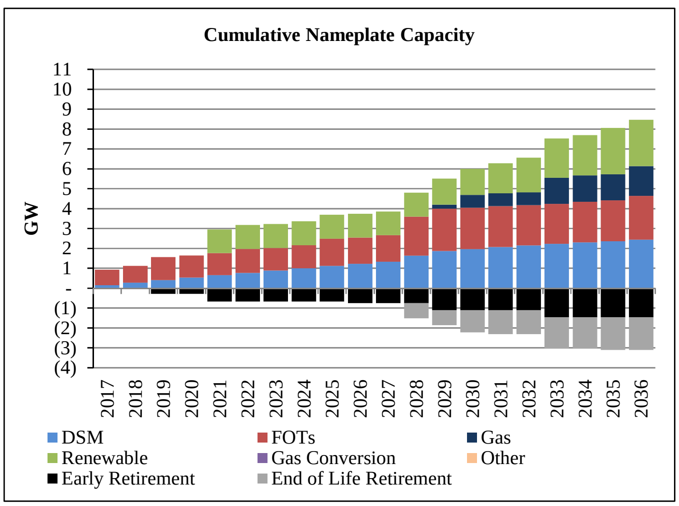
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

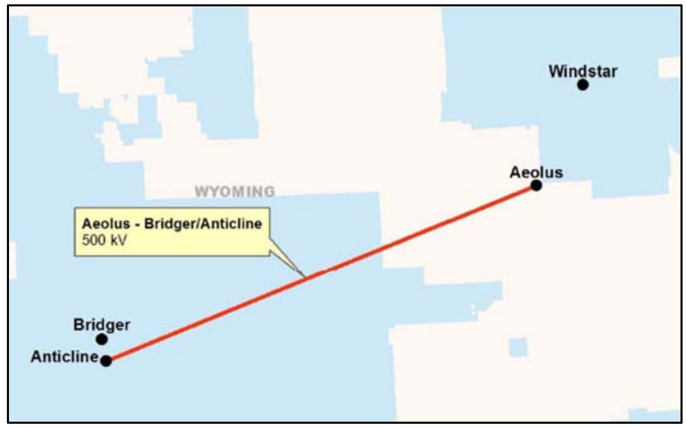
System Cost without Transmission Upgrades	$22,612
Transmission Integration	$94
Transmission Reinforcement	$12
Gateway Transmission	$405
Total Cost	$23,123
Total Cost thru 2050	$22,777

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission Path



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

In core case FR-1, fast ramp resources are added with a capacity of at least 10 percent of the system L&R need. Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage. This case is a variant of core case OP-NT3.

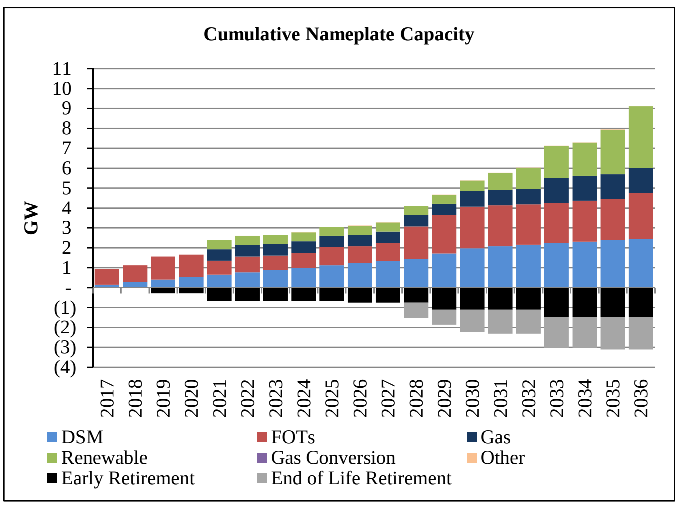
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,463
Transmission Integration	$110
Transmission Reinforcement	$12
Total Cost	$23,585

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

In core case FR-2 fast ramp resources are added with a capacity of at least 20 percent of the system L&R need. Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage. This case is a variant of core case OP-NT3.

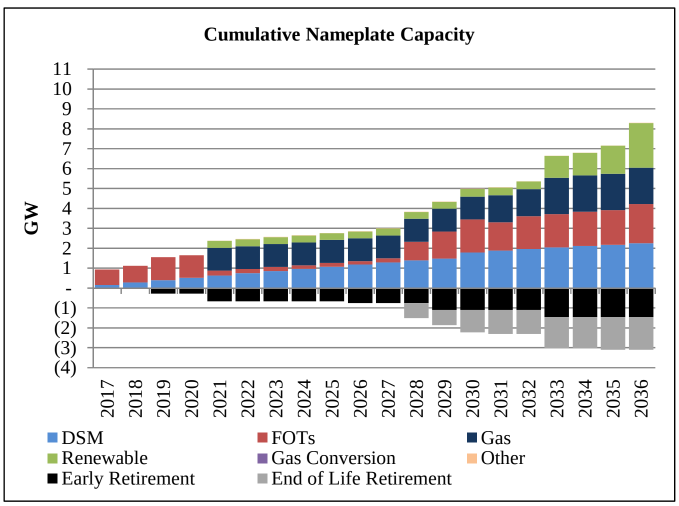
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,136
Transmission Integration	$170
Transmission Reinforcement	$12
Total Cost	$24,319

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1a retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Oregon RPS. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

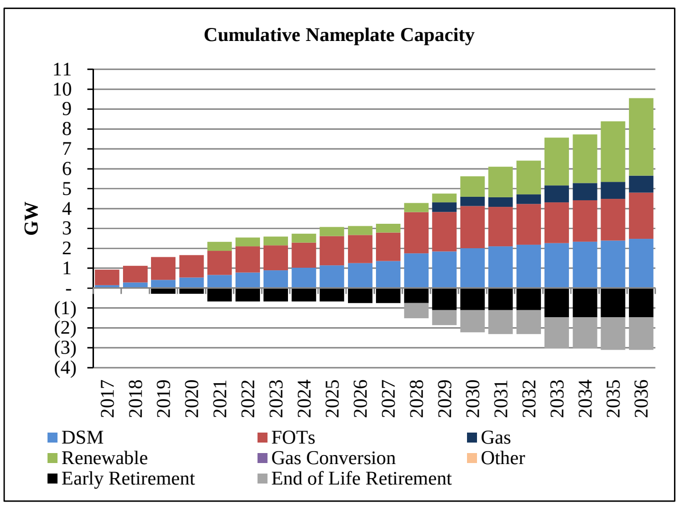
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,945
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,082

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1b retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Washington RPS. West Control Area renewable resource additions only. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

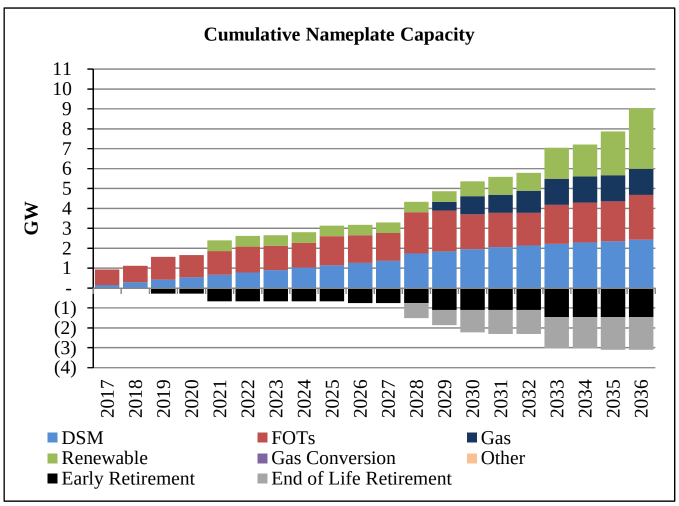
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,962
Transmission Integration	$116
Transmission Reinforcement	$12
Total Cost	$23,091

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1c retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Oregon and Washington RPS. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

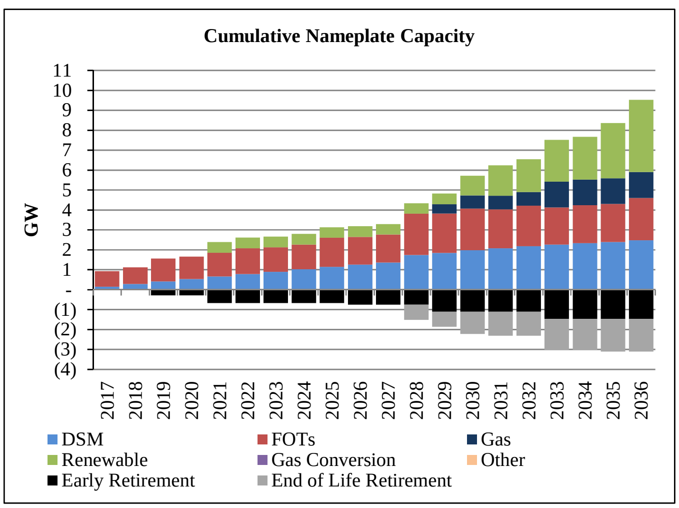
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,016
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,154

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-2 retains endogenous renewables from core case 1 and includes additional renewables to physically comply with projected Oregon RPS requirements. Additions are also made in 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance). This case is a variant of core case OP-NT3.

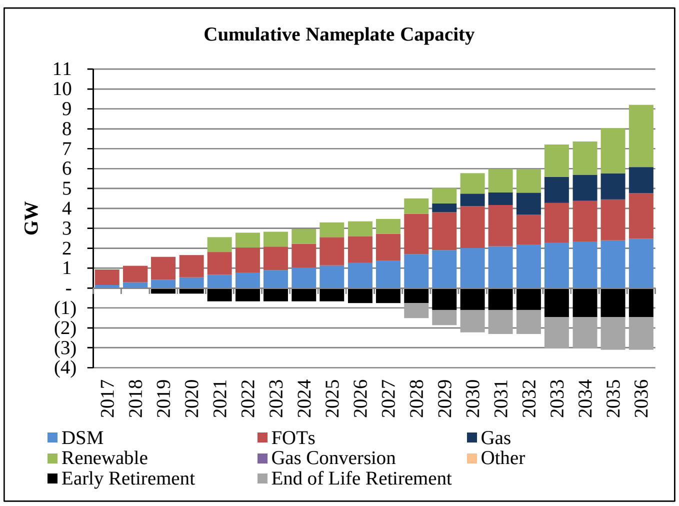
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,967
Transmission Integration	$119
Transmission Reinforcement	$12
Total Cost	$23,098

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case DLC-1 is a reference case with additional Direct Load Control (DLC) added to core case 1 in the first year (2021). Added DLC capacity is at least five percent of the system L&R need. Renewable resource assumptions are consistent with Case 4 (RE-1c), assuming Oregon and Washington physical RPS just-in-time compliance. This case is a variant of core case OP-NT3.

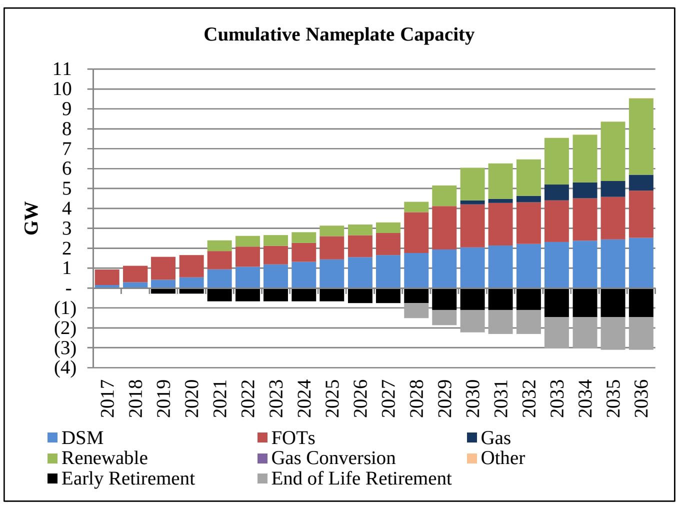
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,942
Transmission Integration	$149
Transmission Reinforcement	$12
Total Cost	$23,103

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

In response to stakeholder feedback, Case RH-2a examines the impact of a Naughton 3 retirement year-end 2017 and a Craig 1 retirement year-end 2025 as an alternative to Case RH-2. This sensitivity is a variant of core case RH2.

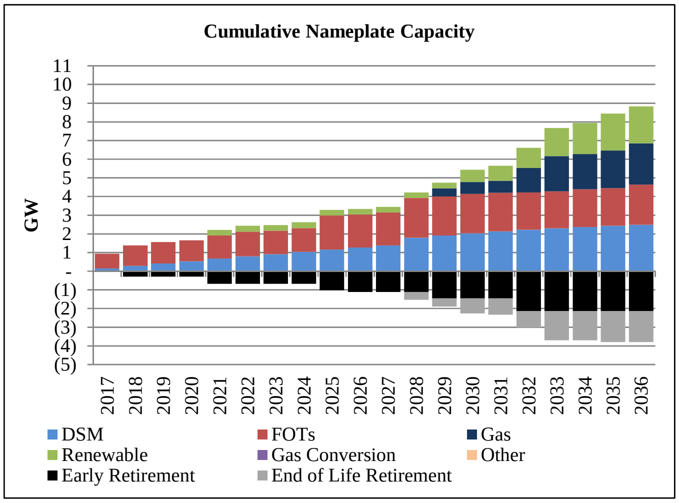
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,237
Transmission Integration	$154
Transmission Reinforcement	$12
Total Cost	$23,404

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Sensitivity RH-2a Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2032
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	Retire Dec 2031
Hunter 2	Retire Dec 2031
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2024
Jim Bridger 2	Retire Dec 2028
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The 1-in-20 peak load sensitivity is a five percent probability extreme weather scenario. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. This sensitivity is a variant of core case OP-1.

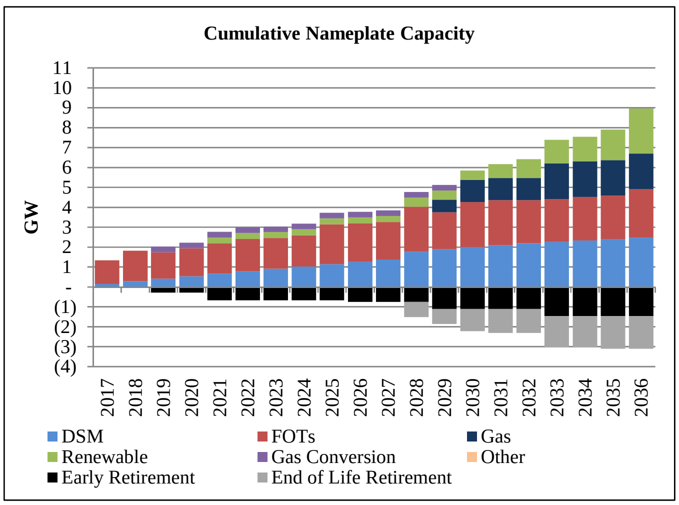
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,207
Transmission Integration	$144
Transmission Reinforcement	$12
Total Cost	$23,364

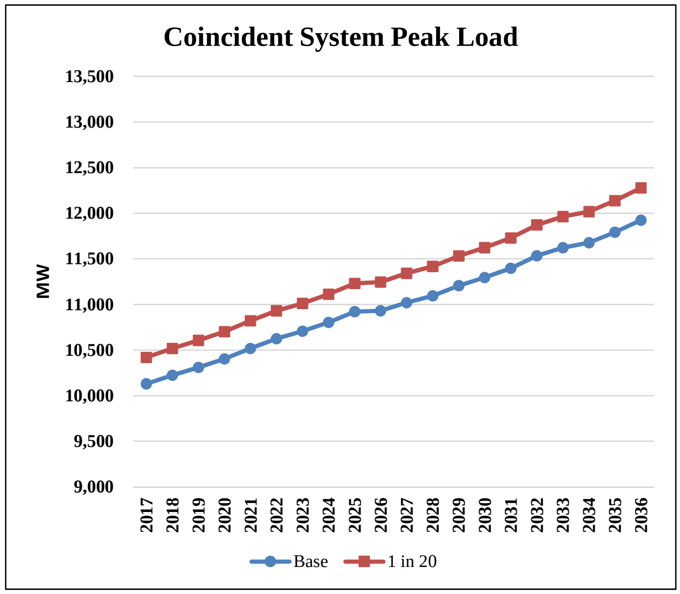
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources. Energy load forecast is identical to Base Case.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low load forecast sensitivity reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low industrial load forecast is taken from 5th percentile. This sensitivity is a variant of core case OP-1.

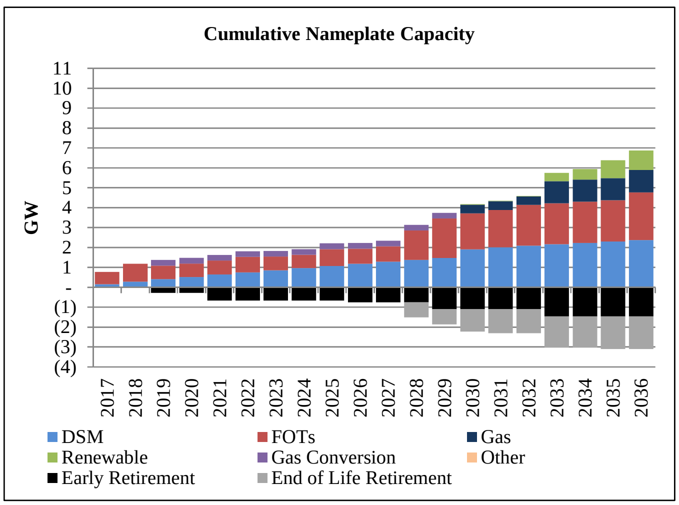
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$21,512
Transmission Integration	$42
Transmission Reinforcement	$12
Total Cost	$21,567

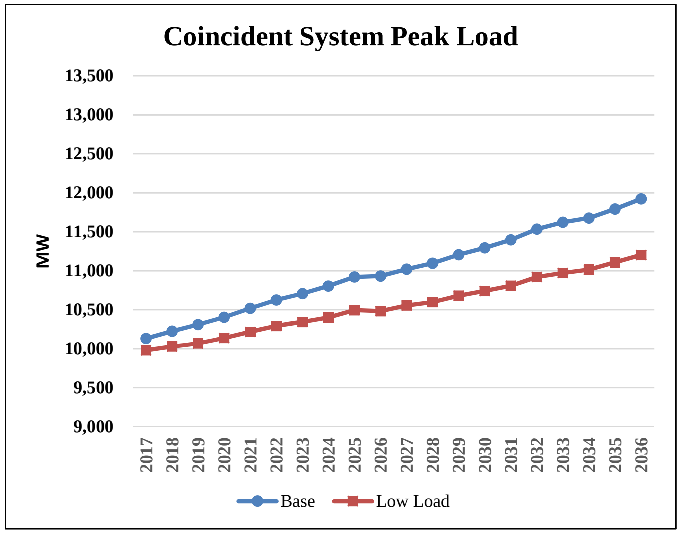
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

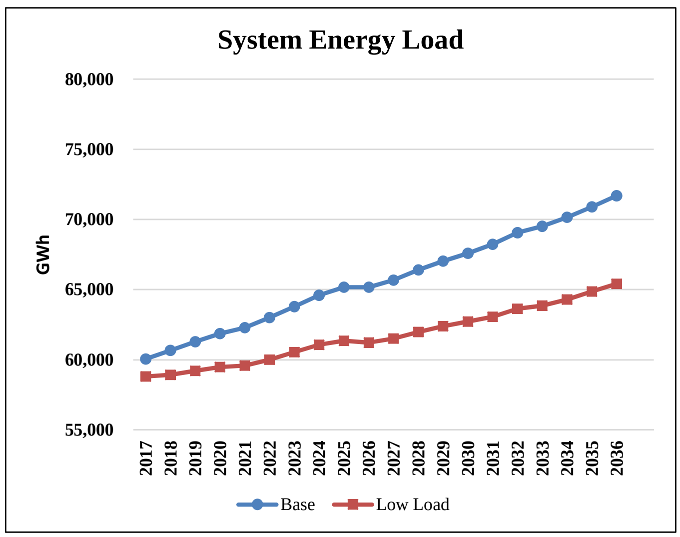


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: High Load (LD-3)

Sensitivity Fact Sheets

CASE ASSUMPTIONS

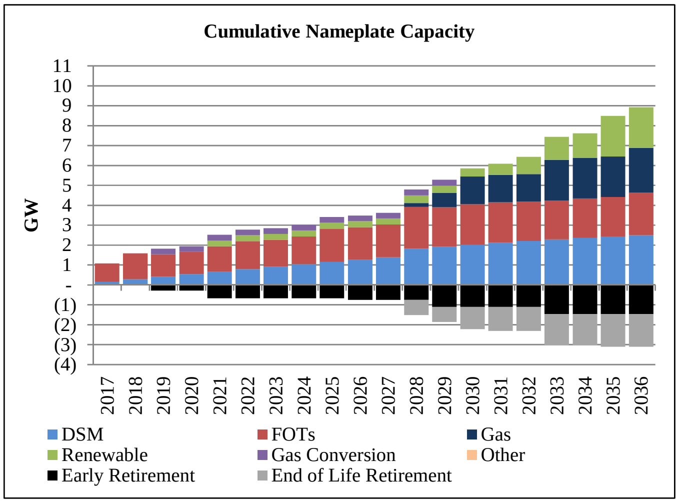
Description
The high load forecast sensitivity reflects optimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The high industrial load forecast is taken from 95th percentile. This sensitivity is a variant of core case OP-1.

PORTFOLIO SUMMARY

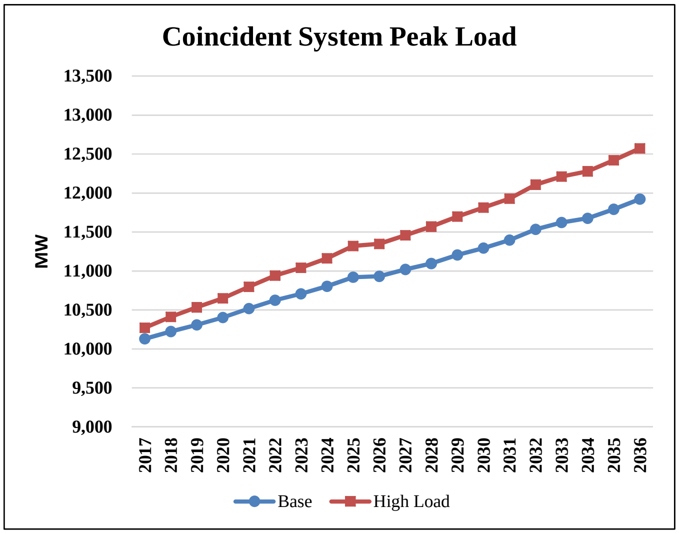
System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,629
Transmission Integration	$177
Transmission Reinforcement	$12
Total Cost	$24,818

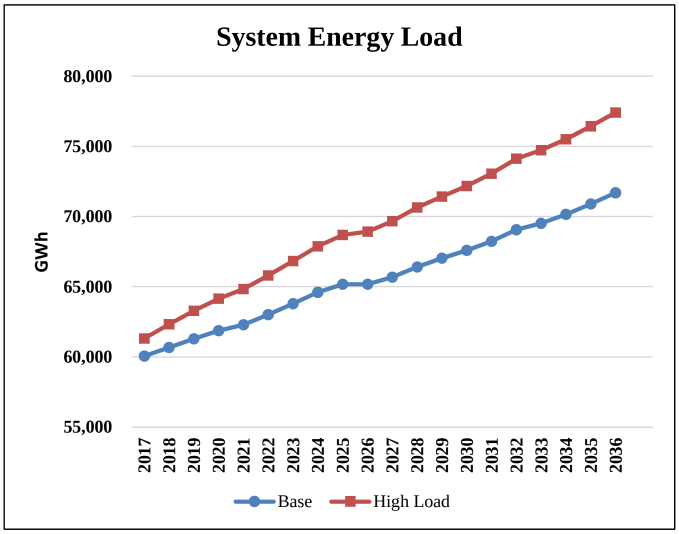
Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Load Forecast
The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low private generation sensitivity reflects reductions in technology costs, reduced technology performance levels, and lower retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of core case OP-1.

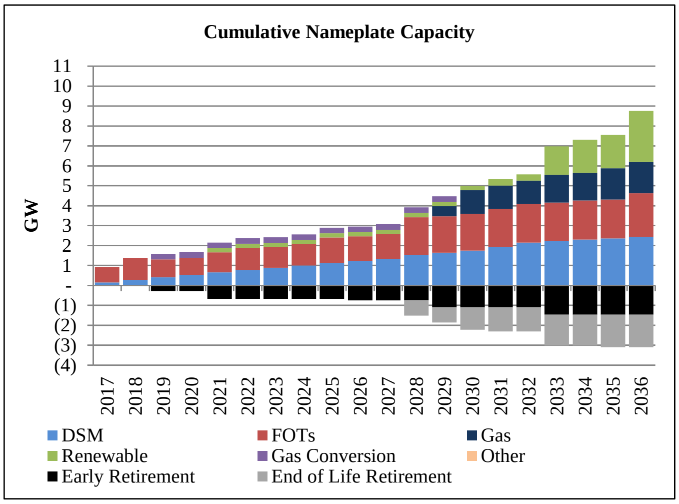
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,203
Transmission Integration	$89
Transmission Reinforcement	$12
Total Cost	$23,304

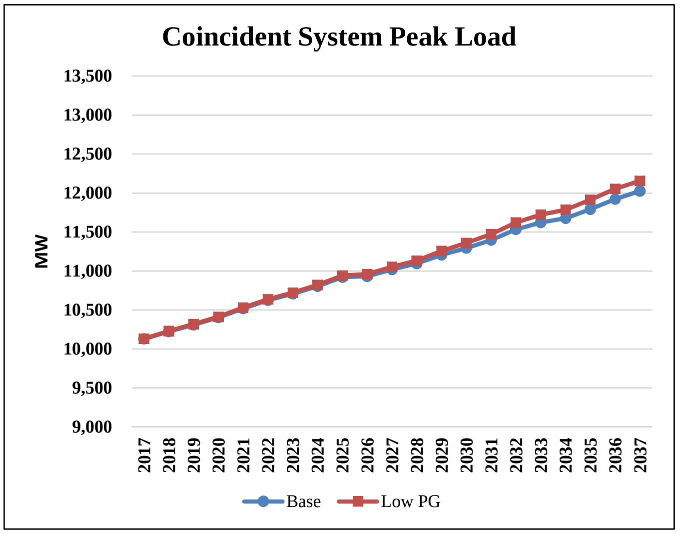
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

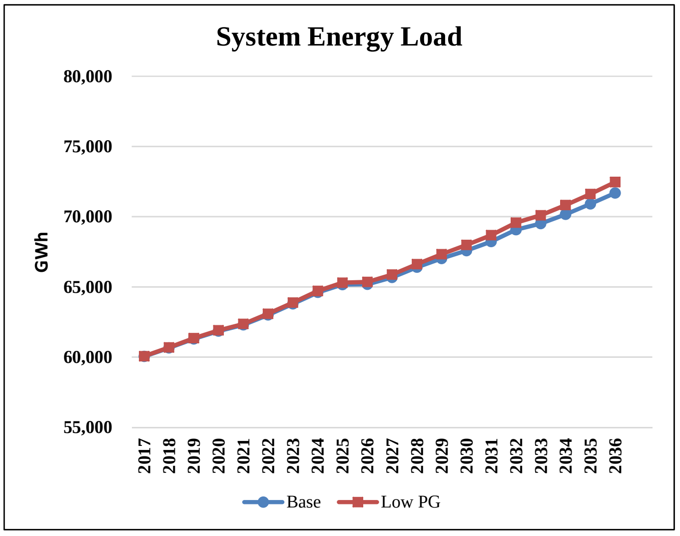


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



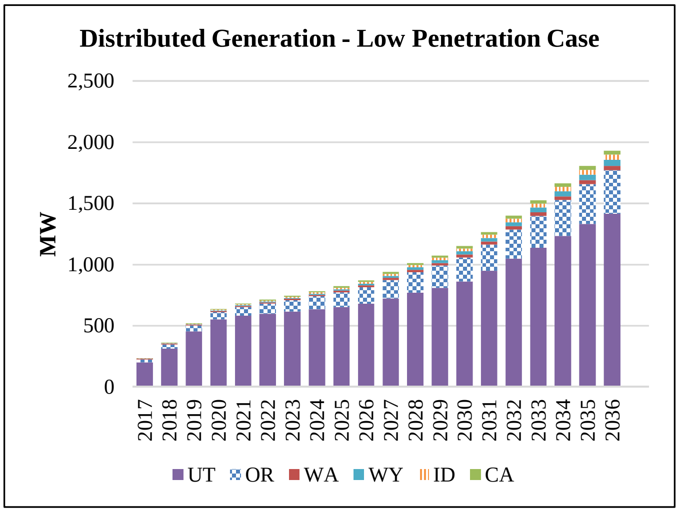
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: Low Private Gen (PG-1)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of core case OP-1.

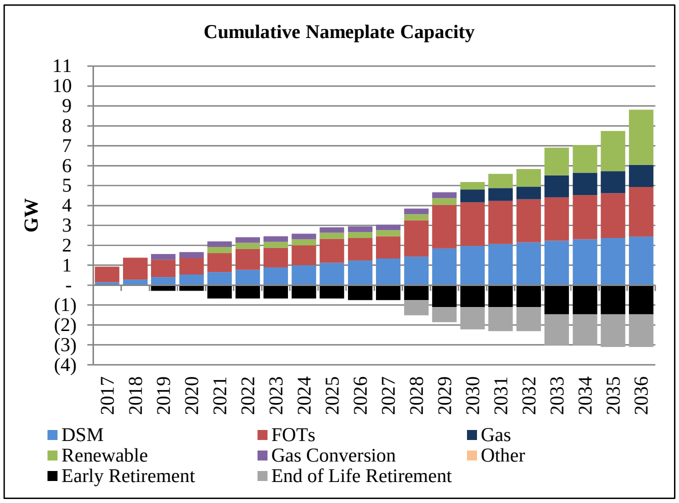
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,782
Transmission Integration	$105
Transmission Reinforcement	$12
Total Cost	$22,899

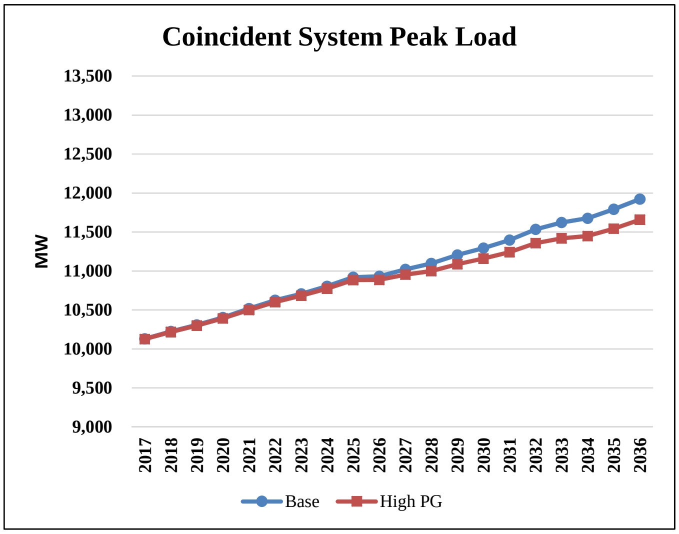
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

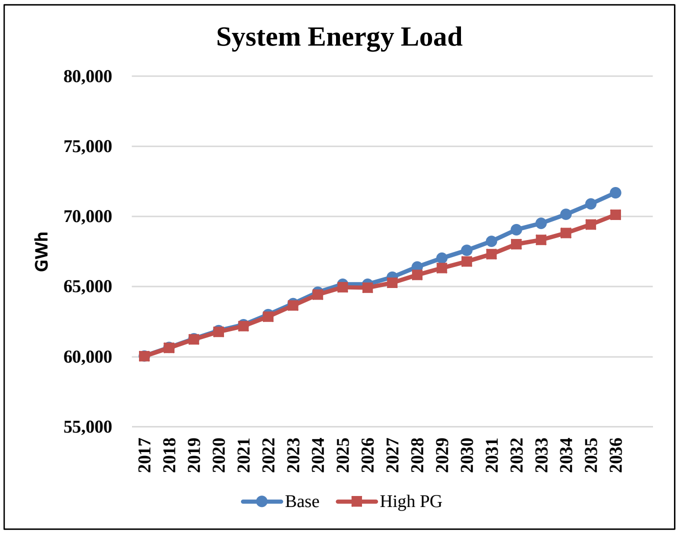


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



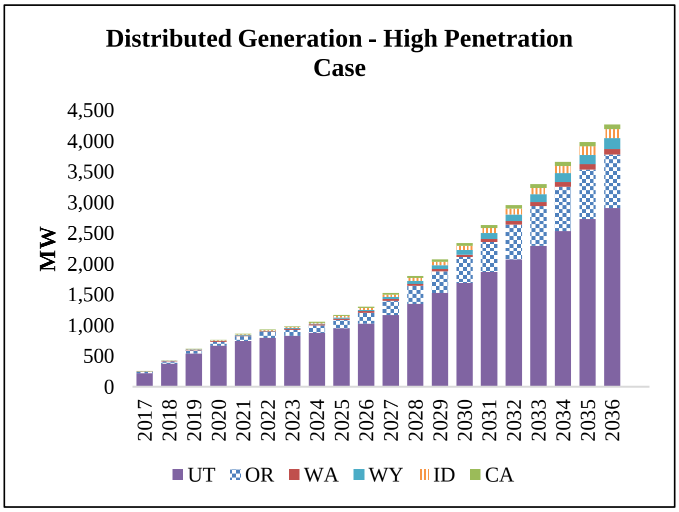
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: High Private Gen (PG-2)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

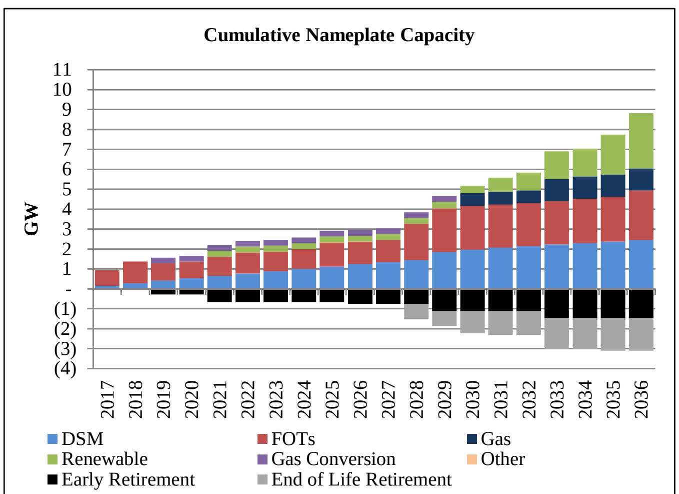
Description
The CPP Mass Cap C scenario reflects the mass based compliance approach with pro-rata allowance allocation based on historical generation with no new source complement less the CEIP (Clean Energy Incentive Program), renewable and output-based set-asides. PacifiCorp does not receive any allocation of set-asides. New resources are not restricted by the CPP cap. (the CEIP is an optional "matching fund" program that states may choose to use to incentivize wind or solar power generation in all communities and energy efficiency measures in low-income communities.) This sensitivity is a variant of core case OP-1.

PORTFOLIO SUMMARY

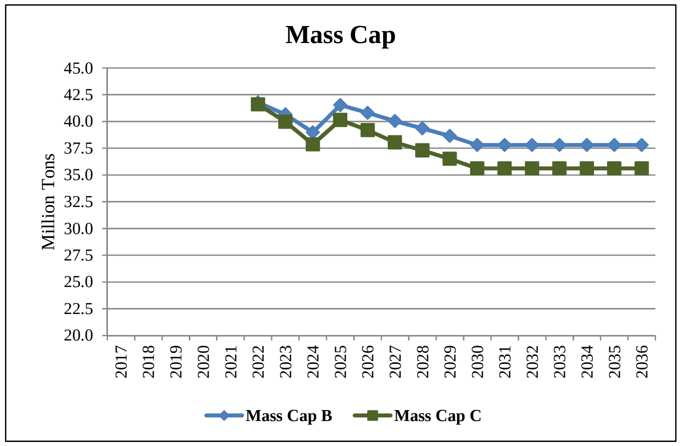
System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,129
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,268

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)
System CO_2 Emissions from System Optimizer are shown alongside those from Base Case in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

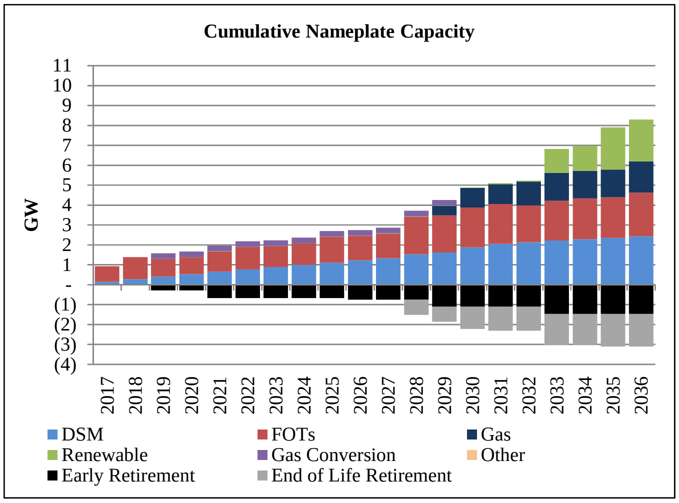
Description
The CPP Mass Cap D scenario reflects the mass based compliance approach with no set-aside program, but does benefit from the new source complement, which assumes that the mass-based limit grows to accommodate new resources needed to meet load growth. This sensitivity is a variant of core case OP-1.

PORTFOLIO SUMMARY

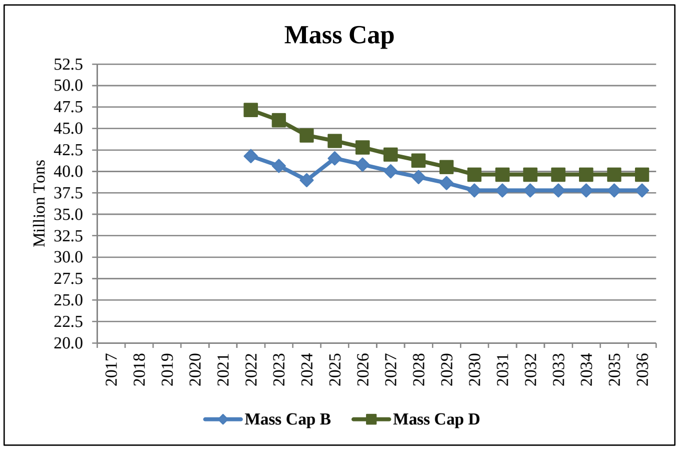
System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,010
Transmission Integration	$79
Transmission Reinforcement	$12
Total Cost	$23,102

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)
System CO_2 Emissions from System Optimizer are shown alongside those from Base Case in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

PacifiCorp develops FOT limits based on its active participation in wholesale power markets; its view of physical delivery constraints, market liquidity, and market depth; and with consideration of regional resource supply. Alternative FOT limit assumptions applied during the portfolio development process eliminates the availability of FOTs at the NOB (100 MW) and Mona (300 MW) market hubs in summer and winter beginning 2021. This sensitivity is a variant of core case OP-1.

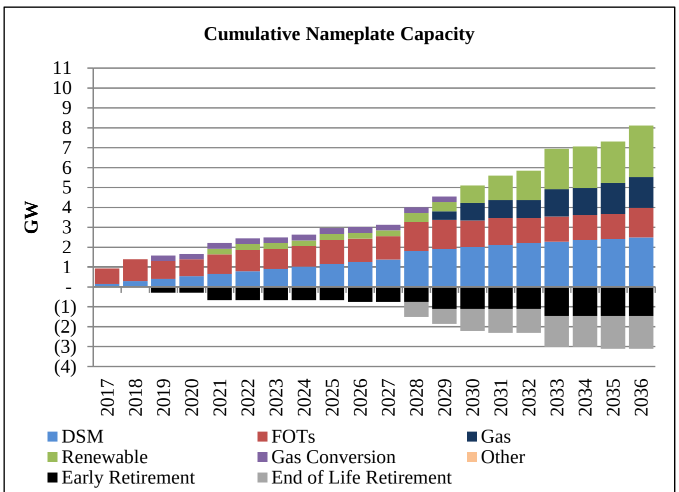
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,189
Transmission Integration	$145
Transmission Reinforcement	$12
Total Cost	$23,347

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CO_2 Price sensitivity_examines the impact of replacing the Clean Power Plan (currently stayed by the U.S. Supreme Court) with an CO_2 proxy price beginning in the year 2025, based on the assumption that even if the CPP is not in effect, there will be some carbon-based policy in place by this time. CO_2 prices applied to each ton of CO_2 emissions from new and existing resources, beginning in 2025 at $4.75/ton and reaching $38.02/ton by 2036. This sensitivity is a variant of core case OP-1.

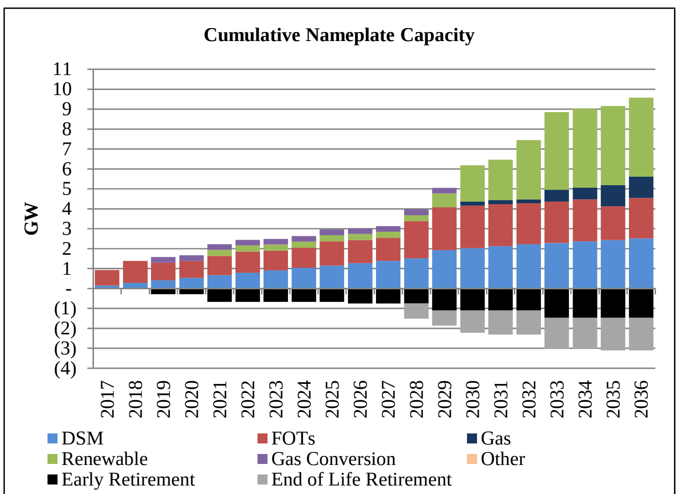
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$26,222
Transmission Integration	$166
Transmission Reinforcement	$12
Total Cost	$26,401

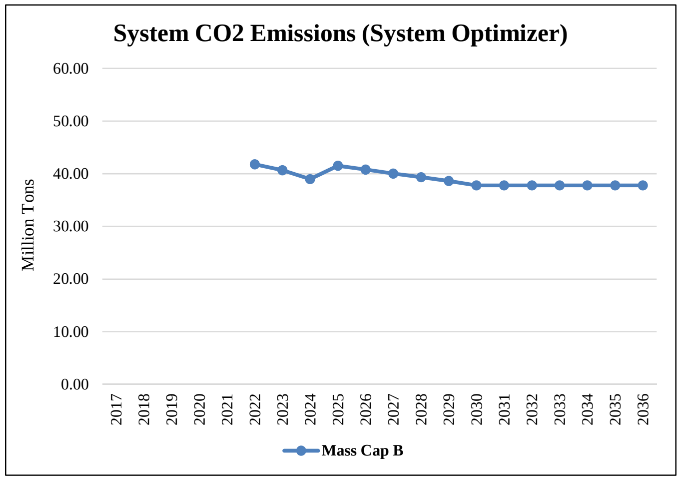
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)

System CO_2 Emissions from System Optimizer are shown in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The No CO_2 sensitivity is a response to a stakeholder request and examines the impact of having no incremental state or federal CO_2 emissions policy in place through the 2017 – 2036 study period. This sensitivity is a variant of core case OP-NT3.

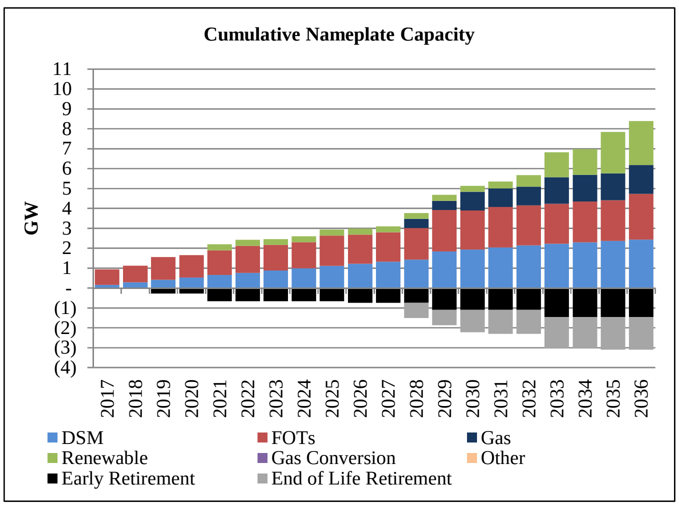
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,787
Transmission Integration	$91
Transmission Reinforcement	$12
Total Cost	$22,891

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The Business Plan sensitivity complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's Fall 2016 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with the draft preferred portfolio selected from the second screening stage. All other resources are optimized. Note that initially, these assumptions were expected to align with core case 1. Due to the timing of this sensitivity, the study was modeled based on the outcome of a later screening stage. This serves to make the business plan sensitivity closer to the eventual preferred portfolio selection, and therefore a more indicative comparison. This sensitivity is a variant of core case OP-NT3.

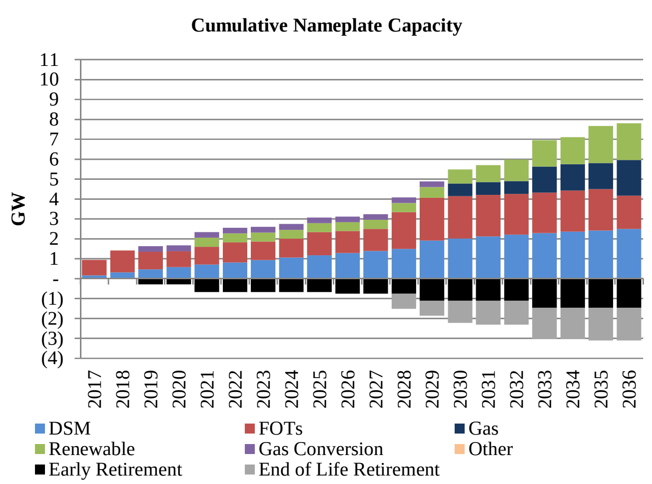
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,053
Transmission Integration	$133
Transmission Reinforcement	$12
Total Cost	$23,198

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW1 includes segment D – Windstar to Anticline (assumed in-service 2022). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

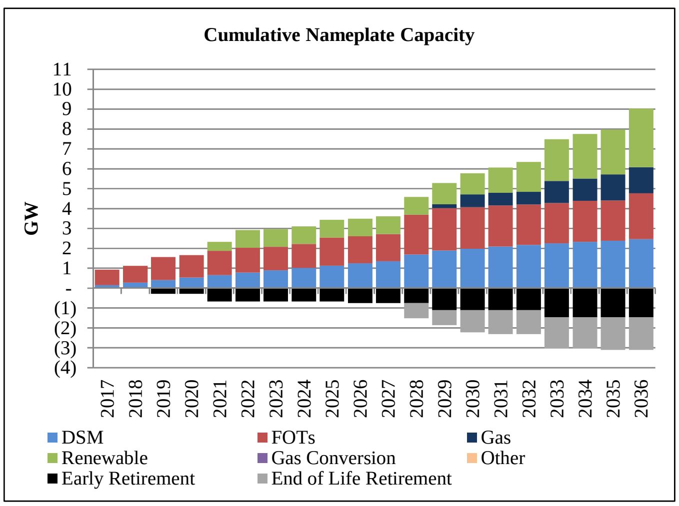
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,803
Transmission Integration	$125
Transmission Reinforcement	$12
	$652
Total Cost	$23,593

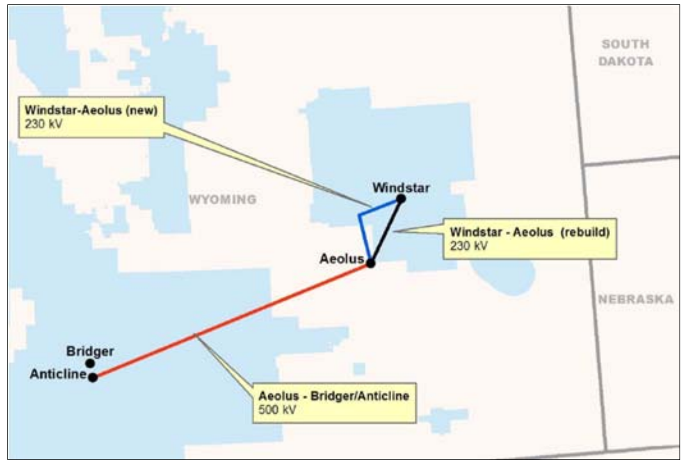
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

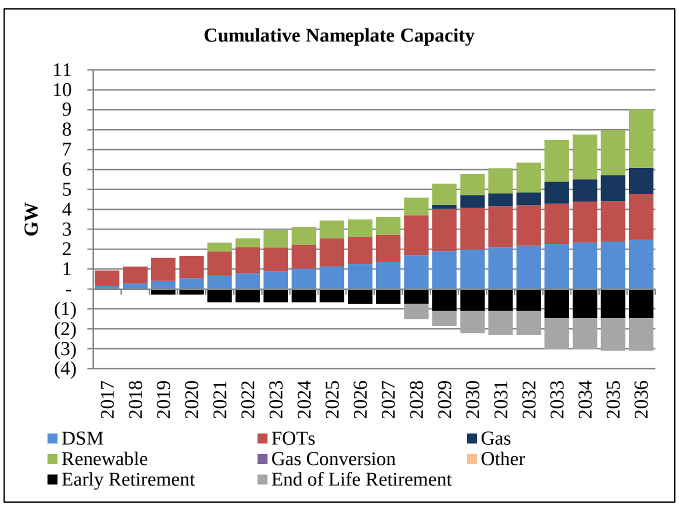
Description
Sensitivity GW2 includes Segment F – Windstar to Mona/Clover (assumed in-service 2023). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

PORTFOLIO SUMMARY

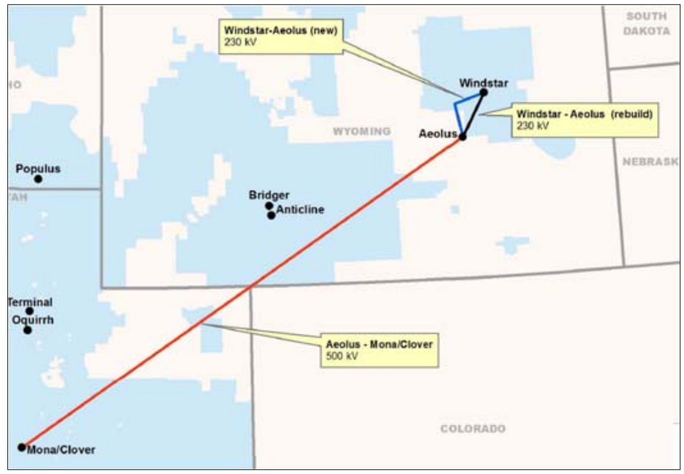
System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,841
Transmission Integration	$132
Transmission Reinforcement	$12
Gateway Transmission	$1,068
Total Cost	$24,054

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission
Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

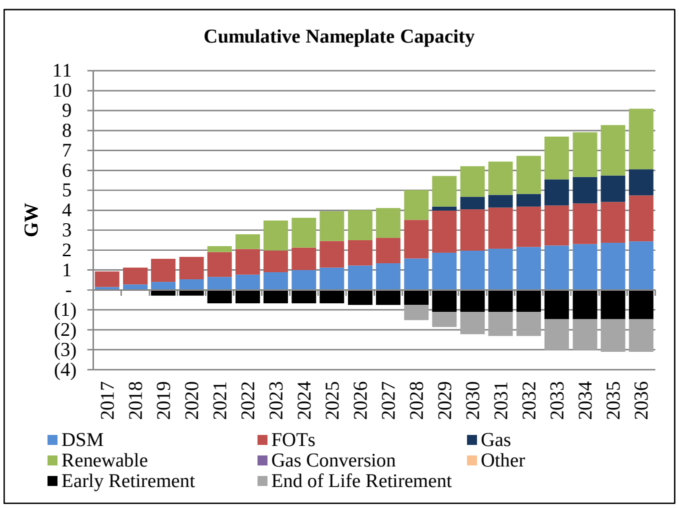
Description
Sensitivity GW3 includes segments D & F – Windstar to Anticline and Aeolus to Mona/Clover (assumed in-service 2022 and 2023, respectively). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 1,200 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

PORTFOLIO SUMMARY

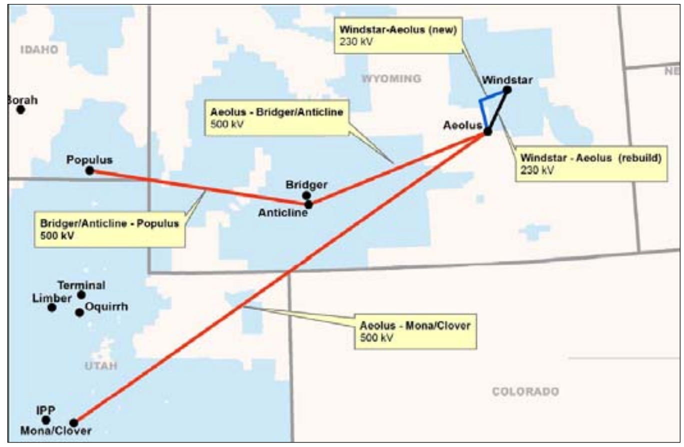
System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,706
Transmission Integration	$96
Transmission Reinforcement	$12
	$1,813
Total Cost	$24,627

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission
Transmission path is shown in the map below



Sensitivity: Energy Gateway 4 (GW4)

Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW4 includes segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). This sensitivity is a variant of core case OP-NT3.

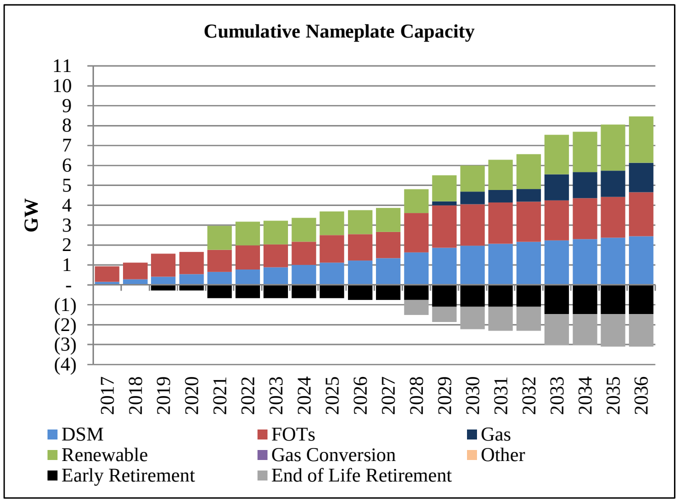
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,648
Transmission Integration	$94
Transmission Reinforcement	$12
Gateway Transmission	$405
Total Cost	$23,159

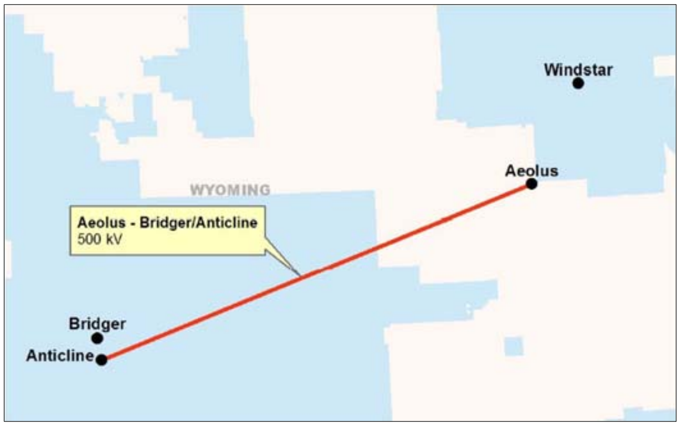
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The battery storage sensitivity is the first of two storage sensitivities that force large scale energy storage resources into the resource portfolio, but allow the models to optimize their usage. This sensitivity forces 80 MW of battery storage capacity also in PacifiCorp's east BAA (Wyoming). The site was based on a qualitative assessment of locations best suited for storage to provide support for added renewables, in the expectation that storage plants have the ability to mitigate the non-dispatchable nature of wind and solar energy production. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This sensitivity is a variant of core case FS-GW4.

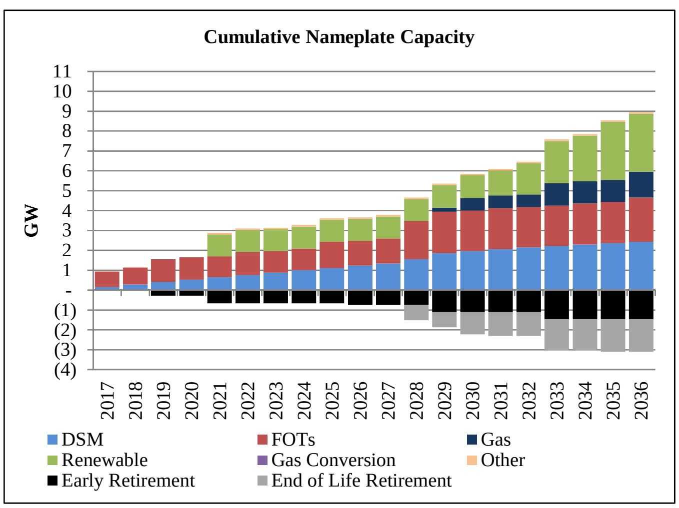
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,735
Transmission Integration	$81
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,162
Total Cost thru 2050	$22,901

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CAES storage sensitivity is the second of two storage sensitivities that force large scale energy storage resources into the resource portfolio, but allow the models to optimize their usage. This sensitivity forces an 80 MW compressed air storage plant (CAES) sited in PacifiCorp's east BAA (Utah South). The site was based on a qualitative assessment of locations best suited for storage to provide support for added renewables, in the expectation that storage plants have the ability to mitigate the non-dispatchable nature of wind and solar energy production. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This sensitivity is a variant of core case FS-GW4.

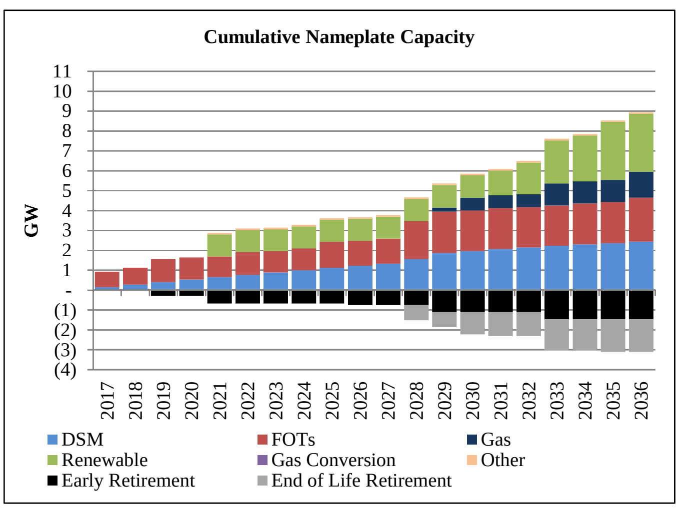
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,659
Transmission Integration	$116
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,121
Total Cost thru 2050	$22,860

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The WCA sensitivity assumes separate balancing authority areas (BAA) for the Company's East and West territory and produces standalone resource portfolios for the WCA, as required by the Washington Utilities and Transportation Commission. Key assumptions include maintaining a 13 percent reserve margin applicable to summer and winter peak; allowing on-peak FOT's with limits at Mid-C (775 MW), COB (400 MW) and NOB (100 MW); including all of Jim Bridger in the west BAA; including Colstrip in the west BAA up to transmission limits; and applying Mass Cap B and CAR emission limits. This sensitivity is a variant of core case FS-REP.

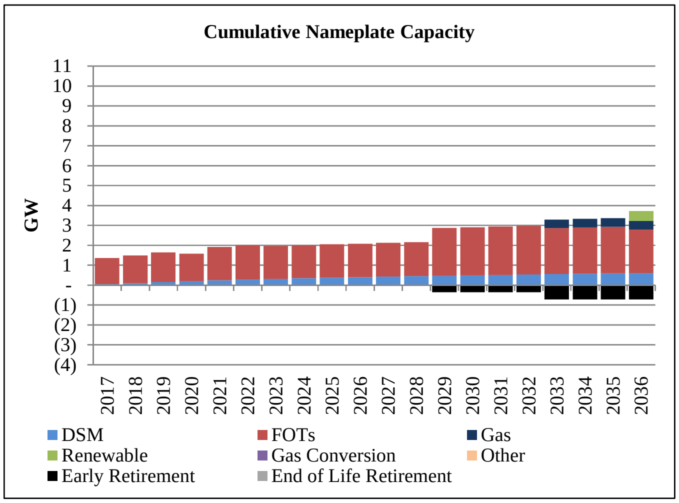
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$7,539
Transmission Integration	$4
Transmission Reinforcement	$0
Total Cost	$7,542

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The WCA RPS sensitivity assumes separate balancing authority areas (BAA) for the Company's East and West territory and produces standalone resource portfolios for the WCA, as required by the Washington Utilities and Transportation Commission. In addition, the sensitivity assumes compliance with Washington RPS requirements. Key assumptions include maintaining a 13 percent reserve margin applicable to summer and winter peak; allowing on-peak FOT's with limits at Mid-C (775 MW), COB (400 MW) and NOB (100 MW); including all of Jim Bridger in the west BAA; including Colstrip in the west BAA up to transmission limits; and applying Mass Cap B and CAR emission limits. This sensitivity is a variant of core case FS-REP.

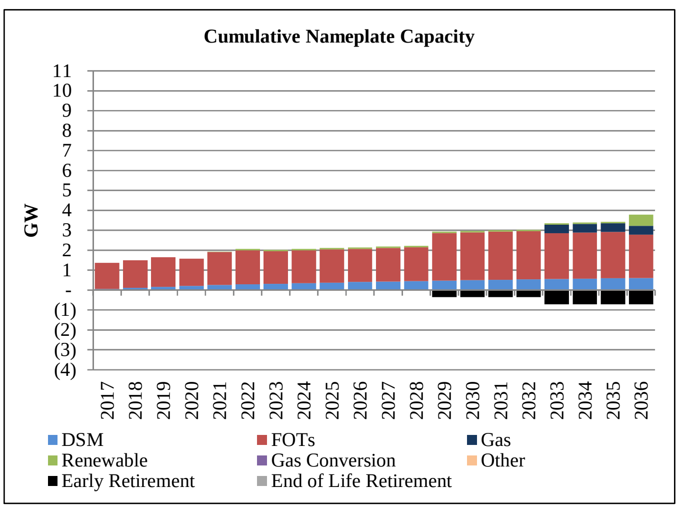
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$7,554
Transmission Integration	$4
Transmission Reinforcement	$0
Total Cost	$7,557

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-REP assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo and Leaning Juniper) and was updated with more current wind shape information. This case is a variant of core case OP-NT3.

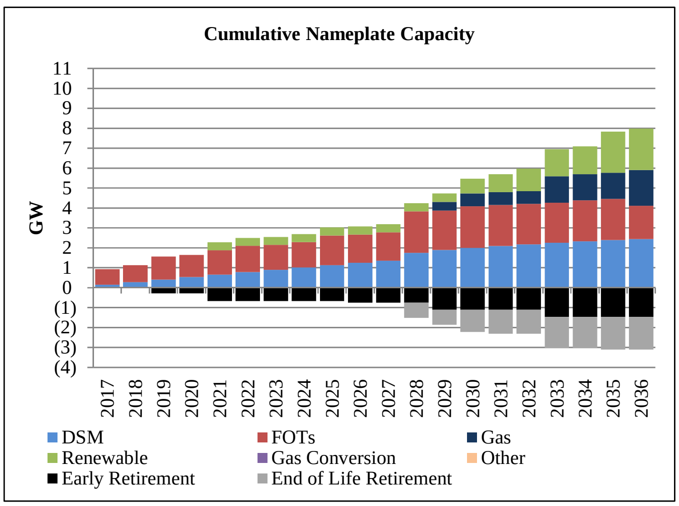
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,907
Transmission Integration	$123
Transmission Reinforcement	$12
Total Cost	$23,042
Total Cost thru 2050	$22,781

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Final Selection Fact Sheets

Case Assumptions

Description

Final screening case FS-GW4 assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This case is a variant of final selection FS-REP.

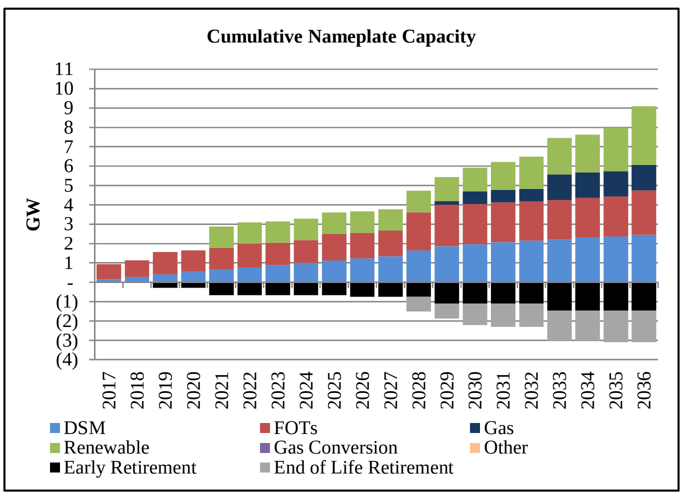
Portfolio Summary

System Optimizer PVRR ($m)

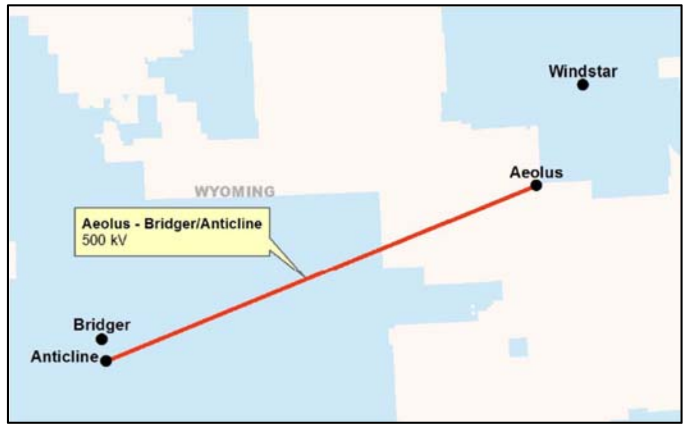
System Cost without Transmission Upgrades	$22,549
Transmission Integration	$95
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$22,990
Total Cost thru 2050	$22,729

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission Path



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-R1c assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This study also includes additional renewables added to physically comply with Oregon and Washington RPS. Renewable additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of final selection FS-GW4.

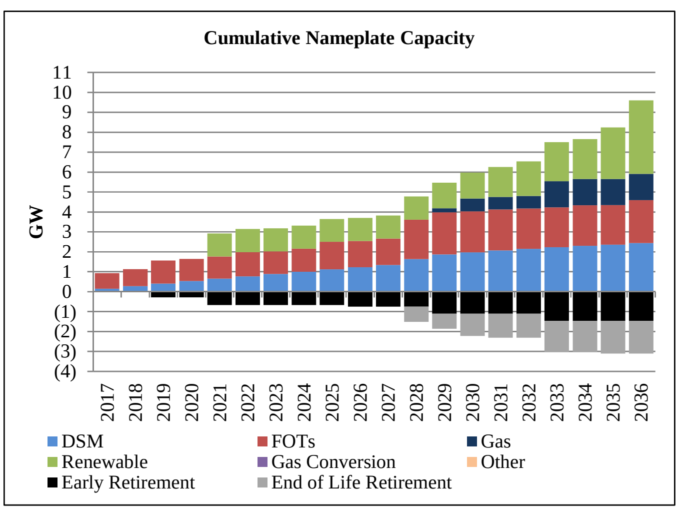
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,561
Transmission Integration	$99
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,006
Total Cost thru 2050	$22,745

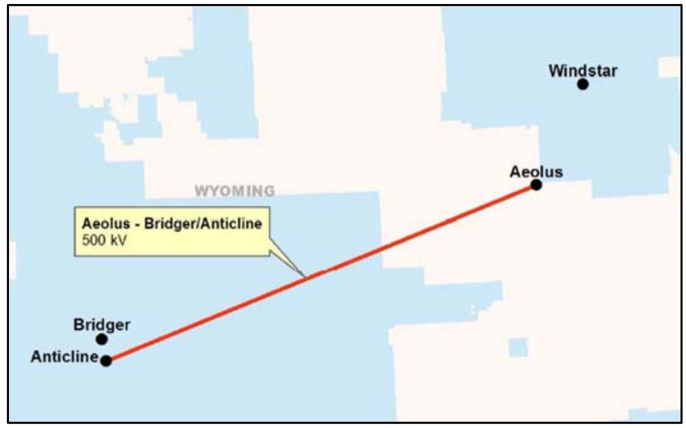
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Final Selection Fact Sheets

CASE ASSUMPTIONS

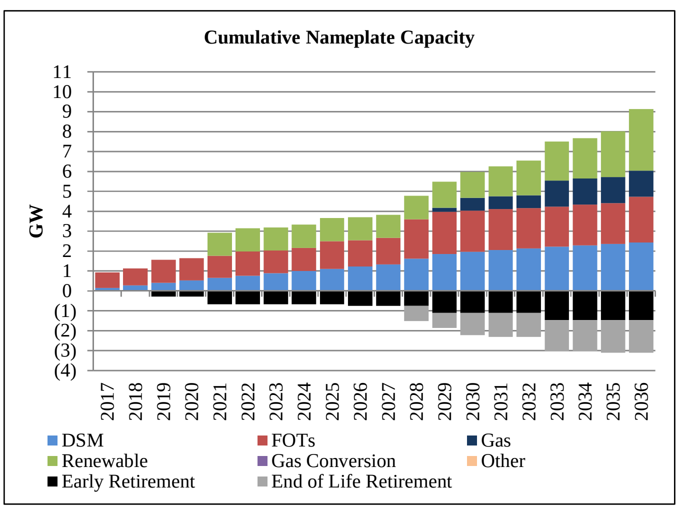
Description
Final screening case FS-R2 assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This study includes additional renewables added to physically comply with projected Oregon RPS requirements. Renewable additions are made in 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance). This case is a variant of final selection FS-GW4.

PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,554
Transmission Integration	$95
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$22,995
Total Cost thru 2050	$22,734

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission
Transmission path is shown in the map below

APPENDIX N – WIND AND SOLAR CAPACITY CONTRIBUTION STUDY

Introduction

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of this report, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability (LOLP). PacifiCorp calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1].

The capacity contribution of wind and solar resources affects PacifiCorp's resource planning activities. PacifiCorp conducts its resource planning to ensure there is sufficient capacity on its system to meet its load obligation at the time of system coincident peak inclusive of a planning reserve margin. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's net coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

PacifiCorp derives its planning reserve margin from a LOLP study. The study evaluates the relationship between reliability across all hours in a given year, accounting for variability and uncertainty in load and generation resources, and the cost of planning for system resources at varying levels of planning reserve margin. In this way, PacifiCorp's planning reserve margin LOLP study is the mechanism used to transform hourly reliability metrics into a resource adequacy target at the time of system coincident peak. This same LOLP study was utilized for calculating the peak capacity contribution using the CF Method. **Error! Reference source not found.**, summarizes the peak capacity contribution results for PacifiCorp's East and West balancing authority areas (BAAs).

The CF Method ignores transmission constraints that can prevent resource output in a location from reaching an area location where loss of load events occur. If transmission constraints prevent resources from reaching areas with loss of load events, additional capacity in those areas may not provide an adequate planning reserve margin or contribute to reliability. At the January 26-27, 2017 public input meeting PacifiCorp identified the potential for transmission constraints to impact

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

the effective capacity contribution from resources in Wyoming Northeast, Oregon, and Utah South.[2]

In light of the inclusion of Energy Gateway transmission segment D2 described in Volume I, Chapter 4 (Transmission) in the 2017 IRP preferred portfolio, the Wyoming Northeast transmission area is less constrained. This is particularly evident during summer months when LOLP is highest, as wind output in that area is relatively low in the summer. The 2017 IRP preferred portfolio also includes significant expansion resources in the 2030 timeframe in Oregon and Utah South. By the time additional capacity is required and new resources are added, transmission congestion in these areas is reduced, relative to the 2020 sample year used in the capacity contribution analysis, as a result of load growth, expiring contracts, and retiring resources.

Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to the more computationally intensive reliability-based effective load carrying capability (ELCC) metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors for a wind or solar resource to produce a weighted average capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

[2] 2017 IRP: Public Input Meeting 7. January 26-27, 2017. Presentation available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM07_1-26-17_Presentation.pdf

where C_i is the capacity factor of the resource in hour *i*, and *CV* is the weighted capacity value of the resource.

To determine the capacity contribution using the CF method, PacifiCorp implemented the following two steps:

1. A 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of the Company's system for a sample year (calendar year 2020). This PaR study is based on the Company's 2017 IRP planning reserve margin study using a 13 percent target planning reserve margin level. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load could not be met with available resources and dividing by 500 (the total number iterations). For example, if in hour 9 on January 12th there are two iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.4 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours. In the example noted above, the sum of LOLP among all hours is 143 percent.[4] The weighting factor for hour 9 on January 12th would be 0.2797 percent.[5] The hourly weighting factors are then applied to the capacity factors of wind and solar resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 9 on January 12th, its weighted annual capacity contribution for that hour would be 0.1146 percent.[6]

Results

Table N.1 summarizes the resulting annual capacity contribution using the CF Method described above as compared to capacity contribution values assumed in the 2015 IRP. In implementing the CF Method, PacifiCorp used actual wind project data from wind resources operating in its system to derive hourly wind capacity factor inputs. For solar resources, PacifiCorp used solar profiles from signed solar projects to apply to the 2017 IRP, differentiated between single axis tracking and fixed tilt projects. Separate solar and wind capacity contribution values were calculated using profiles corresponding to the East and West BAAs.

[3] 0.4 percent = 2 / 500.
[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 715 ENS iteration-hours out of total of 8,760 hours. As a result, the sum of LOLP is 715 / 500 = 143 percent.
[5] 0.2797 percent = 0.4 percent / 143 percent, or simply 0.2797 percent = 2 / 715.
[6] 0.1146 percent = 0.2797 percent x 41.0 percent.

Table N.1 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
2017 IRP Results	15.8%	37.9%	59.7.8%	11.8%	53.9%	64.8%
2015 IRP Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

Figure N.1 presents daily average LOLP results from the PaR simulation, which shows that loss of load events are most likely to occur during the summer when load peaks in July.

Figure N.1 – Daily LOLP

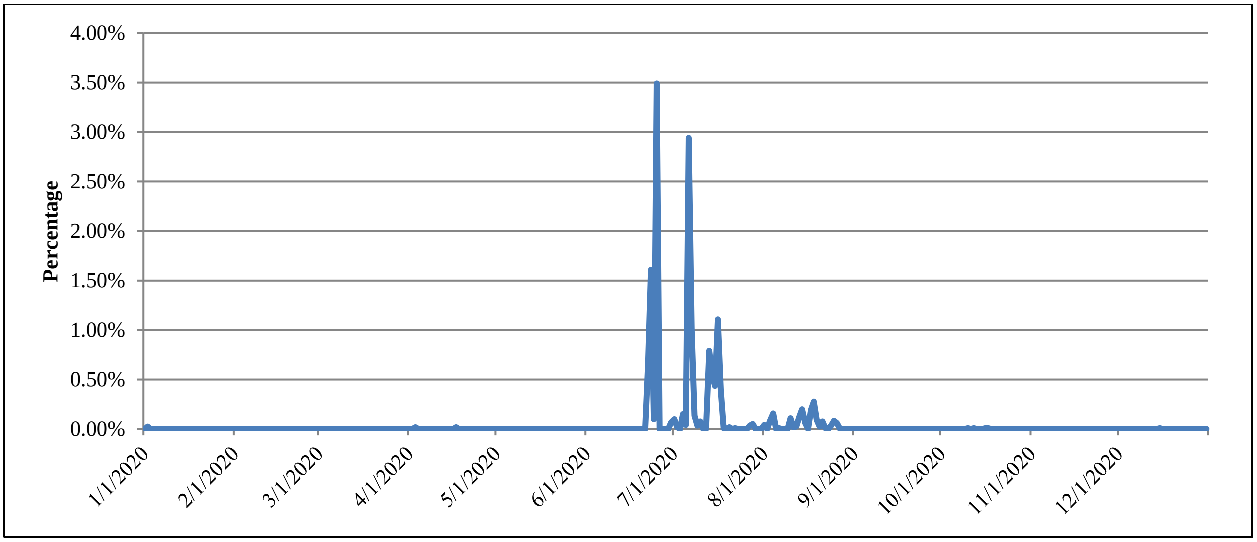


Figure N.2 presents the relationship between monthly capacity factors among wind and solar resources (primary y-axis) and average monthly LOLP from the PaR simulation (secondary y-axis) in PacifiCorp's CF Method analysis. As noted above, the average monthly LOLP is most prominent in summer (July peak loads).

Figure N.2 – Monthly Resource Capacity Factors as Compared to LOLP

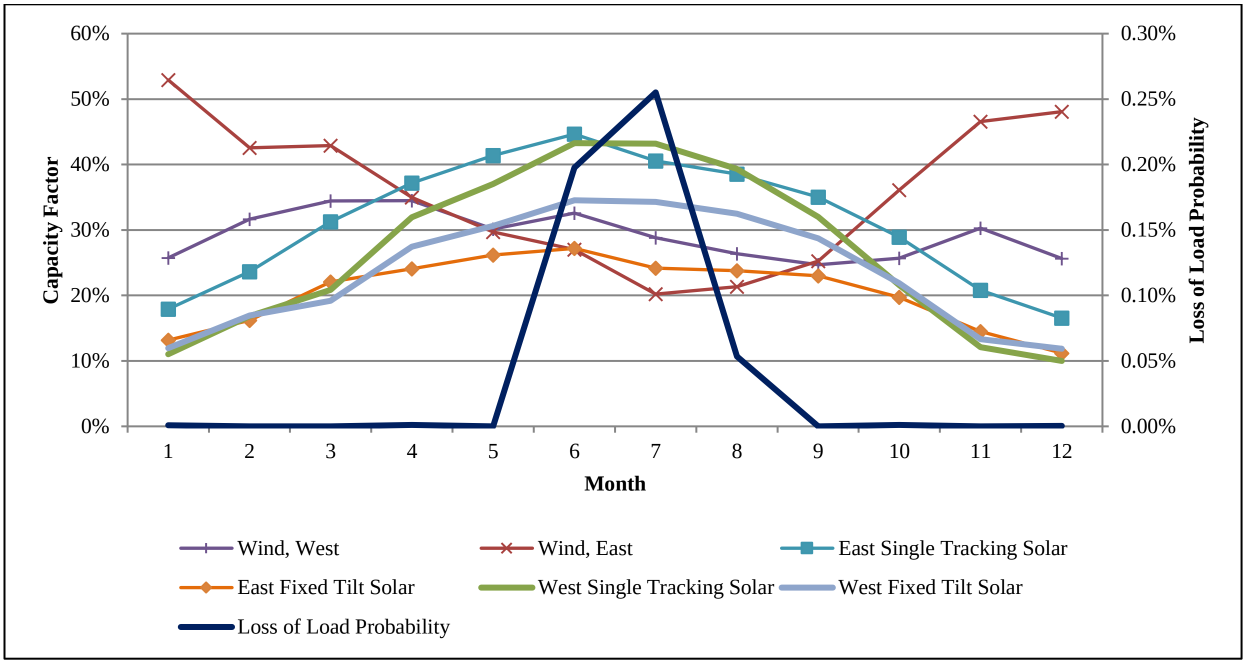
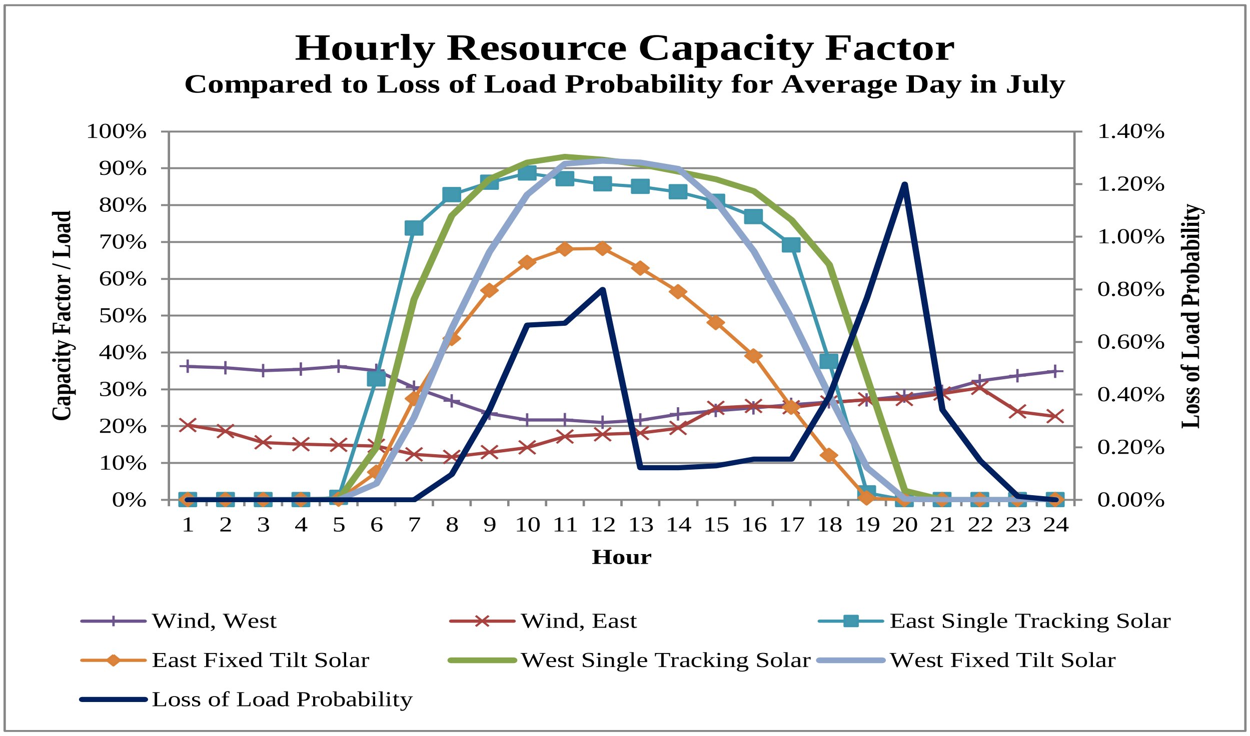


Figure N.3 presents the average hourly capacity factors for wind and solar resources (primary y-axis) as compared to the average hourly LOLP (secondary y-axis) for the month of July. In July, LOLP events peak during higher load hours and during the evening ramp.

Figure N.3 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in July



Conclusion

PacifiCorp conducts its resource planning by ensuring there is sufficient capacity on its system to meet its net load obligation at the time of system coincident peak inclusive of a planning reserve margin. The peak capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is the weighted average capacity factor of these resources during periods when load cannot be met with available resources. The peak capacity contribution values developed using the CF Method are based on a LOLP study that aligns with PacifiCorp's 13 percent planning reserve margin, and therefore represent the expected contribution that wind and solar resources make toward achieving PacifiCorp's target resource planning criteria.

APPENDIX O – PRIVATE GENERATION STUDY

Introduction

Navigant Consulting, Inc. prepared the Private Generation Long-Term Resource Assessment (2017-2036) for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2017 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years.

Private Generation Long-Term Resource Assessment (2017-2036)

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July 29th, 2016
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TABLE OF CONTENTS

Executive Summary 1

Key Findings 2
Report Organization 5

Private Generation Market Penetration Methodology 1

1.1 Methodology 1
1.2 Market Penetration Approach 1
1.3 Assess Technical Potential 2
1.4 Simple Payback 2
1.5 Payback Acceptance Curves 3
1.6 Market Penetration Curves 3
1.7 Key Assumptions 5
1.7.1 Technology Assumptions 5
1.7.2 Scenario Assumptions 13
1.7.3 Incentives 13

Results 17

1.8 PacifiCorp Territories 17
1.8.1 California 18
1.8.2 Idaho 20
1.8.3 Oregon 23
1.8.4 Utah 26
1.8.5 Washington 28
1.8.6 Wyoming 31

APPENDIX A. Customer Data A-1

APPENDIX B. System Capacity Assumptions B-3

APPENDIX C. Storage Evaluation C-7

C.1 Drivers C-7
C.2 Challenges C-8
C.3 Policy C-8
Federal and State C-8
C.4 Storage Customer Applications C-9
Non-Residential Solar + Storage C-10
Residential Solar + Storage C-10
Wind + Storage C-10
Hydro + Storage C-11
CHP + Storage C-11

APPENDIX D. Washington high-efficiency cogeneration Levelized Costs D-12

D.1 Key Assumptions D-12
D.2 Results D-13

APPENDIX E. Comparison of 2016 and 2014 Study E-14

APPENDIX F. Detailed Numeric Results..F-16

F.1 Utah.. F-16
F.2 Oregon F-22
F.3 Washington F-28
F.4 Idaho F-34
F.5 California... F-40
F.6 Wyoming F-46

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July 29th, 2016

EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant) prepared this Long-term Private Generation Resource Assessment on behalf of PacifiCorp. Private generation sources provide customer-sited energy generation and are generally of relatively small size, generating less than the amount of energy used at a particular location. The purpose of this study is to support PacifiCorp's 2017 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.

This study builds on Navigant's previous assessment [1] which supported PacifiCorp's 2015 IRP, incorporating updated load forecasts, market data, technology cost and performance projections. Navigant evaluated five private generation resources in detail in this report:

1. Photovoltaic (Solar) Systems
2. Small Scale Wind
3. Small Scale Hydro
4. Combined Heat and Power Reciprocating Engines
5. Combined Heat and Power Micro-turbines

Project sizes were determined based on average customer load across four customer classes including commercial, irrigation, industrial and residential.

Navigant also evaluated the future potential of energy storage, evaluating the drivers, challenges and applications of energy storage today. Summary findings are detailed in APPENDIX C.

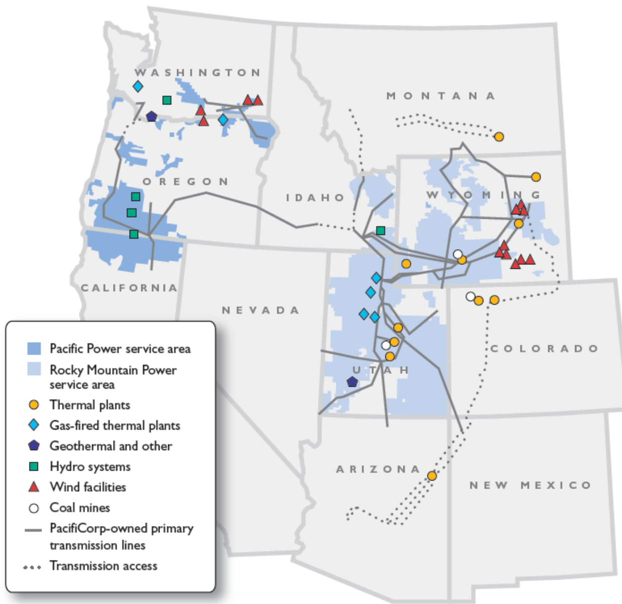
Private generation technical potential[2] and expected market penetration[3] for each technology was estimated for each major customer class in each state in PacifiCorp's service territory. Shown in Figure 1, PacifiCorp serves customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[3] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

Figure 1 PacifiCorp Service Territory[4]



Key Findings

Using PacifiCorp-specific information on customer size and retail rates in each state and public data sources for technology costs and performance, Navigant conducted a Fisher-Pry[5] payback analysis to determine likely market penetration for private generation technologies from 2017 to 2036. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base case scenario, Navigant estimates approximately 1.4 GW AC[6] of private generation capacity will be installed in PacifiCorp's territory from 2017-2036.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 1.0 GW AC and 2.1 GW AC, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate escalation assumptions. These assumptions are provided in Table 7.

Figure 3 indicates that Utah and Oregon will drive the majority of private generation installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales. Reference APPENDIX A for detailed state-specific customer data. In both of these

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[4] http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf.

[5] Fisher-Pry are researchers who studied the economics of "S-curves", which describe how quickly products penetrate the market. They codified their findings based on payback period, which measures how long it takes to recoup initial high first costs with energy savings over time.

[6] Alternating current (AC) is an electric current in which the flow of electric charge periodically reverses direction, whereas in direct current (DC) the flow of electric charge is only in one direction. AC is the form in which electric power is transmitted on the grid.

[7] All capacity numbers across all five resources are projected in MW AC. Figures throughout the report are all in MW AC.

states private generation installations are also driven by local tax credits and incentives. As displayed in Figure 4, solar represents the highest market penetration potential across the five technologies examined, with residential solar development leading the way, followed by non-residential solar (commercial, industrial, and irrigation). The Results section of the report contains results by state and technology for the high, base, and low scenarios.

Figure 2 Cumulative Market Penetration Results (MW AC), 2017 – 2036

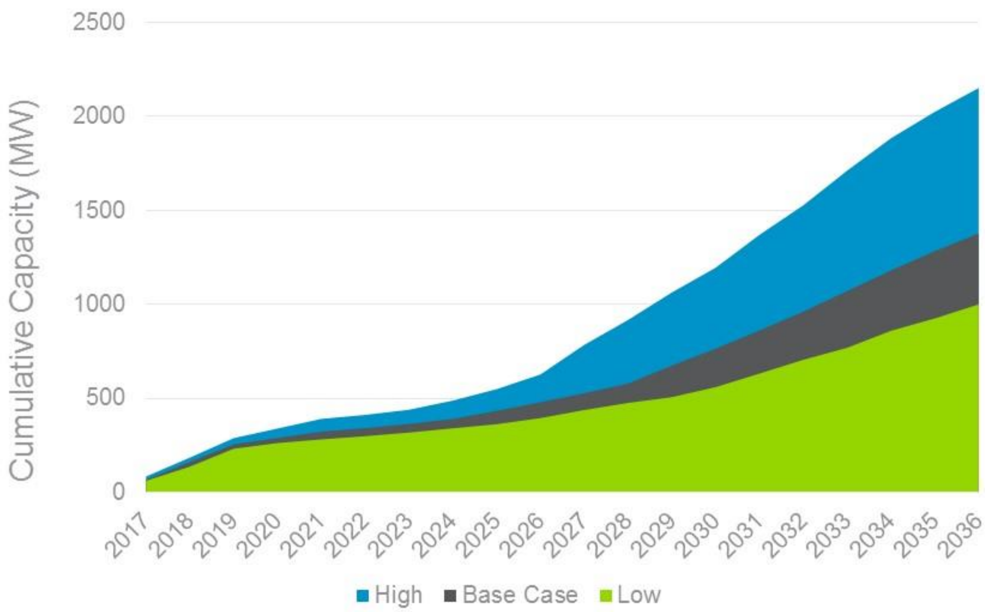


Figure 3 Cumulative Market Penetration Results by State (MW AC), 2017 – 2036, Base Case

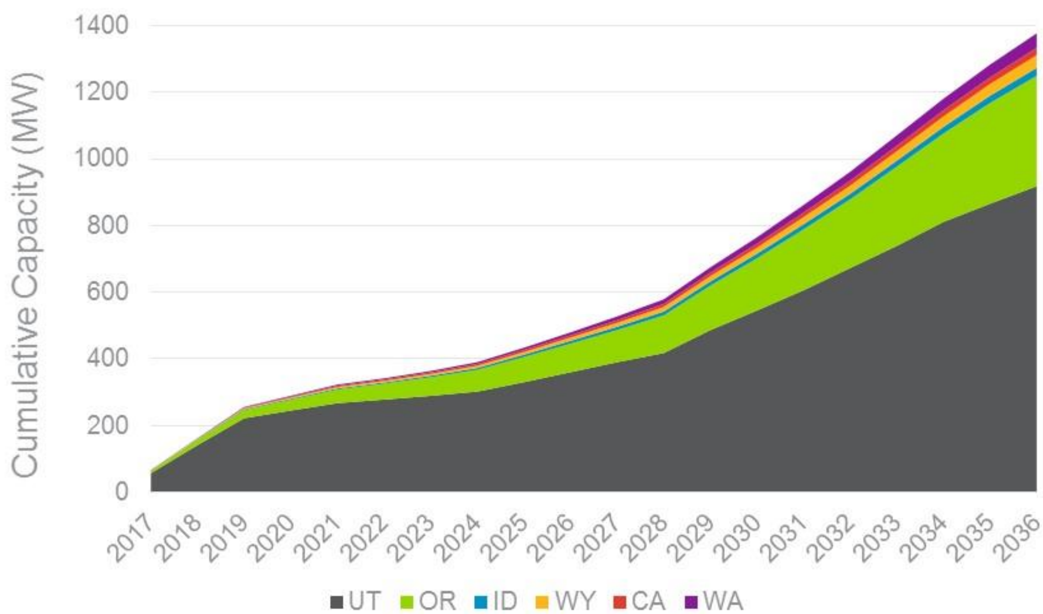
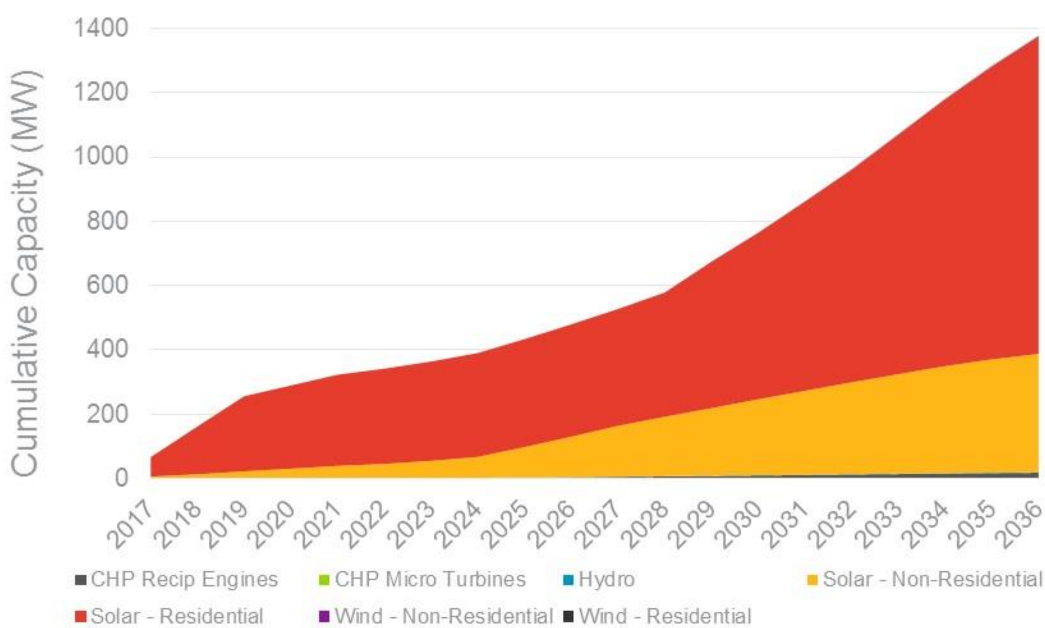


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2017 – 2036, Base Case



Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology
- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Storage Evaluation
- APPENDIX D: Detailed Numeric Results
- APPENDIX E: Washington Levelized Costs
- APPENDIX F: Comparison of 2016 and 2014 Study

PRIVATE GENERATION MARKET PENETRATION METHODOLOGY

This section provides a high-level overview of the study methodology.

1.1 Methodology

In assessing the technical and market potential of each private generation resource and opportunity in PacifiCorp's service area, the study considered a number of key factors, including:

- Technology maturity, costs, and future cost projections
- Industry practices, current and expected
- Net metering
- Federal and state tax incentives
- Utility or third-party incentives
- O&M costs
- Historical performance, and expected performance projections
- Hourly private generation
- Consumer behavior and market penetration

1.2 Market Penetration Approach

The following five-step process was used to estimate the market penetration of private generation resources in each scenario:

1. **Assess a Technology's Technical Potential:** Technical potential is the amount of a technology that can be physically installed without considering economics or other barriers to customer adoption. For example, technical potential assumes that photovoltaic systems are installed on all suitable residential roofs.
2. **Calculate Simple Payback Period for Each Year of Analysis:** From past work in projecting the penetration of new technologies, Navigant has found that Simple Payback Period is a key indicator of customer uptake. Navigant used all relevant federal, state, and utility incentives in its calculation of paybacks, incorporating their projected reduction and/or discontinuation over time, where appropriate.
3. **Project Ultimate Adoption Using Payback Acceptance Curves:** Payback Acceptance Curves estimate the percentage of a market that will ultimately adopt a technology, but do not factor in how long adoption will take.
4. **Project Market Penetration Using Market Penetration Curves:** Market penetration curves factor in market and technology characteristics, projecting the adoption timeline.
5. **Project Market Penetration under Different Scenarios.** In addition to the base case scenario, high and low case scenarios were created by varying cost, performance, and retail rate projections.

These five steps are explained in detail in the following sections.

1.3 Assess Technical Potential

Each technology considered has its own characteristics and data sources that influence the technical potential assessment; the amount of a technology that can be physically installed within PacifiCorp's service territory without considering economics or other barriers to customer adoption. Navigant escalated technical potentials at the same rate PacifiCorp projects its sales will change over time.

1.4 Simple Payback

For each customer class (i.e., residential, commercial, irrigation and industrial), technology, and state, Navigant calculated the simple payback period using the following formula:

Simple Payback Period *= (Net Initial Costs) / (Net Annual Savings)*

Net Initial Costs *= Installed Cost – Federal Incentives – Capacity-Based Incentives*(1 – Tax Rate)*

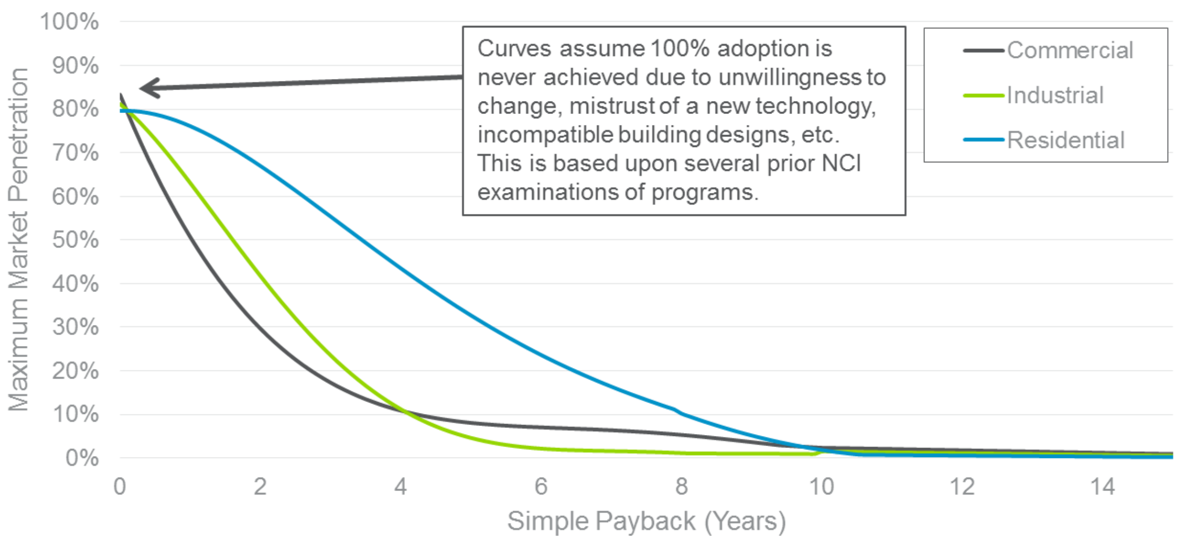
Net Annual Savings *= Annual Energy Bills Savings + (Performance Based Incentives – O&M Costs – Fuel Costs)*(1 – Tax Rate)*

- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *For electric bills savings, Navigant conducted an 8,760 hourly analysis to take into account actual rate schedules, actual output profiles, and demand charges. System performance assumptions are listed in Section 1.3 above. Solar performance and wind performance profiles were calculated for representative locations within each state based on the National Renewable Energy Laboratory (NREL) Solar Advisory Model (SAM), which now also models wind. Building load profiles were provided by PacifiCorp, and were scaled to match the average electricity usage for each customer class based on billing data.*

1.5 Payback Acceptance Curves

For private resources, Navigant used the following payback acceptance curves to model market penetration of private generation sources from the retail customer's perspective.

Figure 5 Payback Acceptance Curves



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These payback curves are based upon work for various utilities, federal government organizations, and state local organizations. They were developed from customer surveys, mining of historical program data, and industry interviews.[8] Given a calculated payback period, the curve predicts the level of maximum market penetration. For example, if the technical potential is 100 MW, the 3-year commercial payback predicts that 15% of this technical potential, or 15 MW, will ultimately be achieved over the long term.

1.6 Market Penetration Curves

To determine the future private generation market penetration within PacifiCorp's territory, the team modeled the growth of private generation technologies from 2017 thru 2036. The model is a Fisher-Pry based technology adoption model that calculates the market growth of private generation technologies. It uses a lowest-cost approach to consumers to develop expected market growth curves based on maximum achievable market penetration and market saturation time, as defined below.[9]

---

[8] Payback acceptance curves are based on a broad set of data from across the United States and may not predict customer behavior in a specific market (e.g. Utah customers may install solar at a faster rate than the rate indicated by the payback acceptance curves due to market specific reasons).

[9] Michelfelder and Morrin, "Overview of New Product Diffusion Sales Forecasting Models" provides a summary of product diffusion models, including Fisher-Pry. Available: law.unh.edu/assets/images/uploads/pages/ipmanagement-new-product-diffusion-sales-forecasting-models.pdf

- **Market Penetration** – The percentage of a market that purchases or adopts a specific product or technology. The Fisher-Pry model estimates the achievable market penetration based on the simple payback period of the technology. Market penetration curves (sometimes called S-curves) are well established tools for estimating diffusion or penetration of technologies into the market. Navigant applies the market penetration curve to the payback acceptance curve shown in Figure 5 Payback Acceptance Curves.
- **Market Saturation Time** – The duration in years for a technology to increase market penetration from around 10% to 80%.

The Fisher-Pry model estimates market saturation time based on 12 different market input factors; those with the most substantial impact include:

- **Payback Period** – Years required for the cumulative cost savings to equal or surpass the incremental first cost of equipment.
- **Market Risk** – Risk associated with uncertainty and instability in the marketplace, which can be due to uncertainty regarding cost, industry viability, or even customer awareness, confidence, or brand reputation. An example of a high market risk environment is a jurisdiction lacking long-term, stable guarantees for incentives.
- **Technology Risk** – Measures how well-proven and the availability of the technology. For example, technologies that are completely new to the industry have a higher risk, whereas technologies that are only new to a specific market (or application) and have been proven elsewhere have lower risk.
- **Government Regulation** – Measure of government involvement in the market. A government-stated goal is an example of low government involvement, whereas a government mandated minimum efficiency requirement is an example of high involvement, having a significant impact on the market.

The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other more qualitative limiting market factors, such as the ability to train quality installers or manufacture equipment at a sufficient rate to meet the growth rates. Corporate sustainability, and other non-economic growth factors, are also not modeled.

The Fisher-Pry market growth curves have been developed and refined over time based on empirical adoption data for a wide range of technologies.[10] The model is an imitative model that uses equations developed from historical penetration rates of real products for over two decades. It has been validated in this industry via comparison to historical data for solar photovoltaics, a key focus of this study.

Navigant Consulting has used gathered market data on the adoption of technologies over the past 120 years and fit the data using Fisher-Pry curves. A key parameter when using market penetration curves is the assumed year of introduction. For the market penetration curves used in this study, Navigant assumed that the first year introduction occurred when the simple payback period was less than 25 years (per the pay-back acceptance curves used, this is the highest pay-back period that has any adoption).

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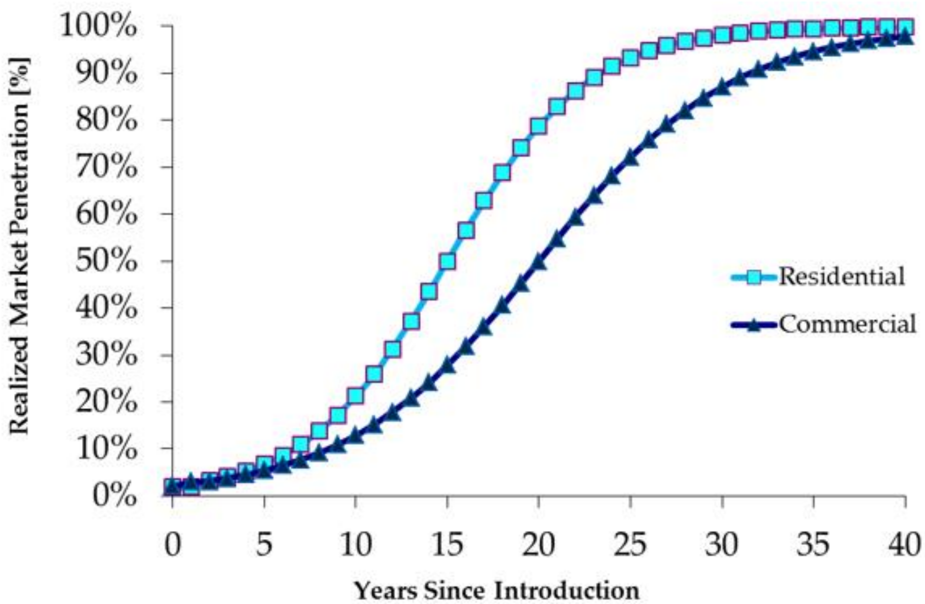
[10] Fisher, J. C. and R. H. Pry, "A Simple Substitution Model of Technological Change", Technological Forecasting and Social Change, 3 (March 1971), 75-88.

When the above payback period, market risk, technology risk, and government regulation factors above are analyzed, our general Fisher-Pry based method gives rise to the following market penetration curves used in this study:

Figure 6 Market Penetration Curves [11]



Source: Navigant Consulting, November 2008 as taken from Fisher, J.C. and R.H. Pry, A Simple Substitution Model of Technological Change, *Technological Forecasting and Social Change*, Vol 3, Pages 75 – 99, 1971.

The model is designed to analyze the adoption of a single technology entering a market, and assumes that the private generation market penetration analyzed for each technology is additive because the underlying resources limiting installations (sun, wind, water, high thermal loads) are generally mutually exclusive, and because current levels of market penetration are relatively low (plenty of customers exist for each technology).

1.7 Key Assumptions

The following section details the key technology-specific and base, low and high scenario assumptions.

1.7.1 Technology Assumptions

Assumptions including costs and performance were decided for each technology evaluated.

[11] Realized market penetration is applied to the maximum market penetration (Figure 6) for each technology, customer payback, and point in time. For example a residential customer with a five-year payback would have a maximum market penetration of around 35 percent, as indicated by the residential payback acceptance curve (Figure 5). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure 6), having a market penetration of about seven percent of the technical potential.

1.7.1.1 CHP: Reciprocating Engines

A reciprocating engine uses one or more reciprocating pistons to convert pressure into rotating motion. In a combined heat and power (CHP) application, a small CHP source will burn a fuel to produce both electricity and heat. In many applications, the heat is transferred to water, and this hot water is then used to heat a building.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size, CHP reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 1 Reciprocating Engine Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 1 Reciprocating Engine Assumptions[12]

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – 100kW	$/kW	$2,900	EPA, Catalog of CHP Technologies, March 2015, pg. 2-15
Change in Annual Installed Cost	%	0.4%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Variable O&M	$/MWh	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	
Private Generation Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	12,637	EPA, Catalog of CHP Technologies, March 2015, pg. 2-10

1.7.1.2 CHP: Micro-turbines

Micro-turbine use natural gas to start a combustor, which drives a turbine. The turbine in turn drives an AC generator and compressor, and the waste heat is exhausted to the user. The device therefore produces electrical power from the generator, and waste heat to the user.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size, CHP reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions

[12] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

on system capacity sizes in each state are detailed in APPENDIX B. Table 2 Micro-turbines Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 2 Micro-turbines Assumptions[13]

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – 30kW	$/kW	$2,690	EPA, Catalog of CHP Technologies, March 2015, pg. 5-7
Change in Annual Installed Cost	%	-0.3%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Variable O&M	$/MWh	$23	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	
Private Generation Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	15,535	EPA, Catalog of CHP Technologies, March 2015, pg. 5-6

1.7.1.3 Small Hydro

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The detailed national small hydro studies conducted by the Department of Energy (DOE) from 2004 to 2013,[14] formed the basis of Navigant's small hydro technical potential estimate. In the Pacific Northwest Basin, which covers WA, OR, ID, and WY, a detailed stream-by-stream analysis was performed in 2013, and DOE provided these data to Navigant directly. For these states, Navigant combined detailed GIS PacifiCorp service territory data with detailed GIS data on each stream / water source. Using this method, Navigant was able to sum the technical potentials of only those streams located in PacifiCorp's service territory. For the other two states, Utah and California, Navigant relied on an older 2006 national analysis, and multiplied the given state figures by the area served by PacifiCorp within that state. Table 3 Small Hydro Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[13] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

[14] Navigant used the same methodology and sources as in the 2014 study.

Table 3 Small Hydro Assumptions[15]

Private Generation Resource Costs	Units	2017 Baseline	Sources
Installed Cost	$/kW	$4,000	Double average plant costs in "Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements." Electric Power Research Institute, November 2011; this accounts for permitting/project costs
Change in Annual Installed Cost	%	0.00%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$52	Renewable Energy Technologies: Cost Analysis Series. "Hydropower." International Renewable Energy Agency, June 2012.
Private Generation Performance Assumptions			
Capacity Factor	%	50% ±5%	Average capacity factor variance will be reflected in the low and high penetration scenarios.

1.7.1.4 Solar Photovoltaics

Solar photovoltaic (solar) systems convert sunlight to electricity. Navigant applied a 20% discount factor to account for system sizing less than 100% of annual load and Direct Current (DC) to Alternating Current (AC) conversion. System size was then multiplied by the number of customers and the roof access factor. Assumptions on system capacity sizes in each state are detailed in APPENDIX B and access factors remained consistent with the 2014 study. Table 4 Solar Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[15] Note: No change from 2014 study.

Table 4 Solar Assumptions

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – Res	$/kW DC	UT: $3,000 Other: $3,500	Navigant Forecast validated by NREL, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial and Utility-Scale Systems
Installed Cost – Non-Res	$/kW DC	All Markets: $2,300	
Average Change in Annual Installed Cost (2015-2034)	%	-2.4% (Res) -2.2% (Non-Res)	
Fixed O&M – Res	$/kW-yr.	$25	National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014;National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, Accessed February 1, 2016
Fixed O&M – Non-Res	$/kW-yr.	$23	

As shown in Figure 7 and Figure 8, the rapid decline in solar costs over the past decade has driven private solar adoption across the country for all customer classes. In the past, these cost declines were primarily due to reduction in the cost of equipment (e.g. panels, inverters and balance of system components) driven by economies of scale and improvements in efficiency. Solar costs are expected to continue to decline over the next decade as system efficiencies continue to increase, although these declines are expected to occur at a slower rate than what occurred in recent years. In the long term, Navigant expects price reductions to decline as the industry matures and efficiency gains become harder to achieve.

Navigant's national solar cost forecast includes a low, base and high forecast. For this project, Navigant developed a PacifiCorp forecast which is the average between the national base and high forecast. Navigant decided to use for California, Idaho, Oregon, Washington and Wyoming, as all of those states currently have relatively small solar markets in PacifiCorp's territory, resulting in less competition and economies of scale to drive down local solar costs. For Utah, Navigant used the base cost forecast, as Utah has a larger and more mature private solar market.

Figure 7. Non-Residential Solar System Costs, 2015-2036

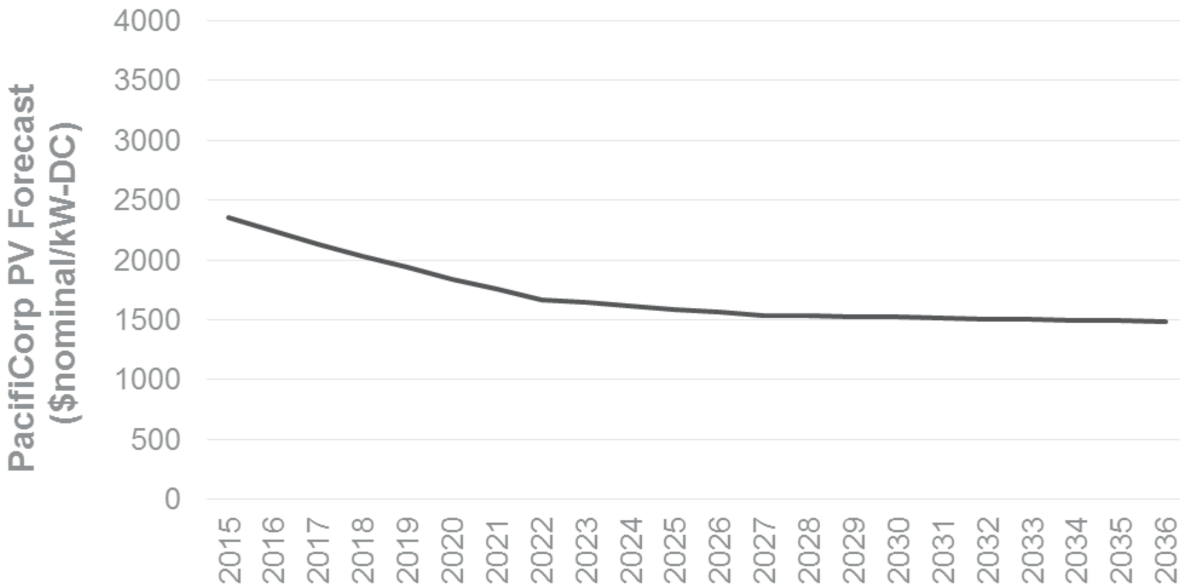
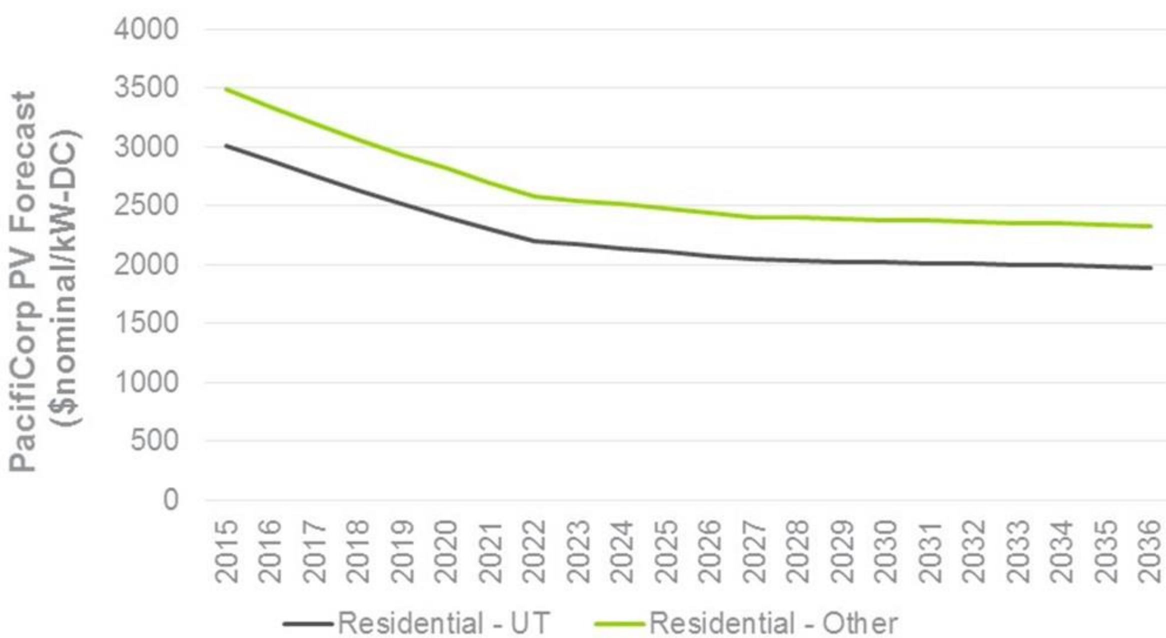


Figure 8 Residential Solar System Costs, 2015-2036



The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

Table 5 Solar Capacity Factors[16]

Performance Assumptions			
		(kW-DC/kWh AC)	**(kW-AC/kWh AC)**
Capacity Factor	UT	16.3%	20.4%
	WY	16.8%	21.0%
	WA	14.0%	17.5%
	CA	16.6%	20.8%
	ID	16.0%	20.0%
	OR	12.4%	15.5%

1.7.1.5 Small Wind

Wind power is the use of air flow through wind turbines to mechanically power generators for electricity. Navigant sized the wind systems at 80% of customer load to reduce the chance that the wind system will produce more than the customer's electric load in a given year. System size was then multiplied by the number of customers and the access factor. The 2014 study access factors were used for this study.

The following cost and performance assumptions were used in the analysis.

[16] NREL, System Advisory Model (SAM) for specific state locations, consistent with 2014 study. Navigant used the default system configuration in SAM, which has a DC to AC derate factor of about 80%.

Table 6 Wind Assumptions

Private Generation Resource Costs	Units	2014 Baseline	Sources
Installed Cost – Res (2.5-10kW)	$/kW	$7,200	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Installed Cost – Com (11-100kW)	$/kW	$6,000	
Change in Annual Installed Cost	%	0.0%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$40	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Change in Annual O&M Cost	%	-1.0%	
Private Generation Performance Assumptions			
Capacity Factor	%	20% (2013) - 25% (2034)	Small scale wind hub heights are lower, with shorter turbine blades, relative to 30% capacity factor large scale turbines.

1.7.2 Scenario Assumptions

Navigant used the market penetration model to analyze three scenarios, capturing the impact of major changes that could affect market penetration. For the low and high penetration cases, Navigant varied technology costs, system performance, and electricity rate assumptions.

Table 7 Scenario Variable Modifications

Cases	Technology Costs	Performance	Electricity Rates
Base Case	See technology and cost section	As modeled	Increase at inflation rate, assumed at 1.9%
Low Penetration	PV: Same as Base Case Other: Mature technologies. Same as base case	PV: Same as Base Case Other: 5% worse	Increases at 1.4%, 0.5%/year lower than the Base Case
High Penetration	PV: 2X steeper cost reduction/year Other: Mature technologies. Same as base case	Reciprocating Engines: 0.5% better (mature) Micro-turbines: 2% better Hydro: 5% better (reflecting wide performance distribution uncertainty) PV/Wind: 1% better (relatively mature)	Increases at 2.4%, 0.5%/year higher than the Base Case

Technology cost reduction is the variable having the largest impact on market penetration over the next 20 years. Average technology performance assumptions are relatively constant across states and sites. Changes in electricity rates are modeled conservatively, reflecting the long-term stability of electricity rates in the United States. Navigant expects short-term volatility for all variables but when averaged over the 20-year IRP period, long-term trends show less variation.

1.7.3 Incentives

Federal and state incentives are a very important private generation market penetration driver, as they can reduce a customer's payback period significantly.

1.7.3.1 Federal

The Federal Business Energy Investment Tax Credit (ITC) allows the owner of the system to claim a tax credit for a certain percentage of the installed private generation system price.[17] The ITC, originally set to expire in 2016 for commercial solar systems and reduce to 10% for residential solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring in

[17] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

2020 through 2022. The 2014 Navigant Distributed Generation Resource Assessment for Long-Term Planning Study assumed that the ITC would expire for commercial solar PV systems at the end of 2016 and step down to 10% for residential PV systems, per the legislation in place at the time of the analysis. The table below details how the ITC applies to the technologies evaluated in this study, however, this schedule may change in the future.

Table 8 Federal Tax Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Micro Turbines	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Small Hydro	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
PV - Com	**30%**	**30%**	**30%**	**30%**	**26%**	**22%**	**10%**
PV - Res	**30%**	**30%**	**30%**	**30%**	**26%**	**22%**	**0%**
Wind - Com	**30%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Wind - Res	**30%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**

1.7.3.2 State

State incentives drive the local market and are an important aspect promoting private generation market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy. Longer-term uncertainty also exists regarding other state incentives. Idaho also has a local state residential personal tax deduction for solar and wind projects. Currently, state incentives do not exist in California[18] or Wyoming. The following tables detail the assumptions made regarding local state incentives.

[18] In 2007, California launched the California Solar Initiative, however, incentives no longer remain in most utility territories, http://csi-trigger.com/.

Table 9 Oregon Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	0	0	0	0	0	0	0
Micro Turbines	0	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0	0
PV – Com ($/W)*	0.81	0.78	0.75	0.72	0.69	0.66	0.63
PV – Res ($/W)* & ($/system)**	0.62 (6,000)	0.60 (6,000)	0.57 (6,000)	0.55 (6,000)	0.52 (6,000)	0.50 (6,000)	0.48 (6,000)
Wind – Com ($/kWh)	0	0	0	0	0	0	0
Wind – Res ($)*	6,000	6,000	6,000	6,000	6,000	6,000	6,000

* Energy Trust of Oregon Solar Incentive (capped at $2M/year for residential and $1.6M/year for non-residential). Energy Trust of Oregon incentives after 2016 are estimated based on assumed system cost trends.
** Residential Energy Tax Credit - $6,000 over the life of the system, distributed $1,500/yr.
http://programs.dsireusa.org/system/program/detail/638
***The Residential Energy Tax Credit (RETC), in its current legislative form, is set to expire at the end of 2017. It is not yet known whether the Oregon Legislature will extend the RETC beyond 2017. Similarly, should the RETC be extended beyond 2017, it is not known if it would have the same value or eligibility criteria. However, for purposes of this analysis, it was assumed that the RETC will be extended beyond 2017 with the same value and eligibility criteria as exists as of the date of this report.

Table 10 Utah Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines (%)	10	10	10	10	10	10	10
Micro Turbines (%)	10	10	10	10	10	10	10
Small Hydro (%)	10	10	10	10	10	10	10
PV – Com (%)	10	10	10	10	10	10	10
PV – Res ($)*	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Wind – Com (%)	10	10	10	10	10	10	10
Wind – Res ($)*	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000

*Renewable Energy Systems Tax Credit, Program Cap: Residential cap = $2,000; commercial systems <660kW, no limit
**The Utah Renewable Energy Systems Tax Credit is assumed for the purpose of this report to continue at its current incentive level. The timing and value of any possible changes to the state tax credit remain unclear.

Table 11 Washington Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com ($/kWh)*	**0.15**	**0.15**	**0.15**	**0.15**	**0.08**	**0**	**0**
PV - Res ($/kWh)*	**0.15**	**0.15**	**0.15**	**0.15**	**0.08**	**0**	**0**
Wind - Com ($/kWh)*	**0.12**	**0.12**	**0.12**	**0.12**	**0.06**	**0**	**0**
Wind - Res ($/kWh)*	**0.12**	**0.12**	**0.12**	**0.12**	**0.06**	**0**	**0**

* Feed-in Tariff: $/kWh for all kWh generated through mid-2020; annually capped at $5,000/year, http://programs.dsireusa.org/system/program/detail/5698

Table 12 Idaho Incentives

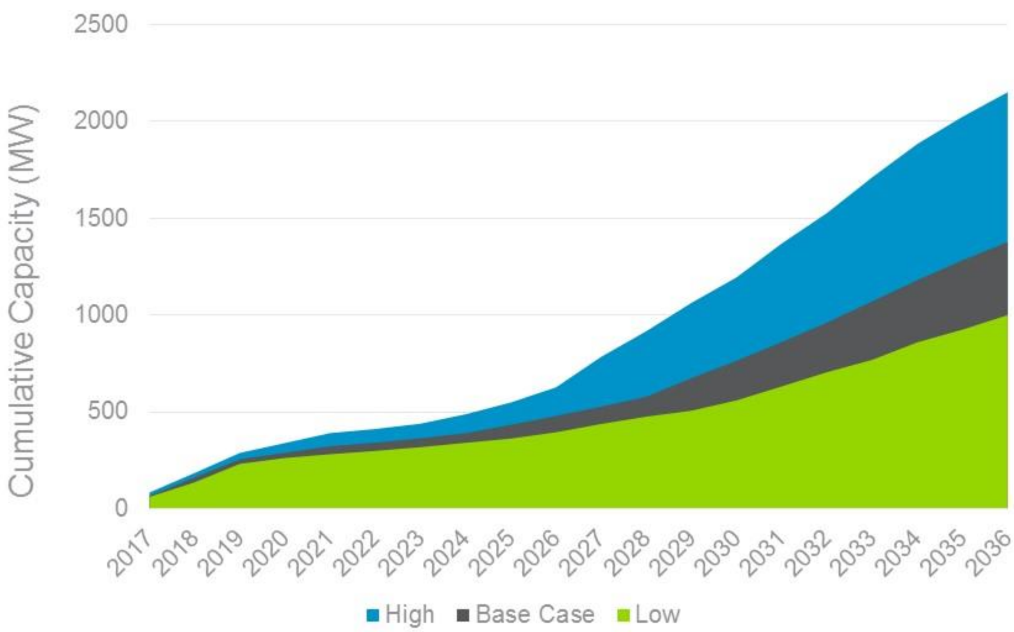
Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**
Wind – Com	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**

* Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

RESULTS

Navigant estimates approximately 1.4 GW of private generation capacity will be installed in PacifiCorp's territory from 2017-2036 in the base case scenario.[19] As shown in Figure 9, the low and high scenarios project a cumulative installed capacity of 1.00 GW and 2.10 GW by 2036, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 9. Cumulative Market Penetration Results (MW AC), 2017 – 2036



1.8 PacifiCorp Territories

The following sections report the results by state, providing high, base and low scenario installation projections. Results for each scenario are also broken out by technology. The solar sector exhibits the highest adoption across all states. Generally non-residential solar adoption is less sensitive to high and low scenario adjustments when compared the residential sector. This is because the residential customer payback is more sensitive to scenario changes (e.g. technology costs, performance, electricity rates) when compared to non-residential sectors.

[19] Solar capacity is projected in DC, while the capacity for all other resources is projected in AC. Figures throughout the report that include all resources forecasted, reflect a combination of AC and DC.

1.8.1 California

PacifiCorp's customers in northern California are projected to install about 22 MW of capacity over the next two decades in the base case, averaging about 1.1 MW annually. California does not currently have any state incentives promoting the installation of private generation and the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations after 2020. The main driver of private generation in California is its high electricity rates relative to other states. Over time, the increase in private generation installation capacity is driven by escalating electricity rates and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of private generation growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 10. The 22 MW from the base case decreases by 32% to 15 MW in the low case and increases by 55% to 34 MW in the high case.

Figure 10. Cumulative Capacity Installations by Scenario (MW AC), California

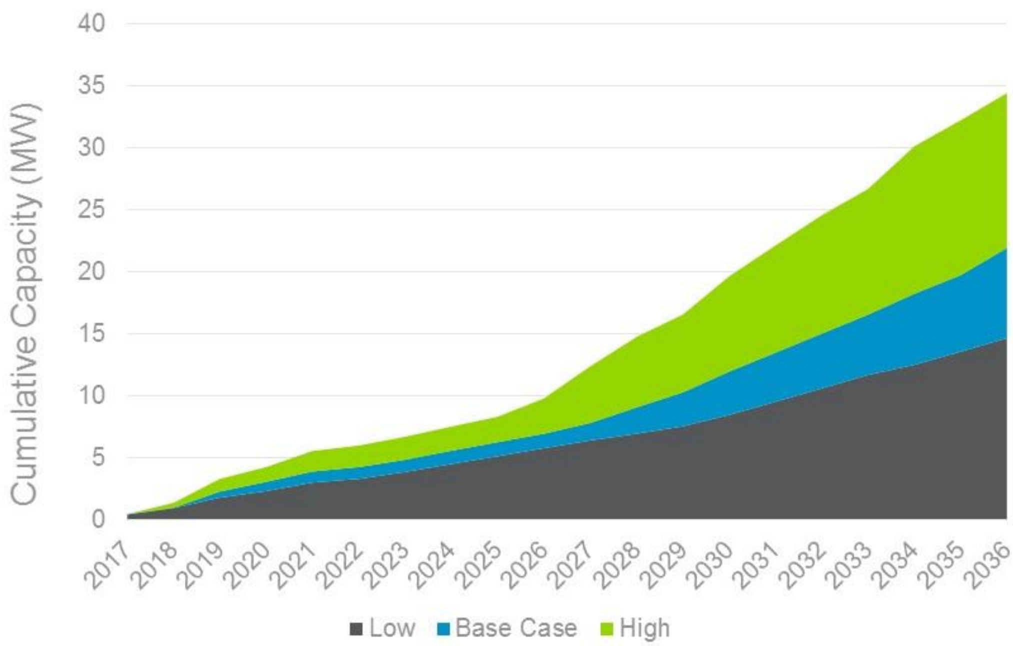


Figure 11. Cumulative Capacity Installations by Technology (MW AC), California Base Case

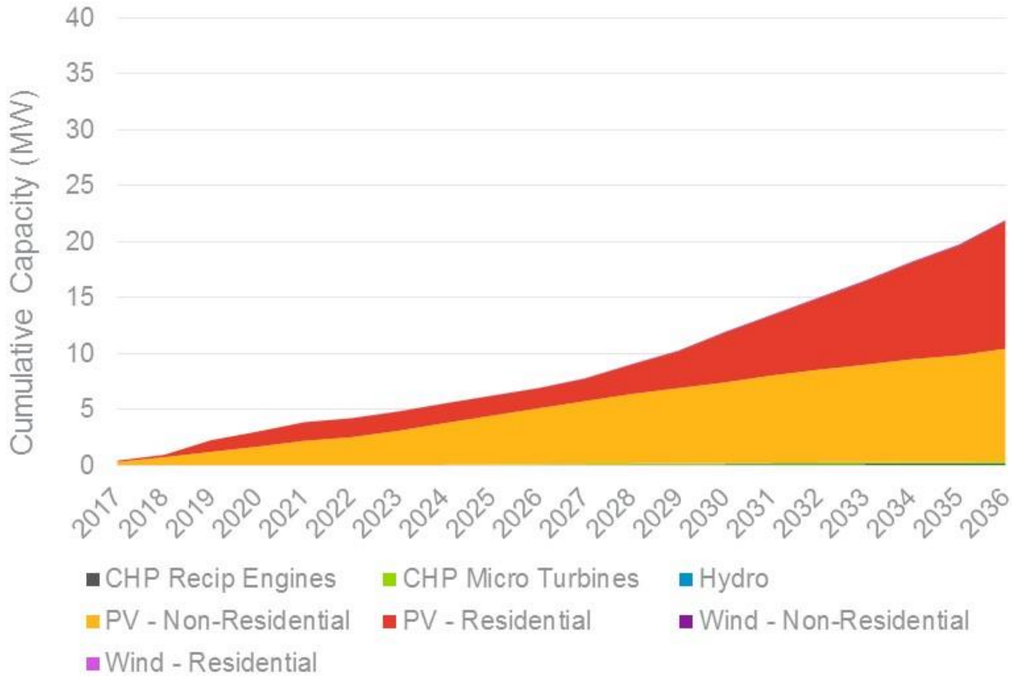


Figure 12. Cumulative Capacity Installations by Technology (MW AC), California High Case

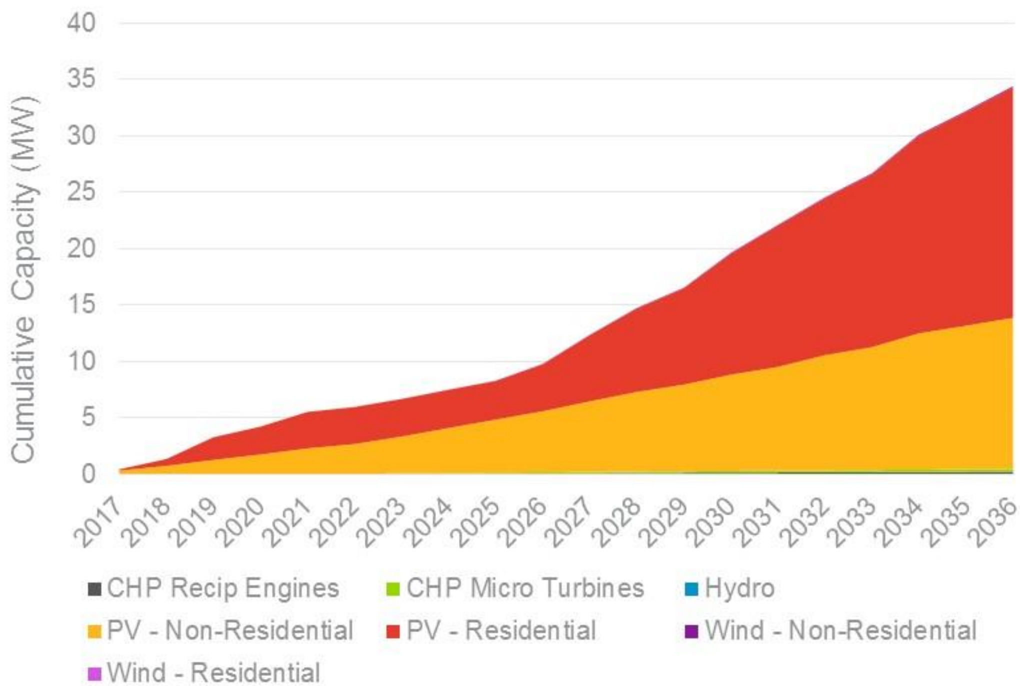
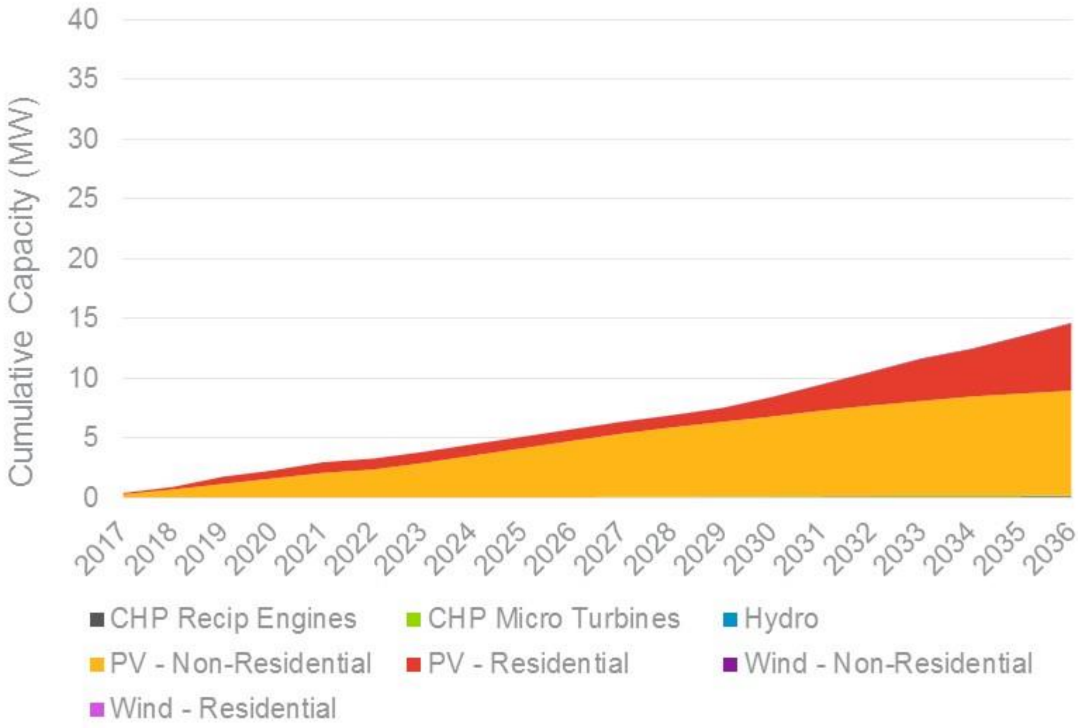


Figure 13. Cumulative Capacity Installations by Technology (MW AC), California Low Case



1.8.2 Idaho

PacifiCorp's Idaho customers are projected to install about 39 MW of capacity over the next two decades in the base case, averaging about 1.9 MW annually. Idaho currently has a Residential Alternative Energy Income Tax Deduction for residential solar and wind installations[20], although this incentive seems to have minimal impact on the market, as non-residential solar installations are responsible for the majority of private generation growth in the early years due to a combination of technical potential and escalating electric rates. The ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations in the short term and overtime the increase in private generation installation capacity is driven by escalating electricity rates and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 14. The 38 MW from the base case decreases by 39% to 23 MW in the low case and increases by 82% to 69 MW in the high case.

[20] Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

Figure 14. Cumulative Capacity Installations by Scenario (MW AC), Idaho

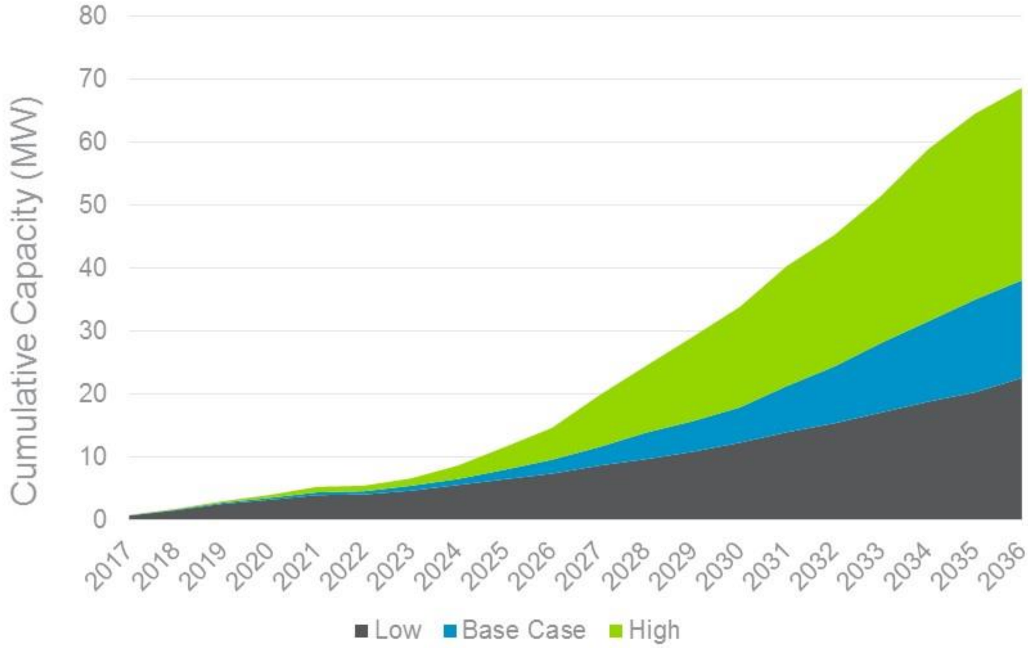


Figure 15. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

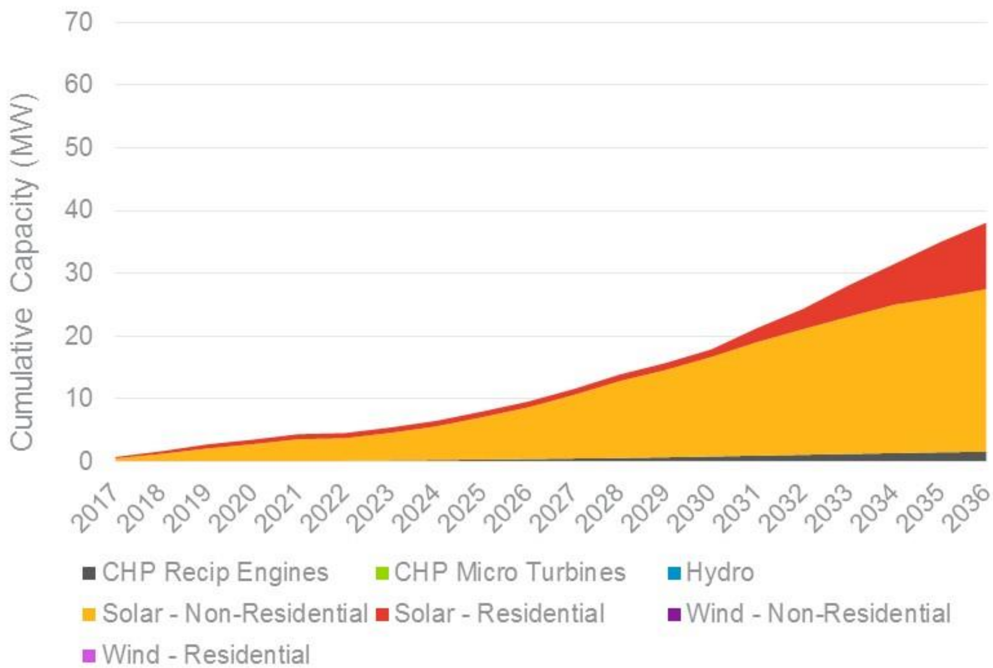


Figure 16. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

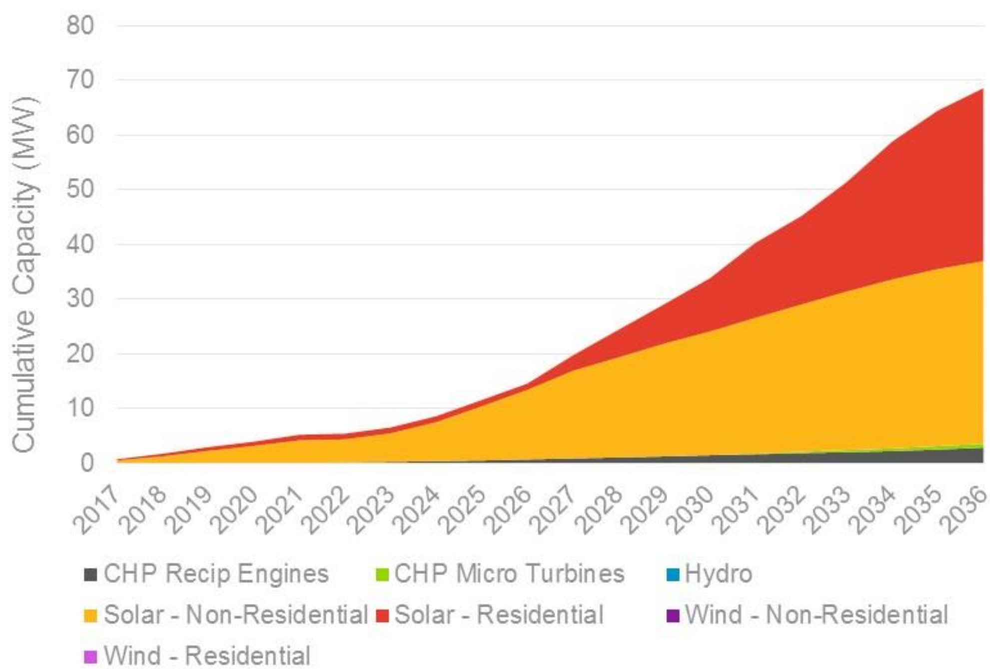
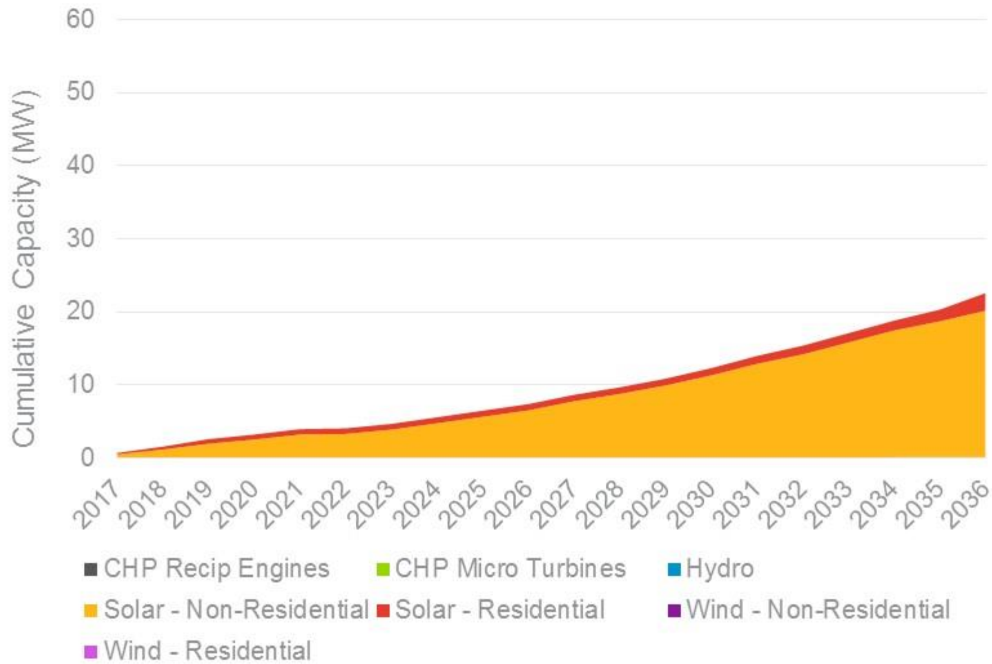


Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 331 MW of private generation capacity over the next two decades in the base case, averaging about 16.6 MW annually. Solar is responsible for all of the private generation growth over the horizon of this study. Although the solar resource in Oregon is not as strong as the majority of other states in PacifiCorp's territory, the Energy Trust of Oregon's Solar Incentive and the state Residential Energy Tax Credit, assumed to extend through 2036, drive solar market adoption. The ratcheting down of the Federal ITC from 2020 to 2022 results in a relatively flat market in the short term but overtime the increase in solar capacity installation is driven by escalating electricity rates and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 18. The 331 MW from the base case decreases by 30% to 232 MW in the low case and increases by 72% to 568 MW in the high case.

Figure 18. Cumulative Capacity Installations by Scenario (MW AC), Oregon

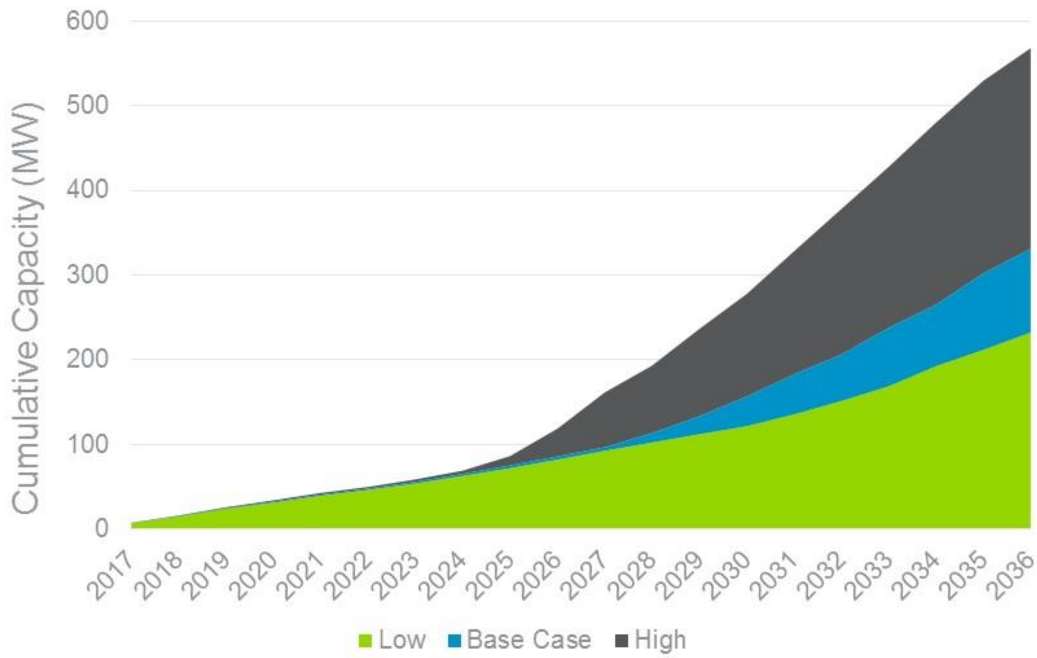


Figure 19. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

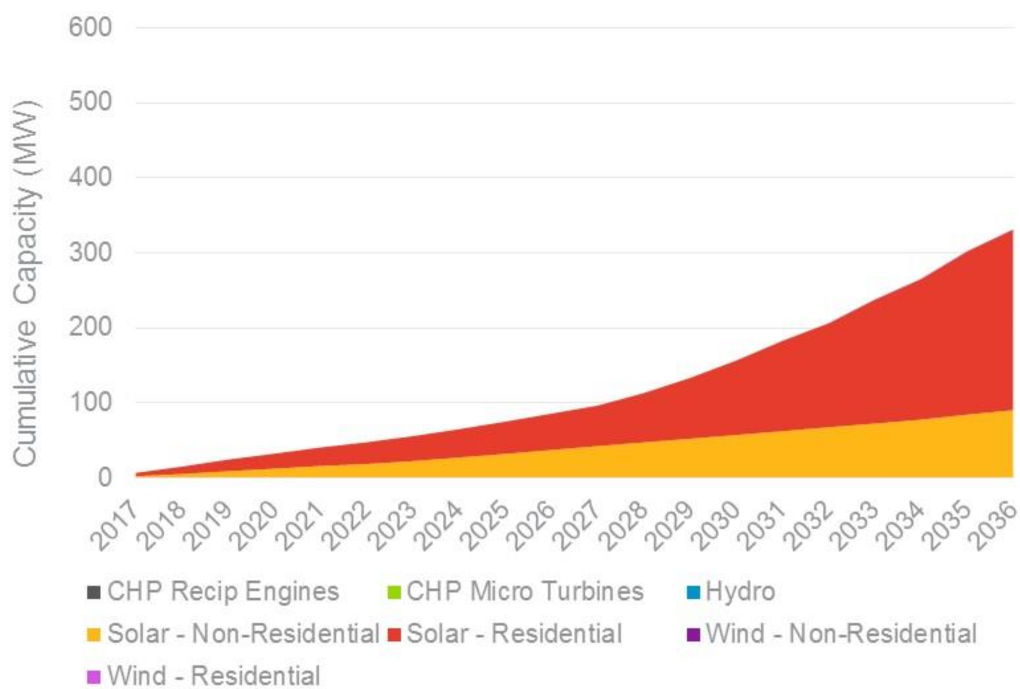
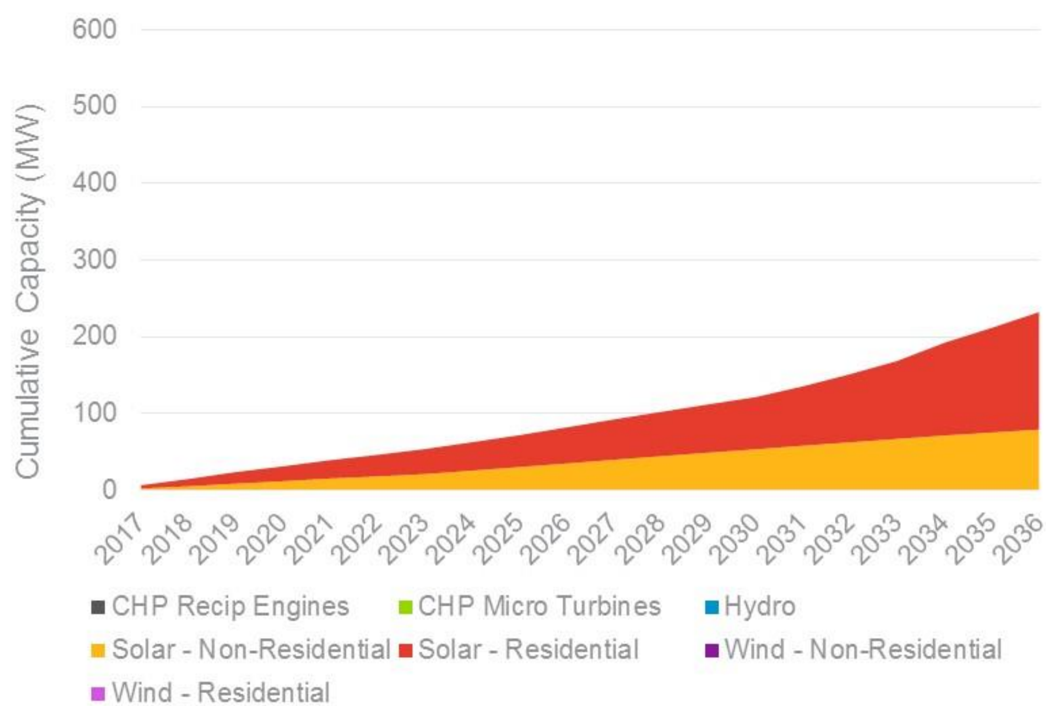


Figure 20. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

Figure 21 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



1.8.4 Utah

PacifiCorp's Utah customers are projected to install about 919 MW of private generation capacity over the next two decades in the base case, averaging around 45 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines being installed in small numbers in future years. Utah has the strongest solar resource in PacifiCorp's territory and system costs are lower than in other states due to Utah's larger and more mature market.

The projection in the early years is dominated by residential customers adopting solar. The state Renewable Energy Systems Tax Credit applies to all technologies evaluated and has an impact on solar adoption. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025 projected capacity installation increases as solar prices continue to decline and utility rates escalate.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 22. The 919 MW from the base case decreases by 25% to 688 MW in the low case and increases by 47% to 1351 MW in the high case.

Figure 22. Cumulative Capacity Installations by Scenario (MW AC), Utah

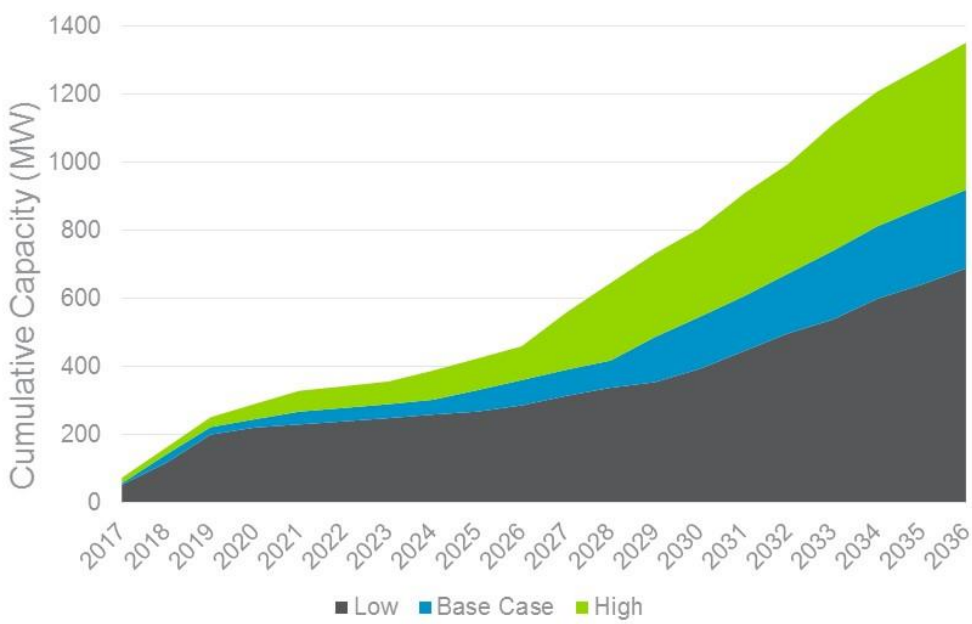


Figure 23. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

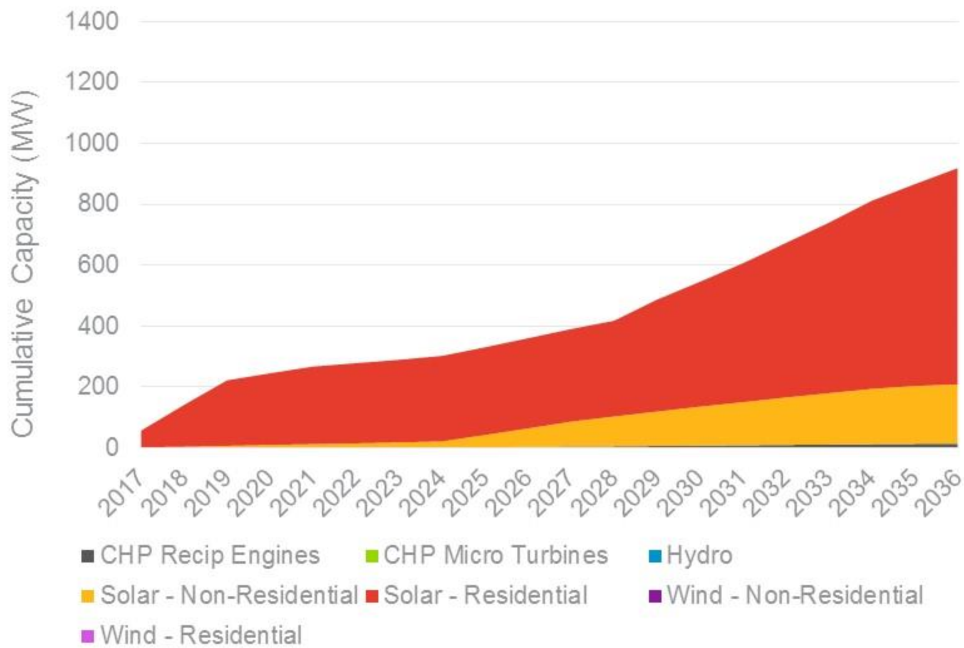


Figure 24. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

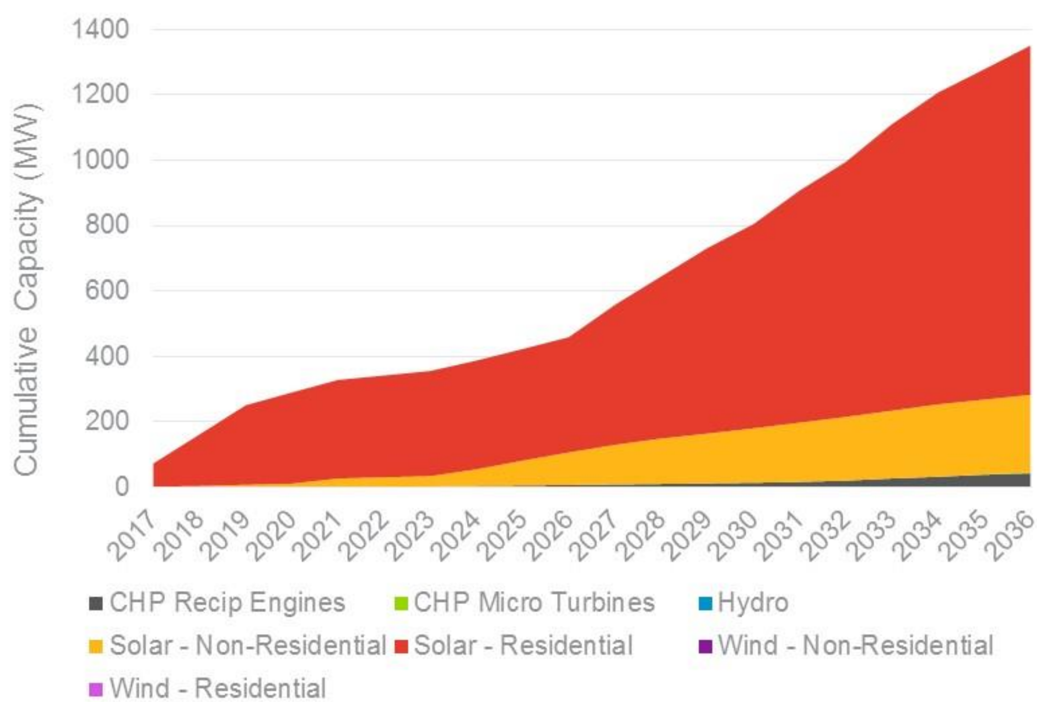
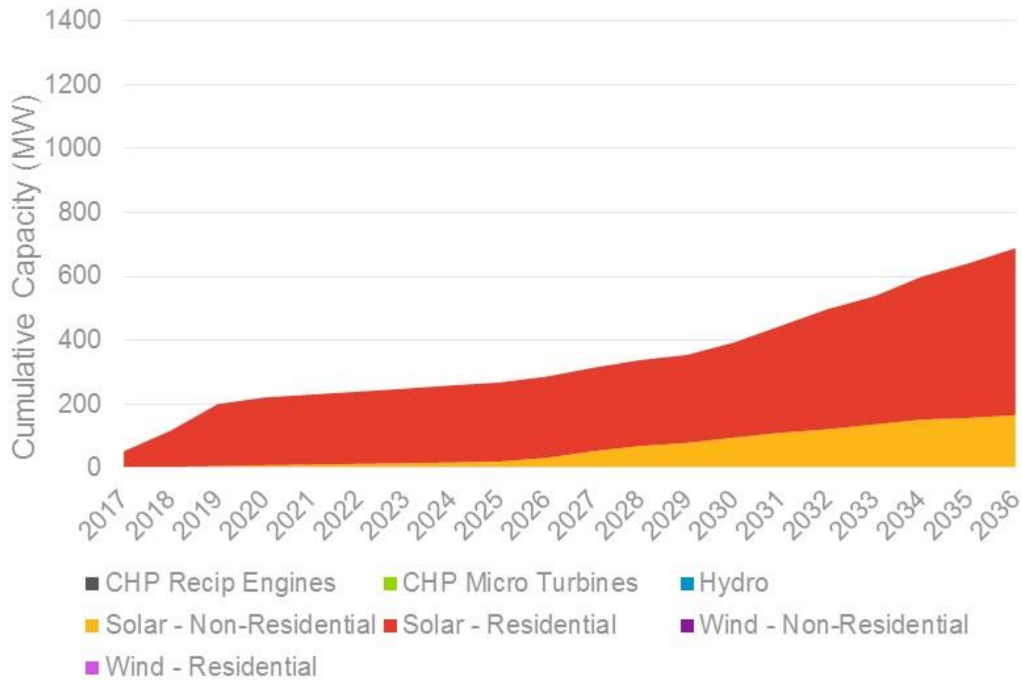


Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 23.9 MW of private generation capacity over the next two decades in the base case, averaging 1.2 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines being installed in small numbers in future years. Washington does not have a very strong solar resource, yet the lucrative Feed-In-Tariff in Washington, which extends through 2020, props up the solar market in the near term. The solar market is driven by non-residential solar installations, most likely due to the lower cost of installing larger systems. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025, installation capacity increases as solar prices continue to decline and utility rates escalate.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 26. The 24 MW from the base case decreases by 29% to 17 MW in the low case and increases by 96% to 47 MW in the high case.

Figure 26. Cumulative Capacity Installations by Scenario (MW AC), Washington

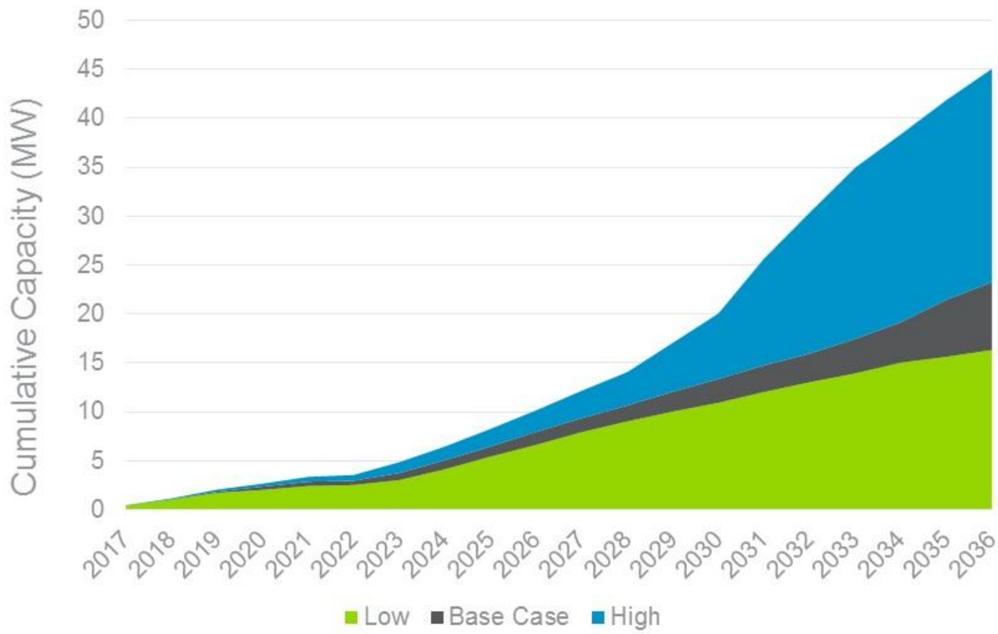


Figure 27. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

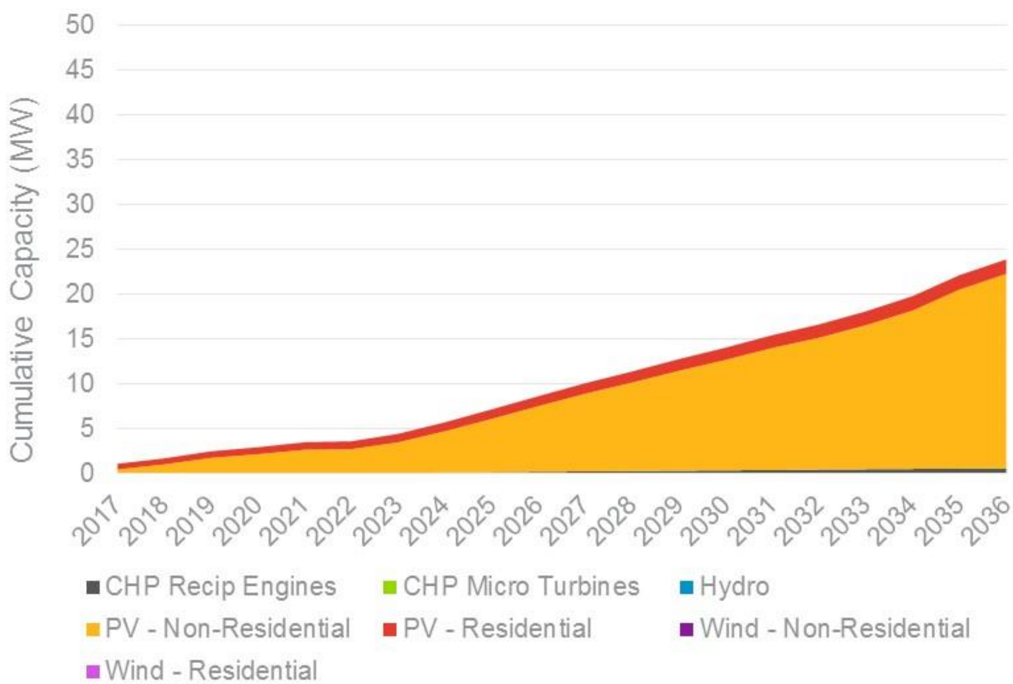


Figure 28. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

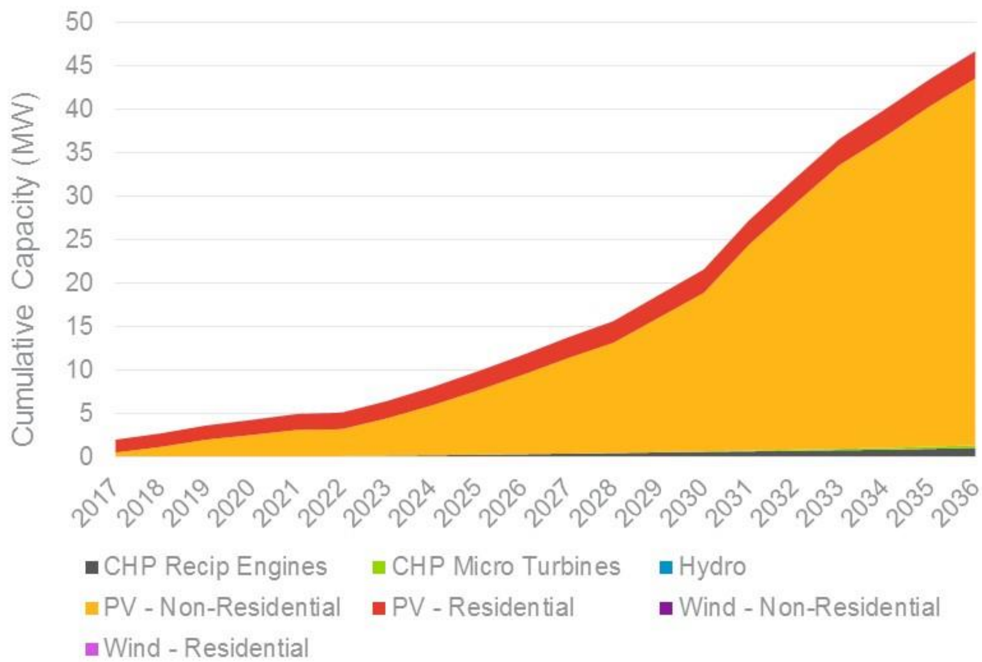
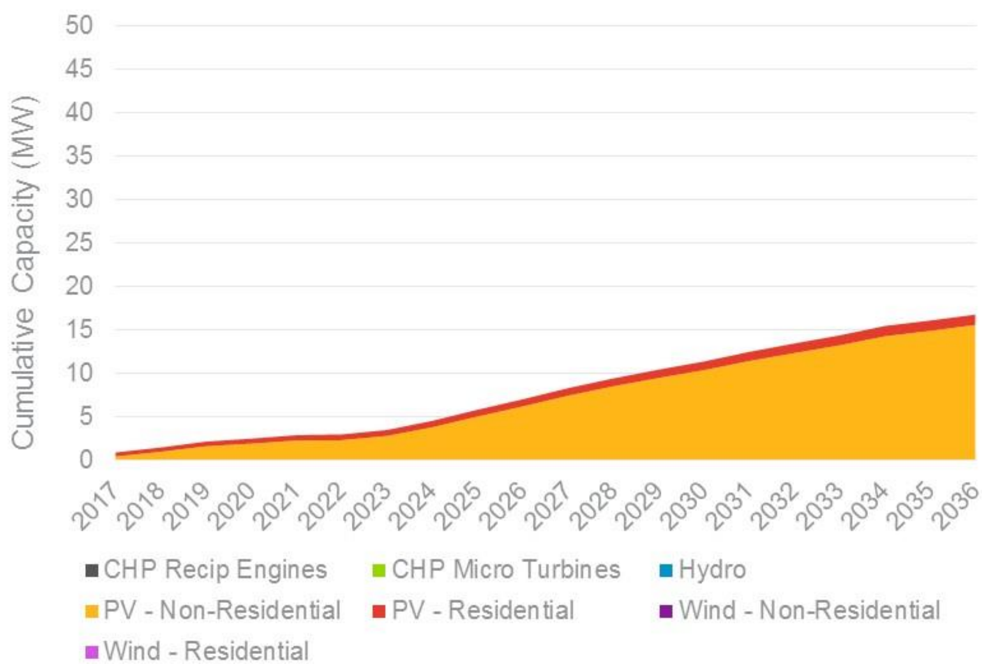


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



1.8.6 Wyoming

PacifiCorp's Wyoming customers are projected to install about 44 MW of capacity over the next two decades in the base case, averaging about 2.2 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines, small hydro, and small wind being installed in small numbers in future years. Wyoming does not have any state incentives promoting the installation of private generation. Similar to other states, the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations but in 2023 the market begins to grow at a faster pace, driven by escalating electricity rates and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of private generation growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 30. The 44 MW from the base case decreases by 48% to 26 MW in the low case and increases by 86% to 82 MW in the high case.

Figure 30. Cumulative Capacity Installations by Scenario, Wyoming

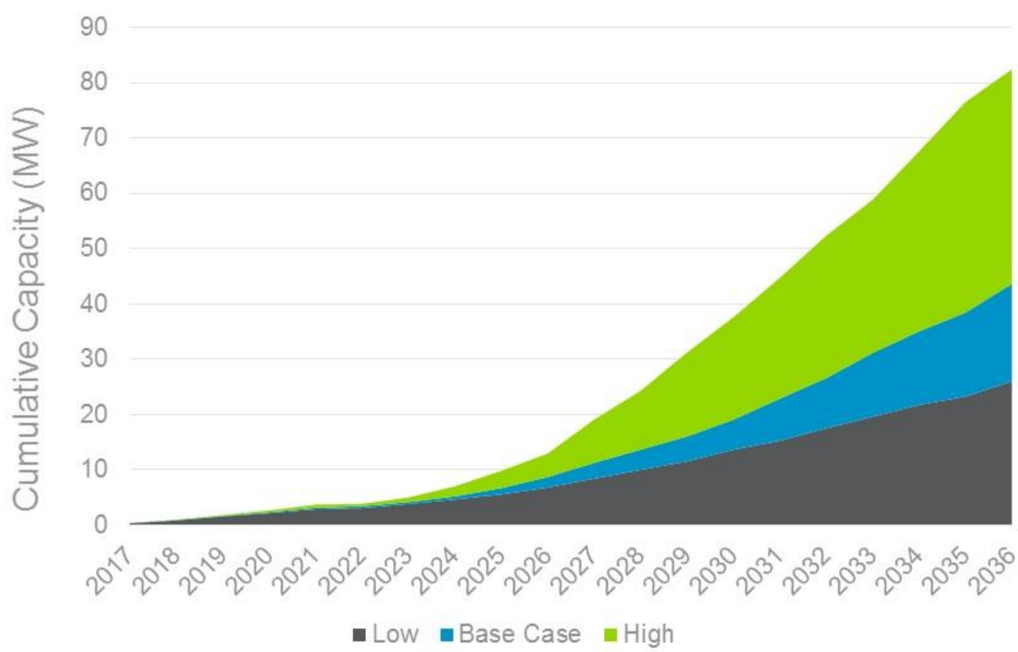


Figure 31. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

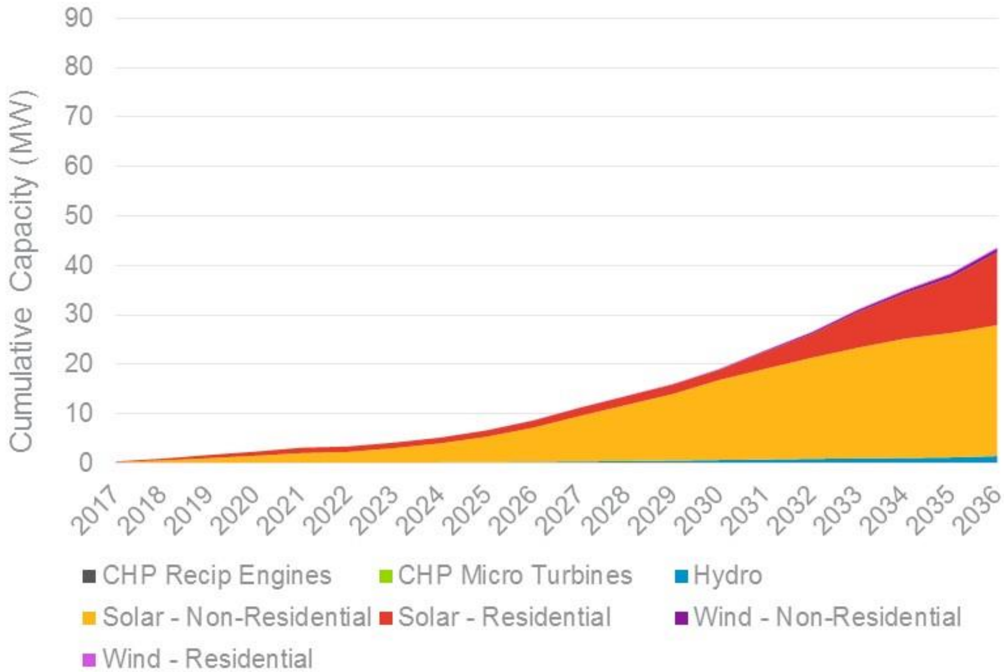


Figure 32. Cumulative Capacity Installations by Technology, Wyoming High Case

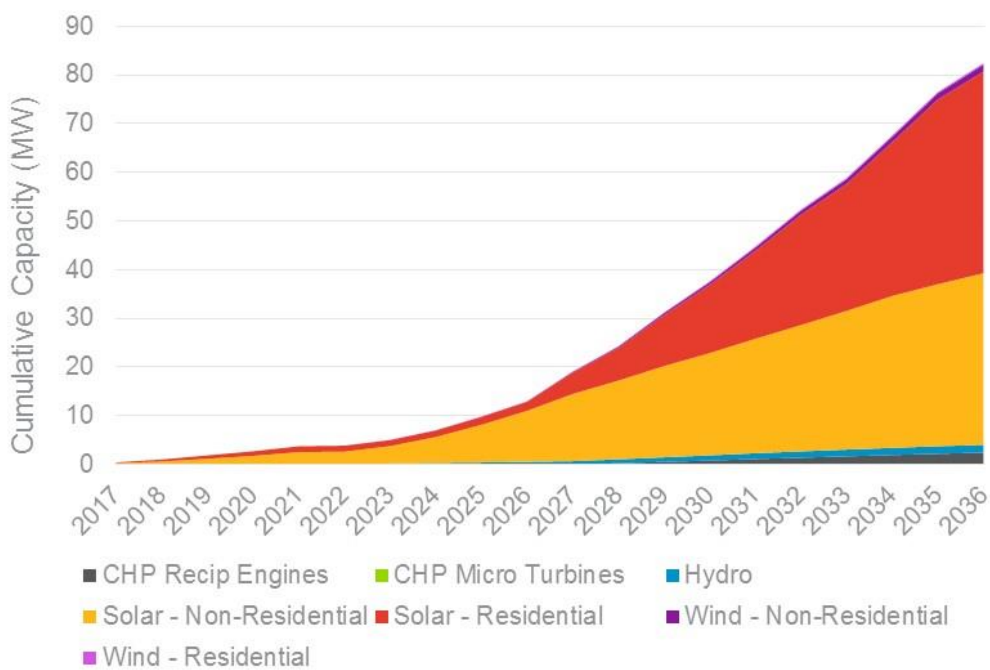
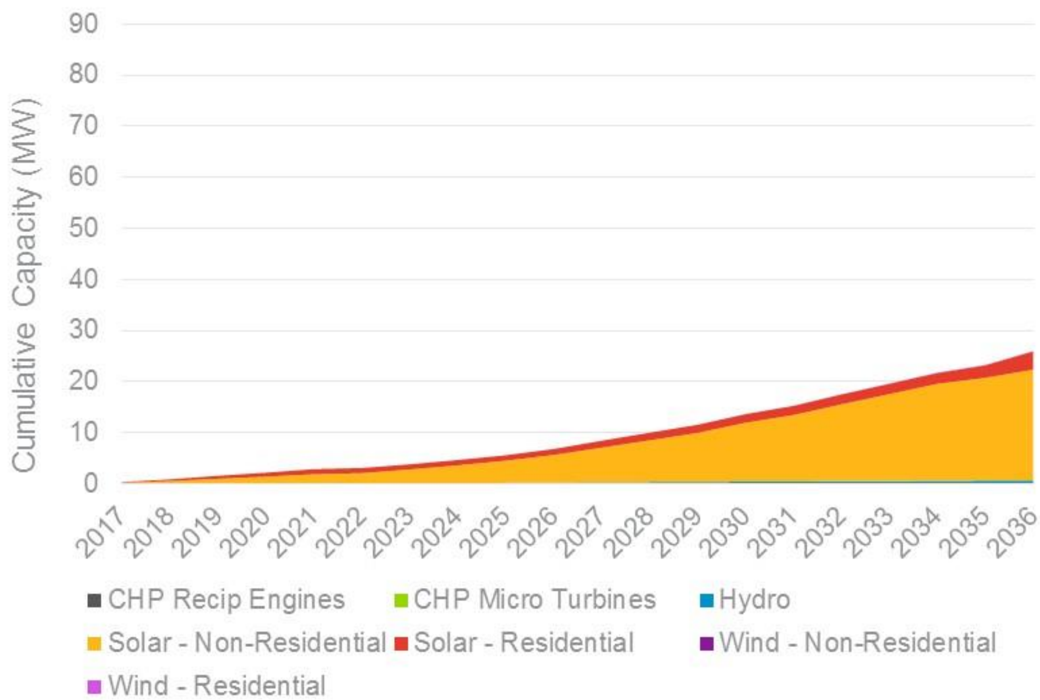


Figure 33. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



APPENDIX A. CUSTOMER DATA

Table 13 California

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	35,461	369,076	0.138
Commercial	7,179	235,760	0.132
Industrial	125	48,336	0.099
Irrigation	1,835	97,790	0.132

Table 14 Idaho

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	61,788	690,071	0.109
Commercial	8,478	468,291	0.083
Industrial	592	1,728,411	0.068
Irrigation	4,947	592,595	0.091

Table 15 Oregon

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	493,990	5,387,920	0.102
Commercial	65,287	5,104,499	0.090
Industrial	1,446	2,192,338	0.071
Irrigation	7,713	338,450	0.096

Table 16 Utah

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	776,356	6,840,892	0.110
Commercial	82,889	8,581,242	0.085
Industrial	5,095	8,870,838	0.065
Irrigation	3,117	216,410	0.077

Table 17 Washington

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	107,382	1,585,732	0.100
Commercial	15,561	1,539,732	0.081
Industrial	500	798,140	0.065
Irrigation	5,091	162,150	0.087

Table 18 Wyoming

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	114,763	1,042,938	0.119
Commercial	22,856	1,510,255	0.086
Industrial	2,073	7,010,964	0.063
Irrigation	743	23,840	0.092

APPENDIX B. SYSTEM CAPACITY ASSUMPTIONS

Table 19 Access Factors (%)

Technology	CA	ID	OR	UT	WA	WY
Recip. Engines	N/A	N/A	N/A	N/A	N/A	N/A
Micro Turbines	N/A	N/A	N/A	N/A	N/A	N/A
Small Hydro	N/A	N/A	N/A	N/A	N/A	N/A
PV - Com	42%	42%	42%	42%	42%	42%
PV - Res	35%	35%	35%	35%	35%	35%
Wind - Com	5%	5%	8%	16%	8%	51%
Wind - Res	5%	5%	8%	16%	8%	51%

Table 20 California (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	2	0	0	28
Micro Turbines	2	0	0	28
Small Hydro	500	0	0	500
PV - Com	18	29	0	212
PV - Res	0	0	6	0
Wind - Com	10	16	0	113
Wind - Res	0	0	3	0

Table 21 Idaho (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	4	0	0	185
Micro Turbines	4	0	0	185
Small Hydro	500	0	0	500
PV - Com	31	68	0	250
PV - Res	0	0	6	0
Wind - Com	29	62	0	1515
Wind - Res	0	0	6	0

Table 22 Oregon (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	0	0	110
Micro Turbines	6	0	0	110
Small Hydro	500	0	0	500
PV - Com	25	32	0	100
PV - Res	0	0	6	0
Wind - Com	30	17	0	584
Wind - Res	0	0	4	0

Table 23 Utah (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	7	0	0	150
Micro Turbines	7	0	0	150
Small Hydro	500	0	0	500
PV - Com	58	39	0	130
PV - Res	0	0	5	0
Wind - Com	56	0	0	938
Wind - Res	0	0	5	0

Table 24 Washington (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	0	0	88
Micro Turbines	6	0	0	88
Small Hydro	500	0	0	500
PV - Com	65	21	0	250
PV - Res	0	0	10	0
Wind - Com	41	13	0	655
Wind - Res	0	0	6	0

Table 25 Wyoming (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	150	0	0	150
Micro Turbines	150	0	0	150
Small Hydro	500	0	0	500
PV - Com	25	17	0	150
PV - Res	0	0	5	0
Wind - Com	23	11	0	1192
Wind - Res	0	0	3	0

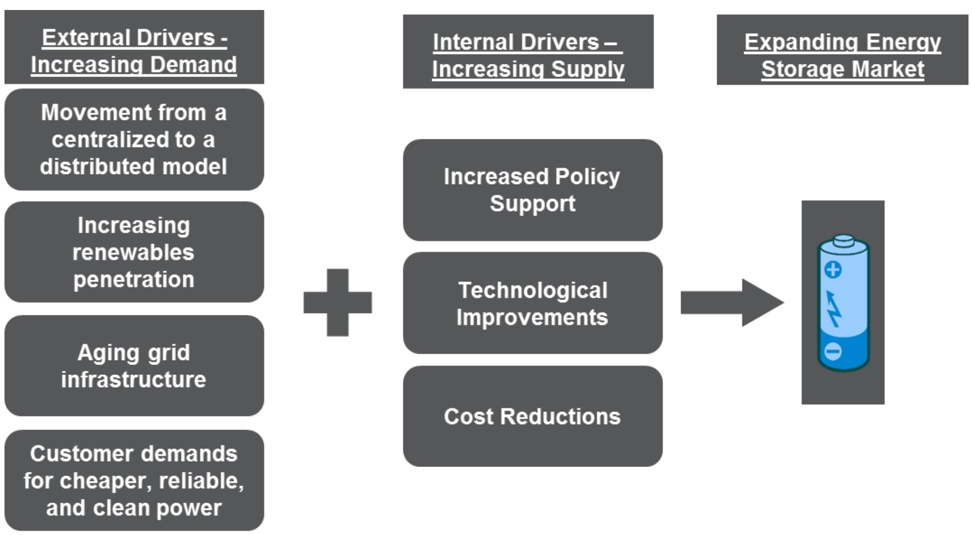
APPENDIX C. STORAGE EVALUATION

Navigant evaluated the future potential of energy storage, evaluating the drivers, challenges and applications of energy storage today.

C.1 Drivers

Changes in the electric sector are increasing the need for storage and changes in the storage sector are increasing the viability. Figure 17 details the external and internal drivers driving the expansion of the energy storage market.

Figure 34. Internal and External Storage Drivers



Sector specific drivers include:

- **Commercial and Industrial**
  - Most commercial customers face demand charges and/or time-of-use (TOU) pricing. This makes storage extremely useful for energy cost management.
  - Storage may also provide additional reliability by smoothing out short term power fluctuations (similar to a large uninterruptible power supply (UPS)), and can provide reactive power to help reduce reactive power charges.
  - Consistent and predictable loads for sub-sets of commercial sites (restaurants, retail, office), will allow for some standardization in terms of product offering.
  - Market may begin to focus on larger scale longer, duration Li-ion battery storage coupled with demand response technology to meet emerging capacity market drivers.

- **Residential**
    - Residential market is currently very small and driven by the back-up power application. It is expected to remain that way in the near term since conventional backup power is still more cost effective.

C.2 Challenges

Storage requires high electricity prices, high demand charges and in many cases a subsidy to make economic sense (e.g. SGIP in California). Sector-specific challenges include:

- **Commercial and Industrial**
    - Limited short-term demand spike facilities with high demand charge
        - Given the current cost of batteries, power conversion technology, software and controls and system integrator services, most projects still require incentives, high demand charge tariffs and emerging financing structures.
    - Customer acquisition and project development costs are high
        - Each specific building load pattern must be analyzed to determine project viability, increasing the cost of customer acquisition.
    - Lack of project finance at scale
        - C&I storage projects, like solar PV, typically do not offer paybacks that meet conventional host return on investment criteria, thereby requiring financing.
        - Despite battery manufacturer's efforts to provide performance guarantees and warranties, financing capital is not available at scale and remains limited.
    - Dispatch algorithm
        - Difficult to design the algorithms correctly so storage discharges at the correct time.
- **Residential**
    - Most residential customers do not pay demand charges or TOU rates. As such, a standalone storage system only provides a reliability benefit.
    - Without regulatory changes, the business case for residential solar + storage will remain NPV negative in all but a few select geographies (e.g. Hawaii).

C.3 Policy

Federal and state policy promoting energy storage remains one of the most important market drivers.

Federal

The predominant federal energy storage policies include the Investment Tax Credit, MACRS, USEPA Clean Power Plan and FERC Rules 792, 755, and 784.

- **The Investment Tax Credit (ITC)** is a federal government established 30 percent tax credit for residences and businesses that invest in solar photovoltaics and other qualifying renewable energy technologies.
    - ITC is applicable for energy storage system coupled with renewable energy.

  - PLR allows 10%-30% ITC depending on RE technology if 75% of energy to battery is renewable.
  - Recapture risk if renewable < 75% to battery in a single year.

- **Federal Modified Accelerated Cost Recovery System (MACRS)**, which classifies photovoltaics (and other technologies) as a five-year property for investment recovery through depreciation deductions. Energy storage systems coupled with RE eligible.

- **USEPA Clean Power Plan** released August 2015 which mandates that utilities reduce carbon emissions. Implementation will be on a state by state basis, with plans due by 2018. Storage may be co-located with fuel assets to improve carbon efficiency, or with renewables or as DR assets to reduce carbon during peak demand or grid stabilization events.

- **FERC Rules 792, 755, and 784** have created a pay for performance structure for frequency regulation which has enabled storage to compete in these markets.

State

The energy storage market is currently driven by a handful of states with high electricity prices, demand charges and supportive policy. Some of the most notable policies currently include the following:

- **California:**
  - **Self-Generation Incentive Program (SGIP)** allows up to $1620/kW for advanced energy storage technologies with a maximum eligible capacity of 3MW. It is budgeted for $83m/year through 2019.
  - **AB 2514** requires 1325MW of storage procurement by 2020 for the large IOUs, including a carve-out of 199MW for behind-the-meter storage.
- **New York REV** has suggested methods of reforming the electricity sector in order to facilitate energy storage installations and controls.
- **Oregon HB-2193-B** which defines the value of storage, and allows utilities to submit rate-recoverable energy storage procurements through to 2017.
- **Massachusetts state government** has allocated $10 million for demonstration projects.
- **Connecticut SB 1078** requires that resources solicited for the Integrated Resource Plan be done through an RFP, and storage may participate in those RFPs.

C.4 Storage Customer Applications

Current Applications

- Demand charge reduction
- Retail rate management
- Energy arbitrage - renewable energy shifting
- Power quality
- Backup power

Future Applications

- Operating Reserves
- Capacity (currently only in PJM and CAISO territories via IOUs)

Non-Residential Solar + Storage

Current Applications
- **Demand charge reduction** – Reduce demand charges by eliminating spikes in demand. Solar coincides with peak but doesn't effectively reduce demand charges due to intermittent production profile.
- **Retail rate management -** Aid with tariff switching by eliminating consistent spikes in demand, minutes long that could be responsible for unfavorable tariff rates.
- **Energy arbitrage** – Storing energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day. Requires a smart inverter in NEM states.
- **Power quality** – Increasing power quality at the facility, ideal for protecting sensitive equipment.

Future Applications
- **Back-up power** – Provide backup power during grid failure. Currently, battery storage is cost prohibitive to serve this application and cannot compete with gas fired back-up generators for non-residential customers.
- **Load shifting** – With the potential future elimination of NEM, storage could allow customers to store excess electricity during daylight hours and discharge during times of high load.

Residential Solar + Storage

The bulk of the residential storage market will be storage tied to solar PV.

Current Applications
- **Back-up power** – Provide back-up power in an outage.

Future Applications
- **Demand response** - Reduce demand charges by eliminating spikes in power demand.
  - Most residential customers do not pay demand charges or TOU rates (AZ only state with demand charges). Many utilities are considering moving toward time of use pricing although only a few have made the move.
- **Energy arbitrage** – Storing energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day.
- **Load shifting** – With the potential future elimination of NEM, storage could allow customers to store excess electricity during daylight hours and discharge during times of high load.

Wind + Storage

Current Applications
- **Demand charge reduction** - Reduce demand charges by eliminating spikes in demand.
- **Retail rate management -** Aid with tariff switching by eliminating consistent spikes in demand, minutes long that could be responsible for unfavorable tariff rates.
- **Energy arbitrage** – Storing wind energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day.
- **Power quality** – Increasing power quality at the facility, ideal for protecting sensitive equipment.

Future Applications

- **Back-up power**– Provide backup power during grid failure. Currently, battery storage is cost prohibitive to serve this application and cannot compete with gas fired back-up generators for non-residential customers.
- **Load shifting** – With the potential future reduction or elimination of NEM benefits, storage could allow customers to store excess electricity during times of high wind and discharge during times of high load.
- **Interconnection costs** – If utility plans to charge large interconnection costs to integrate the variable wind, energy storage could mitigate those impacts.

Hydro + Storage

- Small hydro should have an even electricity generation profile throughout a 24 hour period, so coupling storage with hydro has minimal impact compared with intermittent renewables (e.g. solar and wind).
- Did not make the short list of storage for renewables integration applications in recent Navigant Research report.
- To a lesser degree, storage can still provide the following benefits when coupled with hydro:
    - Demand charge reduction
    - Retail rate management
    - Power quality
    - Back-up power
    - Load shifting

CHP + Storage

- Availability of storage will likely not impact forecasts for CHP.
- Both reciprocating engines and micro-turbines are load following technologies for customers with high thermal loads.
- Load following technologies already help customers manage energy and demand charges.
- Customers with high thermal load will chose CHP over energy storage because CHP reduces thermal and electricity costs, simultaneously.

APPENDIX D. WASHINGTON HIGH-EFFICIENCY COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code[21] establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. To supplement the analysis in the main body of this report addressing reliability and feasibility, this appendix, analyzes the levelized cost of energy (LCOE) of these resources, for use in cost-effectiveness analysis.

Key assumptions for the analysis are presented in Table 26 and Table 27. It is worth noting that the LCOE calculation is for the electrical generation component only and the cost of the heat recapture and recovery was taken out of the total installed system cost. PacifiCorp provided the natural gas pricing and the weighted average cost of capital (WACC) assumptions.

D.1 Key Assumptions

Table 26 Reciprocating Engines LCOE – Key Assumptions[22]

private generation Resource Costs	Units	2017	2026	2036	Notes
Installed System Cost	$/W	$2.61/W	$2.71/W	$2.82/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 10% to exclude heating generation costs.
Asset Life	Years	25	25	25	
Capacity Factor	%	85%	85%	85%	Navigant Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

[21] http://apps.leg.wa.gov/WAC/default.aspx?cite=480-109-100

[22] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

Table 27 Micro-turbines LOE – Key Assumptions[23]

private generation Resource Costs	Units	2017	2026	2036	Notes
Installed System Cost	$/W	$2.561/W	$2.55/W	$2.54/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 5% to exclude heating generation costs.
Asset Life	Years	25	25	25	Assumption
Capacity Factor	%	85%	85%	85%	Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

D.2 Results

The results of the LCOE analysis are presented in Table 28, with levelized costs estimated to range from $88/MWh to $111/MWh over the forecast period, varying by year and technology.

Table 28 LCOE Results – Electric Component Only

Technology	Units	2017	2026	2036
Reciprocating Engines	$/MWh	98.0	99.7	108.7
Microturbines	$/MWh	87.5	99.6	110.9

[23] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

APPENDIX E. COMPARISON OF 2016 AND 2014 STUDY

The growth of the solar industry is the main driver in the difference between the 2014 and 2016 study results across PacifiCorp's territory. Cumulative solar market penetration for the combined residential and non-residential sectors is expected to increase at about six times the rate projected in 2014. This increase in penetration is driven by the ITC extension and the continued decline of solar installation costs. The ITC, originally set to expire in 2016 for commercial solar systems and reduce to 10 percent for residential solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring from 2020 through 2022. The 2014 Study assumed that the ITC would expire for commercial solar PV systems at the end of 2016 and step down to 10 percent for residential PV systems, per the legislation in place at the time of the analysis. Additionally, solar costs have continued to rapidly decline at a faster rate than expected the last few years, with 2017 residential and non-residential solar costs declining by 15 and 25 percent, respectively between the 2014 and 2016 studies.

Another difference between the market penetration results is the adoption of CHP micro-turbines and reciprocating engines. Based on the latest references, the cost of installing a micro-turbine remained relatively constant to the assumptions made in 2014, yet CHP reciprocating engines increased by about 30 percent. Additionally, in the 2014 study, technology costs were expected to decline aggressively at 1.4 percent annually over the next 20 years, while the 2016 study expects the equipment costs of these fairly mature technologies to stay relatively flat.

All other technologies evaluated had minimal cumulative market penetration in both the 2014 and 2016 studies.

Figure 35. Cumulative Market Penetration Results by Technology (MW AC), 2017 – 2036, Base Case (Current Study)

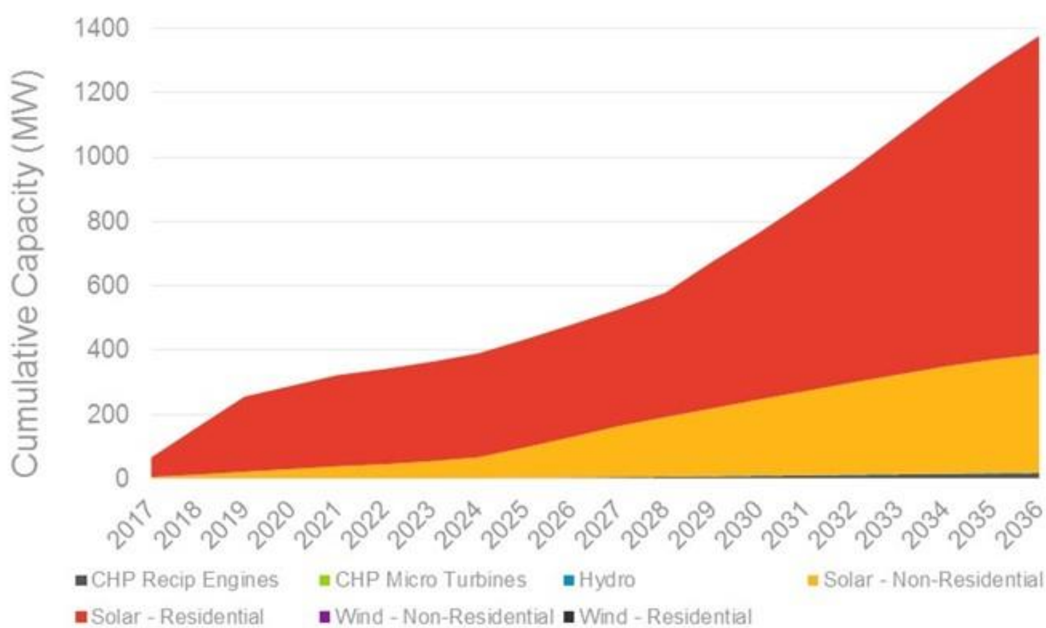
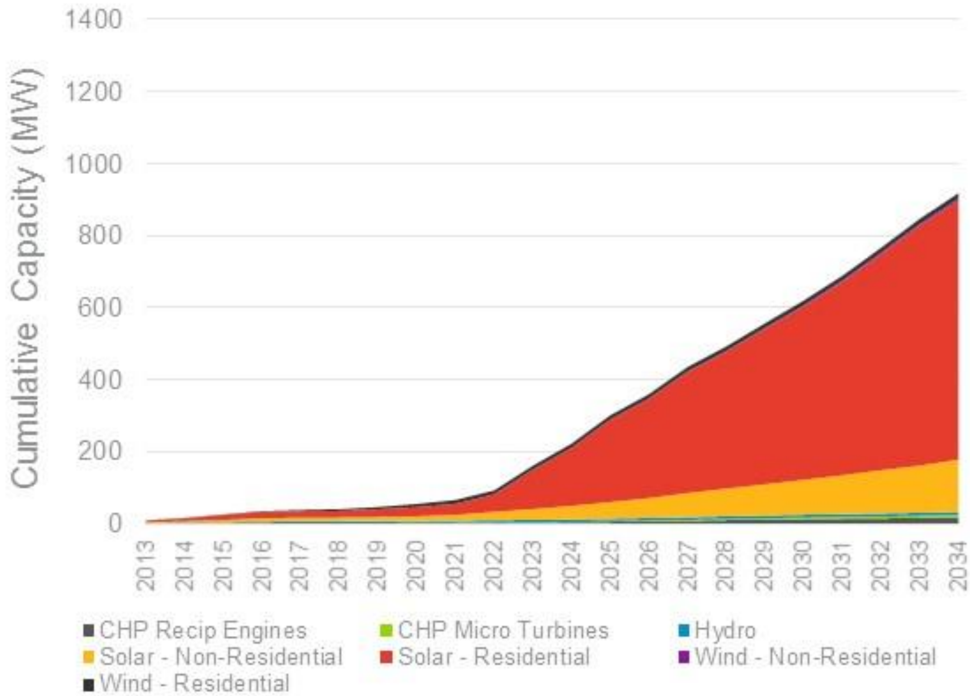


Figure 36. Cumulative Market Penetration Results by Technology (MW AC), 2013 – 2034, Base Case (2014 Study)



APPENDIX F. DETAILED NUMERIC RESULTS

F.1 Utah

Table 29. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.9	0.9	1.2	1.1	1.2	1.4	1.1	1.2	1.0	1.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	55.4	82.0	77.7	20.2	19.5	8.3	8.4	9.3	7.4	7.9	8.0	10.5	53.0	42.6	46.1	51.4	52.3	57.8	45.2	47.0
PV	Commercial	1.8	2.0	2.4	2.2	1.8	2.1	2.1	2.3	19.3	20.0	19.9	15.0	13.9	13.8	12.5	12.7	11.2	11.3	5.4	2.5
PV	Industrial	0.1	0.1	0.3	0.5	0.5	0.1	0.1	0.5	0.8	0.7	0.9	0.6	0.6	0.7	0.6	0.9	1.6	1.3	2.8	1.9
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 30. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	17	1090	1551	1767	2379	2657	3128	4076	4265	4987	7044	6664	9214	8485	8665	10487	8562	8652	7690	7411
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	99113	146737	139036	36123	34960	14844	15007	16617	13279	14202	14234	18753	94911	76192	82487	91991	93634	103402	80897	84212
PV	Commercial	3200	3651	4357	3879	3292	3734	3775	4180	34562	35862	35657	26883	24894	24753	22367	22737	19995	20245	9657	4460
PV	Industrial	177	202	448	865	971	250	253	939	1476	1325	1570	987	1150	1214	1163	1588	2954	2338	4981	3325
PV	Irrigation	53	60	72	64	78	62	63	260	264	532	773	676	677	966	671	690	637	641	395	352
Wind	Residential	0	1	1	1	0	1	1	1	0	0	0	1	0	1	1	1	0	1	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 31. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	50.6	62.7	80.5	18.4	6.8	7.1	7.1	7.9	6.3	6.8	6.8	7.8	6.4	22.3	37.1	41.4	25.4	45.7	36.9	38.7
PV	Commercial	1.7	1.9	2.3	2.0	1.7	2.0	2.0	2.2	1.7	10.7	20.1	15.4	9.3	15.4	14.7	9.8	14.1	14.2	4.5	8.3
PV	Industrial	0.1	0.1	0.1	0.3	0.4	0.1	0.1	0.2	0.7	0.7	0.8	0.5	0.5	0.6	0.5	0.5	0.6	0.5	0.3	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.2	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 32. Utah – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	7	12	19	13	7	11	11	15	6	8	8	13	5	10	11	16	8	12	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	90623	112341	144056	32940	12169	12653	12791	14164	11318	12105	12133	13974	11535	39933	66480	74086	45520	81816	66117	69300
PV	Commercial	2999	3422	4085	3637	3086	3500	3539	3918	3131	19117	35909	27611	16732	27625	26238	17557	25265	25404	8050	14804
PV	Industrial	172	196	234	528	750	224	227	413	1207	1254	1503	918	861	1147	864	949	1144	972	524	524
PV	Irrigation	47	54	64	81	156	58	59	203	218	261	224	289	375	396	535	709	708	739	288	555
Wind	Residential	0	0	1	1	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 33. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.2	0.3	0.3	0.6	0.7	0.9	1.2	1.4	1.6	1.6	1.7	1.7	1.8	2.7	3.8	6.5	5.4	6.2	4.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.4
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	71.2	86.1	85.7	35.5	22.6	10.0	10.1	11.2	8.9	11.0	75.6	67.7	71.4	57.5	85.1	69.9	96.2	77.6	56.6	57.7
PV	Commercial	1.9	2.2	2.6	2.9	14.4	2.6	2.6	18.3	23.5	22.0	19.6	15.1	10.7	10.7	11.6	10.4	9.7	11.1	6.0	7.2
PV	Industrial	0.1	0.1	0.5	0.5	0.6	0.2	0.2	1.0	1.0	1.0	1.2	2.0	2.4	3.0	2.9	2.9	2.7	2.6	1.1	1.5
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3	0.6	0.6	0.7	0.5	0.3	0.4	0.3	0.4	0.2	0.3	0.2	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 34. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	263	1527	1979	2529	4623	5190	7009	8666	10053	11582	11847	12878	13006	13440	20087	28503	48346	39904	46391	33085
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7483	10723
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	127507	154195	153509	63551	40508	17892	18087	20029	16005	19661	135315	121192	127912	102994	152448	125061	172300	138896	101378	103387
PV	Commercial	3385	3862	4609	5224	25777	4575	4625	32747	42125	39369	35037	27103	19088	19151	20771	18628	17286	19877	10791	12971
PV	Industrial	184	210	970	944	1040	276	364	1770	1762	1834	2160	3602	4363	5314	5243	5276	4832	4623	2046	2640
PV	Irrigation	59	67	80	71	109	70	71	602	1097	1140	1333	853	588	736	502	635	440	462	304	211
Wind	Residential	0	1	1	1	0	1	1	1	0	0	0	1	0	1	1	1	1	1	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	113
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

F.2 Oregon

Table 35. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.4	5.4	5.8	4.4	4.6	4.3	4.4	4.5	5.1	5.5	5.6	11.7	15.2	18.2	21.2	18.1	26.6	22.1	30.2	23.2
PV	Commercial	2.5	2.7	3.4	3.2	3.4	2.6	3.5	4.5	4.5	4.7	4.6	4.5	4.4	4.5	4.5	4.5	4.1	4.5	5.5	5.1
PV	Industrial	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.1	0.2	0.2	0.1	0.2	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.5	0.4	0.5	1.0	0.7
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 36. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	170	667	819	788	967	869	824	919	955	822	703
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5946	7341	7853	6031	6273	5863	5961	6080	6991	7538	7663	15924	20755	24760	28945	24615	36228	30123	41169	31558
PV	Commercial	3388	3730	4630	4345	4659	3600	4787	6095	6132	6419	6324	6140	6053	6119	6137	6194	5641	6163	7430	6982
PV	Industrial	39	55	69	51	63	6	66	100	100	117	114	110	96	153	158	200	198	171	172	132
PV	Irrigation	92	215	287	195	263	26	278	397	384	454	430	399	378	329	381	665	593	639	1321	905
Wind	Residential	-1	0	0	0	0	0	0	0	0	0	0	20	30	31	31	32	31	32	25	25
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	127	152	163	168	172
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	1	8	9	10	11	12	10	12	10

Table 37. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.1	5.2	5.7	4.2	4.6	4.3	4.4	4.4	4.5	5.5	5.6	5.1	5.3	5.1	9.3	11.4	12.7	19.3	15.5	16.7
PV	Commercial	2.5	2.7	3.1	3.0	3.3	2.6	3.0	4.1	4.3	4.3	4.5	4.3	4.3	4.1	4.4	4.1	4.3	4.1	3.7	3.6
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.1	0.1	0.2	0.1	0.2	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 38. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5628	7113	7766	5771	6207	5843	5939	6054	6162	7487	7615	6945	7174	6992	12636	15583	17377	26370	21109	22733
PV	Commercial	3353	3679	4249	4109	4516	3583	4080	5639	5895	5902	6081	5907	5856	5561	5946	5609	5897	5582	4976	4941
PV	Industrial	35	50	65	40	53	5	35	90	91	99	105	92	78	90	79	92	74	90	128	127
PV	Irrigation	91	170	259	178	222	23	201	332	352	380	397	367	298	300	355	300	274	286	180	172
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	25
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

Table 39. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.8	5.5	5.8	4.6	4.8	4.3	4.4	5.0	11.7	26.5	36.7	25.9	36.6	33.2	41.4	36.6	38.6	42.8	40.0	29.7
PV	Commercial	2.5	2.9	3.6	3.4	3.7	2.7	4.1	4.8	4.9	5.1	5.3	4.8	5.5	6.6	7.7	11.6	9.7	8.0	8.4	7.8
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
PV	Irrigation	0.1	0.2	0.2	0.2	0.2	0.0	0.3	0.3	0.4	0.4	0.5	0.7	0.8	1.0	1.1	1.1	1.0	0.9	0.5	0.6
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 40. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	350	566	726	772	996	1037	1173	1163	1235	1455	2279	2305	2401	2028	2011
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	6497	7468	7962	6308	6558	5892	5992	6759	15981	36114	50073	35265	49878	45265	56411	49921	52575	58317	54574	40466
PV	Commercial	3410	3956	4917	4603	4975	3624	5594	6607	6679	7012	7255	6490	7496	8975	10456	15821	13264	10884	11468	10593
PV	Industrial	43	56	79	57	74	7	99	125	127	163	293	206	237	250	224	232	224	236	181	177
PV	Irrigation	129	241	289	250	265	33	411	471	502	501	627	960	1155	1399	1437	1434	1321	1263	641	772
Wind	Residential	-1	0	0	0	0	0	0	0	28	37	38	38	38	38	32	45	47	48	47	37
Wind	Commercial	-1	0	0	0	0	0	0	0	0	0	0	97	173	174	191	207	213	192	189	189
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	8	9	11	12	14	13	15	11	14	13	13

F.3 Washington

Table 41. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.6	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
PV	Commercial	0.4	0.5	0.7	0.4	0.4	0.0	0.6	1.0	1.1	1.2	1.1	1.0	1.0	1.0	1.0	0.8	1.0	1.2	1.9	1.4
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 42. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	39	88	101	141	142	163	247	207	342	331	232	350	336	193	392	305	290	274	260
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	961	69	82	77	93	69	86	87	105	75	92	93	113	82	100	98	96	96	0	0
PV	Commercial	657	794	1012	550	647	69	976	1577	1758	1826	1742	1557	1602	1500	1529	1240	1471	1811	2996	2121
PV	Industrial	40	54	68	50	61	5	76	93	109	105	110	140	147	175	183	154	154	190	125	122
PV	Irrigation	18	10	11	11	13	10	94	170	204	189	198	177	182	143	291	269	458	462	412	401
Wind	Residential	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 43. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Commercial	0.4	0.5	0.6	0.3	0.3	0.0	0.4	0.8	1.1	1.0	1.0	0.9	0.8	0.7	0.9	0.7	0.7	0.9	0.5	0.5
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 44. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	26	45	41	63	38	42	59	45	94	48	0	25	8	0	10	30	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	707	51	60	57	68	51	63	64	77	55	68	68	83	61	74	72	71	71	0	0
PV	Commercial	628	761	901	405	462	61	637	1296	1615	1508	1603	1430	1247	1146	1413	1136	1106	1365	757	724
PV	Industrial	38	50	63	43	52	4	53	86	88	97	94	86	79	73	73	137	139	107	119	118
PV	Irrigation	12	9	11	10	12	9	23	157	173	176	185	142	144	157	133	129	124	122	82	214
Wind	Residential	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 45. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
PV	Commercial	0.5	0.6	0.7	0.5	0.5	0.1	1.1	1.2	1.4	1.4	1.4	1.3	2.2	2.2	4.9	4.0	3.9	2.8	3.0	2.6
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.1	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 46. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	88	128	176	225	248	297	377	397	509	512	477	551	458	449	496	471	445	714	980
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	209	240	220	336	277	285	262	263
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2272	114	135	128	153	114	142	145	173	124	153	154	187	136	165	163	160	160	0	0
PV	Commercial	696	898	1150	725	762	79	1623	1912	2129	2209	2147	1974	3387	3451	7525	6136	6029	4298	4640	4022
PV	Industrial	42	59	75	59	68	7	103	122	142	259	261	197	236	202	209	210	210	176	167	369
PV	Irrigation	67	28	13	12	15	11	107	204	241	228	435	442	622	628	634	607	563	399	376	230
Wind	Residential	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	3	6	6	6

F.4 Idaho

Table 47. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	1.0	1.0	1.8	1.5	2.3	1.8
PV	Commercial	0.2	0.3	0.3	0.2	0.3	0.0	0.3	0.3	0.3	0.4	0.4	0.6	0.5	0.8	1.1	0.8	0.8	0.8	0.6	0.5
PV	Industrial	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3
PV	Irrigation	0.3	0.4	0.4	0.3	0.4	0.1	0.4	0.5	0.9	0.9	1.3	1.4	1.0	1.0	1.0	1.0	0.9	0.9	0.3	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 48. Idaho – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	144	177	236	295	324	406	503	529	621	621	645	797	994	1013	1032	1000	1003	944	690
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	366	384	407	98	152	43	44	48	41	45	45	134	136	189	1774	1750	3143	2584	4121	3090
PV	Commercial	371	439	542	431	464	63	523	595	600	615	709	1071	849	1355	1944	1458	1417	1418	1064	894
PV	Industrial	99	123	219	157	196	22	108	279	295	313	325	255	248	251	250	208	246	256	126	505
PV	Irrigation	505	624	723	574	657	102	779	821	1540	1659	2297	2415	1805	1796	1738	1700	1558	1511	558	765
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 49. Idaho – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.8
PV	Commercial	0.2	0.2	0.3	0.2	0.2	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.4	0.5	0.5	0.5	0.7	0.7
PV	Industrial	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.3	0.3	0.4	0.3	0.4	0.0	0.3	0.4	0.4	0.4	0.8	0.6	0.8	1.0	1.0	0.7	1.0	1.0	0.4	0.7
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 50. Idaho – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	0	0	0	0	0	0	30	35	116	92	2	153	49	43	172	176	182	106	103
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	356	344	397	90	109	39	40	43	38	41	41	44	38	125	138	194	143	153	428	1444
PV	Commercial	342	425	527	379	401	59	367	557	566	516	585	446	418	415	788	818	831	824	1239	1179
PV	Industrial	92	120	170	125	157	19	45	194	270	290	265	233	185	232	186	238	182	188	174	103
PV	Irrigation	469	607	704	509	629	86	606	780	704	711	1318	1075	1390	1749	1799	1163	1805	1816	761	1233
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 51. Idaho – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.2	0.0	0.0	0.0	0.0	0.0	1.7	2.2	2.1	2.5	4.0	2.4	3.9	5.2	3.8	2.6
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.0	0.4	0.4	0.7	1.0	1.6	1.1	1.0	0.8	0.9	0.7	0.8	0.6	0.4	0.2
PV	Industrial	0.1	0.1	0.2	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.6	0.6	0.6	0.5	0.4
PV	Irrigation	0.3	0.4	0.5	0.5	0.6	0.1	0.5	1.3	1.8	1.6	1.5	1.0	1.1	0.9	1.0	0.8	0.7	0.7	0.5	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 52. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	33	183	229	306	369	416	786	978	1055	1331	1358	1320	1498	1544	1355	1540	1257	1447	2125	2618
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	759	1044	1052	897	911	850
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	379	427	385	177	406	53	54	59	51	55	2919	3929	3740	4466	6959	4281	6768	9116	6608	4635
PV	Commercial	386	482	567	458	533	68	689	696	1275	1739	2727	1899	1810	1354	1622	1208	1346	1022	776	400
PV	Industrial	102	156	285	177	217	25	235	341	394	383	358	327	275	632	617	1081	1104	1111	903	761
PV	Irrigation	524	647	836	868	976	109	834	2281	3202	2818	2713	1766	1972	1508	1679	1326	1189	1202	928	575
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

F.5 California

Table 53. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.1	0.8	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.2	0.6	0.7	1.2	0.9	1.0	1.1	1.2	1.2	1.6
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.2	0.4
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 54. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	11	33	45	56	67	74	91	97	108	108	117	111	100	106	87	83	66	63	58	76
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	4	13	17	20	26	31	41	69	90	94	129	140	114	113	130	100	84	77	68	59
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	192	204	1489	565	577	49	46	57	39	49	388	1118	1240	2112	1639	1847	1956	2175	2102	2904
PV	Commercial	440	484	529	534	580	393	676	753	678	684	674	701	546	541	678	561	501	539	382	725
PV	Industrial	31	56	108	74	103	6	41	154	193	170	166	111	123	118	108	104	68	87	54	32
PV	Irrigation	183	201	220	222	241	163	280	313	281	284	280	291	226	224	281	233	208	223	158	301
Wind	Residential	-1	-1	-1	0	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	3	4	6	7	9	9	11	12	13	11	13	10	12	9	9	8	10
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
Wind	Irrigation	0	0	0	1	1	2	3	4	4	4	5	5	4	5	4	5	4	4	4	3

Table 55. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.1	0.4	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.6	0.6	0.7	0.4	0.8	0.9
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.1	0.1
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 56. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	8	26	34	41	51	60	87	79	87	91	95	90	88	82	79	39	62	57	51
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	1	6	7	8	14	17	21	22	27	27	29	35	30	30	29	28	25	24	23	15
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	176	198	705	140	399	28	27	34	23	29	29	38	238	862	1008	1178	1307	778	1455	1584
PV	Commercial	414	489	530	527	537	345	673	700	666	661	636	569	490	476	542	463	394	417	262	260
PV	Industrial	30	41	84	65	75	5	14	113	153	168	173	106	132	95	123	88	105	74	71	38
PV	Irrigation	172	203	220	218	223	143	279	290	276	274	264	236	203	197	225	192	164	173	109	108
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	2	3	4	5	5	6	6	6	7	10	8	8	8	7	7	7	7
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	1	2	2	2	2	2	2	3	4	3	3	3	3	3	3	3

Table 57. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.5	1.4	0.5	0.8	0.0	0.0	0.1	0.0	0.7	1.7	1.5	1.1	2.2	1.8	1.4	1.4	2.2	1.4	1.5
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.4	0.6	0.4	0.7	0.5	0.8	0.4	0.4
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 58. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	14	41	47	58	69	82	93	106	113	122	118	133	130	113	132	109	94	139	98	96
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	6	16	27	42	68	88	94	110	118	126	128	129	109	116	98	97	85	89	93	100
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	198	890	2563	850	1375	90	84	106	71	1334	3102	2796	2076	3990	3265	2533	2548	4036	2565	2689
PV	Commercial	435	479	553	548	596	460	731	787	806	787	963	939	715	1020	767	1233	821	1465	772	804
PV	Industrial	32	75	139	84	111	7	122	211	162	179	165	127	111	108	101	105	95	106	83	94
PV	Irrigation	180	199	229	227	247	191	303	326	334	326	399	389	297	423	318	512	341	608	320	334
Wind	Residential	-1	-1	-1	0	-1	0	0	0	-1	0	0	0	0	0	0	0	0	0	5	5
Wind	Commercial	0	0	0	4	5	7	8	11	11	12	13	14	14	14	14	14	10	12	9	26
Wind	Industrial	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Wind	Irrigation	0	0	0	2	2	3	3	4	5	5	5	6	6	6	6	6	4	5	4	11

F.6 Wyoming

Table 59. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.2	0.3	0.2	0.2	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	1.4	1.4	2.4	1.9	2.1	3.5
PV	Commercial	0.2	0.3	0.3	0.3	0.4	0.2	0.6	0.7	1.0	1.4	1.9	1.7	1.8	2.3	1.8	1.7	1.6	1.5	0.8	1.0
PV	Industrial	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 60. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1410
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	44	55	74	85	103	132	145	170	180	226	286	308	375	467	472	471	440	267	418	384
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	258	381	531	397	427	38	36	47	240	336	340	278	253	203	2562	2486	4437	3558	3816	6454
PV	Commercial	357	481	628	629	715	360	1055	1257	1782	2506	3538	3193	3249	4281	3323	3221	2919	2737	1457	1922
PV	Industrial	86	114	161	172	237	16	250	440	513	643	607	658	584	612	596	592	555	449	456	435
PV	Irrigation	9	12	21	18	29	2	26	44	81	81	90	80	77	78	72	68	59	55	30	36
Wind	Residential	0	0	0	0	0	0	0	26	36	36	36	30	34	28	34	27	29	39	41	41
Wind	Commercial	1	1	1	0	0	0	0	0	0	0	0	0	-1	228	247	266	226	282	295	246
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	3	4	4	4	4	5	4	5	4	3

Table 61. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.2	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	1.1
PV	Commercial	0.2	0.3	0.3	0.3	0.4	0.1	0.5	0.6	0.7	0.8	1.0	1.1	1.1	1.6	1.2	1.7	1.7	1.7	0.9	1.4
PV	Industrial	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 62. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	36	47	60	73	89	107	125	147	143	165	175	180	146	167	152	117	121	146	241	144
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	232	362	480	367	357	34	32	43	27	216	324	264	177	192	183	257	176	183	610	2056
PV	Commercial	333	466	609	572	681	267	999	1117	1208	1401	1933	1982	2020	3035	2124	3200	3131	3104	1654	2550
PV	Industrial	81	110	146	132	165	59	232	277	352	523	536	517	516	464	533	535	413	504	330	311
PV	Irrigation	8	11	17	14	20	5	25	32	44	58	82	56	74	77	75	54	68	46	53	31
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	15	27	27	27	20	27	20
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3	3	4

Table 63. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.3	0.3	0.3	0.0	0.0	0.1	0.3	0.2	2.5	2.3	3.8	3.5	4.0	4.6	3.4	5.5	6.3	3.5
PV	Commercial	0.2	0.3	0.4	0.4	0.6	0.0	0.8	1.4	2.0	2.3	2.8	1.9	2.1	1.8	1.9	1.5	1.3	1.4	0.9	0.9
PV	Industrial	0.0	0.1	0.1	0.1	0.2	0.0	0.2	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.6	0.9	1.2	1.3	1.2	1.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 64. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	1821	2133	2097	2258	2026	2035	2063	1953	1743
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	49	64	83	101	116	203	219	378	397	449	601	531	510	511	468	428	360	316	303	197
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	277	428	567	469	467	43	40	191	493	421	4644	4271	6966	6501	7442	8499	6287	10160	11676	6473
PV	Commercial	373	501	681	825	1039	77	1491	2618	3661	4224	5164	3563	3880	3321	3473	2786	2408	2637	1683	1592
PV	Industrial	89	122	244	199	293	19	409	592	694	741	833	700	753	791	1082	1643	2217	2302	2118	1969
PV	Irrigation	9	13	30	29	31	2	52	79	90	96	99	80	82	73	66	62	64	55	32	44
Wind	Residential	1	1	1	0	0	21	49	47	47	39	45	31	52	53	51	51	48	38	41	51
Wind	Commercial	1	1	1	0	0	0	0	0	-1	47	252	266	298	332	305	364	314	316	328	326
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	1	4	4	5	5	6	5	5	6	5	5	5	5

APPENDIX P – ENERGY STORAGE STUDIES

To support PacifiCorp's 2017 Integrated Resource Plan (IRP) two energy storage studies, initiated for previous IRPs, were updated including a battery energy storage study that focused on battery technologies and a bulk energy storage study that focused on pumped hydro and compressed air energy storage (CAES).

DNV-GL's Battery Energy Storage Study provided PacifiCorp with a catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. To further support PacifiCorp's bi-annual IRP, DNV GL produced probabilistic cost graphs for each of the proposed technologies, broken out by technology, energy conversion system, controls, and the remaining balance of system.

The Bulk Energy Storage Study prepared by Black and Veatch (B&V) is an update to work HDR Navigant performed to support the 2015 IRP, incorporating updated information on three pumped hydro energy storage projects and a compressed air energy storage project within PacifiCorp's territory. The study provides an update to information on commercially available utility-scale energy storage technologies, as well as their applications, performance characteristics, and estimated capital and operating costs.

The estimates and information in the studies was used to inform the 2017 IRP and may be used to develop alternative applications to traditional utility transmission and distribution issues.

Battery Energy Storage Study for the 2017 IRP

PacifiCorp

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Table of contents

1 INTRODUCTION 1
1.1 Objective and Scope of Work 1
1.2 Background and Materials 1

2 STAGE OF COMMERCIAL DEVELOPMENT 3
2.1 Lithium-Ion Batteries.. 3
2.2 Sodium Sulfur Batteries 5
2.3 Vanadium Redox Batteries.. 6
2.4 Zinc Redox Batteries.. 7
2.5 Zinc Hybrid Cathode Batteries... 8
2.6 Commercialization Data 9

3 PERFORMANCE CHARACTERISTICS 10
3.1 Power Capability 10
3.2 Energy Capacity 10
3.3 Recharge Rates..11
3.4 Round Trip Efficiency 11
3.5 Availability 11
3.6 Degradation...11
3.7 Expected Life 13
3.8 Environmental Effect Upon Disposal...13
3.9 Technical Parameters Data 15

4 COST ESTIMATES AND TRENDS 16
4.1 Energy Storage Equipment Costs 16
4.2 Power Conversion System Equipment Costs...16
4.3 Power Control System Costs 17
4.4 Balance of System..17
4.5 Installation 17
4.6 Fixed O&M..17
4.7 Total System Cost Estimates...19
4.8 Example Installed Cost Calculation 20
4.9 System 10-Year Cost Trends...21

5 UTILITY APPLICATIONS AND VALUE STREAM 25
5.1 Considered Applications 25
5.2 PacifiCorp Territory Regulatory Concerns and Application Drivers 28
5.3 Application Ranking Methodology and Results 31

6 CONCLUSION 34

List of tables

Table 1 Li-Ion Battery Manufacturers 5
Table 2 NaS Battery Manufacturers 6
Table 3 VRB Manufacturers 7
Table 4 ZnBr Battery Manufacturers 8
Table 5 Zinc-Hybrid Cathode Battery Manufacturer 8
Table 6 Installation and Commercialization Data 9
Table 7 Combustion Byproducts of Commercially Available Batteries 14
Table 8 Technical Parameters and Performance Characteristics Data, from Both Cell and Project-Scale Perspectives 15
Table 9 Energy storage system cost estimates 19
Table 10 Example Installed Capital Cost Calculation for 10 MW, 20 MWh NCM Li-Ion Energy Storage System 20
Table 11 Application Rankings in Current Market Rules Scenario 32
Table 12 Application Rankings for CAISO Market Rules Scenario 33

List of figures

Figure 1 General Schematic and Components of a Cell-Based Battery Energy Storage System 4
Figure 2 General Schematic and Components of a Redox Flow Battery Energy Storage System 6
Figure 3 Projected DC System Cost Trends for Various Technologies, From 2016 to 2026 21
Figure 4 Projected PCS Cost Trends for Various Technologies, From 2016 to 2026 23
Figure 5 Projected Controls Cost Trends for Various Technologies, From 2016 to 2026 23
Figure 6 Projected Balance of System Cost Trends for Various Technologies, From 2016 to 2026 24

1 INTRODUCTION

1.1 Objective and Scope of Work

At the behest of PacifiCorp, DNV GL has provided a status report and assessment of future potential applications for battery energy storage. DNV GL understands that PacifiCorp's objective is to compile and maintain a catalog of engineering estimates of costs and performance metrics for utility scale battery energy storage technology, both demonstrated for currently commercially available technology as well as forecasted for emerging technology. The 2017 PacifiCorp Integrated Resource Plan (IRP) will include a portfolio of generating resources and energy storage options for evaluation. The provided estimates and information is intended for PacifiCorp's use when preparing their upcoming and future IRPs and assessing energy storage applications for traditional utility transmission and distribution planning issues.

The scope of work is divided between cataloging technology updates and cost trends. The technology updates are broken down by current stage of commercialization, utility applications with associated value streams, and a detailed list of technology performance metrics. The cost analysis includes current system costs for the battery, PCS, controls, installation and O&M, as well as 10-year cost trends for each listed technology. PacifiCorp has specifically requested the scope to include NCM, $LiFePO_4$, and LTO Lithium-Ion (Li-Ion) batteries, Sodium Sulfur (NaS) batteries, Vanadium Redox (VRB) and Zinc Redox (ZnBr) flow batteries, as well as Zinc Hybrid Cathode (also known as Zinc-air) batteries. The report scope does not include application modeling or costs related to a specific vendor, but instead aims to cover the broader energy storage industry as it applies to applications being pursued by PacifiCorp.

The final report provides PacifiCorp with a catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. DNV GL has compiled this catalog through the proposed scope of work. To further support PacifiCorp's bi-annual IRP, DNV GL has produced probabilistic cost graphs for each of the proposed technologies, broken out by technology, energy conversion system, controls, and the remaining balance of system.

1.2 Background and Materials

In 2013, PacifiCorp hired HDR Engineering to prepare an energy storage screening study, examining utility-scale storage potential, which was updated by HDR for PacifiCorp's 2015 IRP. This study covered operating and cost data for various energy storage technologies, with a section dedicated to batteries, including details on system size and lifecycle, comparing them to other storage options. The HDR study considers specific manufacturer's products and reference cases under standard operating conditions. PacifiCorp utilized the information from the HDR research to contribute to the modeling of future energy consumption, and how various technologies impact load profiles, costs, and CO2 emissions. This and other previous energy storage studies performed for PacifiCorp are available at www.pacificorp.com/es/irp.html. Energy storage continues to be of interest to stakeholders – and options for advanced large batteries (one megawatt or larger) are detailed in the IRP as quoted from the HDR study, including the battery types DNV GL has been requested to explore. To the extent possible, DNV GL has built upon and utilized existing studies and reports, to expand and update a battery catalog to include a deeper dive into battery technologies, costs, and applications for PacifiCorp's use in their 2017 IRP.

As a global advisory, classification, certification, and technical assurance company, DNV GL has served the energy sector as well as maritime and oil & gas industries for over 150 years. DNV GL is a leading authority on consulting, implementation, research, testing, and certification of solutions for the energy sector. Recognized as a global leader in the area of energy storage, DNV GL provides strategic advisory services, innovative modeling tools, and independent testing and certification of energy storage products to clients across various sectors. DNV GL operates as an independent entity without ties to any vendor, with no investments, affiliations, or financial interest with any equipment or service providers.

Most notably related to this effort, DNV GL has been actively involved in supporting multiple energy storage procurement efforts in the US. Our models for energy storage cost-effectiveness have been employed by state energy commissions, system operators, electric utilities, and project developers to assess the application value of energy operating the grid for a variety of current and future applications. DNV GL has performed independent bid evaluation for utility wholesale and distribution connected energy storage RFOs. This work involved processing energy storage offers from project developers and providing a ranking and bid evaluation on the capital and O&M costs as well as an assessment of the proposed warranty and performance guarantees. Finally, DNV GL is the industry leader in providing independent engineering analysis and technical due diligence to support third-party financing of energy storage deployments. As part of this work, DNV GL has gained significant insight into the costs, technical characteristics, and life-time performance guarantees of energy storage projects being developed in the US. For this report, DNV GL leveraged their experience with battery technology and the broader energy industry to develop reasonable average values for technology parameters, as well as how these parameters affect the cost and feasibility of a particular technology for an application.

Additionally, this study draws on a recommended practice (RP) document called GRIDSTOR (DNVGL-RP-0043), which was developed by DNV GL in partnership with members of the energy storage industry, including technology vendors, grid service providers, energy consultants, and universities. The GRIDSTOR RP provides a breadth of actionable information for deploying safe and reliable grid-connected energy storage systems, offering a blueprint for an independent quality guarantee of the safe implementation and operation of energy storage systems. This guideline draws on DNV GL experience, credible industry insight, and globally accepted regulations and best practices (such as IEC, ISO, and IEE standards), and was utilized as a reference for this report. GRIDSTOR is publicly available for free download at www.dnvgl.com/energy/brochures/download/gridstor.html.

Finally, under the scope of this effort, DNV GL also conducted current market research. This research included a review of published reports from consulting and energy-related clearinghouses, such as Navigant and IRENA, publicly available specification sheets and pricing for reviewed systems, and university and government sponsored research.

2 STAGE OF COMMERCIAL DEVELOPMENT

In this chapter, DNV GL provides an overview of the commercial development of each battery technology requested by PacifiCorp. DNV GL understands the importance of assessing the commercial viability of technologies which are intended to be procured as 10 to 20 year critical assets. With this consideration, DNV GL has provided definitions and basic information surrounding each considered technology and the associated system, followed by a sample of technology providers and sample products available on the market. This is followed by a summary of data available on current industry installation rates, including additional insight into some of the drivers behind the recent trends on installations.

2.1 Lithium-Ion Batteries

Lithium-Ion (Li-Ion) batteries utilize the exchange of Lithium ions between electrodes to charge and discharge the battery. Li-ion is a highly attractive material for batteries because it has high reduction potential, i.e., a tendency to acquire electrons (-3.04 Volt versus a standard hydrogen electrode), and it is lightweight. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications. Today, Li-Ion batteries have been implemented for applications relating to ancillary services in grid connected storage. Because of its characteristics, Li-Ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications.

Li-Ion batteries do carry some safety and environmental risk. Toxic or reactive gases may be released both during creation of the battery cells, as well as in case of thermal runaway within an operating system. However, this risk is being managed across the industry. During cell manufacture, effluent gases can be scrubbed and captured, to be disposed of safely.

Once fully constructed, Li-Ion battery systems come with various methods of cooling, not only to help prevent thermal runaway but also to provide the most beneficial operating temperatures for the battery cells. This risk is being managed from a broader perspective, too; local authorities are preparing to appropriately address any fire concerns. The New York Fire Department (FDNY) and their stakeholders in the National Fire Protection Association (NFPA) have worked with DNV GL to develop ventilation, extinguishing, and cooling requirements for battery fires. Similar types of precautions have been taken industry-wide, in coordination with local communities.

Figure 1 provides a schematic showing what is entailed in a general Li-Ion battery system. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

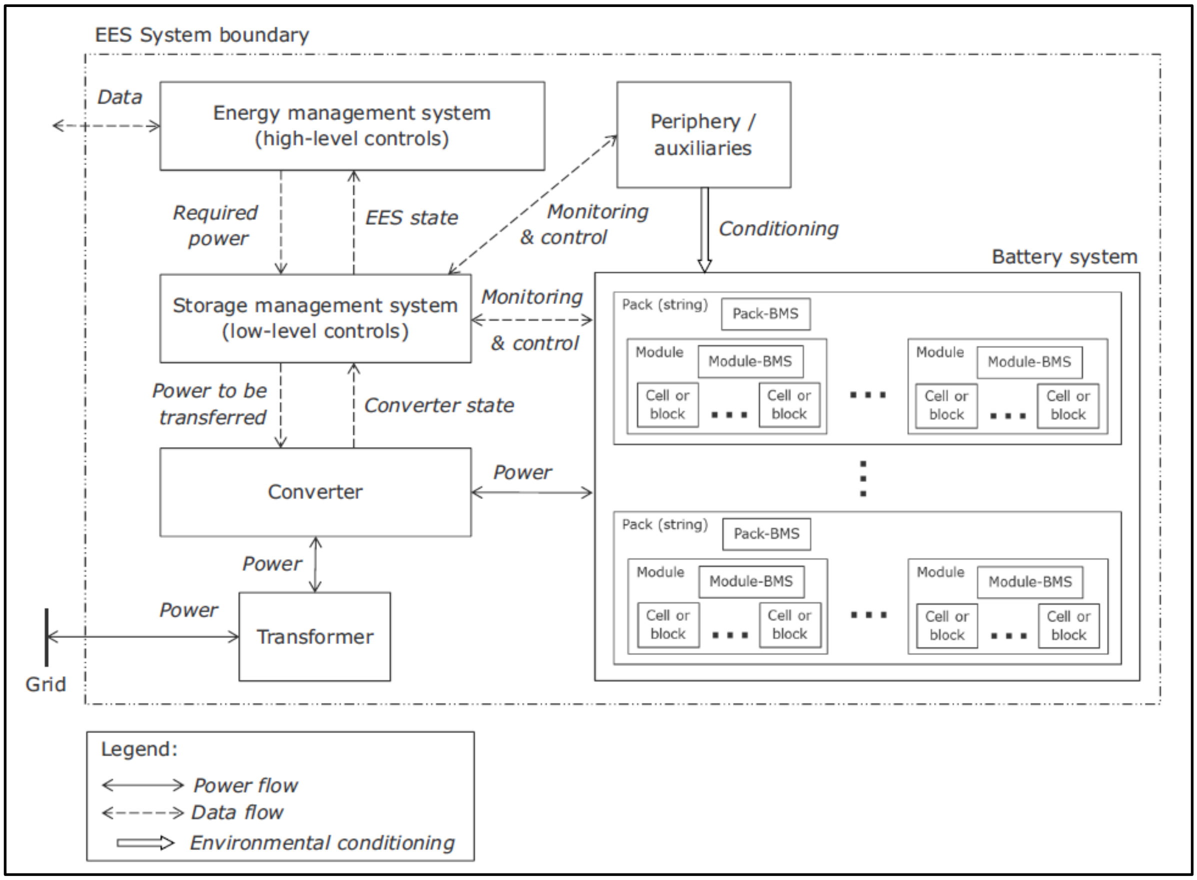

Figure 1 General Schematic and Components of a Cell-Based Battery Energy Storage System

Li-ion technology varies between chemistries. This report will focus on three of the most prominent and promising chemistries, Lithium Nickel Manganese Cobalt Oxide ($LiNiMnCoO_2$ or NCM), Lithium Iron Phosphate ($LiFePO_4$), and Lithium Titanate (Li_4Ti5O_{12} or LTO), and compare and contrast their attributes.

NCM is one of the most commonly used chemistries in grid-scale energy systems. This technology demonstrates balanced performance characteristics in terms of energy, power, cycle life, and cost. NCM chemistry is very common due to these features – it provides an engineering compromise.

$LiFePO_4$, on the other hand, can be purchased at a low cost for a high power density, and its chemistry is considered one of the safest available within Li-Ion batteries. Further, due to its very constant discharge voltage, the cell can deliver essentially full power to 100% DOD. However, LiFePO4 batteries are typically applicable to a more limited set of applications due to its low energy capacity and elevated self-discharge levels.

Finally, LTO offers a stable Li-Ion chemistry, one of the highest cycle lifetimes reported, and a high power density. Further, it is the fastest charging Li-Ion chemistry of those reviewed here. However, in balance, it has a much lower energy density and much higher average cost.

These systems are manufactured widely, but there is relatively high turn-over in manufacturers. Some of the more prominent or market-tested systems are included below, in Table 1.

Table 1 Li-Ion Battery Manufacturers

Technology	Manufacturer	Cell or System Product
NCM	Enerdel	CE175-360, 160-365 Moxie+
	Hitachi	
	LeClanche	Graphite/NMC
	LG Chem	JH2
	Panasonic	NCR18650A
	PBES	
	Samsung	25R
	XALT	31,40, 53, 75Ah HE; 31, 40, 63, 75Ah HP; 31, 37Ah UHP
	Electronova	
$LiFePO_4$	A123	AMP20, AHP14, ANR26650, APR18650
	BYD	
	K2 Energy	LFP123A
	Microvast	
	Saft	VL10Fe, VL25Fe
	Sony	IJ1001M
	Thundersky	WB-LYP, TS-LYP
	XO Genesis	
LTO	Altainano	nLTO
	LaClanche	LTO
	Microvast	LpTO (Gen 1)
	Toshiba	SCiB 2.9, 20, 23Ah
	XALT	60Ah LTO

2.2 Sodium Sulfur Batteries

Sodium-sulfur (NaS) batteries are a type of molten-salt battery. The systems have high energy density, fast response times, and long cycle lives. They also have some of the longest durations available on the market.

The inclusion of the term “molten” alludes to the battery operating temperature. NaS batteries store electricity through a chemical reaction which operates at 300 °C or above. At lower temperatures the chemicals become solid and reactions cannot occur. The high operating temperature makes the NaS batteries suitable for larger applications supporting the electric grid, but not personal electronic devices or vehicles. Further, due to the high temperature and natural reactivity of pure Sodium when exposed to water, the system can present a safety hazard if damaged.

Figure 1 above provides a schematic showing what is entailed in a general NaS battery system, which is parallel in its architecture to Li-Ion systems. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

NaS batteries are a mature technology, and the system cost has generally leveled off. Although manufactured by more than one company, the market-share, and thus proven performance, of the company listed in Table 2 represents the majority of installations.

Table 2 NaS Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
NaS	NGK	NAS

2.3 Vanadium Redox Batteries

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. “Redox” is the abbreviation for “reduction-oxidation” reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, the two electrolytes are separated by a semi-permeable membrane. This membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. Figure 2 below provides a schematic showing what is entailed in a general VRB system. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

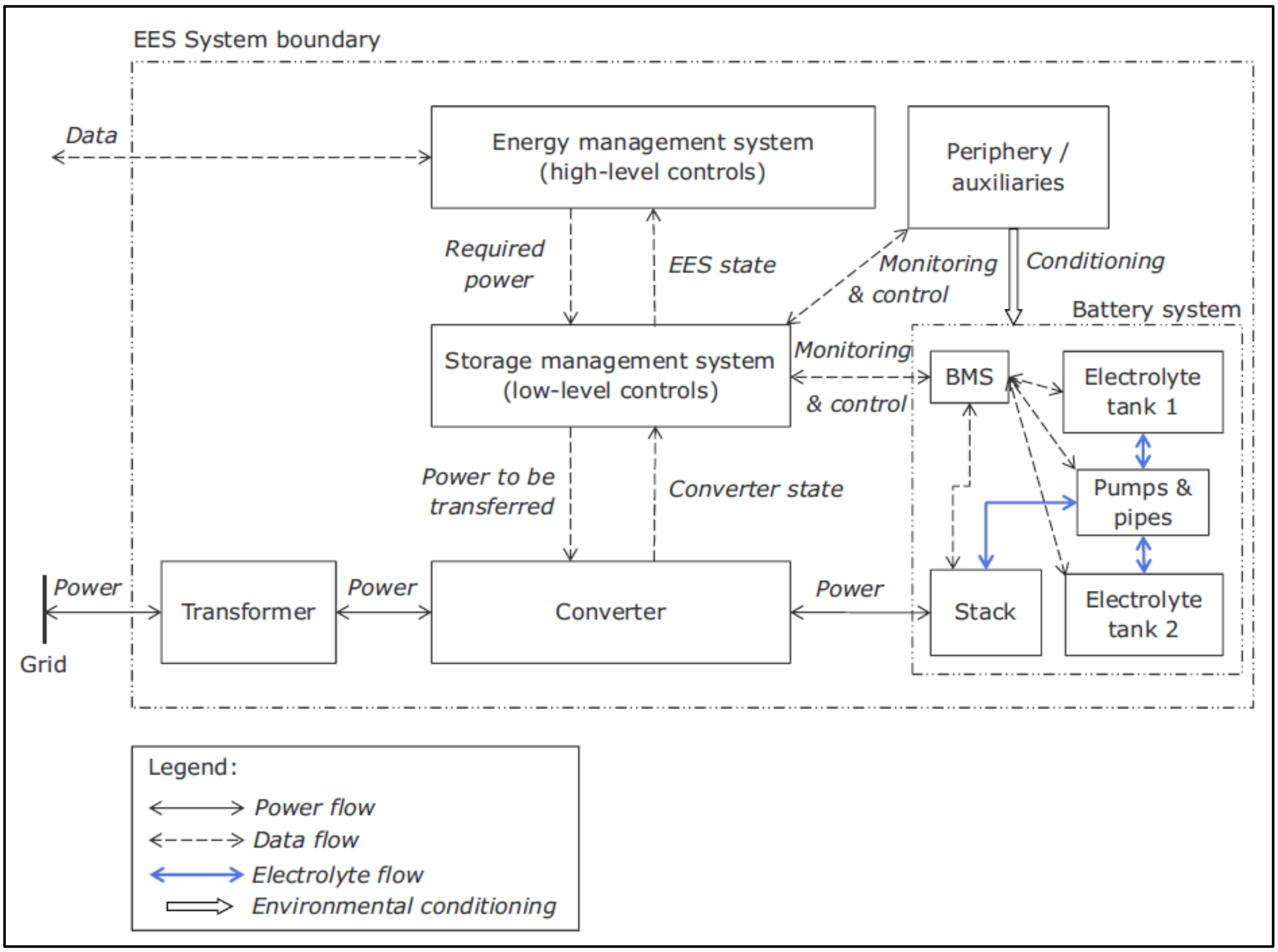

Figure 2 General Schematic and Components of a Redox Flow Battery Energy Storage System

In VRBs, the liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. This allows the energy capacity of the battery to be increased at a low cost. Energy and power are decoupled since energy content depends on the amount of electrolyte stored. VRB systems are unique in that they use one common electrolyte, which provides opportunities for increased cycle life. These large, liquid solution containers do however limit the VRB to stationary storage applications.

An important advantage of VRB technology is that it can be "stopped" without any concern about maintaining a minimum operating temperature or state of charge. This is a key point to most flow batteries in that the batteries can actually be "turned off." This technology can be left uncharged essentially indefinitely without significant capacity degradation.

These systems are relatively new to the battery industry but are solidifying their place in the market. Some of the more prominent or market-tested systems are included below, in Table 3.

Table 3 VRB Manufacturers

Technology	Manufacturer	Cell or System Product Description
VRB	American Vanadium Imergy UET/UniEnergy Vionx	CellCube ESP5, 50, 250 UniSystem, ReFlex

2.4 Zinc Redox Batteries

The Zinc Bromine (ZnBr) battery utilizes similar flow battery technology as the previously discussed VRB. Due to this, it shares many of the same advantages: little to no claimed degradation over time (both in use and in the fully-discharged state), high energy density, 100% DOD, and easily scalable. The ZnBr consists of a zinc-negative electrode and a bromine-positive electrode, separated by a micro-porous separation. Solutions of zinc and a bromine complex compound are circulated through the two compartments. In a ZnBr the electrodes (Zn- and Br+) serve as substrates for the reaction. During charging, the Zinc is electroplated at the anode and bromine is evolved at the cathode. When not cycled, there is a potential for the Zinc to form dendrites that can degrade capacity or damage the battery components. To prevent this, the battery must be regularly and fully discharged.

Figure 2 above provides a schematic showing what is entailed in a general ZnBr system, which is of similar physical structure to VRB, though differing completely in chemistry at the core of energy storage. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

The response time for this technology is thought to be inadequate for fast-response applications; this should be verified on a case by case basis as new system designs may be able to improve on this limitation. ZnBr is a promising technology for balancing low-frequency power generation and consumption. However, cycle life tends to be less than that of VRBs.

These systems are in the early stages of commercialization but are being produced by multiple manufacturers. Some of the more prominent or market-tested systems are included below, in Table 4.

Table 4 ZnBr Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
ZnBr	Enphase (Previously ZBB) Primus Power Flow RedFlow	Enerstor, Agile EnergyCell ZBM2, ZBM3

2.5 Zinc Hybrid Cathode Batteries

Zinc hybrid cathode (Zinc-air) batteries are a type of metal-air battery which uses an electropositive metal in an electrochemical couple with oxygen from the air to generate electricity. Zinc-air batteries take oxygen from the surrounding air to generate current. The oxygen serves as an electrode while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery.

Zinc-air batteries have power densities similar to Li-ion batteries, but lower energy density. On the other hand, Zinc-air batteries in comparison to flow batteries can have both higher power and energy densities. Unlike Li-Ion, however, Zinc-air batteries are generally claimed to be benign, though their electrolytes – like those of other battery technologies – contain acidic or alkaline compounds and could produce SO2 if burned. The main Zinc-air battery material, zinc-oxide, is theoretically fully recyclable, though this has yet to be demonstrated at scale. In addition, the metals used or proposed in most metal-air designs are low cost.

Zinc-air systems appear attractive for utility applications if their ability to charge and recharge can be improved. The challenge for researchers has been to devise a method where the air electrolyte is not deactivated in the recharging cycle to the point where the oxidation reaction is slowed or stopped. The cessation of the oxidation reaction reduces the number of times that a Zinc-air battery can be recharged. Some of the newest emerging technology, as created by Eos, claims to have addressed these issues by implementing a near-neutral, non-dendritic, and self-healing electrolyte solutions. This, Eos claims, prevents air electrode clogging, rupture of the membrane due to dendrites, and the drying out of the electrolyte, along with other innovations that have prepared the system for commercial launch.

Potential applications include integrating renewable assets, peak shifting and load balancing, and frequency regulation. Consolidated Edison (ConEd) is currently pursuing one of the first utility-scale systems for demonstration with Eos technology.

These systems are in the early stages of commercialization and, as such, manufacturing is limited. Although being researched by more than one company, the earliest product being actively used in demonstration projects is produced by the manufacturer listed in Table 5.

Table 5 Zinc-Hybrid Cathode Battery Manufacturer

Technology	Manufacturer	Product name (if available)
Zinc-air	Eos	Znyth cell in Aurora 1000, 4000

2.6 Commercialization Data

Commercialization and installation data are based on DNV GL's research and publicly available information. This data excludes projects that have been decommissioned for any reason, or construction has not yet started.

Table 6 Installation and Commercialization Data

System Attributes	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air[1]
Typical project size (kW)[2]	6,500	5,000	2,000	6,000	4,000	1,000	3,500
Typical project size (kWh)	15,000	3,100	1,300	40,000	14,000	2,000	13,000
Largest project size installed (kW)[3]	30,000	31,500	40,000	50,000	15,000	1,000	250
Largest project size installed (kWh)	60,000	12,000	40,000	300,000	60,000	2,000	1,000
Current total power capacity installed (MW)[4]	77	142	31	186	66	5	0.25
Current total energy capacity installed (MWh)	30	220	19	1,254	226	25	1

[1] Zinc-air is an emerging technology. Due to this, the majority of the projects DNV GL cited are publicly announced but not yet installed and operational. This clarification is provided to give context to the typical system size being larger than the largest installed system size.
[2] Typical project size, both kW and kWh, are based on averages of publicly known projects that are operational, under construction, contracted, and announced. Decommissioned projects have been excluded from these counts.
[3] Largest project size, both kW and kWh, is based on projects that are currently operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.
[4] Current total power and energy capacity installed are based on publicly known projects that are operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.

3 PERFORMANCE CHARACTERISTICS

This chapter of the report provides a summary of technical parameters for each of the proposed storage technologies in a number of requested fields identified by PacifiCorp as useful for consideration within their 2017 IRP. The specific technology parameters of interest, as identified by PacifiCorp, are as follows:

1. Power Capacity
2. Energy Capacity
3. Recharge Rates
4. Roundtrip Efficiency
5. Availability
6. Degradation
7. Expected Life
8. Environmental Impact upon disposal

Each of the specified parameters are first defined and discussed below followed by a summary of values for each technology. Further, these characteristics are utilized later in this report, in Chapter 5, in determining the appropriateness of a technology for a particular application.

3.1 Power Capability

In composing this analysis, a variety of values were available given DNV GL's experience in the field, depending on operating conditions as well as marketing versus as-built specs. In all cases, all technologies in the study were available down to at least the 1 MW power capacity level, with many having wide use at smaller sizes, for commercial and industrial, residential or non-stationary storage applications. The maximum values were based on the largest installed or proposed and contracted systems to date.

The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources. Storage is emerging as a technology being considered to provide utility services from aggregated behind-the-meter resources. Most notably, in 2014 Southern California Edison awarded two (2) capacity contracts to aggregated behind-the-meter energy storage.

3.2 Energy Capacity

The energy capacity DNV GL has compiled is what has been quoted by manufacturing specs as the optimal charge pattern of the entire capacity of the battery as designed. However, in many cases, these units are sold and marketed at a capacity reduced from the system's true total capacity. As such, useable or nameplate system capacity values are provided specified so that the system operates at a usable 0-100% SOC range.

3.3 Recharge Rates

All batteries have certain tolerances with regard to the rate at which they are charged or discharged. The current rating determines the C-rate for the battery, i.e., the rate at which a battery is discharged relative to its maximum energy capacity. Some batteries are more tolerant than others to high discharge rates. On the manufacturer specification sheets that accompany batteries, C-rates that are less than 1 are typically conservative, and may be recommended by the manufacturer to attain longer cycle lifetimes. Typically, discharge rates are higher than charge rates.

3.4 Round Trip Efficiency

Efficiency data provided in this report is the full energy storage system round trip efficiency (RTE). Full system RTE includes the losses from the power conversion system, HVAC equipment loads, control system losses, and self-consumption. Often a manufacturer will provide battery efficiency rather than RTE when promoting their technology. However, there can be a 5-10% difference between these efficiency ratings, when conversion equipment, air conditioning, and other “parasitic” balance of plant devices from the full system are taken into consideration. Auxiliary losses like air conditioning or heating vary considerably according to the technology and the specific application it must perform. For example, the heating requirement for a NaS battery is about 3 percent of its rating but heating is not needed if the battery is discharged daily because heat released during discharge will keep it warm. In this case, typically RTE values are reported based on the system performed a minimum amount of cycling per day.

3.5 Availability

The availability that DNV GL notes is based on guarantees being offered by manufacturers and distributors. Aside from these availability guarantees, annual planned maintenance carve-outs are typically included which do not contribute to these availability figures. Data here is provided based on currently observed guarantees being offered along with utility-scale energy storage systems, however, it should be noted that longer term operation experience will be required before these values are fully verified in practice.

3.6 Degradation

Storage is a unique technology in that its performance characteristics are significantly influenced by degradation. Degradation is highly dependent on system operation. System operation is in turn affected by location, power and energy capacity, applications, and how frequently those applications are utilized. Typically, manufacturer packaging, control and management systems, and environmental considerations are in place to ensure these parameters stay within safe and non-destructive ranges. However, outside influences and one-time events resulting from environmental control failure, BMS failures, or dispatch control error can lead to significant degradation of the device.

The degradation ranges that DNV GL has provided are given at year 10 after installation, based upon the average system operation, segmented by application type. The most common energy applications include electric time shift, electric supply capacity, spinning and non-spinning reserves, and T&D congestion relief. The Power applications include regulations, voltage support, load following and ramping support, and frequency response.

As noted previously, battery performance deteriorates as a result of various degradation mechanisms. The complexity and interactions of these mechanisms are given in detail below.

- **Temperature**: All batteries have an ideal temperature operating range; most batteries control their operation to 30ºC or less. High temperatures (generally above 30-40ºC) tend to degrade capacity severely. Many battery chemistries will indicate operational temperature ranges between 0-60ºC, however operation at or near these limits can severely impact efficiency of the cell as well as lifetime.
- **Charge and Discharge Rates:** For many batteries, high charge/discharge rates lead to higher temperature, compounding the degradation effect.
- **High or Low Average State of Charge:** If a battery spends a significant amount of time at a high state of charge, it will degrade faster than if it is left and maintained at a mid-level state of charge. Some batteries are more sensitive to this than others, but generally it is known that the higher the average state of charge (SOC) over the battery life, the faster it will degrade. Similarly, if a battery is kept at very low average SOC, it will also degrade quickly. This phenomenon has been studied extensively and it has been shown that battery capacity and average SOC are inversely proportional.
- **Depth of Discharge:** Generally, the greater the average depth of discharge (DOD), the faster the battery capacity will fade. In most cases, battery spec sheets will list the lifetime of the battery as number of cycles until 80% of capacity is reached at 100% DOD at 25 C. These conditions are considered nominal and if cycle life of the battery is mentioned without these additional specifications, it is important to verify the DOD, final capacity, and temperature of the tests. Unfortunately, these conditions are often unlike what the battery may experience in an actual application. It is often not noted whether long rest times between charge and discharge were implemented (allowing the battery to cool). Longer rest times can inflate the total cycle life.
- **Calendar Life:** The calendar life of the battery can affect its capacity as much or more than the cycling effects, but it is largely dependent on temperature. Assessing the time the battery is left at rest as a function of temperature is relevant to assessing its state of health. For this reason, most state of health predictions includes both calendar and cycling components.
- **Maintenance:** It is assumed that batteries will not operate completely autonomously. This Maintenance ensures unit operate optimally, given product specific operating constraints. Some manufacturers will further offer capacity maintenance agreements wherein systems are provided with maintenance, supplemental units integrated into the system, or refreshed electrolyte solutions in order to ensure capacity does not degrade past agreed to trigger points.
- **Compounding and Consequential Effects:** It is not possible to list the degradation factors from greatest to least without caveat considerations for specific chemistries, environment and duty cycle, but within the conservative limits established on a battery specification sheet, it may generally be assumed that abuse factors from least to greatest are: Temperature > Depth of Discharge > C-Rates . All of these factors are linked, however, and therefore have compounding effects depending on the battery duty cycle.

3.7 Expected Life

Most systems have not been available at a commercially mature stage for long enough to provide meaningful field data on lifetime performance, so the expected life is currently based on vendor projections, accelerated life-testing (ALT) on cells or modules and limited field results. Cell life tests are typically a good representation of the maximum possible lifetime under ideal conditions, and validation of these results is recommended on a case-by-case basis. With these caveats in mind, the expected life based on standardized cycling and disregarding extenuating circumstances is at least 10 years in all cases. Many manufacturers claim longer calendar lives; these claims assume periodic maintenance, including integrating new modules or adding new electrolyte. The number of cycles that these claims cover varies from technology to technology, based on the applications expected for use. As with calendar life claims, vendors typically claim cycle life in excess of 3,000 cycles. These claims are tied to the same periodic maintenance as previously mentioned. Further, all of the mechanisms discussed above that cause degradation are related to expected life and the system’s ability to continue to meet the needs of the customer.

3.8 Environmental Effect Upon Disposal

While batteries claim advantages over traditional energy sources, including the ability to provide energy and power essentially instantaneously and without emission, the components will eventually require disposal. Disposal or recycling, however, comes with consequences. The United States Environmental Protection Agency states that no rechargeable electrochemical cells may lawfully be disposed of to be taken to a landfill. Li-ion and nickel-based electrochemical cells are classified as toxic due to the presence of lead, as well as cobalt, copper, nickel, chromium, thorium, and silver.

The majority of energy storage technologies covered in this report have yet to see adoption rates, much less decommissioning rates, high enough that significant research has been conducted on opportunities and limitations to recycling. While the US Department of Energy has pursued research on the subject, even producing functional Li-Ion cells from recycled materials, the process is so far limited to small pilot operations. For this reason, when decommissioning, disposing of, or pursuing potential recycling of batteries, the manufacturer of the energy storage system should be consulted for guidance. As energy storage systems are deployed in greater numbers, decommissioning and recycling are rising as important facets to financing agreements, contributing to the total cost of ownership.

Lead-acid battery repurposing and recycling activities are a well-established and extremely successful system. The policy has not addressed lithium and nickel-based battery recycling the same way it has lead-acid, and this is due to a number of challenges. The construction materials used in these systems are similar to the advanced technologies covered in this report (alloy and mild steel, aluminum alloys, copper, titanium, HPDE, etc.) and thus the majority of the challenge faced has to do with disassembly, destruction, sorting and any potential contamination. These batteries are mechanically varied between manufacturers and technologies, and packs are very sophisticated relative to lead-acid. In addition, there is a much larger range of materials in each battery, as well as a wide range of chemistries between batteries. Mined Lithium itself is low cost so although recycling is feasible, at present it is not economical. Instead, the primary components of interest are nickel and cobalt (and copper), and not all Li-ion batteries contain them in sufficient quantities. In many cases, the metals involved may just be sent to slag, to be burned for process heat (with the appropriate emission scrubbing). Materials can be recovered from this slag, but they must be in high enough quantity, quality, and demand to merit the additional effort. NCM batteries, for instance, contain a high enough percentage of valuable constituents (nickel and cobalt) to be recyclable.

Beyond the potential for emissions from burning slag, the chemicals have additional properties that affect disposal options. A universal issue for Li-Ion battery recycling is Lithium's high reactivity, creating a risk of fire if handled incorrectly. Otherwise, DNV GL's own research indicates that the materials within Li-Ion batteries are individually not exotic – for instance, Iron Phosphate is used as a non-toxic pesticide – but their destruction or combustion can create flammable gases such as ethylene, methane, and carbon monoxide. Toxic gases are also created, such as hydrogen fluoride, hydrogen chloride, and hydrogen cyanide. It should be noted that all of these gases are also created during the burning of plastics. To provide perspective as to Li-Ion battery toxicity, on a mass and volume equivalence, plastics are equally or more toxic than the by-products of Li-ion battery combustion.

As to redox flow batteries, electrolytes such as Zinc bromide and Vanadium solutions can typically be reused, sometimes for the life of the battery. However, contaminants or impurities may occur, requiring monitoring and removal. Additionally, upon decommissioning, the Vanadium and Zinc from these batteries may be recycled. It should be noted, however, that several materials commonly found in redox flow batteries are environmentally hazardous and regulated and thus should be disposed of according to regional government requirements. VRB electrolytes can dry or evaporate to form V_2O_5 dust as well as sulfate salts, while ZnBr electrolytes can evolve bromine at temperatures above 50ºC.

Finally, Zinc-air batteries, upon decommissioning, have similar overall construction materials that can be recycled via standard processes. Further, the aqueous electrolyte is non-flammable and non-hazardous (both non-toxic to humans and the environment). This electrolyte solution contains salts that are mildly corrosive but are not uniquely different or more hazardous than competing chemistries. The main component of Zinc-air batteries is Zinc-oxide, which is theoretically fully recyclable, although this has not yet been demonstrated on a large scale.

Properties of potential byproducts of battery decomposition are shown in Table 7.

Table 7 Combustion Byproducts of Commercially Available Batteries

		Concentration (ppm unless otherwise noted)								
	Chemical Formula	**LEL (Lower Explosion Limit)**	**IDLH (Immediately Dangerous to Life and Health)**	**Solubility in Water (mg/L)**	**Autoignition Temp (degC)**	**Thermal Instability Threshold (deg C)**	**NFPA Flammability**	**NFPA Health**	**NFPA Reactivity**	**Ref.**
Methane	CH4	50,000	5,000	22.7	537	-	4	1	0	NJ DOH
Carbon Monoxide	CO	12,500	1,500	27.6	609	-	4	2	0	CDC.gov
Ethylene	C2H4	27,000	-	2.9	490	-	4	2	2	Matheson MSDS
H2S	H2S	4,000	300	4,000.0	260	-	4	4	0	CDC.gov
Hydrogen Fluoride	HF	-	30	miscible	-		0	4	0	CDC.gov
Hydrogen Chloride	HCl	-	100	720.0	-	1500	0	3	1	CDC.gov
Hydrogen Cyanide	HCN	-	50	miscible	-		4	4	2	CDC.gov
V2O5 Dust	V2O5	-	35 mg/m^3	0.8	-		0	3	0	CDC.gov
Pb Vapor, salts, dust	Pb	-	700 mg/m^3	10^-5 to 4400	-		0	2	0	CDC.gov
SO2	SO2	-	100	94,000.0	-		0	3	0	CDC.gov

3.9 Technical Parameters Data

System parameters and characteristics are based on DNV GL's industry experience, internal research, and publicly available data. They are subject to the assumptions detailed in the previous sections.

Table 8 Technical Parameters and Performance Characteristics Data, from Both Cell and Project-Scale Perspectives

Parameter/ Technology		Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Power capability	Available down to 1 MW[1]	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Maximum[2] (MW)	35	35	40	50	20	20	15
Energy capacity[3]	SOC upper limit	90%	85%	98%	90%	95%	98%	98%
	SOC lower limit	10%	15%	10%	10%	5%	5%	10%
Recharge rates		1C	2C-1C	3C-1C	1C-0.5C	1C-0.25C	1C-0.25C	2C-1C
Round trip efficiency		77 - 85%	78 - 83%	77 - 85%	77 - 83%	65 - 78%	65 - 80%	72 - 75%
Availability	Up-time	97%	97%	96%	95%	95%	95%	96%
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	1 wk/yr	1 wk/yr	72 hr/yr
Energy Capacity Degradation[4]	Energy Applications	30-40%	20-40%	15-25%	15-30%	5-10%	5-10%	15-25%
	Power Applications	10-20%	15-25%	5-15%	5-15%	5-10%	5-10%	5-15%
Expected life[5]	Years	10	10	10	15	10	10	10
	Cycles	3,500	2,000	15,000	4,500	5,000	3,000	5,000
Environmental effect upon disposal?[6]		Yes	Yes	Yes	Yes	Yes	Yes	Yes

[1] The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources.
[2] Maximum power capability based on largest publicly proposed project.
[3] For usable energy capacity, manufacturers will commonly advertise their battery as allowing 100% DOD based on nameplate capacity. SOC limits given here reflect limits with respect to actual installed energy capacity.
[4] Degradation value based on percent of installed nameplate capacity lost after 10 years of operation. These values assume maintenance is performed as a part of normal operation. Flow battery degradation (VRB and ZnBr) can be mitigated to an extant through normal maintenance and chemistry refresh.
[5] Expected life in calendar years is given for the energy storage component of an ESS and is based on operation at 100% DOD, 25°C, 1C for the number of cycles shown. These values assume maintenance is performed as a part of normal operation. Full system life, including PCS and balance of plant equipment have been observed in range of 15-25 years, implying full replacement of energy storage system components.
[6] Discussion of the severity and risk of these effects are discussed in detail in section 3.8.

4 COST ESTIMATES AND TRENDS

In addition to the commercial and technical review, PacifiCorp requested DNV GL utilize industry experience, in-house data, and market research to the prepare capital and O&M cost estimates for each technology, expressed in mid-2016 dollars. Costs estimates are broken down as follow:

1. Energy Storage Equipment
2. Power Conversion Equipment
3. Power Control System
4. Balance of System
5. Installation
6. Fixed Operation and Maintenance

Each of these costs components are provided as a range covering currently observed industry estimates. In addition to current cost estimates, cost trends over 10 years will be provided as graphs demonstrating a breakdown of system costs in the requested components.

The capital cost for an installed energy storage system is calculated for a system by adding the costs of the energy storage equipment, power conversion equipment, power control system, balance of system, and the installation costs. Each of these categories is accounted for separately because they provide different functions or cost components and are priced based on different system ratings. System component costs based on the power capacity ratings are priced in $/kW, while component costs based on the energy capacity ratings, such as the DC energy storage system, are priced in $/kWh. A description of the system and project development elements included in each cost component is provided below, followed by a summary table of all system costs and graphs depicting 10-year cost trends of relevant components.

4.1 Energy Storage Equipment Costs

Energy storage equipment costs are inclusive of the DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, along with associated costs of assembling these components into a DC battery system. For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system will include internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks and container costs for the system along with associated cycling pumps and battery management controls. Energy storage equipment costs are provided on a $/kWh basis which is most appropriate for quantifying the cost of an energy capacity constrained resource. The DC system cost trends are shown in Figure 3.

4.2 Power Conversion System Equipment Costs

Power conversion system (PCS) costs are inclusive of the cost of the inverter, packaging, container, and controls. Inverters employed in energy storage systems are more expensive than the grid-tied inverters widely deployed for solar PV generation, and differentiated by their bi-directional, 4-quadrant operational capabilities. The cost of the power conversion equipment is proportional to the power rating of the system and provided in $/kW. The PCS cost trends are shown in Figure 4.

4.3 Power Control System Costs

Unique to energy storage systems are the required high-level controllers being deployed to dispatch and operate the systems. With dispatch becoming an ever more important part of storage system design, controllers have to combine multiple functions – from forecasting the load, to understanding the tariff structure and factoring in the type of charge management required for a specific application and technology. The energy industry is currently seeing a number of software companies emerging which are focused solely on control and management of energy storage systems. This includes companies such as Geli, Greensmith, 1Energy Systems, and Intelligent Generation. System integrators and battery storage vendors themselves are also producing controls to operate their systems. These companies include storage and renewable energy companies such as Stem, Advanced Microgrid Systems, RES Americas and SolarCity, as well as established utility energy industry players such as General Electric, Schneider Electric, and ABB. For systems owned or operated by a utility, these controllers must additionally be integrated with utility monitoring and control systems such as Supervisory Control and Data Acquisition Systems (SCADA), Energy Management Systems (EMS), and Distribution Management Systems (DMS), among others. As more advanced applications are considered, such as the energy storage Virtual Power Plants (VPP) currently being considered at Duke Energy and Consolidated Edison, these control layers will become increasingly critical to the success of a given project. At present, the costs for the power control systems have been observed to vary widely and are provided here based on the power capacity of a plant as $/kW. The trend graphs show conservative reduction in costs over ten years; as controls grow more prevalent and efficiencies are found, the control requirements and designs will likely increase in intricacy. The controls cost trends are shown in Figure 5.

4.4 Balance of System

The equipment cost of the storage system will further depend on ancillary equipment necessary for the full storage system interconnection. The balance of system cost here includes wiring, interconnecting transformer, and additional ancillary equipment. For some technologies, this may include the cost of centralized HVAC systems which is required for maintaining acceptable environmental equipment. The balance of system cost is proportional to the power rating of the system and provided in $/kW. The balance of system cost trends are shown in Figure 6.

4.5 Installation

Installation cost accounts for associated Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, and procurement and transportation of all equipment.

4.6 Fixed O&M

Yearly operation and maintenance costs is currently a debated issue for storage projects employing the technologies discussed in this report, as the industry does not yet have longer term operating experience with the technologies. O&M requirements for Li-Ion systems are generally assumed to be light and include maintenance of HVAC system, tightening of mechanical and electrical connections, cabinet touch up painting and cleaning, and landscaping maintenance. Further, the majority of projects being developed for utilities applications include some type of capacity maintenance agreement. This capacity maintenance agreement guarantees some fixed level of available energy capacity in the system over the term of the project. The cost of the capacity maintenance agreement can be accounted for in the Fixed O&M or as part of the upfront capital costs of the system. For flow battery systems, maintenance services include power stack and pump replacements, tightening of plumbing fixtures, tightening of mechanical and electrical connections, as well as semi-annual chemistry refresh and full discharge cycles to refresh capacity. Further, while many technologies are developing third party training and qualification programs for O&M services, at present many of vendors technology companies themselves are providing O&M services.

Variable O&M costs, while typical to conventional generation sources, are generally assumed negligible for most energy storage systems. It is noted that systems operators can use a variable O&M cost as one means of including the capacity degradation within an energy storage dispatch model. However, there is not currently a uniform or industry acceptable methodology for quantifying variable O&M in this manner. For the purposes of this report, energy storage variable O&M is considered to be negligible.

4.7 Total System Cost Estimates

System costs are based on DNV GL's industry experience, internal research, and publicly available data. These costs are provided in 2016 dollars. This information is given in further context in Section 4.9, which provides calculations for an example installation.

Table 9 Energy storage system cost estimates[1]

Cost Parameter/ Technology	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Energy storage equipment cost ($/kWh)[2]	$325-$450	$350-$525	$500-$850	$800-$1000	$500-$700	$525-$725	$200-$400
Power conversion system equipment cost ($/kW)[3]	$350-$500	$350-$500	$350-$500	$500-$750	$500-$750	$500-$750	$350-$500
Power control system cost ($/kW)[4]	$80-$120	$80-$120	$80-$120	$80-$120	$100-$140	$100-$140	$100-$140
Balance of system ($/kW)[5]	$80-$100	$80-$100	$80-$100	$100-$125	$100-$125	$100-$125	$80-$100
Installation ($/kWh)[6]	$120-$180	$120-$180	$120-$180	$140-$200	$140-$200	$140-$200	$120-$180
Fixed O&M cost ($/kW yr)[7]	$6-$11	$6-$11	$6-$11	$7-$12	$7-$12	$7-$12	$6 - $12

[1] All cost estimates provided in mid-2016 dollars
[2] Energy storage equipment includes the full DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, internal wiring and connections, packaging and containers, and battery management system (BMS).
[3] PCS equipment includes the inverter, packaging, container and inverter controls.
[4] Control system includes supervisory control software, along with the controller and communications hardware required to dispatch and operate energy storage systems.
[5] Balance of system includes site wiring, interconnecting transformer, and additional ancillary equipment.
[6] Installation includes Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, procurement and transportation of equipment.
[7] Fixed O&M costs are provided as real levelized dollars with assumed 20 year project life.

4.8 Example Installed Cost Calculation

Table 10 below shows an example calculation to estimate the installed cost of 10 MW, 20 MWh NCM Li-Ion energy storage system using the cost estimates provided in Table 9. The provided cost estimates result in a low side estimate of $14,000,000 and a high side estimate of $19,800,000 for the system, with component sub-total costs based on the power or energy rating of the system.

Table 10 Example Installed Capital Cost Calculation for 10 MW, 20 MWh NCM Li-Ion Energy Storage System

Cost Parameter	ESS Size	Component Unit Cost Low	Component Unit Cost High	Component Sub-Total Low	Component Sub-Total High
Energy storage equipment cost ($/kWh)	20,000 kWh	$325/kWh	$450/kWh	$6,500,000	$9,000,000
Power conversion equipment cost ($/kW)	10,000 kW	$350/kW	$500/kW	$3,500,000	$5,000,000
Power control system cost ($/kW)	10,000 kW	$80/kW	$120/kW	$800,000	$1,200,000
Balance of system ($/kW)	10,000 kW	$80/kW	$100/kW	$800,000	$1,000,000
Installation ($/kWh)	20,000 kWh	$120/kWh	$180/kWh	$2,400,000	$3,600,000
				Low Total	**High Total**
				$14,000,000	$19,800,000
				Average $16,900,000	

4.9 System 10-Year Cost Trends

As referenced in sections 4.1 to 4.4, graphs depicting 10-year future cost trends are shown below. Cost trends are based on currently available industry projections, as well as DNV GL's interaction with industry partners, and basic cost reduction assumptions, as well as the information discussed in the relevant section, 4.1 through 4.4. These trends are provided for the period from 2016 to 2026.

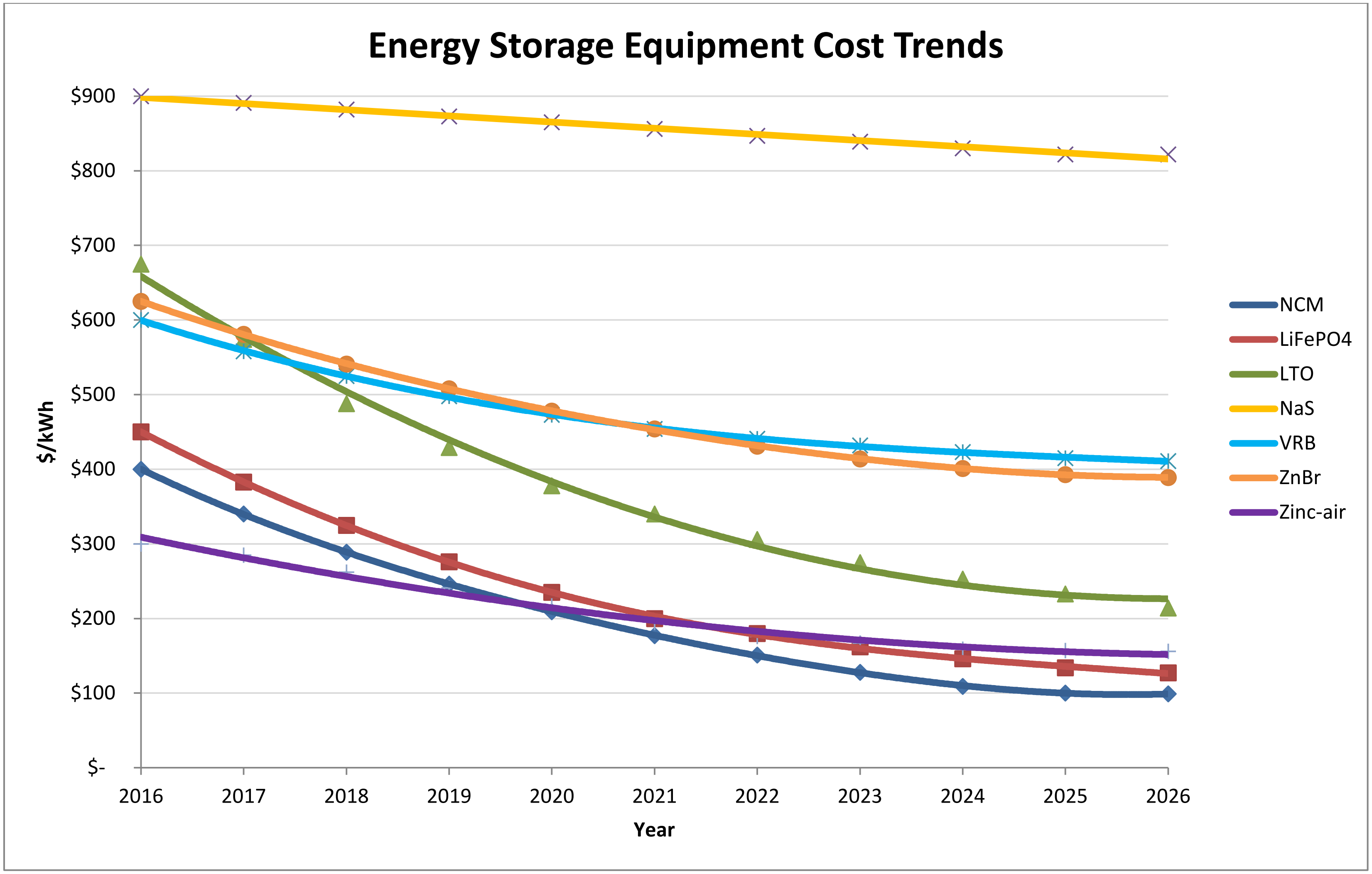

Figure 3 Projected Energy Storage Equipment Cost Trends for Various Technologies, From 2016 to 2026

PCS cost trends are shown in Figure 4. The PCS cost trends mirror each other across two technology groupings. The PCS costs for all Li-ion and Zinc-air technologies are expected to follow similar trends as they are pulling from the same manufacturers utilizing more mature PCS architectures. PCS costs for flow batteries, while currently offered at a higher price point, are expected to converge to similar costs as the Li-ion over time as these technologies mature and gain additional commercial adoption. While NAS is a more mature technology, current PCS costs are above those of Li-ion technologies with future cost reductions expected to benefit from increased adoption of flow battery PCS architectures.

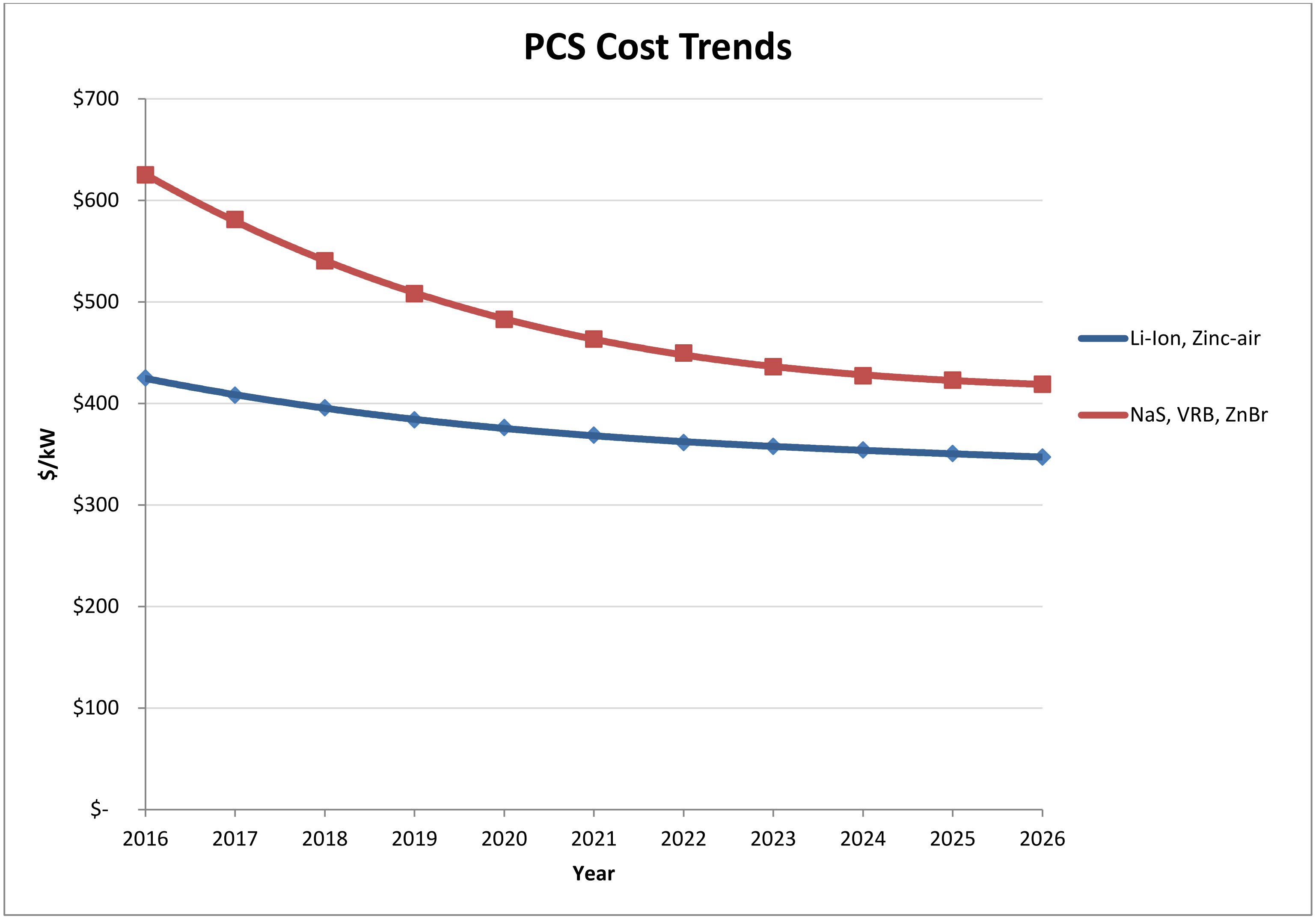

Figure 4 Projected PCS Cost Trends for Various Technologies, From 2016 to 2026

Controls cost reductions, shown in Figure 5, are expected to be relatively uniform across all technologies. While competition in the space is expected to continue, the need for increasingly sophisticated controllers which interact with both utility and distributed behind-the-meter storage assets are expected to result in modest cost reductions over time, converging to a relatively uniform price across technologies.

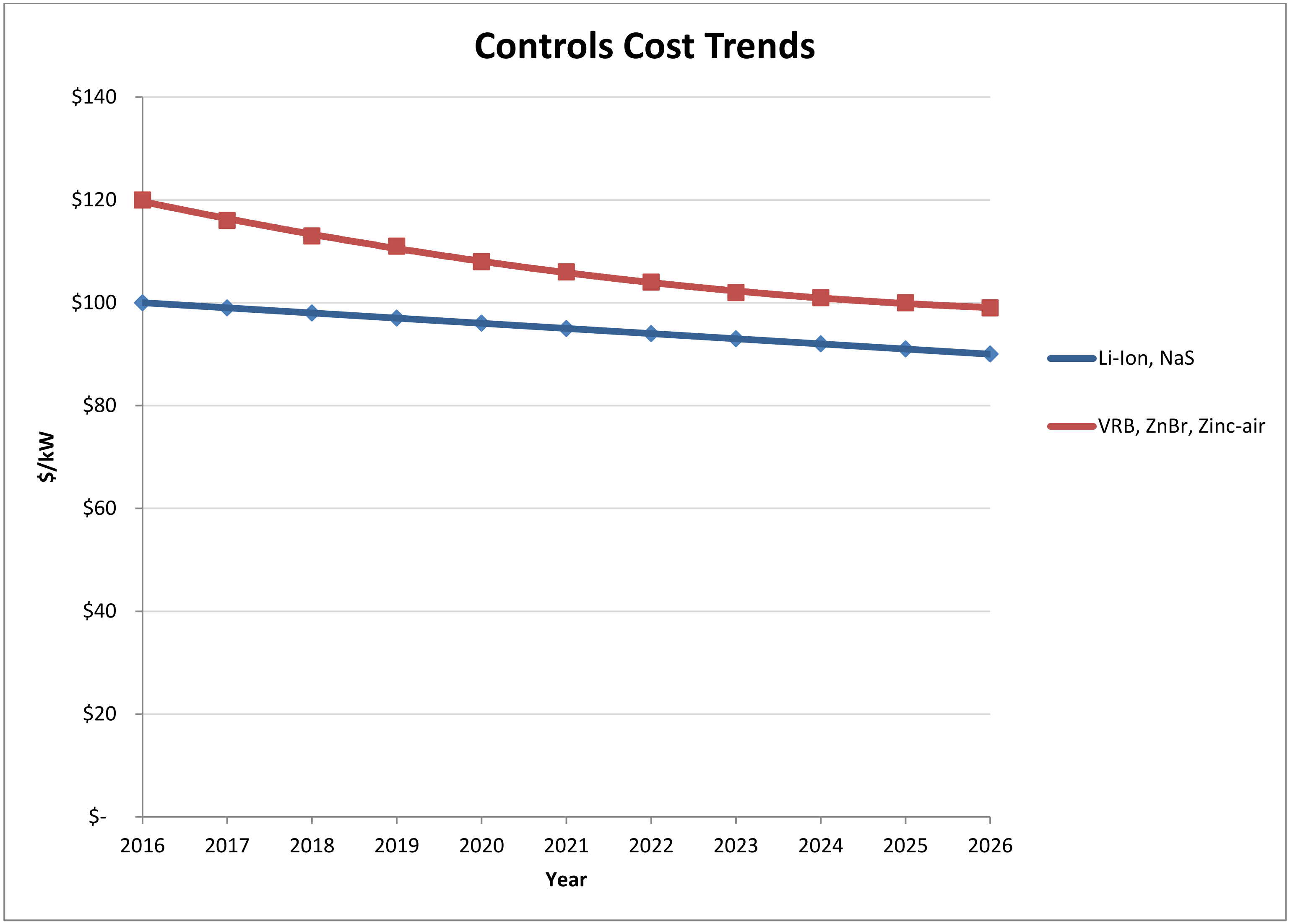

Figure 5 Projected Controls Cost Trends for Various Technologies, From 2016 to 2026

Balance of system costs, shown in Figure 6, is expected to fall dramatically over the next 5 years with continued modest gains through 2026. Cost reductions are expected as project developers gain experience deploying these technologies and system interconnection requirements become more uniform for storage technologies. Li-ion technologies and Zinc-air follow similar trends due to similarities in construction and balance of plant requirements, while reductions for flow batteries and NaS systems are expected to follow similar patterns.

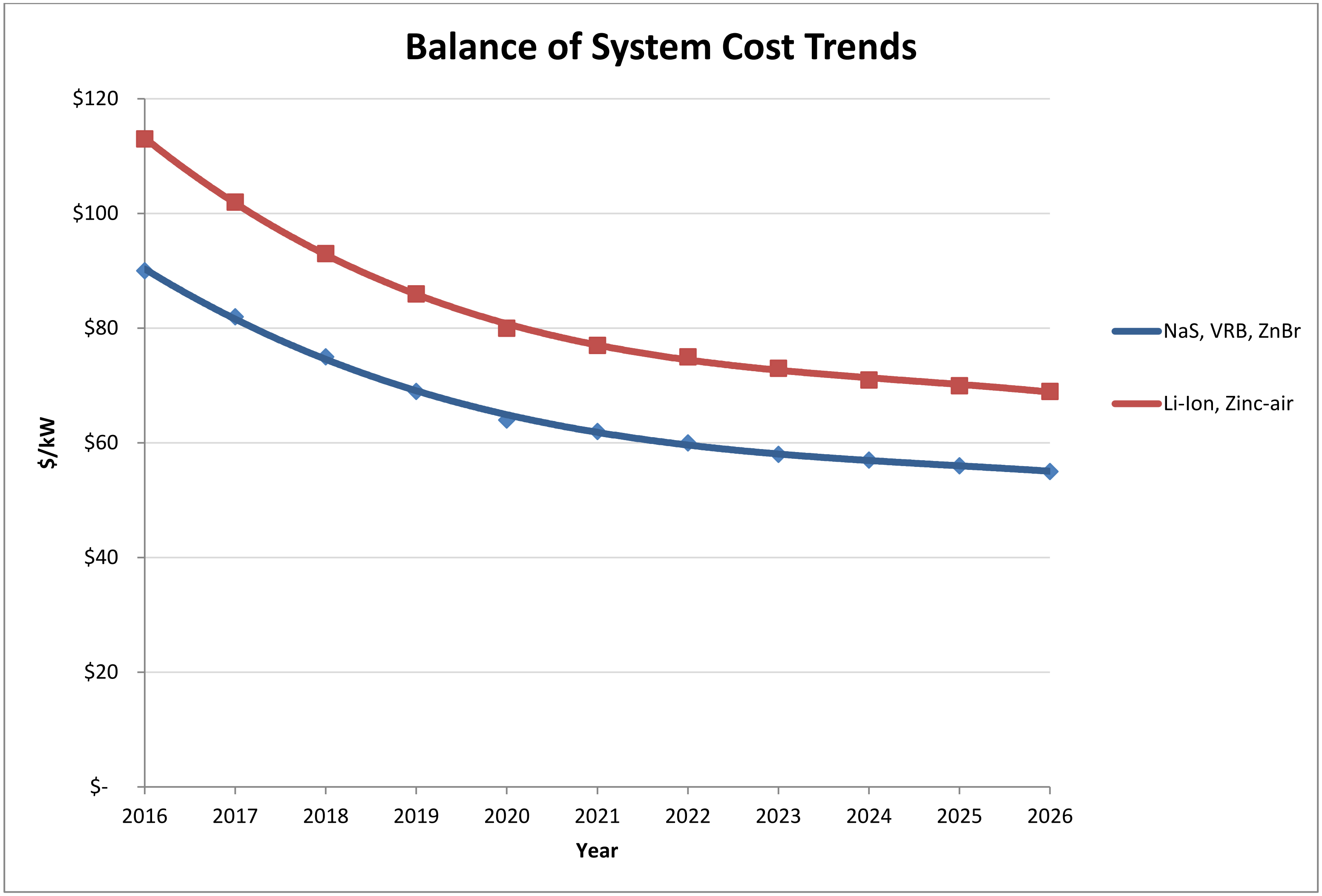

Figure 6 Projected Balance of System Cost Trends for Various Technologies, From 2016 to 2026

5 UTILITY APPLICATIONS AND VALUE STREAM

In this chapter, an application-technology ranking is provided which is intended to indicate the applicability of each technology and their relative potential for generating economic value for at least one of eight (8) benefit cases within PacifiCorp's service territory over the next 20 years. This assessment considers both the likelihood that a particular storage application is relevant to the current PacifiCorp market, as well as the appropriateness of a specific technology to serve the needs of that application. The eight applications identified by PacifiCorp for considerations are as follows:

1. Electric Energy Time Shift
2. Electric Supply Capacity
3. Regulation
4. Spinning, Non-Spinning, and Supplemental Reserves
5. Voltage Support
6. Load Following/Ramping Support for Renewables
7. Frequency Response
8. T&D Congestion Relief

In this chapter, definitions of each application will be provided, followed by an overview of regulatory concerns specific to PacifiCorp territory providing an assessment of both planned regulatory initiatives and local network and market conditions in the PacifiCorp region. These will be reviewed specifically as they relate to energy storage potential. Finally, results of the assessment are provided indicating the applicability of each technology and the relative potential for generating economic value for at least one of the benefit cases within PacifiCorp's service territory over the next 20 years. These rankings are provided on a 1 to 10 scale.

At PacifiCorp's request, this report additionally includes an assessment on applicability of each technology and the relative potential for generating economic value under an alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO).

5.1 Considered Applications

DNV GL reviewed applications for energy storage systems based on the regulations and standards in place in PacifiCorp territories, including the availability of financial resources to support energy storage development, as well as the general expansion of demand. Descriptions of these applications are provided below, based on the Department of Energy's Energy Storage Handbook and DNV GL's recommended practice guide, GRIDSTOR.

- **Electric energy time shift –** Energy storage systems operating within an electrical energy time-shift application are charged with inexpensive electrical energy and discharged when prices for electricity are high. On a shorter timescale, energy storage systems can provide a similar time-shift duty by storing excess energy production from, for example, renewable energy sources with a variable energy production, as this might otherwise be curtailed. If the difference in energy prices is the main driver and energy is stored to compensate for (for example) diurnal energy consumption patterns, this application is often referred to as arbitrage.

Storing energy (i.e. in charge mode) at moments of peak power to prevent curtailment or overload is a form of peak shaving. Peak shaving can be applied for peak generation and also – in discharge mode – for peak demand (e.g. in cases of imminent overload). Peak shaving implicates that the energy charged or discharged is discharged or recharged, respectively, at a later stage. Therefore, peak shaving is a form of the energy time-shift application.

An energy storage system used for energy time-shift could be located at or near the energy generation site or in other parts of the grid, including at or near loads. When the energy storage system used for time-shift is located at or near loads, the low-value charging power is transmitted during off-peak times.

Important for an energy storage system operating in this application are the variable operating costs (non-energy related), the storage round-trip efficiency and the storage performance decline as it is being used (i.e. ageing effects).

- **Electric Supply Capacity -** An energy storage system could be used to defer or reduce the need to buy new central station generation capacity and/or purchase capacity in the wholesale electricity market. In this application, the energy storage system supplies part of the peak capacity when the demand is high, thus relieving the generator by limiting the required capacity peak. Following a (partial) discharge, the energy storage system is recharged when the demand is lower. The power supply capacity application is a form of generation peak shaving, therefore a form of electrical energy time-shift. An energy storage system participating in the electrical capacity market may be subject to restrictions/requirements of this market, for example required availability during some periods.
- **Regulation** - Regulation is used to reconcile momentary differences between demand and generation inside a control area or momentary deviations in interchange flows between control areas, caused by fluctuations in generation and loads. In other words, this is a power balancing application. Conventional power plants are often less suited for this application, where rapid changes in power output could incur significant wear and tear. Energy storage systems with a rapid-response characteristic are suitable for operation in a regulation application.

  Energy storage used in regulation applications should have access to and be able to respond to the area control error (ACE) signal (where applicable), which may require a response time of fewer than five seconds. Furthermore, energy storage used in regulation applications should be reliable with a high quality, stable (power) output characteristics.
- **Spinning, Non-spinning, and supplemental reserves** - A certain reserve capacity is usually available when operating an electrical power system. This reserve capacity can be called upon in case some generation capacity becomes unavailable unexpectedly, thus ensuring system operation and availability. A subdivision can be made based on how quickly a reserve capacity is available:
  - Spinning reserve is reserve capacity connected and synchronized with the grid and can respond to compensate for generation or transmission outages. In remote grids spinning reserve is mainly present to cover for volatile consumption. In case a reserve is used to maintain system frequency, the reserve should be able to respond quickly. Spinning reserves are the first type of backup that is used when a power shortage occurs.

- Non-spinning reserve is connected but not synchronized with the grid and usually available within 10 minutes. Examples are offline generation capacity or a block of interruptible loads.
- Supplemental reserve is available within one hour and is usually a backup for spinning and non-spinning reserves. Supplemental reserves are used after all spinning reserves are online.

Stored energy reserves are usually charged energy backups that have to be available for discharge when required to ensure grid stability. An example of a spinning reserve is an uninterruptible power supply (UPS) system, which can provide nearly instantaneous power in the event of a power interruption or a protection from a sudden power surge. Large UPS systems can sometimes maintain a whole local grid in case of a power outage; this application is called island operation.

- **Voltage support** - Grid operators are required to maintain the grid voltage within specified limits. This usually requires management of reactive power (but also active power, e.g. in the LV grid), therefore also referred to as Volt/VAr support. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.

  Voltage support typically is a local issue at low voltage (LV), medium voltage (MV) or high voltage (HV) level. The distributed placement of energy storage systems allows for voltage support near large loads within the grid. Voltage support can also be provided by operation of generators, loads, and other devices. A possible advantage of energy storage systems over these other systems is that energy storage systems are available to the grid even when not generating or demanding power.

  Note that no (or low) real power is required from an energy storage system operating within a voltage/VAr support application, so cycles per year are not applicable for this application and storage system size is indicated in MVAr rather than MW. The converter needs to be capable of operating at a non-unity power factor in order to source or sink reactive power. The nominal duration needed for voltage support is estimated to be 30 minutes, which allows the grid time to stabilize and/or begin orderly load shedding.

- **Load following / ramping support for renewables** - Load following is one of the ancillary services required to operate a stable electricity grid. Energy storage systems used in load following applications are used to supply (discharge) or absorb (charge) power to compensate for load variations. Therefore, this is a power balancing application. In general, the load variations should stay within certain limits for the rate of change, or ramp rate. Therefore, this application is a form of ramp rate control. The same holds for generation variations, which is very applicable to renewable energy sources. Due to the intermittency of renewables production, having a storage device with several hour durations can provide a large advantage to renewable efficiencies, easing of grid impacts, and renewable production. Conventional power generation can also operate with a load following (or RES compensating) application. Within these applications, the benefits of energy storage systems over conventional power generation are that:
  - most systems can operate at partial load with relatively modest performance penalties
  - most systems can respond quickly with respect to a varying load

- systems are suitable for both load following down (as the load decreases) and load following up (as the load increases) by either charging or discharging.

Note that an energy storage system operating with a load-following or ramp rate control application within a market area needs to purchase (when charging) or sell (when discharging) energy at the going wholesale price. As such the energy storage efficiency is important when determining the value of the load following application.

- **Frequency response -** Synthetic inertia behavior is the increase or decrease in power output proportional to the change of grid frequency; physical inertia is provided by conventional power generators, i.e. synchronous generators. If the total amount of physical inertia decreases in a power system, the amount of synthetic inertia should be increased to maintain a certain minimum amount of total inertia. Many grid-connected renewable energy sources do not provide additional synthetic inertia. Therefore, larger grid frequency deviations may occur as the total inertia in the power system decreases. Keeping track of the total system inertia could be a future task of ISOs.

  Some energy storage systems add synthetic inertia to the system and can thereby be used to compensate for fluctuations in the grid frequency. Causes of fluctuations could be the loss of a generation unit or a transmission line (causing a sudden power imbalance). Various generator response actions are needed to counteract a sudden frequency deviation, often within seconds.

  Energy storage within a frequency response application could support the grid operator and thereby assure a smoother transition from an upset period to normal operation. For a frequency response type of application, the energy storage is required to provide support within milliseconds. Storage helps to maintain the grid frequency and to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC). Aside from this quick response, the frequency response application is similar to load following and regulation, as described previously.

- **Transmission and distribution congestion relief** – During moments of peak demand, it may occur that the available transmission lines do not provide enough capacity to deliver the least-cost energy to some or all of the connected loads. This transmission congestion may increase the energy cost.

  Energy storage systems at strategic positions within the electricity grid help to avoid congestion-related costs and charges. The energy storage system can be charged when there is no congestion and discharged when congestion occurs. Energy storage can, in this way, additionally delay and sometimes avoid the need to upgrade a transmission or distribution system.

5.2 PacifiCorp Territory Regulatory Concerns and Application Drivers

Currently, the largest drivers of energy storage deployment nationally have been a direct result of state and federal level regulatory actions encouraging or mandating procurement and installation of energy storage technologies. Much of the regulatory action has come as follow-up initiatives to more aggressive renewable portfolio standards (RPS) with storage seen as an enabling technology which can mitigate issues associated with higher level of renewable penetration. To a lesser extent, regulatory action around energy security has additionally spurred some development opportunities for energy storage as a reliability resource.

Additionally, a small set of cost-effective applications in select markets, such as frequency regulation, supply capacity, and transmission and distribution deferral have been driving installations. Where market operators have permitted energy storage systems to obtain capacity credits, larger-scale energy storage systems have been justified financially based on the capacity payments over 10-20 year contracts. These structures have additionally supported storage applications for transmission and distribution (T&D) congestion relief. Finally, markets which have developed mechanisms to compensate fast regulation or pay-for-performance market products, have allowed for an opportunity for battery energy storage systems which can obtain high-performance scores in these markets.

Of note, the growth of commercial and industrial behind-the-meter storage installations has been driven in select markets where customers are exposed to high retail rates, and more importantly, high monthly peak demand charges. At the residential level, in select markets where net-metering rules are unfavorable to customers installing solar generation, and high retail energy rates exist, residential self-supply is also seen as a cost-effective energy storage application.

Based on these current trends, storage applications related to capacity such as supply capacity and T&D congestion relief, as well as applications supporting renewable integration, such as renewable time shifting, regulation, and load following, and to a lesser extent, frequency response and voltage support, are likely to be the more likely application for storage over the next 20 years. The relative ranking of these applications is more nuanced and requires a look at the policies in-place or planned for PacifiCorp's service territory.

The PacifiCorp territory is comprised of regions throughout California, Oregon, and Washington (under PacificPower), and Idaho, Utah, and Wyoming (under Rocky Mountain Power). Each state observes a variety of regulations relating to energy security, distribution, and storage. Further, the federal government provides additional regulation that must be observed. At both the state and federal level, incentives are additionally provided in some cases.

The PacificPower region, in particular, has a well-developed set of regulations and incentives already in place. Oregon, Washington, and California all have Renewable Portfolio Standards (RPS) as well as other legislation that encourages utility pursuit of clean energy and potentially energy storage systems.

Oregon's most influential energy storage-specific legislation that passed in 2015, HB 2193, directs the state's electric utility companies to procure one or more energy storage systems capable of storing a specified energy capacity by 2020, allowing them to recover all costs through electrical rates. Additionally, SB 1547 passed in 2016, requiring, among other things, an RPS which would amount to 50% renewables for PacifiCorp by 2040, and the elimination of coal-generated energy utilization by 2030. This legislation will put additional pressure for energy storage to support the growing renewables portfolio.

In the state of Washington, several bills have been passed that create a supportive infrastructure for energy storage. For example, HB 1897 established a program in support of R&D to develop next generation clean energy technology sustainably; HB 1296 legislated that an IRP is required to include energy storage; SB 5025 amended laws to support the meeting of renewable energy targets by utilities and minimum standards for energy efficient buildings; and HB 1895, a bill currently pending a hearing, if passed would promote the deployment of clean distributed energy, and prioritizes deployment of smart grids and microgrids. Further, the Energy Independence Act, or I-937, specifically requires a 15% RPS by 2020. The pursuit of these standards has recently been supported by HB 1115. This legislation sets aside $44 million in grants that are to be directed towards renewables advancement and technology, specifically including energy storage.

California has for many years been a leading state in the pursuit of clean energy. Many pieces of legislation support renewable technology infrastructure, especially focused on the causes of reducing emissions and improving energy resiliency. For instance, SB 1358 specifies emission performance standards and SB 350 requires an increase in the amount of electricity generated and sold from renewable energy resources in order to strengthen the diversity and resilience of the electrical system. California further passed SB 83, requiring public utilities to enact net metering tariffs to enhance diversification and reliability of the state's energy resources. Recently, AB 1530 states that clean distributed energy must be deployed by utilities, and prioritizes deployment of smart grids and microgrids. Specifically, California utilities must meet an RPS of 50% by 2030, with intermediate goals, as initiated by AB 327 and SB 350, noted previously.

In contrast, the Rocky Mountain Power region does not have as many or as specific regulation or support. While Utah provides a renewable energy target of 20% by 2025, but not an RPS, neither Idaho nor Wyoming has any RPS or voluntary renewable goals. There are, however, several pieces of legislation that support, directly or indirectly, energy storage, chiefly as a method to support reliability and resiliency.

Utah leads the way with SB 0115, called the Sustainable Transportation and Energy Plan (STEP) Act. This bill allows for the Public Service Commission to authorize the implementation of tariffs by utilities in order to establish electric efficiency technology programs, allows the utility to provide incentives for air quality improvement technology and electric vehicle infrastructure development, and provides support for clean energy programs implemented by utilities. PacifiCorp has already reacted to this legislation with their STEP initiative. This includes the STEP Pilot programs, 5-year programs providing funding to, among other projects, battery storage development. Additionally, PacifiCorp has applied to the Public Service Commission to offer large customers the option to participate in a Renewable Energy Tariff, paying directly to get part or all of their electricity from a specific renewable project. Further, Utah has passed SB 280, which promotes the development of diverse energy resources, including nonrenewable and renewable resources, nuclear, and alternative transportation fuels. This distributed generation policy's focus is to promote resiliency and reliability of the grid, and will likely naturally lead to an investigation of energy storage procurement and integration.

Idaho passed HB 189, which removed all property taxes on renewable generation sites, in favor of a 3-3.5% tax on generation. Otherwise, although Idaho has neither net metering law nor RPS, it does offer tax credits for renewable energy.

Wyoming, meanwhile, has no net metering law and provides no credits or exemptions for clean distributed energy resources. Further, Wyoming taxes wind generation and is currently considering further raising those taxes. As noted previously, Wyoming has no RPS.

Finally, the Federal Government has put in place regulations to encourage renewables and energy storage. Widely known and utilized is the Investment Tax Credit provided by the Federal government. This 30% direct tax credit was extended until 2019, reduced stepwise annually after that, to 26% in 2020, 22% in 2021, and 10% in 2022, before ending. As to standards, the Clean Power Plan, as regulated by the EPA, assigns each state an emissions reduction target by 2030, contributing to a 32% reduction nationwide. Specific to PacifiCorp, Wyoming, Utah, and Washington have aggressive reduction targets, above 31%, while California, Oregon, and Idaho have reduction targets below 20%, in comparison with 2012 levels. These targets are based on, among other things, generation activity, as well as actions already taken to reduce emissions. States are required to submit a plan for compliance by September 2016, or be subject to a federally developed plan, both likely to directly affect utilities. Although there is some Congressional action to block these requirements, none has currently passed.

5.3 Application Ranking Methodology and Results

DNV GL developed a ranking system for the various applications that battery energy storage systems may be utilized for within PacifiCorp territory. Within this ranking system, information about each technology is used to ascertain its appropriateness for a particular application. The battery type's typical size, technology maturity level, market penetration, as well as technical parameters and various costs influenced these rankings.

First, each application was defined by its requirements for power, energy, cycling, and response time. These Application Requirements were scored on a comparative scale. For instance, in the case of the application of Electric Energy Time Shift, the energy capacity of the system is paramount and thus ranked highly. Alternatively, in the case of the application for Frequency Response, the energy capacity of the system is of lesser importance while response time and power capability are the prioritized requirements. Each technology was then defined by its capabilities to meet these requirements for power, energy, cycling, and response time. These technology capabilities were similarly scored on a comparative scale. For instance, Li-ion technology provides nearly instantaneous response time and was thus ranked highest in that parameter. Flow batteries, on the other hand, scored highest for cycling as they are capable of fully discharging daily with less impact on lifetime and degradation. A Technology Maturity score was then also assigned to technology each based on its current stage of commercialization and scale of field deployments.

The Application Requirements and Technology Capability scores were then compared, defining how well-matched a specific technology was for a given application. For instance, if an application required fast response time, the technologies that provide a fast response time would score highest. Scores across each property were then averaged to provide a Technology Application score for each technology providing each application.

A PacifiCorp Application Need score was then assigned to each application based on the high-level cost-effectiveness and regulatory analysis of the PacifiCorp territory. Based on current PacifiCorp market scenario, storage applications with high value that are not dependent on market-related rule changes, such as T&D congestion relief, are expected to be the most likely candidates for PacifiCorp to deploy energy storage. Additionally, as noted in the review, renewable portfolio standards across the PacifiCorp region will drive some renewable integration applications such as renewable time shifting, regulation, and load following. Faster regulation applications such frequency response and voltage support are likely to be lower value applications. A second set of Scores for PacifiCorp Application Need scores were provided for the alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO). For this scenario, CAISO market rules which directly allow storage to qualify for supply capacity credit increased this application score. Also, further developed fast regulation and emerging ramping market products increased the PacifiCorp Application Need score for frequency regulation and applications tied to renewable integration.

Finally, PacifiCorp application rankings were computed for each application and technology under each market rules scenarios. The final rankings were computed by taking the average score over the Technology Application score, the Technology Maturity Score, and the PacifiCorp Need score. This methodology resulted in Table 11 and Table 12.

Table 11 Application Rankings in Current Market Rules Scenario

Application	Current Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	8	8	9	8	8	7
Electric Supply Capacity	9	9	9	9	8	8	7
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	8	8	9	8	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	8	8	9	8	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Table 12 Application Rankings for CAISO Market Rules Scenario

Application	CAISO Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	9	9	9	9	9	7
Electric Supply Capacity	9	9	9	9	9	9	8
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	9	9	9	9	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	9	9	9	9	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

6 CONCLUSION

The data from this study is intended to support PacifiCorp in making decisions regarding energy storage procurement and grid integration to support their 2017 IRP, giving confidence in the current state of the industry while providing insight into what trends and regulations which will prevail in the future. Further, this study is intended to provide general guidance on the appropriateness of each presented technology for specific applications, as needs and requirements vary across each PacifiCorp region. The inclusion of battery energy storage, particularly when paired with other distributed energy resources, will allow PacifiCorp to comply with emerging energy regulations while also providing greater flexibility, resiliency, and efficiency in the allocation of resources.

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FINAL

BULK STORAGE STUDY FOR THE 2017 INTEGRATED RESOURCE PLAN

B&V PROJECT NO. 192472

PREPARED FOR

PacifiCorp

19 AUGUST 2016

BLACK & VEATCH
Building a world of difference.

Table of Contents

1.0 Introduction ... **1**
2.0 Pumped Storage Hydroelectric ... **2**
2.1 General ... 2
2.2 Swan Lake North ... 3
2.3 JD Pool ... 4
2.4 Seminoe ... 5
2.5 Operating Characteristics and Regulatory Overview ... 6
2.6 Capital, Operating, and Maintenance Costs ... 6
2.7 Summary ... 9
3.0 Compressed Air Energy Storage ... **10**
3.1 CAES Technology Description ... 10
Appendix A. Data Tables ... **14**

LIST OF TABLES

Table 1 Swan Lake North Pumped Storage Project Facilities Summary ... 14
Table 2 JD Pool Pumped Storage Project Facilities Summary ... 16
Table 3 Seminoe Pumped Storage Project Facilities Summary ... 18
Table 4 Cost Opinion Comparison ... 20
Table 5 Annual Cost Comparison ... 20
Table 6 Pumped Storage Technology Summary Matrix ... 21
Table 7 Estimated 5-year EPC expenditure pattern for a pumped storage facility ... 22
Table 8 Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016 ... 23
Table 9 CAES and LAES project descriptions ... 24
Table 10 CAES and LAES project descriptions (continued) ... 25
Table 11 Magnum CAES Data ... 26

LIST OF FIGURES

Figure 1 Estimated 5-year EPC expenditure pattern for a pumped storage facility ... 22

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1.0 Introduction

Black & Veatch Corporation (B&V) was retained by PacifiCorp to perform a Bulk Energy Storage Study (Study) to support PacifiCorp's 2017 Integrated Resource Plan (IRP). IRPs are developed by power utilities to evaluate a portfolio of generating resources and energy storage options for their system in order to balance increasing levels of variable energy resources and, as generation from variable energy resources and their relative percentage of load grow, the need for additional system flexibility to assure grid reliability. For PacifiCorp, generating resource options include fossil fuel options, such as coal and natural gas, as well as renewable options including wind, geothermal, hydro, biomass, and solar.

Energy storage technologies have been evaluated in the past by PacifiCorp.

- HDR Engineering (HDR) was retained by PacifiCorp to perform an energy storage study titled "Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System" dated December 9, 2011, to support PacifiCorp's 2013 IRP.
- To support PacifiCorp's 2015 IRP, HDR provided an updated version of their 2011 study titled "Update to Energy Storage Screening Study for Integrating Variable Energy Resources within the PacifiCorp System" dated July 9, 2014.

As requested by PacifiCorp to support their 2017 IRP, the scope of work for this Study is only an update of the estimates of costs, schedules, and operating/performance characteristics provided in the previous HDR energy storage studies with a focus on two primary energy storage technologies with specific projects of each in various stages of planning as follows.

- Pumped Storage Hydroelectric
  - Swan Lake North
  - JD Pool - Klikitat
  - Seminoe
- Compressed Air Energy Storage
  - Magnum Energy

The results of the Study are provided in the following report sections and appendices. The information presented has been gathered from and is based on public and private documentation, studies, reports, and project data of the specific projects associated with the two primary energy storage technologies of the scope of work. Although not included in the scope of work for this Study, a thorough and applicable discussion of considerations for integrating variable energy resources into power systems is provided in HDR's 2011 and 2014 reports for information purposes and will not be restated herein.

2.0 Pumped Storage Hydroelectric

The previous HDR 2011 and 2014 energy storage studies considered potential pumped storage hydroelectric projects within the PacifiCorp operating power system region as follows:

- HDR 2011 Study
  - Swan Lake North
  - Yale-Merwin
  - JD Pool
  - Parker Knoll
- HDR 2014 Study
  - Swan Lake North
  - JD Pool
  - Black Canyon[1]

For this Study, PacifiCorp has requested that only the estimated costs, schedules, and operating/performance characteristics from the HDR 2014 study be updated for the Swan Lake North, JD Pool, and Seminoe projects.

2.1 GENERAL

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand or when required to absorb energy, excess energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or a peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity. The pumping and generating is typically accomplished by a reversible pump-turbine/motor-generator. In addition to providing electricity at times of peak power demand, applications for pumped storage hydroelectric projects include:

- Providing transmission system support through ancillary services, such as load shifting and following, frequency control, grid stabilization, and reserve generation, etc.
- Energy storage for less dependable renewable resources, such as wind and solar energy.

Pumped storage projects may be categorized as either open-loop or closed-loop pumped storage projects. The Federal Energy Regulatory Commission (FERC) defines these classifications as follows:

- Open-loop pumped storage projects are continuously connected to a naturally-flowing water feature.

[1] Black Canyon Pumped Storage Project is a precursor to the Seminoe Pumped Storage Project.

- Closed-loop pumped storage projects are not continuously connected to a naturally-flowing water feature.

For open-loop pumped storage systems, acquisition of environmental approvals has become increasingly challenging due to the need to develop a lower reservoir on an active river or existing lake. To mitigate this issue, many recent pumped storage developments have proposed closed-loop systems, which often utilize existing features such as abandoned quarries or underground mines as the lower reservoir of the pumped storage system. This allows the pumped storage project to be developed and operated off-stream, reducing environmental impacts and also reducing costs associated with development of the lower reservoir.

2.2 SWAN LAKE NORTH

2.2.1 Current Project Status

In HDR's 2014 study, it is noted that various preliminary Federal Energy Regulatory Commission (FERC) permits and a draft license application were filed for the Swan Lake North Pumped Storage Project (FERC No. 13318) (Project) between 2010 and 2012. Over this period, the proposed capacity of the project went from 1,000 megawatts (MW) to 600 MW due to the developer, Swan Lake North Hydro LLC, making a number of changes to the project layout, size of reservoirs, water conveyance arrangement, and consideration of surface penstocks. The 600 MW project capacity was the basis for HDR's 2014 study.

Since 2014, a Final License Application (FLA) was filed by Swan Lake North Hydro LLC on October 27, 2015, and is currently under consideration by the FERC. In this document, the proposed project capacity was further reduced to 400 MW due to further project optimization during the course of final license application development. Although drawings from the final license application are not publically available through the FERC website, it is assumed that the general project configuration will be similar to the site layout and profile provided in the HDR 2014 study, only at a lower capacity. The 400 MW project capacity and the description of the project facilities provided in the final license application exhibits that is publically available from the FERC website are the basis for this Study.

2.2.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 393.3 MW in generating mode. It will be located approximately 11 miles northwest of Klamath Falls, Oregon. A general summary of the proposed Project facilities is provided in Table 1 in Appendix A.

2.2.3 Schedule

The proposed construction schedule for the Project is described and presented in Exhibit C of the FLA. The schedule assumes approximately 24 months for final design with an expected completion date in 2017. Final review and approval of the design is anticipated to take 6 to 12 months after which construction will begin. Construction will take approximately 4 years to complete. The proposed commercial operation date is November 2022, assuming a FERC Notice-to-Proceed in January 2018.

2.3 JD POOL

2.3.1 Current Status

In HDR's 2014 study, it is noted that an original preliminary FERC permit and a successive application had been filed by the Public Utility District No. 1 of Klickitat County, Washington (KPUD) for the JD Pool Pumped Storage Project (FERC No. 13333) (Project) on November 29, 2008, and April 30, 2012, respectively. The information provided in the successive application was the basis of information for HDR's 2014 study. The proposed Project capacity at that time was 1,500 MW.

After the HDR 2014 study, a Pre-Application Document (PAD) was filed by KPUD in October 2014. The information in the PAD revised the project configuration and reduced the Project proposed capacity to 1,200 MW. Due to the effective date of the successive application, KPUD filed a second successive preliminary permit application on November 3, 2015, in order to extend the effective date of the application. At the same time, Clean Power Development LLC (Clean Power) filed a competing preliminary permit application for the proposed Columbia Gorge Renewable Energy Balancing Project (FERC No. 14729) (Columbia Gorge Project) at the same location.

The lower reservoir site for both applications is currently undergoing a cleanup process due to decades of contamination from the former operation of the Columbia Gorge Aluminum smelter. Given the uncertainty of the timeline for the site cleanup and its suitability for development, FERC found it not prudent to issue a preliminary permit for the site and dismissed both applications.

The above information concerning the Project status and dismissal of the preliminary permit applications filed by KUPD and Clean Power is summarized from FERC's "ORDER DISMISSING PRELIMINARY PERMIT APPLICATIONS" document dated December 23, 2015. FERC also notes in this document that they may consider development applications in the future for the site, but the applications must thoroughly address all concerns related to developing the Project at a previously contaminated site. Thus, permitting this site in the future may require special considerations, and its timeline is unknown at this time.

Based on the public information available from the FERC website, the 1,200 MW project capacity and the description of the project facilities provided in the PAD are the basis for this Study.

2.3.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 1,200 MW in generating mode. It will be located approximately 8 miles southwest of Goldendale, Washington. A general summary of the proposed Project facilities is provided in Table 2 in Appendix A.

Based on a review of the PAD information, there is a high likelihood that the Project can be further optimized to reduce costs, such as finalizing the total storage requirement of the reservoirs and the number and/or size of the water conveyance conduits.

2.3.3 Schedule

The proposed development and construction schedule for the Project is outlined in the PAD as follows:

- Pre-filing Schedule for Filing License Application: 1 year
- Pre-construction Development Activities after FERC Issuance of License, Including Design/Construction Drawings: 3 years
- Project Construction: 5 years
- Anticipated Commissioning of Project: 5th Year of Construction

2.4 SEMINOE

2.4.1 Current Status

The HDR 2014 study included the Black Canyon Pumped Storage Project (FERC No. P-14087). A preliminary FERC permit application for the project was prepared by Gridflex Energy, LLC and filed by Black Canyon Hydro, LLC on January 25, 2011. The application showed several possible alternatives for pumped storage development that included two new upper reservoirs that could be connected to one of two existing lower reservoirs, the Seminoe and Kortes Reservoirs. Both of the existing reservoirs are owned and operated by the U.S. Department of Interior's Bureau of Reclamation. The original preliminary permit for the project, along with Gridflex's response to HDR's Request for Information (RFI), was the basis of information for HDR's 2014 study. As noted by HDR, there was conflicting information relative to generating and pumping capacities between the original preliminary permit and the RFI response.

On July 1, 2014, Gridflex prepared and Black Canyon Hydro, LLC filed a successive preliminary permit application for the Black Canyon Pumped Storage Project (FERC No. P-14087). This filing occurred about the time HDR had concluded their 2014 study. The successive application identified and included an additional alternative for consideration. However, on November 26, 2014, FERC issued an order denying the successive preliminary permit on the general basis that very little progress toward the filing of a development application had been made during the course of the original three-year permit term and did not warrant a successive permit.

Gridflex prepared and Black Canyon Hydro, LLC filed a preliminary FERC permit application for the Seminoe Pumped Storage Project (FERC No. P-14787) (Project) on June 16, 2016. This Project is similar to and utilizes the concept of the Black Canyon Pumped Storage Project. Per FERC letter dated June 21, 2016, some deficiencies and the need for additional information were identified with regard to the application. Gridflex prepared and Black Canyon Hydro, LLC filed an amended preliminary FERC permit application on June 28, 2016, which was accepted by FERC on June 30, 2016. The proposed total Project capacity is 700 MW and consists of two developments (i.e. East and West) that utilize the existing Seminoe Reservoir as their lower reservoir.

2.4.2 Project Description

The Project is an open-loop pumped storage system with a total installed capacity of 700 MW in the generating mode. It will be located approximately 30 miles northeast of Rawlins, Wyoming. The Project utilizes the water resources of the North Platte River as stored and conveyed through the existing reservoir. The Project includes two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir. In the generating mode, the East and West powerhouses have installed capacities of 400 and 300 MW, respectively, for a total Project installed capacity of 700 MW. A general summary of the proposed Project facilities is provided in Table 3 in Appendix A.

2.4.3 Schedule

The preliminary permit includes a three-year duration schedule for studies to design the technical aspects of the Project and confirm its economic viability. No overall schedule for Project implementation was provided; however, it would be anticipated that the FERC final license application would be completed in 2019 with final engineering, construction, and commercial operation of the Project completed during the 2020 through 2025 timeframe.

2.5 OPERATING CHARACTERISTICS AND REGULATORY OVERVIEW

A relevant discussion of typical pumped storage hydroelectric project operating characteristics relating to the beneficial services that such projects can provide, and general considerations and important aspects concerning environmental and regulatory factors with regard to siting and developing a potential pumped storage project are provided in HDR's 2014 report for information purposes and will not be restated herein.

2.6 CAPITAL, OPERATING, AND MAINTENANCE COSTS

The following sections provide an update of the cost estimates from the HDR 2014 study with regard to expected capital and operation and maintenance (O&M) costs for the three potential pumped storage projects in the PacifiCorp region selected for this Study. Costs provided are expressed in mid-2016 dollars.

2.6.1 Capital Cost

The HDR 2014 study provided a general discussion of capital costs associated with pumped storage projects. As noted in the HDR 2014, which is particularly true, the direct cost to construct a pumped storage facility may vary greatly and is dependent upon a number of physical site factors. The HDR 2014 study also notes the direct and indirect cost items generally included for capital costs, which would also generally include Owner project contingency, development, and project team costs. In addition to those cost items, capital cost assumptions for this Study include an Engineer-Procure-Construct (EPC) type of project delivery methodology and estimates reflecting a +/- 30% order of accuracy, which would approach an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimate classification.

2.6.1.1 Swan Lake North

As reported in the HDR 2014 study, EDF provided an AACE Class 4 cost estimate of $2,300/kW for the envisioned 600 MW facility at that time, which apparently compared favorably to earlier cost opinions prepared by HDR for the Project. Escalating this cost to mid-2016 dollars using a rate of 3% per year results in a total project cost of approximately $2,500/kW. The 3% per year escalation rate was used in the HDR 2014 study and is considered appropriate for escalating HDR values to mid-2016 dollars for this Study.

No recent cost information was available from Swan Lake North Hydro LLC for the current Project capacity of 400 MW and description provided in their FLA dated October 27, 2015. Based on our review of the Project described in the FLA, a cost opinion on the order of $2,600/kW would be expected, which compares favorably to the developer's escalated unit cost of $2,500/kW.

2.6.1.2 JD Pool

As reported in the HDR 2014 study, HDR performed a reconnaissance level study and AACE Class 5 cost opinion in 2005 for the 1,500 MW Project envisioned at that time. Their study resulted in an escalated cost opinion of $2,500/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, this cost opinion would be approximately $2,700/kW.

No recent cost information was available from KPUD for the current Project described in their PAD dated October 2014, having a capacity of 1,200 MW. However, as reported in the HDR 2014 report, KPUD did provide a cost opinion of $2 billion to $2.5 billion for a 1,000 to 1,200 MW project in their Preliminary Permit Application, which equated to unit costs of $1,700 to $2,500/kW. Escalating to 2016 using a rate of 3% per year, these cost opinions would be approximately $1,800 to $2,700/kW. Based on our review of the Project described in the PAD, a cost opinion on the order of $2,700/kW would be expected, which compares favorably to the developer's escalated unit cost for a 1,200 MW Project.

2.6.1.3 Seminoe

As reported in the HDR 2014 study, HDR noted that the Developer's estimated cost of $1,500/kW in 2014 dollars appeared too low to satisfactorily cover the direct and indirect costs (i.e. capital costs) of the original Black Canyon Pumped Storage Project, which has a different installed capacity than the Seminoe Pumped Storage Project. HDR's cost opinion for Black Canyon was on the order of $2,000 to $2,300/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, these costs would be approximately $1,600/kW and $2,100 to $2,400/kW, respectively. Based on our review of the 700 MW Seminoe Project described in the preliminary permit, an average cost opinion for the combined East and West facilities on the order of $2,600/kW would be expected, which compares favorably to the upper range of HDR's escalated cost opinion for the Black Canyon Project.

2.6.1.4 Summary

A comparison of the cost opinions is provided in Table 4 in Appendix A. It would appear that the capital cost of a pumped storage hydroelectric project would be in the range of $1,800 to $2,700/kW.

2.6.2 Annual Operation and Maintenance (O&M) Costs

The "Pumped Storage Planning and Evaluation Guide" dated January 1990 by the Electric Power Research Institute (EPRI) is an appropriate resource for estimating annual costs for pumped storage hydroelectric projects and was used by HDR in their 2014 study. Based on this document, estimating the annual costs to operate and maintain a pumped storage hydroelectric project would include the following.

- Operation and Maintenance (O&M). O&M costs can be estimated by the following equation:

$$\text{O\&M Costs (1987\$/yr)} = 34{,}730 \times C^{0.32} \times E^{0.33}$$

where:

C = Plant Capacity, MW

E – Annual Energy, GWh

- General expenses. A 35% surcharge of the site specific O&M cost is suggested to cover administration expenditures.
- Insurance. To cover payments for insurance, a surcharge of 0.1% of the plant investment cost is suggested.

As noted in the HDR 2014 study, using the EPRI information, a 2.06 escalation factor had to be used to obtain the annual costs in 2014 dollars. Escalating to 2016, using 3% per year, this factor becomes 2.19. Table 5 in Appendix A summarizes the annual costs for the three Projects considered for this Study.

2.6.3 Bi-Annual Outage Costs

As noted in the HDR 2014 study, it is recommended within the hydro industry that bi-annual outages be conducted for inspections and possible repairs following the inspections. The frequency of inspections and possible repairs can vary greatly from project to project depending upon the usage (hours/year) and cycling of the units that may occur, along with site specific conditions that may impact the condition of the units over time. The assumption of taking two units out of service during a 3-week outage every two years for a 4 unit, 1,000 MW powerhouse at an estimated cost of $262,000 in 2014 dollars is reasonable. Escalating this cost using 3% per year would be approximately $280,000 in 2016 dollars and appropriate for budgeting purposes. Our review of the bi-annual outage cost compares favorably with the escalated value; assuming only nominal repairs are required.

2.6.4 Major Maintenance Costs

As noted in the HDR 2014 study, it is also recommended within the hydro industry that a pump-turbine overhaul (i.e. major unit rehabilitation) and generator rewind be scheduled at year 20, and the typical outage duration for this work is approximately 6 to 8 months. Because of the nature of this type of facility, pumped storage projects typically operate more hours per year than conventional generating units. This results in increased cycling of the units, which impacts service life requiring major maintenance. These are reasonable assumptions and suggested for this Study.

Because the scope of this type of rehabilitation work can vary greatly, HDR in their 2014 study suggested an estimated cost of $6.28 million for reversible Francis units at year 20. Escalating this value using 3% per year would be approximately $6.7 million in 2016 dollars. This value appears to be slightly low. In using the “Hydropower Modernization Guide” date July 1989 by the EPRI, a range of major rehabilitation average costs for the size of units being considered at Swan Lake North, JD Pool, and Seminoe (i.e. 100 MW to 300 MW) would be approximately $3.7 to $8.0 million. We suggest using this range of costs for major maintenance costs during the plant life.

2.7 SUMMARY

A matrix of operating parameters and costs for the pumped storage bulk energy storage option is provided in Table 6 in Appendix A. An estimated EPC expenditure timeline for a pumped storage facility based on a 5-year EPC schedule is also provided in Table 7 and Figure 1 in Appendix A.

3.0 Compressed Air Energy Storage

3.1 CAES TECHNOLOGY DESCRIPTION

3.1.1 Current Project Status

The DOE maintains a Global Energy Storage Database.[2] Black & Veatch filtered and sorted the data as shown in Table 8 in Appendix A. The characteristics of the identified projects included in the DOE database for the Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016 are shown. Descriptions for these projects as given in the DOE database are provided in Table 8, Table 9 and Table 10 in Appendix A. While the information in the DOE database is informative, not all the data is current.

As noted in the HDR 2014 study, only two CAES plants are currently in operation; the Power South (formerly AEC) McIntosh plant rated at 110 MW in McIntosh, Alabama which began operation in June 1991 and the 290 MW Huntorf facility which began operation in December 1978 in Hannover, Germany. Both of these plants use a solution mined salt cavity and are diabatic type CAES plants.

Other large CAES plants have been proposed but, as of yet, have not moved forward beyond conceptual design or have been cancelled.

With respect to the larger CAES projects, several were identified in the HDR 2014 study and include the following;

- Western Energy Hub Project
- Norton Energy Storage (NES) Project
- PG&E Kern County CAES Plant
- ADELE CAES Plant in Stassfut, Germany

Updates for CAES plants are as follows:

3.1.1.1 Western Energy Hub Project

The Western Energy Hub is situated directly above a salt dome at a nominal depth of 3,000 feet. Three-dimensional seismic mapping of the formation indicates the salt dome measures at least one mile thick and is approximately three miles wide. The Western Energy Hub project is planned to include multiple phases and services to support the expansion and utilization of renewable energy technologies. The Western Energy Hub will feature solution-mined salt caverns capable of storing natural gas, compressed air, and liquid energy products (including refined products of aviation fuel, diesel, and motor gasoline) underground.

[2] http://www.energystorageexchange.org/projects

Magnum is currently developing the Magnum Refined Products phase and it is expected to be the first underground salt cavern storage facility for refined products in the Rocky Mountain Region. The Magnum Gas Storage Project would also include the first High-Deliverability Multi-Cycle (HDMC) storage facility in the Rocky Mountain Region. The facility will contain four solution mined storage caverns capable of storing 54 billion cubic feet of natural gas. It will be interconnected with the interstate natural gas pipeline system by a new 61-mile-long header pipeline.

In addition to these services, the Western Energy Hub project will include a CAES plant in conjunction with a combined-cycle power generation project. The CAES plant will include additional solution-mined caverns to store compressed air. Off-peak renewable generation will be used to compress air into the caverns. The compressed air will be released to produce power during periods of peak power demand. Magnum anticipates an in-service date for the CAES plant of around 2021. Additional information on the CAES plant as provided to PacifiCorp by Magnum is included in Table 11 in Appendix A.

3.1.1.2 Norton Energy Storage (NES)

As noted in the HDR 2014 study; "In December 2012, First Energy suspended construction on the project due to unfavorable economic conditions including low cost of power prices and insufficient demand. As of September 2013, the Ohio Power Siting Board invalidated the certificate at this site." No further activity has been noted.

3.1.1.3 PG&E Kern County CAES

PG&E continues to evaluate the potential development of a Compressed Air Energy Storage (CAES) project and issued a Request for Offers (RFO) on October 9, 2016. Offers were received on June 1, 2016 with potential negotiations with shortlisted bidders to commence in August 2016. PG&E anticipates the project would be between 100 and 350 MW and would be required to have a minimum storage duration of 4 hours.

The RFO is intended to potentially procure products and services related to the CAES project, and to determine the technical and economic feasibility of energy storage using compressed air in a depleted natural gas reservoir in a porous rock formation, approximately one half to one mile underground.

The depleted natural gas field in San Joaquin County, California was selected for the project site and was subjected to air injection/withdrawal testing. PG&E notes that specific findings on geology, preliminary engineering, environmental analysis, and other information was gathered through testing and analyses for the site.

3.1.1.4 ADELE CAES

No new information could be found for the adiabatic ADELE CAES plant. It does not appear that there has been any recent development activity.

3.1.1.5 APEX Bethel Energy Center

This 317 MW CAES plant with 96 hours of storage was announced in 2013. In 2014 the project was placed on hold. It does not appear that there has been any recent development activity.

3.1.2 Performance Characteristics

3.1.2.1 Site Elevation

Site elevation will impact the compression work required to charge the storage for any CAES technology. Given the compressor section is not directly connected to the expansion turbine for conventional CAES operation, the volume flow of compressed air made available to the expansion turbine is not affected by site atmospheric pressure, but is instead driven by storage pressure. There is only a minor impact for conventional CAES plant output due to variation in exhaust pressure due to site elevation. Other configurations which may include a combustion turbine would see a greater impact due to site elevation.

3.1.2.2 Reliability/Availability

In addition to the historic availability data given in the HDR 2014 study, the Huntorf CAES plant has reportedly operated with 99 percent starting reliability.

3.1.2.3 Start Times

In addition to the start times given in the HDR 2014 study, newer CAES plants can achieve start times and fast ramp rates as noted in Table 11 in Appendix A. This data was provided to PacifiCorp by APEX Magnum.

3.1.2.4 Emission Profiles/Rates

No updates.

3.1.2.5 Air Quality Control System Design

In addition to Dry-Low NO_x combustion technology, water injection may also be used to control NO_x. A selective catalytic reduction (SCR) system can be included in the recuperator design to further reduce NO_x emissions. CO catalysts can also be incorporated into the recuperator design to control CO emissions if required by the CAES plant design and air permit requirements.

3.1.3 Geological Considerations

In addition to the geological formations generally considered for storing compressed air: salt domes, aquifers, and rock caverns; depleted methane reservoirs, which are being considered for the PG&E Kern River CAES plant, can be used.

For the Huntorf and McIntosh plants, there were large vertical salt domes that were accessible for solution mining of single caverns for compressed air storage. In some parts of the country, the salt is deposited between rock layers, creating shorter, squatter caverns with susceptibility to overhead shale spalling. These cavern costs can be higher.

In addition, underwater storage reservoirs, as offered by Hydrostor, are possible. Above ground storage can be considered for smaller plants or when geological conditions are not favorable for a site.

3.1.4 Capital, Operating, and Maintenance Cost Data

Regarding the HDR 2014 study's discussion of project schedule, it is noted the project durations can be driven by the storage system development. Based on a Front End Engineering Design (FEED) study prepared for the NYSEG Seneca CAES Project for a 136 MW to 210 MW utility-owned facility, it is noted that the development time required to complete the three cavern system required for the site was estimated at approximately six years. The CAES plant would have initially gone into service with only one third of the required storage capacity and would not achieve full capability until after approximately five years of commercial operation. The above emphasizes the point that the time required to develop storage can be very site dependent.

3.1.4.1 Capital Costs

The HDR 2014 study assumes project capital costs to include project direct costs associated with equipment procurement, installation labor, and commodity procurement as well as construction management, project management, engineering, and other project and owner indirect costs. The HDR estimate does not include storage cavern cost. Values were presented in 2014 dollars.

Table 11 in Appendix A shows a capital cost, including site development costs, of $1,740/kW as provided by APEX Magnum. No further cost breakdown or clarification for this cost was provided. Black & Veatch interprets this cost to be the installed cost including the solution-mined caverns. This cost is assumed to not include any Owners costs.

Site-specific factors can strongly influence the design of the CAES plant, the cavern and associated costs and ultimately the project economics.

3.1.4.2 Operating Costs

In addition to the operating costs given in the 2014 report, expected O&M costs for the Magnum CAES facility are given in Table 11 in Appendix A.

Appendix A. Data Tables

Table 1 Swan Lake North Pumped Storage Project Facilities Summary[3]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoir:	
Storage:	
Total:	3,229 acre-feet (ac-ft)
Live:	2,562 ac-ft
Surface Area:	
Maximum Fill:	64.21 acres (ac)
Minimum Fill:	45.87 ac
Operating Levels:	
Maximum:	6,128 mean sea level (msl)
Minimum:	6,084 msl
Elevation Change During Operation:	44 feet
Overflow Spillway Capacity:	3,230 cubic feet/sec (cfs)
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Lower Reservoir:	
Storage:	
Total:	3,206 ac-ft
Live:	2,581 ac-ft
Surface Area:	
Maximum Fill:	60.41 ac
Minimum Fill:	39.89 ac
Operating Levels:	
Maximum:	4,457 msl
Minimum:	4,408 msl
Elevation Change During Operation:	49 ft
Overflow Spillway Capacity:	3,230 cfs
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Source of Initial Fill and Long-term Refill:	Local Groundwater Agriculture Pumping System (Three existing wells)
Water Conveyance:	
Headrace Penstock:	
Diameter:	13.8 ft (4.2 meter)(1 pipe)
Length:	9,655 ft

[3] The information in this table has been obtained from Exhibits A and B of the FLA filed by Swan Lake North Hydro LLC on October 27, 2015

ITEM	DESCRIPTION
Tailrace Penstock:	
Diameter:	9.8 ft (3.0 meter)(3 pipes)
Length:	1,430 ft
Anchor Blocks (number):	5
Powerhouse:	
Footprint:	
Substructure:	220 ft x 62.5 ft (Bottom 65 ft below ground level @ EL 4248.3 msl)
Superstructure:	305 ft x 176 ft
Crane Capacity:	190 ton
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Mode:	
Total Maximum Capacity:	393.3 MW
Total Maximum Flow:	3,072 cfs
Gross Turbine Head Range:	Between 1,627 and 1,720 ft
Time per Day:	9.5 hours
Pumping Mode:	
Total Maximum Capacity:	415.8 MW
Total Maximum Flow:	2,427 cfs
Time per Day:	11.5 hours
Annual Energy Production (Based on Operational Modeling for 8.3 hours per Day):	1,187 Gigawatt-hours (GWh)
Transmission Line:	
Voltage:	230 Kilovolts (kV)
Length:	32.8 miles (mi)
Structures:	
Height:	80 to 120 ft
Type:	Steel Monopole
Right-of-Way:	
Length:	32.8 mi
Width:	300 ft
Intertie:	BPA Malin Substation (existing) near Malin, Oregon
Project Boundary Area:	
Reservoirs and Associated Features:	857 ac
Transmission Right-of-Way:	1,637 ac
Total Project:	2,494 ac

Table 2 JD Pool Pumped Storage Project Facilities Summary[4]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoirs:	
Configuration:	Two Reservoirs Connected By Tunnel
Total Active Storage:	11,800 ac-ft
Reservoir 1:	
Storage:	
Total:	5,000 ac-ft
Active:	4,700 ac-ft
Surface Area at Maximum Operating Level:	46 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Reservoir 2:	
Storage:	
Total:	7,700 ac-ft
Active:	7,100 ac-ft
Surface Area at Maximum Operating Level:	67 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Dams:	
Type:	Rockfill Embankment
Reservoir 1:	
Height:	165 ft
Length:	5,200 ft
Reservoir 2:	
Height:	165 ft
Length:	6,300 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Lower Reservoir:	
Storage:	
Total:	12,100 ac-ft
Active:	11,800 ac-ft
Surface Area at Maximum Operating Level:	100 ac

[4] The information in this table has been obtained from the PAD filed by KPUD in October 2014

ITEM	DESCRIPTION
Operating Levels:	
Maximum:	580 msl
Minimum:	430 msl
Elevation Change During Operation Storage:	150 ft
Dam:	
Type:	Rockfill Embankment
Height:	165 ft
Length:	7,800 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Initial Fill and Long-term Refill:	
Source:	Columbia River
Upgraded Existing Pump Station Capacity:	34.6 cfs
Pipeline Length to Lower Reservoir:	11,800 ft
Estimated Annual Net Water Loss Due to Evaporation:	746 ac-ft
Water Conveyance:	
Main Waterway Diameter:	21 ft
Waterway Segments Number/Length:	
Upper Reservoir Connection Tunnel:	1/2,010 ft
Low Pressure Tunnel:	2/1,140 and 1,290 ft, respectively
Vertical Power Shaft:	2/2,100 ft each
High Pressure Tunnel:	2/3,420 and 4,050 ft, respectively
Manifold:	2/270 ft each splitting into 4 penstocks
Penstocks:	4/190, 410, 610, and 820, respectively
Draft Tube Tunnel:	4/250, 350, 320, 420 ft, respectively
Tailrace Tunnel:	2/800 and 1,110 ft, respectively
Powerhouse:	
Type:	Pit Style
Footprint:	
Substructure Each Unit:	86 ft Diameter x 235 ft Deep
Superstructure:	710 ft Long x 96 ft Wide x 88 ft High
Pump-Turbine/Motor-Generator:	
Type:	Variable Speed
Number of Units:	4
Generating Mode:	
Total Capacity:	1,200 MW
Total Rated Flow:	7,000 cfs
Capacity per Unit:	300 MW
Rated Flow Per Unit	1,750 cfs
Rated Net Head:	2,200 ft (approximate)
Time per Day:	10.0 hours

ITEM	DESCRIPTION
Annual Energy Production (Based on Operating 10 Hours a Day, 50 Weeks of the Year):	4,200 GWh
Transmission Line:	
Voltage:	230 kV
Length:	3,000 ft
Intertie:	BPA Harvalum Substation (existing)
Project Area:	2,255 ac

Table 3 Seminoe Pumped Storage Project Facilities Summary[5]

ITEM	DESCRIPTION
Project Type:	Open-Loop Pumped Storage
Configuration:	Two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir
Upper Reservoirs:	
East Forebay:	
Storage:	4,800 ac-ft
Surface Area:	85 ac
Operating Level:	7,370 msl
Dam Embankment A:	
Type:	Concrete-Faced Rockfill (CFRD)
Height:	85 ft
Crest Length:	1,320 ft
Dam Embankment B:	
Type:	CFRD
Height:	Varies (5 ft at grade to 55 ft)
Crest Length:	5,890 ft
West Forebay:	
Storage:	3,740 ac-ft
Surface Area:	63 ac
Operating Level:	7,400 msl
Dam Embankment:	
Type:	CFRD
Height:	Varies (5 ft at grade to 60 ft)

5 The information in this table has been obtained from the Preliminary FERC Permit filed by Black Canyon Hydro, LLC in June 2016.

ITEM	DESCRIPTION
Crest Length:	5,890 ft
Lower Reservoir:	Seminoe Reservoir (existing)
Storage:	1,016,717 ac-ft
Surface Area:	20,291 ac
Operating Level:	6,359 msl
Dam (Existing):	
Type:	Concrete Arch
Height:	295 ft
Crest Length:	530 ft
Source of Reservoir Filling:	North Platte River (existing Seminoe Reservoir)
Water Conveyance:	
East Headrace Tunnel:	
Diameter:	18.8 ft (Tunnel/Shaft)
Length:	3,000 ft (Tunnel) 1,250 ft (Shaft)
East Tailrace Tunnel:	
Diameter:	22.6 ft
Length:	1,300 ft
West Headrace Tunnel:	
Diameter:	16.1 ft (Tunnel/Shaft)
Length:	1,300 ft (Tunnel) 1,800 ft (Shaft)
West Tailrace Tunnel:	
Diameter:	19.3 ft
Length:	2,800 ft
East Powerhouse:	
Footprint:	250 ft long x 65 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	400 MW
Maximum Static Head:	1,079 ft
West Powerhouse:	
Footprint:	220 ft long x 55 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	300 MW
Maximum Static Head:	1,098 ft
Annual Energy Production (combined East and West powerhouses):	1,840 GWh
Transmission Line:	

ITEM	DESCRIPTION
Voltage:	230 kV
Length:	35 mi (approximate)
Intertie:	Either Aeolous Substation (PacifiCorp)(planned) near Medicine Bow, WY or TransWest Express Terminal Substation (planned) near Sinclair, WY

Table 4 Cost Opinion Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
B&V Cost Opinion ($/kW)	$2,600	$2,700	$2,600
Developer Estimated Capital Cost ($/kW)	$2,500	$1,800 - $2,700	$2,100 - $2,400[6]

Table 5 Annual Cost Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
Plant Capacity (MW)	400	1,200	700
Annual Energy (GWh)	1,187	4,200	1,840
O&M Cost ($/yr)	5,400,000	11,500,000	7,400,000
General Expense ($/yr)	1,900,000	4,000,000	2,600,000
Plant Investment Unit Cost ($/kW)	2,600	2,700	2,600
Insurance ($/yr)	1,000,000	3,200,000	1,800,000
Total Annual Cost Opinion ($/yr)	8,300,000	18,700,000	11,800,000

[6] As noted in HDR's 2014 study, developer's estimated capital cost was deemed too low. HDR's cost opinion is shown.

Table 6 Pumped Storage Technology Summary Matrix

ITEM	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
General Criteria			
Location	OR	WA	WY
FERC Licensing Status	Final License Application Filed	Preliminary Permits Dismissed	Preliminary Permit Filed
Project Type (Closed/Open Loop)	Closed Loop	Closed Loop	Open Loop
Upper Reservoir Maximum Operating Elevation (msl)	6,128	2,935	7,370 (East) 7,400 (West)
Lower Reservoir Maximum Operating Elevation (msl)	4,457	580	6,359
Static Head (maximum/minimum) (ft)	1,720/1,627	2,505/2,205	1,079 (East)(max.) 1,098 (West)(max.)
Upper Reservoir Usable Volume (ac-ft)	2,562	11,800	4,800 (East) 3,740 (West)
Lower Reservoir Usable Volume (ac-ft)	2,581	11,800	> 8,540
Distance to Electrical Transmission Interconnection (mi)	32.8	< 1	35 (approximate)
Interconnection Size (kV)	230	230	230
Performance Characteristics[7]			
Energy Storage/Day (MWh)	3,800	12,000	7,000
Assumed Hours of Storage/Day (hrs)	9.5	10.0	10.0
Installed Capacity (MW)	400	1,200	700
Estimated Annual Generation (GWh)	1,187	4,200	1,840
Annual Forced Outage Rate (% of time)	0 – 3%[8]		
Type of Pump-Turbine/Motor-Generator	Variable Speed		
Round Trip Efficiency (%)	77		
Expected Life of Generating Equipment (yrs)	20+		
Expected Life of Project (yrs)	50+		
Basis of Cost Opinions (Costs are expressed in 2016 dollars.)			
Range of Capital Costs ($/kW)	$1,800 - $2,700		
Range of O&M Costs ($/kW-yr)	$4.45 - $6.99		
Bi-annual Outage Costs ($)	$280,000		
Range of Major Maintenance Costs/Unit ($)	$3,700,000 - $8,000,000		
Replacement Frequency (yrs)	20		

[7] Other performance characteristics, such as ramp rate, minimum loads, and time to switch from pumping to generating modes and vice versa for variable speed units, are presented in Table 3 of HDR's 2014 study and are reasonable and appropriate for this Study.

[8] Range of annual forced outage rate aligns with values presented in HDR's 2014 study.

Table 7 Estimated 5-year EPC expenditure pattern for a pumped storage facility

YEAR	QUARTER	CUMULATIVE QUARTER	QUARTERLY EXPENDITURE (%)	CUMULATIVE EXPENDITURE (%)
		0	0%	0%
1	1	1	2%	2%
1	2	2	2%	4%
1	3	3	3%	7%
1	4	4	3%	10%
2	1	5	4%	14%
2	2	6	4%	18%
2	3	7	5%	23%
2	4	8	5%	28%
3	1	9	6%	34%
3	2	10	6%	40%
3	3	11	8%	48%
3	4	12	8%	56%
4	1	13	8%	64%
4	2	14	8%	72%
4	3	15	7%	79%
4	4	16	7%	86%
5	1	17	7%	93%
5	2	18	3%	96%
5	3	19	3%	99%
5	4	20	1%	100%

Figure 1 Estimated 5-year EPC expenditure pattern for a pumped storage facility

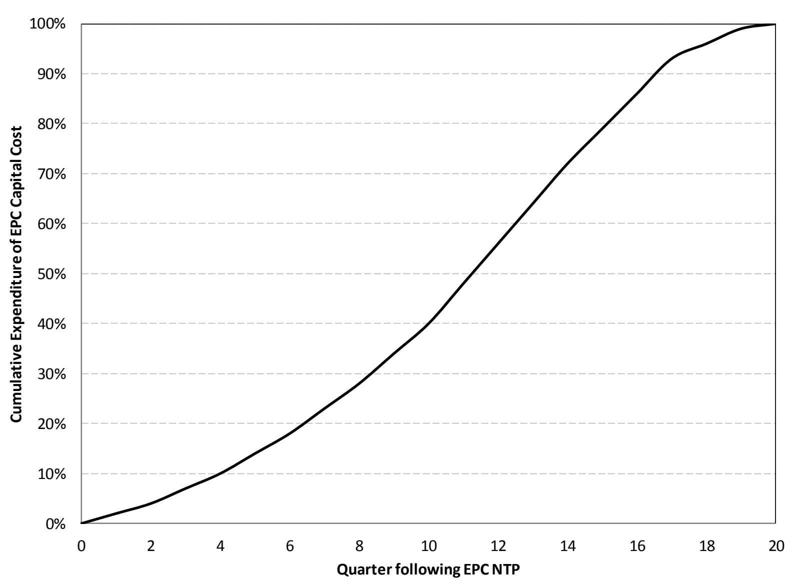

Table 8 Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016

Project Name	McIntosh CAES Plant	PG&E Advanced Underground Compressed Air Energy Storage (CAES)	Next Gen CAES using Steel Piping - NYPA	SustainX Inc Isothermal Compressed Air Energy Storage	Highview Pilot Plant	NYSEG Seneca/Watkins Glen CAES Project	Texas Dispatchable Wind	Apex Bethel Energy Center	Hydrostor UCAES Demonstration Facility	Hydrostor UCAES Aruba Project	Kraftwerk Huntorf	Pollegio-Loderio Tunnel ALACAES Demonstration Plant	Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	ATK Launch Systems Microgrid CAES [1]	Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	Adele CAES Project [1]
Technology Type	In-ground Natural Gas Combustion Compressed Air	In-ground Compressed Air Storage	Modular Compressed Air Storage	Modular Iso-thermal Compressed Air	Modular Compressed Air Storage	In-ground Compressed Air Storage	In-ground Iso-thermal Compressed Air	In-ground Compressed Air Storage	Modular Compressed Air Storage	Modular Compressed Air Storage	In-ground Natural Gas Combustion Compressed Air	Adiabatic Compressed Air Storage	Liquid Air Energy Storage	Modular Compressed Air Storage	Compressed Air Storage	In-ground Iso-thermal Compressed Air
Record Created	6/28/2012	6/29/2012	6/29/2012	7/18/2012	10/31/2012	5/2/2013	5/21/2013	10/11/2013	10/25/2013	10/25/2013	1/30/2014	6/25/2014	5/25/2016	5/6/2013	9/10/2015	11/4/2013
Last Updated	5/23/2016	6/14/2016	5/24/2016	5/24/2016	5/26/2016	9/5/2014	5/18/2016	1/28/2015	5/10/2016	7/23/2014	4/18/2016	5/19/2016	5/26/2016	7/11/2014	9/28/2015	10/27/2014
Rated Power in kW	110,000	300,000	9,000	1,500	350	0	2,000	317,000	1,000	1,000	321,000	500	5,000	80	0	200,000
Duration at Rated Power HH:MM	26:0.00	10:0.00	4:30.00	1:0.00	7:0.00	0:0.00	250:0.00	96:0.00	4:0.00	8:0.00	2:0.00	4:0.00	3:0.00	0:45.00	0:0.00	5:0.00
Status	Operational	Announced	Announced	Operational	Operational	Announced	Operational	Announced	Under	Contracted	Operational	Under	Under	Under	Announced	Under
City	McIntosh	San Joaquin	Queens	Seabrook	Slough	Reading	Seminole	Tennessee	Toronto	San Nicolas	Große Hellmer 1E	Loderio	Bury	Promontory	Pomona	Staßfurt
State/Province	Alabama	California	New York	New Hampshire	Berkshire	New York	Texas	Texas	Ontario	Aruba	Elsfleth	Ticino	Lancashire	Utah	California	Sachsen-Anhalt
Country	United States	United States	United States	United States	United Kingdom	United States	United States	United States	Canada	Netherlands	Germany	Switzerland	United Kingdom	United States	United States	Germany
Announcement Date		01.01.2010	01.06.2012		01.03.2010	30.11.2010		01.07.2013		01.10.2013		01.01.2013	13.02.2014	06.05.2013	20.08.2015	
Construction Date					01.02.2011		01.01.2011		01.01.2013	01.02.2015		13.06.2014	26.02.2015			01.01.2013
Commissioning Date	01.01.1991	01.01.2020		11.09.2013	31.07.2011		19.12.2012		01.09.2014		12.01.1978	01.06.2016				
ISO/RTO	N/A	CAISO	NYISO	ISO-NE	N/A	NYISO	SPP	ERCOT	IESO	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Utility	PowerSouth	Pacific Gas and Electric Company	New York Power Authority (NYPA)		SSE (Scottish and Southern Energy)	New York State Electric & Gas (NYSEG)				WEB Aruba N.V.	E.ON		Electricity North West	Rocky Mountain Power	Southern California Edison	
Energy Storage Technology Provider	Dresser-Rand			SustainX	Highview Power Storage		General Compression, Inc.	Dresser-Rand	Hydrostor	Hydrostor	BBC, Alstom	ALACAES	Highview Power Storage			
Expected Use Cases:																
Black Start			X			X		X			X					
Electric Supply Reserve Capacity - Non-Spinning												X	X			
Electric Supply Reserve Capacity - Spinning	X	X	X		X	X	X				X					
Load Following (Tertiary Balancing)							X									
Ramping				X				X								
Voltage Support													X			
Electric Energy Time Shift	X	X	X		X	X					X				X	X
Electric Supply Capacity							X									X
Transmission Congestion Relief				X		X							X			
Transmission Support													X			
Renewables Capacity Firming		X	X	X	X				X	X						
Distribution upgrade due to solar																
Distribution upgrade due to wind																
Transmission upgrades due to solar																
Transmission upgrades due to wind																
Electric Bill Management					X							X		X		
Grid-Connected Commercial (Reliability & Quality)																
Grid-Connected Residential (Reliability)																
Frequency Regulation	X	X	X			X		X			X		X			
Transportable Transmission/Distribution Upgrade Deferral																
Stationary Transmission/Distribution Upgrade Deferral																
Onsite Renewable Generation Shifting							X									
Electric Bill Management with Renewables																
Renewables Energy Time Shift				X	X		X	X	X	X		X				
On-Site Power														X		
Transportation Services																
Microgrid Capability																
Resiliency																
Demand Response																

Note 1: DOE still verifying record entry.

Source: DOE Global Energy Storage Database (http://www.energystorageexchange.org/projects)

Table 9 CAES and LAES project descriptions

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
McIntosh CAES Plant	110,000	26:0.00	The 2nd commercial CAES plant, in operation since 1991. Like the Huntorf plant, the McIntosh Unit 1 facility stores compressed air in a solution-mined salt cavern. The cavern is 220 ft in diameter and 1,000 ft tall, for a total volume of 10 million cubic feet. At full charge, the cavern is pressurized to 1,100 psi, and it is discharged down to 650 psi. During discharge, 340 pounds of air flow out of the cavern each second. The cavern can discharge for 26 hours. The plant also utilizes nuclear-sourced night-time power for compression and then produces peak power during the day by releasing the compressed air into a 110-MW gas-fired combustion turbine built by Dresser Rand. The turbine unit also makes use of an air-to-air heat exchanger to preheat air from the cavern with waste heat from the turbine. The waste heat recovery system reduces fuel usage by roughly 25%. Compared to conventional combustion turbines, the CAES-fed system can start up in 15 minutes rather than 30 minutes, uses only 30% to 40% of the natural gas, and operates efficiently down to low loads (about 25% of full load). The key function of the facility is for peak shaving.
PG&E Advanced Underground Compressed Air Energy Storage (CAES)	300,000	10:0.00	A 300 MW A-CAES demo plant will use an underground storage container (depleted gas reservoir), and next-generation turbomachinery. The project has 3 phases: Phase 1 - preliminary engineering, geologic reservoir engineering, econmoic analyses, and regulatory permitting; Phase 2 - Construction and plant commissioning; Phase 3: Plant operation and plant performance monitoring. Ph 2 of the project will go ahead if the Ph1 results show PG&E and California regulatory management that the project is cost effective.
Next Gen CAES using Steel Piping - NYPA	9,000	4:30.00	9-MW plant will use steel piping to hold pressurized air instead of geologic based air store. Preliminary plant design complete; NYSERDA funding expected in July 2012; Vendors, utility sponsor, and site location determined. Groundbreaking slated for 2013 to 2014 time frame.
SustainX Inc Isothermal Compressed Air Energy Storage	1,500	1:0.00	SustainX is constructing a 1.5MW pilot system in Seabrook, New Hampshire to demonstrate their modular isothermal compressed air energy storage system (ICAES). This second generation ICAES system is scheduled for completion in 2013, with the third generation field-deployed ICAES system ready for operation by 2014. The current schedule would have SustainX's isothermal system ready for commercial production in 2015. SustainX's ICAES system captures the heat from compression in water and stores the captured heat until it is needed again for expansion. Storing the captured heat eliminates the need for a gas combustion turbine and improves efficiency. SustainX achieves isothermal cycling by combining patented innovations with a design control on mature industrial components and principles. The system is designed for a 20-year lifetime. It achieves full power output from start-up in less than one minute, and it does not use toxic chemicals.
Highview Pilot Plant	350	7:0.00	Highview's technology uses off-peak or 'wrong-time' power to liquefy air (710 litres of air becomes one litre of liquid air), which is then held in a tank until electricity is required. The liquid air is then returned to gaseous form, expanding 710 times, to drive a turbine. Extreme cold is recovered and stored to assist with subsequent liquefaction, thus greatly improving the overall efficiency of the system. If waste heat is available (e.g. from a neighbouring power plant or industrial process) then this can be introduced at the expansion phase, enhancing system efficiency.
NYSEG Seneca/Watkins Glen CAES Project	0	0:0.00	***09/2012: NYSEG has concluded that the economics of the project are not favorable for development in the current and forecast wholesale electric market in New York State, and further project development work is not warranted.*** Read the final project report here: http://goo.gl/HbiWQ9 New York State Electric & Gas (NYSEG) intended to build an advanced compressed air energy storage (CAES) plant with a rated capacity of 150 MW (2.4 GWh) using an existing 4.5 million cubic foot underground salt cavern in Reading, New York. The plant was to be sited between the bulk of U.S. wind resources and the heavy population centers of the East Coast. The plant will have the capacity to operate 16 hours a day and will provide energy arbitrage for approximately 2,300-2,500 hours each year. It will use off-peak electricity to compress air into the cavern. When electricity is needed the air will be withdrawn, heated, and passed through a turbine to drive an electric generator, burning one-third the amount of fuel compared to conventional combustion turbines. NYSEG's CAES plant will provide flexible generation capability to accommodate fluctuations in load. The plant will be tied to NYSEG's cross-state 230 kV/345 kV transmission system that feeds major metropolitan centers in Central New York. The 230 kV line is the recipient of a large proportion of wind power and is tied to the New York City load areas. It will provide redundancy in capacity, ensure against congestion and power fluctuations, and can provide improved power quality to the grid. Iberdrola USA, the parent of NYSEG, plans to conduct a feasibility study in the future to determine the ability to increase the plant's capacity to 360 MW or greater.
Texas Dispatchable Wind	2,000	250:0.00	The Gaines, Texas Dispatchable Wind Project is a 2.0MW wind generation project located in West Texas. It is owned and operated by Texas Dispatachable Wind 1, LLC, a subsidiary of General Compression. The project consists of a wind turbine, a General Compression Advanced Energy Storage (GCAES™) system, a storage cavern, and other electrical & ancillary facilities. The project has the capability to, during periods of low demand, store portions of the energy generated by the wind turbine and later, during periods of increased demand, release the stored energy. Construction of the project began in 2011 and the project was commissioned in late 2012.
Apex Bethel Energy Center	317,000	96:0.00	Development of the 317 MW compressed air energy storage facility with 96 hours of storage has been put on hold as of 10/2014. New information on development is anticipated in summer 2015.

Table 10 CAES and LAES project descriptions (continued)

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
Hydrostor UCAES Demonstration Facility	1,000	4:0.00	Construction is underway on a 1 MW/4 MWh demonstration facility to showcase Hydrostor's first-of-a-kind system. Located Approx. 5km from the shore of Toronto, the system will be situated in Lake Ontario at a depth of 80m.
Hydrostor UCAES Aruba Project	1,000	8:0.00	Hydrostor's proprietary technology is based on a simple idea: Anchor a low-cost air cavity to the bottom of a lake or ocean floor, and store energy in it by filling it with compressed air created using surplus renewable energy. The energy is discharged from the system by releasing the air stored underwater to drive a turbine recreating electricity when it is most needed - either to meet daily demand peaks or to cover periods of calm winds or cloud cover that prevent power from being harnessed.
Kraftwerk Huntorf	321,000	2:0.00	1st commercial CAES plant, operational since 1978. The 321-MW plant utilizes nuclear-sourced night-time power for compression and produces peak power during the day via a natural gas turbine. The facility stores the compressed air in two ""solution-mined"" salt caverns which comprise a total of 310,000 cubic meters. (Water was pumped into and out of a salt deposit to dissolve the salt and form the cavern.) The depth of the caverns is more than 600 m which ensures the stability of the air for several months' storage, and guarantees the specified maximum pressure of 100 bar. One cavern is cycled on a diurnal basis. The second cavern serves as a black start asset if the nearby nuclear power plant unexpectedly goes down.
Pollegio-Loderio Tunnel ALACAES Demonstration Plant	500	4:0.00	A demonstration plant to test a novel advanced adiabatic compressed air energy storage concept. An abandoned tunnel in the Swiss alps is used as the air storage cavern and a packed bed of rocks thermal energy storage is used to store the heat created during compression. The thermal energy storage is placed inside the pressure cavern. Project construction concluded in April 2016. The project is operating in the commissioning phase from April 2016 until June 2016. In June 2016 the plant will start full operation.
Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	5,000	3:0.00	Highview and project partners, leading UK renewable energy and recycling company Viridor, were awarded funding of more than £8 million ($11.6 million) by the British Government Department of Energy & Climate Change (DECC) for a 5 MW Liquid Air Energy Storage (LAES) technology system. The funding is supporting the design, build and testing of a Pre-Commercial LAES Technology Demonstrator alongside Viridor's landfill gas generation plant at Pilsworth in Greater Manchester UK. In addition to providing energy storage, the LAES technology plant will convert low grade waste heat from the onsite landfill gas engines to electrical power. The project will operate for at least one year and will demonstrate LAES providing a number of grid balancing services in the UK, including Short Term Operating Reserve (STOR), Secondary frequency response testing, Triad Avoidance (supporting the grid during the winter peaks) and also testing for the US regulation market.
ATK Launch Systems Microgrid CAES [1]	80	0:45.00	The Alliant Techsystems (ATK) Launch Systems project takes place at a single customer site – but, it's a large one. ATK Launch Systems in Promontory, Utah comprises over 540 buildings on a sprawling 19,900-acre site accessible by 75 miles of roads. Their power system of three main substations and 60 miles of power lines deliver about 17 MW (on-peak) to the facilities, with an annual energy bill of over $15 million. In recent years, utility tariff changes have significantly increased the portion of the monthly bills attributable to demand charges. ATK's Corporate Energy Team, established in 2003, and has already implemented a number of energy saving projects, realizing energy costs reductions of $2 million/year or more. As a result of a comprehensive plant-wide energy assessment (partially funded by DOE) in 2006/2007, ATK identified a new set of energy projects at the Promontory site. This project will integrate an ambitious and highly diverse set of distributed resources. These include four heat recovery systems using organic Rankin cycle (ORC) generators connected to Ormat energy converters, for a total of 1400 kW. Heat for the system will be supplied by a concentrating solar thermal array, air compressor waste heat and low pressure steam. The project will also incorporate about 140 kW of wind turbines, a yet-to-be-determined amount of hydro turbine capacity, and about 40 kW of micro-hydro turbines. For storage, the project includes up to 1440 kW of pumped hydro capacity for two - four hours, and an above-ground compressed air energy storage (CAES) and generation system (80 kW capacity for 30-60 minutes).
Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	0	0:0.00	Engineers from the University of California Los Angeles Henry Samueli School of Engineering and Applied Science have won a $1.62 million grant to build a hybrid energy storage system. The team with work with Southern California Edison, which will help operate the system on the Cal Poly Pomona campus upon completion, to build a system to store "energy harvested from intermittently productive renewable sources such as solar panels and wind farms, then releases that energy into the grid when demand is high," according to a news release. Lead by Pirouz Kavehpour, a professor of mechanical and aerospace engineering at UCLA, the team will build a system that uses both compressed air and thermal energy storage technologies to enhance capacity and reduce costs. "Our estimated cost of energy for this unit is about $100 per kilowatt hour, which is much lower than any battery system of which we are aware," said Kavehpour, in a prepared statement.
Adele CAES Project [1]	200,000	5:0.00	The first adiabatic CAES project; the heat that appears during compression is also stored, and then returned to the air when the air is expanded. Construction will begin in 2013 in Staßfurt, a city in Sachsen-Anhalt, Germany (ADELE stands for the German acronym for adiabatic compressed air energy storage for electricity supply). The project is a joint effort between RWE, General Electric, Zueblin, and the German Aerospace Center. The German Federal Ministry of Economics is also providing state funding. Altogether, the project members will contribute an amount of EUR 10 million.

Note 1: DOE still verifying record entry.

Source: DOE Global Energy Storage Database (http://w w w .energystorageexchange.org/projects)

Table 11 Magnum CAES Data

RESOURCE	CAES
Installation Name	320 MW Magnum CAES
Base Capital ($)	556,800,000
Pro-rated site development cost ($)	included in Base Capital
Net Capacity (MW)	320
Rated Energy Capacity (MWh)	15,360
Expected use cases	Energy, capacity, spinning, regulation, non-spinning, black start
Total Implementation Time (yrs)	3
Commercial Operation Year	2021
Design Life (yrs)	30+
Base Capital ($/KW)	1,740
Var O&M ($/MWh)	0.77
Fraction Var O&M Capitalized	0.41
Fixed O&M ($/KW-yr)	18.9
Fraction Fixed O&M Capitalized	0
Average Full Load Heat Rate (HHV Btu/KWh)	4,227
EFOR (%)	3%
POR (%)	1.5%
Heat Input for Warm Start (HHV, MMBtu)	0
Water Consumed (Gal/MWh)	294
SO2 (lbs/MMBtu)	0.001
NOx (lbs/MMBtu)	0.009
Hg (lbs/TBTu)	N/A
CO2 (lbs/MMBtu)	117
Minimum Capacity (MW)	3.3
Spinning Reserves (MW)	156.7
Run-up Rate (first fire to min capacity, warm start, MW/hr)	180
Ramp Up Rate (min capacity to full load, MW/min)	32
Ramp Down Rate (full load to min capacity, MW/min)	32
Start-Up Time to Minimum Capacity (min)	5 min
Minimum Operational Up Time (hr)	N/A
Minimum Operational Down Time (hr)	N/A
Recharge rate (MWh/hour)	150
AC to AC efficiency (%) [1]	~50%

Note 1: The basis for this efficiency value is unclear. PacifiCorp has requested Magnum to clarify the definition used to determine this value but at the time of this report, clarification had not been received. Given the technology for CAES can include the use of fuel during the discharge mode, parameters for Energy Charge Ratio (kWh_{in}/kWh_{out}) and Net Heat Rate (Btu/kWh) during discharge mode (which considers the fuel added) are metrics typically used.