Xcel Energy®
RESPONSIBLE BY NATURE®

Public Service Company of Colorado

2016 Electric Resource Plan
Volume 2

(CPUC Proceeding No. 16A-0396E)
May 27, 2016

This Page Intentionally Blank

TABLE OF CONTENTS

2.0 CONTENTS OF THE RESOURCE PLAN ... 11

ERP Rules Completeness Matrix ... 12

2.1 RESOURCE ACQUISITION AND PLANNING PERIOD ... 23

Resource Acquisition Period ... 23
Planning Period ... 23

2.2 ELECTRIC ENERGY AND DEMAND FORECASTS ... 24

Introduction ... 24
Figure 2.2-1 Native Load Peak Demand Forecasts ... 25
Peak Demand Discussion ... 26
Annual Energy Discussion ... 28
Actual and Forecasted Demand and Energy ... 29
Energy and Demand Forecasts, 2015-2055 ... 31
Forecast Overview ... 40
Forecast Methodologies ... 41
Demand Forecast ... 45
Variability Due to Weather ... 47
High Growth Forecast ... 50
Low Growth Forecast ... 51
Forecast Accuracy ... 55

2.3 HOURLY LOAD PROFILES ... 80

Introduction ... 80

2.4 EVALUATION OF EXISTING RESOURCES ... 141

Company Owned Resources ... 141
In-Service Date for Facilities Granted a CPCN ... 144
Purchased Power ... 144
Demand Side Management ... 148

2.5 TRANSMISSION RESOURCES ... 154

Electric Transmission System Overview ... 154
TOT Transmission System Operating Limitations ... 156
SB07-100 New Transmission Additions ... 161
Other Transmission Additions ... 165
Transmission Injection Capability ... 166
Transmission Service Agreements ... 169
Coordination Agreements ... 170

2.6 RESERVE MARGINS AND CONTINGENCY PLANS ... 171

Planning Reserve Background ... 171
Reliability Planning at Public Service ... 172

Planning Reserves for the 2016 ERP 174
Contingency Plan 175
Contingency Events 175
Contingency Plan Options 175
Critical Factors 176
Corrective Actions 176

2.7 PHASE I PLAN DEVELOPMENT AND MODELING DETAILS 180

Strategist Model Description 180
Modeling Assumptions 180
Generic Resource Costs and Performance 196
Projected Emissions 199

2.8 WATER RESOURCES 210

Use of Water in Electric Generation 210
Public Service's Water Consumption and Intensity 210

2.9 PHASE II COMPETITIVE ACQUISITION 215

Company Activities Following the Release of an RFP 215
Initial Economic Analysis and Screening 217

2.10 CONFIDENTIAL AND HIGHLY CONFIDENTIAL INFORMATION 230

Public Information 230
Confidential Information 235
Highly Confidential Information 237
Information that Public Service will Provide Bidders 237
Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results 238

2.11 OTHER ISSUES REQUIRED TO BE ADDRESSED BY COMMISSION ORDER 239

Accounting Standards 240
Filler Capacity Adjustment 247
Surplus Capacity Credit 249
Gas Price Volatility Mitigation Adder (GPVM) 251
Annuity Tails 254
Flexible Resources 261
Carbon Costs 262

2.12 LOAD AND RESOURCES TABLE 262

2.13 REFERENCES 268

Attachment 2.13-1 Wind ELCC Study Report
Attachment 2.13-2 Coal Cycling Study Report
Attachment 2.13-3 Flex Reserve Study Report
Attachment 2.13-4 2GW/3GW Wind Integration Study Report
Attachment 2.13-5 Reserve Margin LOLP Report
Attachment 2.13-6 Appendix E from Proceeding No. 13I-0215E

LIST OF TABLES

TABLE 2.0-1 ERP Rules Completeness Matrix 12
Table 2.2-1 Actual and Forecasted Summer Native Load Peak Demand 27
Table 2.2-2 Actual and Forecasted Annual Native Load Energy Sales 28
Table 2.2-3 Actual and Forecasted Summer Peak Demand and Annual Energy 30
Table 2.2-4 Base Case: Energy/Coincident Summer and Winter Demand 32
Table 2.2-5A Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class 33
Table 2.2-5B Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class 34
Table 2.2-6 Base Case: Energy and Capacity Sales to Other Utilities 35
Table 2.2-7 Base Case: Intra-Utility Energy and Capacity Use 36
Table 2.2-8A Base Case: Losses by Major Customer Class 37
Table 2.2-8B Base Case: Losses by Major Customer Class 38
Table 2.2-9 Base Case: Energy and Peak Demand Incremental DSM Savings 39
Table 2.2-10 Actual and Forecasted Summer Peak Demand 40
Table 2.2-11 Actual and Forecasted Annual Sales 41
Table 2.2-12 Native Peak Demand Weather Variability 48
Table 2.2-13 Annual Native Energy Sales Weather Variability 49
Table 2.2-14 Base Case, High, and Low Sales of Energy (MW) 53
Table 2.2-15 Base Case, High and Low Coincident Summer and Winter Peak Demand54
Table 2.2-16 Native Sales Forecast Comparison (GWh) 56
Table 2.2-17 Forecast Sales less Actual Sales (GWh) 56
Table 2.2-18 Coincident Summer Demand Forecast Comparison (MW) 57
Table 2.2-19 Forecast Demand less Actual Summer Native Peak Demand (MW) 57
Table 2.2-20 Weather Normalized Coincident Summer Demand Forecast Comparison (MW) 58
Table 2.2-21 Forecast Demand less Actual Summer Demand (MW) 58
Table 2.2-22 Coincident Winter Demand Forecast Comparison (MW) 59
Table 2.2-23 Forecast Demand less Actual Winter Demand (MW) 59
Table 2.2-24 2011 ERP Forecast vs. 2016 ERP Forecast 62

Table 2.2-25 Number of Residential Electric Customers 65
Table 2.2-26 Residential Electric Customers – Regression Statistics 65
Table 2.2-27 Residential Electric Customers 66
Table 2.2-28 Residential Electric Sales per Customer.. 66
Table 2.2-29 Residential Electric Sales per Customer.. 67
Table 2.2-30 Residential Electric Sales per Customer.. 67
Table 2.2-31 Commercial / Industrial Electric Sales 68
Table 2.2-32 Commercial/Industrial Electric Sales 69
Table 2.2-33 Commercial & Industrial Electric Sales 70
Table 2.2-34 Electric Sales to Other Public Authorities 70
Table 2.2-35 Electric Sales to Other Public Authorities – Regression Statistics............ 71
Table 2.2-36 Electric Sales to Other Public Authorities – Definitions and Sources 71
Table 2.2-37 Electric Street and Highway Lighting Sales 72
Table 2.2-38 Electric Street and Highway Lighting Sales – Regression Statistics......... 73
Table 2.2-39 Electric Street and Highway Lighting Sales – Deficitions and Sources 73
Table 2.2-40 Residential Contribution to System Peak Demand 74
Table 2.2-41 Residential Contribution to System Peak Demand – Regression Statistics75
Table 2.2-42 Residential Contribution to System Peak Demand – 76
Table 2.2-43 Non-residential Contribution to System Peak Demand............................. 77
Table 2.2-44 Non-residential Contribution to System Peak Demand – Regression Statistics... 78
Table 2.2-45 Non-residential Contribution to System Peak Demand – Definitions and Sources.. 79
Table 2.4-1 Name and Location of Public Service Owned Generation Facilities....... 141
Table 2.4- 2 Public Service Owned Generation Facilities (MW) 142
Table 2.4-3 Projected Capacity Factors.. 143
Table 2.4-5 PPA Duration and Contract Modification Terms 146
Table 2.4-6 Clean Power Plan Affected Units (Public Service Owned) 147
Table 2.4-7 Clean Power Plan Affected Units... 147
Table 2.4-8 Demand Response Goals (MW) 148
Table 2.5-1 TOT Transmission Transfer Capability Limitations (2015)...................... 159
Table 2.5-2 SB07-100 Projects Likely to be In-Service During the RAP.................... 164
Table 2.6-1 Hierarchy of Contingency Plan Alternatives 178

Table 2.7-2 Fuel and Market Price Inputs ... 182
Table 2.7-6 Wind Integration Costs by Scenario ... 189
Table 2.7-7 Average Coal Cycling Costs by Scenario ... 191
Table 2.7-8 Average Solar Integration Costs (All Scenarios) ... 193
Table 2.7-10 Generic Dispatchable Resource Cost and Performance ... 197
Table 2.7-11 Total Capacity Costs of RAP Dispatchable Generic Resources ... 198
Table 2.7-12 Generic Renewable Resource Cost and Performance ... 199
Table 2.7-13 Projected SO_2 Emissions (Tons) From Existing Resources ... 200
Table 2.7-14 Projected SO2 Emissions (Tons) from Generic Resources ... 201
Table 2.7-15 Projected NO_x Emissions (Tons) from Existing Sources ... 202
Table 2.7-16 Projected NOx Emissions (Tons) from Generic Sources ... 203
Table 2.7-17 Projected PM Emissions (Tons) from Existing Sources ... 204
Table 2.7-18 Projected PM Emissions (Tons) from Generic Sources ... 205
Table 2.7-19 Projected Mercury Emissions (lbs) from Existing Resources ... 206
Table 2.7-20 Projected Mercury Emissions (lbs) from Generic Resources ... 207
Table 2.7-21 Projected CO_2 Emissions (Tons) from Existing Resources ... 208
Table 2.7-22 Projected CO_2 Emissions (Tons) from Generic Resources ... 209
Table 2.8-1 2014 Water Use and Generation by Public Service Facility ... 211
Table 2.8-2 Annual Consumptive Water Use and Intensity by Public Service Facility 213
Figure 2.11-4 Modified Commission Carbon Price Recommendation and Three-Source Blend ... 263
Figure 2.11-5 Proposed Low Carbon Proxy Price and Sources ... 264
Table 2.11-4 Proposed High and Low Carbon Proxy Price Values ... 265

LIST OF FIGURES

Figure 2.2-1 Native Load Peak Demand Forecasts 25
Figure 2.2-2 Native Load Energy Sales Forecasts 25
Figure 2.2-3 Native Electric Sales (GWh) 45
Figure 2.2-4 Native Peak Demand (MW) 47
Figure 2.2-5 Native Peak Demand Weather Confidence Bands (MW) 50
Figure 2.2-6 Native Sales Weather Confidence Bands (GWH) 50
Figure 2.2-7 Base Case, High and Low Peak Native Sales Forecast Comparison – Base, High, Low 52
Figure 2.2-8 Base Case, High and Low Peak Demand Forecast 52
Figure 2.2-9 Forecast Comparison to Actual Native Energy Sales 60
Figure 2.2-10 Forecast Comparison to Actual Summer Native Peak Demand 60
Figure 2.2-11 Forecast Comparison to Actual Winter Native Peak Demand 61
Figure 2.2-12 Energy Sales Forecast Comparison – 2011 ERP & 2016 ERP 63
Figure 2.2-13 Summer Native Load Peak Demand Forecast Comparison – 2011 ERP & 2016 ERP 64
Figure 2.3-1 Residential January 81
Figure 2.3-2 Residential February 82
Figure 2.3-3 Residential March 83
Figure 2.3-4 Residential April 84
Figure 2.7-5 Residential May 85
Figure 2.7-6 Residential June 86
Figure 2.7-7 Residential July 87
Figure 2.7-8 Residential August 88
Figure 2.7-9 Residential September 89
Figure 2.7-10 Residential October 90
Figure 2.7-11 Residential November 91
Figure 2.7-12 Residential December 92
Figure 2.7-13 Commercial & Industrial (Secondary) January 93
Figure 2.7-14 Commercial & Industrial (Secondary) February 94
Figure 2.7-15 Commercial & Industrial (Secondary) March 95

Figure 2.7-16 Commercial & Industrial (Secondary) April 96
Figure 2.7-17 Commercial & Industrial (Secondary) May 97
Figure 2.7-18 Commercial & Industrial (Secondary) June 98
Figure 2.7-19 Commercial & Industrial (Secondary) July 99
Figure 2.7-20 Commercial & Industrial (Secondary) August 100
Figure 2.7-21 Commercial & Industrial (Secondary) September 101
Figure 2.7-22 Commercial & Industrial (Secondary) October 102
Figure 2.7-23 Commercial & Industrial (Secondary) November 103
Figure 2.7-24 Commercial & Industrial (Secondary) December 104
Figure 2.7-25 Commercial & Industrial (Primary) January 105
Figure 2.7-26 Commercial & Industrial (Primary) February 106
Figure 2.7-27 Commercial & Industrial (Primary) March 107
Figure 2.7-28 Commercial & Industrial (Primary) April 108
Figure 2.7-29 Commercial & Industrial (Primary) May 109
Figure 2.7-30 Commercial & Industrial (Primary) June 110
Figure 2.7-31 Commercial & Industrial (Primary) July 111
Figure 2.7-32 Commercial & Industrial (Primary) August 112
Figure 2.7-33 Commercial & Industrial (Primary) September 113
Figure 2.7-34 Commercial & Industrial (Primary) October 114
Figure 2.7-35 Commercial & Industrial (Primary) November 115
Figure 2.7-36 Commercial & Industrial (Primary) December 116
Figure 2.7-37 Commercial & Industrial (Transmission) January 117
Figure 2.7-38 Commercial & Industrial (Transmission) February 118
Figure 2.7-39 Commercial & Industrial (Transmission) March 119
Figure 2.7-40 Commercial & Industrial (Transmission) April 120
Figure 2.7-41 Commercial & Industrial (Transmission) May 121
Figure 2.7-42 Commercial & Industrial (Transmission) June 122
Figure 2.7-43 Commercial & Industrial (Transmission) July 123
Figure 2.7-44 Commercial & Industrial (Transmission) August 124
Figure 2.7-45 Commercial & Industrial (Transmission) September 125
Figure 2.7-46 Commercial & Industrial (Transmission) October 126
Figure 2.7-47 Commercial & Industrial (Transmission) November 127
Figure 2.7-48 Commercial & Industrial (Transmission) December 128

Figure 2.7-49 FERC Jurisdictional January ... 129
Figure 2.7-50 FERC Jurisdictional February ... 130
Figure 2.7-51 FERC Jurisdictional March ... 131
Figure 2.7-52 FERC Jurisdictional April ... 132
Figure 2.7-53 FERC Jurisdictional May ... 133
Figure 2.7-54 FERC Jurisdictional June ... 134
Figure 2.7-55 FERC Jurisdictional July ... 135
Figure 2.7-56 FERC Jurisdictional August ... 136
Figure 2.7-57 FERC Jurisdictional September ... 137
Figure 2.7-58 FERC Jurisdictional October ... 138
Figure 2.7-59 FERC Jurisdictional November ... 139
Figure 2.7-60 FERC Jurisdictional December ... 140
Figure 2.5-1 Colorado Transmission Map ... 155
Figure 2.5-2 Colorado TOT Transmission Path Map ... 158
Figure 2.5-3 Energy Resource Zones with Generation Development Areas ... 163
Figure 2.5-4 Potential Injection Values and Locations ... 168
Figure 2.5-1 Regional Reliability Councils of NERC ... 171
Figure 2.8-1 Water Intensity ... 212
Figure 2.9-1 Indicative Phase II Timeline ... 216
Figure 2.9-2 Least-Cost Company Self-Build Portfolio ... 224
Figure 2.9-3 Depiction of Strategist Model with Locked-down Resources ... 225
Figure 2.9-4(a) Illustration A of a Portfolio of Bids and Company Proposals ... 226
Figure 2.9-4(b) Illustration B of a Portfolio of Bids and Company Proposals ... 226
Figure 2.9-5 Comparison of Higher and Lower-Cost Bid Portfolios ... 227

2.0 CONTENTS OF THE RESOURCE PLAN

Commission Rule 3604 of the Electric Resource Planning rules sets forth the required contents of the Resource Plan. Table 2.0-1 provides a matrix of the rule requirements and indicates where the information can be found throughout Volume 1, Volume 2, and/or Volume 3 of the 2016 ERP.

ERP Rules Completeness Matrix

TABLE 2.0-1 ERP RULES COMPLETENESS MATRIX

CPUC Rule	Required Information	Where
Rule 3604	**Contents of the Resource Plan.**	
	The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following:	
Rule 3604	**Resource Acquisition Period and Planning Period.**	
3604(a)	A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.	Vol.1, Section 1.5
Rule 3604(b) & 3606	**Electric Demand and Energy Forecast.**	
3604(b)	An annual electric demand and energy forecast developed pursuant to rule 3606.	Vol. 2, Section 2.2
3606(a)	Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period:	
3606(a)(I)	Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.	
3606(a)(II)	Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.	
3606(a)(III)	Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.	
3606(a)(IV)	Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.	
3606(a)(V)	Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.	

CPUC Rule	Required Information	Where
3606(a)(VI)	Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.	Volume 2 2.3
3606(b)	Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy of coincident summer and winter peak demand and energy sales during the planning period.	Vol. 2, Section 2.2
3606(c)	Required detail.	
3606(c)(I)	In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.	
3606(c)(II)	The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.	
3606(d)	Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.	

CPUC Rule	Required Information	Where
3606(e)	Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.	Vol. 2, Section 2.2
3606(f)	Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.	
Rule 3604(c) & 3607	**Evaluation of Existing Resources.**	
3604(c)	An evaluation of existing resources developed pursuant to rule 3607.	
3607(a)	Existing generation resource assessment. The utility shall describe its existing resources, all utility-owned generating facilities for which the utility has obtained a Certificate of Public Convenience and Necessity (CPCN) from the Commission pursuant to § 40-5-101, C.R.S., at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following:	Vol. 2, Section 2.4
3607(a)(I)	Name(s) and location(s) of utility-owned generation facilities.	
3607(a)(II)	Rated capacity and net dependable capacity of utility-owned generation facilities.	
3607(a)(III)	Fuel type, heat rates, annual capacity factors and availability factors projected for utility- owned generation facilities over the resource acquisition period.	
3607(a)(IV)	Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.	
3607(a)(V)	Estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense.	
3607(a)(VI)	The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.	

CPUC Rule	Required Information	Where
3607(a)(VII)	The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.	Vol. 2, Section 2.5
3607(a)(VIII)	The projected emissions, in terms of pounds per MWh and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).	Vol. 2, Section 2.7
3607(a)(IX)	The expected demand-side resources during the resource planning period from (1) existing measures installed through utility-administered programs, and (2) from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved plan.	Vol. 2, Section 2.4
3607(b)	Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.	Vol. 2, Section 2.4
Rule 3604(d) & 3608	**Transmission Resources.**	
3608(a)	The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.	Vol. 2, Section 2.5
3608(b)	With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., that, as identified in that report, could reasonably be placed into service during the resource acquisition period.	
3608(c)	For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:	
3608(c)(I)	Length and location.	
3608(c)(II)	Estimated in-service date.	

CPUC Rule	Required Information	Where
3608(c)(III)	Injection capacity.	Vol. 2, Section 2.5
3608(c)(IV)	Estimated costs.	
3608(c)(V)	Terminal points.	
3608(c)(VI)	Voltage and megawatt rating.	
3608(d)	In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.	
3608(e)	The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.	
Rule 3604(e) & 3609	**Planning Reserve Margin & Contingency Plans.**	
3604(e)	An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.	Vol. 2, Section 2.6
3609(a)	The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).	
3609(b)	The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: (1) the development of generation, (2) losses of generation capacity, (3) purchase of power, (4) losses of transmission capability, (5) risks due to known or reasonably expected changes in environmental regulatory requirements, and (6) other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.	

CPUC Rule	Required Information	Where
3609(c)	Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of (1) additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610, or (2) replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The utility will identify the estimated costs it will incur in developing the contingency plan for addressing the acquisition of these resources (*e.g.,* purchasing equipment options, establishing sites, engineering). The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3618(b)(II). The provisions of paragraph 3617(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.	Vol. 2, Section 2.6
3604(f) & 3610	**Assessment of Need for Additional Resources.**	
3604(f)	An assessment of the need for additional resources developed pursuant to rule 3610.	Vol. 1, Section 1.4
3610(a)	By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to rule 3609, the utility shall assess the need to acquire additional resources during the resource acquisition period.	
3610(b)	In assessing its need to acquire additional resources, the utility shall also:	
3610(b)(I)	Determine the additional renewable energy resources (*e.g.,* retail distributed generation (DG), wholesale DG, non-DG) resources, if any, the utility will need to acquire to comply with the Commission's Renewable Energy Standard Rules.	
3610(b)(II)	Take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611.	

CPUC Rule	Required Information	Where
3610(c)	The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.	
3604(g) & 3611	**Resource Acquisition Plan.**	
3604(g)	The utility's plan for acquiring these resources pursuant to rule 3611, including a description of the projected emissions, in terms of pounds per MWh and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Vol. 1, Section 1.6
3611(a)	It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost- effective resource plan (*i.e.,* an all-source solicitation).	
3611(b)	Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.	
3611(c)	If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition.	

CPUC Rule	Required Information	Where
3611(d)	Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its plan filed under rule 3603 the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.	Vol. 3
3611(e)	In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its plan submitted under rule 3603, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.	N/A
3611(f)	The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide sufficient cost information in support of its proposal such that the Commission can reasonably compare the utility's proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery.	
3611(g)	Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan. The utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits.	Vol. 2, Section 2.9

CPUC Rule	Required Information	Where
3611(h)	In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the following best value employment metric information regarding each resource:	N/A
3611(h)(I)	The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;	
3611(h)(II)	The employment of Colorado workers as compared to importation of out-of-state workers;	
3611(h)(III)	Long-term career opportunities; and	
3611(h)(IV)	Industry-standard wages, health care, and pension benefits.	
3604(h)	**Water Resources.**	
3604(h)	The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWh) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Vol. 2 Section 2.8
3604(i)	**RFPs and Model Contracts.**	
	The proposed RFP(s) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3616.	Vol. 3

CPUC Rule	Required Information	Where
3604(j)	**Confidential and Highly Confidential Information.**	
	A list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1100 of the Commission's Rules of Practice and Procedure in a timely manner.	Vol. 2, Section 2.10
3604(k)	**Alternative Plans.**	
	Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the Renewable Energy Standard, 4 CCR 723-3-3650 et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.	Vol. 1, Section 1.5

CPUC Rule	Required Information	Where
3604(l)	**Additional Renewable Resources.**	
	An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, including peer-reviewed studies, consistent with the amounts of renewable energy resources the utility proposes to acquire.	Vol. 1, Section 1.5

2.1 RESOURCE ACQUISITION AND PLANNING PERIOD

Resource Acquisition Period

The Resource Acquisition Period or RAP is the period in which the utility works to acquire generation resources to meet the electric system resource need projected in the ERP. The Commission's resource planning rules allow jurisdictional utilities the option of selecting a RAP of between six to ten years from the date the plan is filed. For the 2016 ERP, Public Service specifies an 8-year RAP that will run from 2016 to 2023, thereby addressing the summer peak needs of our systems for years 2016 through 2023.

A detailed discussion of the selection of the RAP for the 2016 ERP as well as Public Service's anticipated resource need and related issues is included in Section 1.3 of Volume 1.

Planning Period

The ERP Rules prescribe a Planning Period between twenty to forty years. Due to the fact that the Strategist model that will be used in the evaluation of Phase II power supply proposals is dimensioned for years 2016 to 2054, Public Service proposes a 39-year Planning Period for the 2016 ERP.

2.2 ELECTRIC ENERGY AND DEMAND FORECASTS

Introduction

Projections of future energy and peak demand are fundamental inputs into Public Service's resource need assessment. As required by ERP Rule 3606(b), Public Service prepared a base forecast and high and low forecast sensitivities.

Public Service projects base or median native load peak demand (retail and firm wholesale requirements customers) to grow at a compounded annual rate of 1.6% or an average of 86 MW per year through the RAP. This is larger than the 0.1% growth rate over the last five years. The loss of wholesale customers, high levels of DSM, and increase of on-site solar during the historical period explains the lackluster growth rates during the last five years. Public Service's low growth sensitivity for peak demand increases at a compounded growth rate of 0.6% through 2023, and the high growth sensitivity for peak demand increases at a compounded growth rate of 2.6% per year over the same period of time.

Public Service projects base or median annual energy sales to increase at a compounded annual growth rate of 1.5% or an average of 479 GWh per year through the RAP. Public Service's low growth sensitivity for the forecast of annual energy sales increases at a compounded annual growth rate of 0.3% through 2023, and the high growth sensitivity for the forecast of annual energy sales grow at a compounded rate of 2.5% per year.

Figures 2.2-1 and 2.2-2 show the base, high, and low forecasts of native load peak demand and energy sales graphically. Tables 2.2-1 and 2.2-2 show the data supporting the charts.

The base peak demand forecast assumes economic growth based on projections from IHS Global Insight, Inc., and median summer peak weather conditions.[1] Public Service estimates that there is a 70% chance that the actual peak demands will fall between the high and the low forecast scenarios.

[1] Median is synonymous with the 50th percentile, or it is higher than 50% of the estimates and lower than 50% of the estimates.

Figure 2.2-1 Native Load Peak Demand Forecasts

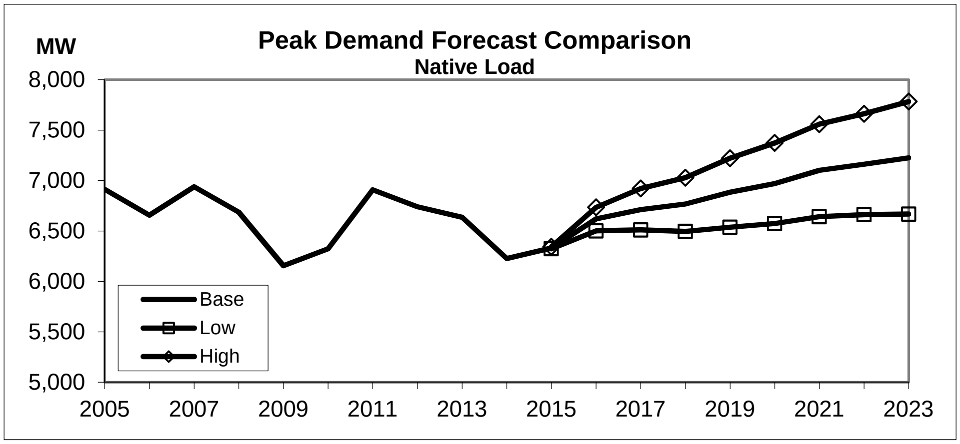
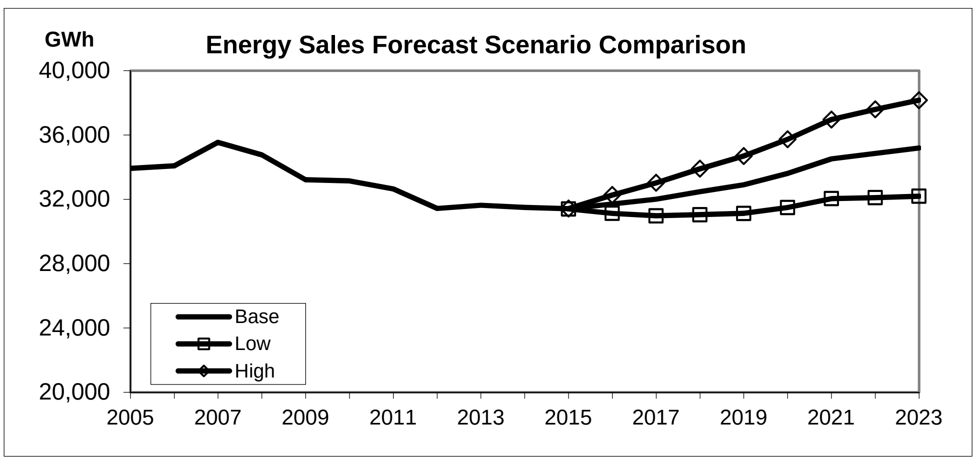


Figure 2.2-2 Native Load Energy Sales Forecasts



Peak Demand Discussion

Native load peak demand in Public Service's service territory has demonstrated modest growth during the past five years, advancing 71 MW. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this weak load growth.[2] Since 2009, Public Service's firm wholesale load has decreased by 473 MW. The loss of wholesale load was offset by load growth within the retail sector, which has averaged gains of 2.0% or 109 MW annually during the past five years.

Colorado's economy has recovered since the housing market and the financial sector crisis that started in 2008. This recovery is evidenced by gains in real personal income, real gross state product ("GSP"), non-farm employment, and home construction. In the five years ending in 2014, Colorado real GSP has averaged gains of 2.2% annually and real personal income advanced 3.0% annually. Jobs gains since 2011 have resulted in an advancement of non-farm employment averaging 1.8% annually. Colorado population has increased 1.5% per year since 2009. During the same period, Public Service's residential sectors added 52,440 customers, an increase of 4.6% over the 2009 customer count.

The economic outlook for Public Service's service territory through the RAP ending in 2023 indicates that Colorado will experience similar growth compared with the previous five years. Growth in Colorado real GSP and real personal income are expected to be 2.6% per year from 2016 to 2023. Nonfarm employment should advance by 1.6% annually over the same period. Population growth will continue at its recent historical pace of 1.4% annually. Public Service residential customers are expected to increase by 126,381 customers over the next 8 years with average gains of 1.4% per year through 2023.

Native load peak demand growth has been variable over the past five years with gains in the retail sector being partially offset by declines from wholesale load. Public Service's residential air conditioning load has grown over the last few years. The 2014 Residential Energy Use Survey conducted by Xcel Energy's Market Research Department indicates that 82% of Public Service's customers had some form of air condition/cooling

[2] Public Service's wholesale customers Intermountain Rural Electric Association and Holy Cross Energy reduced their wholesale load on Public Service's system by using a portion of the Comanche 3 coal-fired generation resource to serve their load.

system in 2014, which has grown compared with the 2010 survey that reported that 74% of Public Service's customers had some form of air condition/cooling system.

We expect native load peak demand growth over the RAP, through 2023, to advance by 1.6% (86 MW) per year.

Table 2.2-1 shows Public Service's native load summer peak demand forecasts along with ten years of history. It also shows annual growth and compounded growth to/from 2014. The bold line across the table delineates historical from projected information.

Table 2.2-1 Actual and Forecasted Summer Native Load Peak Demand[3]

	MW[4]			Annual Growth			Compound Growth to/from 2014		
	Base	Low	High	Base	Low	High	Base	Low	High
2005	6,912			7.2%			-1.1%		
2006	6,656			-3.7%			-0.8%		
2007	6,939			4.3%			-1.5%		
2008	6,687			-3.6%			-1.1%		
2009	6,156			-7.9%			0.3%		
2010	6,324			2.7%			-0.3%		
2011	6,909			9.2%			-3.3%		
2012	6,737			-2.5%			-3.7%		
2013	6,674			-0.9%			-6.3%		
2014	6,252			-6.3%			0.0%		
2015	6,332	6,324	6,344	1.3%	1.1%	1.5%	1.3%	1.1%	1.5%
2016	6,620	6,501	6,734	4.6%	2.8%	6.2%	2.9%	2.0%	3.8%
2017	6,712	6,511	6,921	1.4%	0.2%	2.8%	2.4%	1.4%	3.4%
2018	6,768	6,495	7,029	0.8%	-0.2%	1.6%	2.0%	1.0%	3.0%
2019	6,884	6,538	7,222	1.7%	0.7%	2.8%	1.9%	0.9%	2.9%
2020	6,970	6,574	7,373	1.2%	0.6%	2.1%	1.8%	0.8%	2.8%
2021	7,102	6,642	7,559	1.9%	1.0%	2.5%	1.8%	0.9%	2.7%
2022	7,161	6,662	7,662	0.8%	0.3%	1.4%	1.7%	0.8%	2.6%
2023	7,225	6,667	7,784	0.9%	0.1%	1.6%	1.6%	0.7%	2.5%

[3] 1 megawatt (MW) = 1,000 kilowatts (kW)
[4] Native Load Peak Demand MW is reflected on "Native Load" row in the Loads and Resources Table (Section 2.12). The Company's Firm Obligation load is calculated by subtracting the annual Firm Interruptible Load (Strategic Issues Demand Response Goal) from this native peak demand.

Annual Energy Discussion

Table 2.2-2 shows Public Service's forecast for its total annual energy sales with ten years of history. It also shows annual growth and compounded growth to/from 2014. The bold line across the table delineates historical from projected information with the 2015 values reflecting actual sales through June.

The decrease in 2008 is caused by the termination of the firm wholesale contract with Cheyenne Light Fuel & Power Company. The decrease in 2010 and 2011 are due to the participation of Intermountain Rural Electric Association and Holy Cross Energy in the Comanche 3 project. The decrease in 2012 is attributable to the termination of the wholesale contract with Black Hills Colorado.

Table 2.2-2 Actual and Forecasted Annual Native Load Energy Sales[5]

	GWh			Annual Growth			Compound Growth to/from 2014		
	Base	Low	High	Base	Low	High	Base	Low	High
2005	33,921			5.1%			-0.8%		
2006	34,082			0.5%			-1.0%		
2007	35,544			4.3%			-1.7%		
2008	34,764			-2.2%			-1.6%		
2009	33,213			-4.5%			-1.1%		
2010	33,146			-0.2%			-1.3%		
2011	32,643			-1.5%			-1.2%		
2012	31,435			-3.7%			0.1%		
2013	31,630			0.6%			-0.4%		
2014	31,497			-0.4%			0.0%		
2015	31,411	31,403	31,428	-0.3%	-0.3%	-0.2%	-0.3%	-0.3%	-0.2%
2016	31,714	31,126	32,270	1.0%	-0.9%	2.7%	0.3%	-0.6%	1.2%
2017	32,009	30,973	33,031	0.9%	-0.5%	2.4%	0.5%	-0.6%	1.6%
2018	32,482	31,044	33,904	1.5%	0.2%	2.6%	0.8%	-0.4%	1.9%
2019	32,911	31,123	34,697	1.3%	0.3%	2.3%	0.9%	-0.2%	2.0%
2020	33,615	31,493	35,737	2.1%	1.2%	3.0%	1.1%	0.0%	2.1%
2021	34,518	32,043	36,965	2.7%	1.7%	3.4%	1.3%	0.2%	2.3%
2022	34,860	32,106	37,598	1.0%	0.2%	1.7%	1.3%	0.2%	2.2%
2023	35,198	32,194	38,167	1.0%	0.3%	1.5%	1.2%	0.2%	2.2%

[5] 1 gigawatt hour (GWh) = 1 million kilowatt hours (kWh).

Due to the declines in wholesale sales, native load energy sales have decreased an average of -1.1% (-544 GWh) per year from 2009 to 2014. With the wholesale customers stabilizing, retail growth will be seen during the RAP ending in 2023. Native load energy sales will grow, advancing at 1.5% per year.

High and Low Case Forecasts

Development and use of different energy sales and demand forecasts for planning future resource additions is an important aspect of the planning process. Low and high growth sensitivities to the base case were developed for the 2016 ERP. Monte Carlo simulations were developed to establish confidence bands around the base forecast to determine the possible extent of variation in Public Service's service territory's economic growth.

Tables 2.2-1 and 2.2-2 summarize the base, low, and high energy sales and peak demand forecasts.

Actual and Forecasted Demand and Energy

Table 2.2-3 depicts Public Service's base case demand and energy forecast in the context of the last ten years of history. The bold line across the table delineates historical from projected information with 2015 values reflecting actual sales through June 2015.

Table 2.2-3 Actual and Forecasted Summer Peak Demand and Annual Energy

	Summer Peak Demand (MW)	Annual Increase (MW)	Energy Sales (GWh)	Annual Increase (GWh)	
2005	6,912	467	33,921	1,646	
2006	6,656	-256	34,082	161	
2007	6,939	283	35,544	1,462	
2008	6,687	-252	34,764	-781	
2009	6,156	-531	33,213	-1,550	History
2010	6,324	168	33,146	-68	
2011	6,909	585	32,643	-502	
2012	6,737	-171	31,435	-1,208	
2013	6,674	-63	31,630	194	
2014	6,252	-422	31,497	-132	
2015	6,559	306	31,367	-130	
2016	6,620	61	31,716	348	
2017	6,712	92	32,011	295	
2018	6,768	55	32,484	473	
2019	6,884	116	32,913	429	
2020	6,970	86	33,617	704	
2021	7,102	132	34,519	903	
2022	7,161	59	34,862	343	
2023	7,225	64	35,200	338	
2024	7,299	74	35,634	435	
2025	7,352	53	35,868	233	
2026	7,413	61	36,192	324	
2027	7,479	66	36,548	356	
2028	7,557	77	36,981	433	
2029	7,615	59	37,321	340	
2030	7,680	65	37,686	365	
2031	7,738	58	38,029	343	
2032	7,802	64	38,436	407	
2033	7,850	48	38,703	267	
2034	7,902	52	39,045	343	
2035	7,962	60	39,399	354	Forecast
2036	8,045	82	39,826	428	
2037	8,098	54	40,076	250	
2038	8,163	64	40,396	320	
2039	8,225	63	40,725	329	
2040	8,299	73	41,125	399	
2041	8,352	54	41,371	246	
2042	8,416	64	41,698	327	
2043	8,481	65	42,021	322	

	Summer Peak Demand (MW)	Annual Increase (MW)	Energy Sales (GWh)	Annual Increase (GWh)
2044	8,554	73	42,416	396
2045	8,613	59	42,756	340
2046	8,670	57	43,081	325
2047	8,717	47	43,406	325
2048	8,761	44	43,827	421
2049	8,802	41	44,164	337
2050	8,841	39	44,492	328
2051	8,877	36	44,819	327
2052	8,911	34	45,255	436
2053	8,941	31	45,563	308
2054	8,970	28	45,865	302
2055	9,020	51	46,168	303

Energy and Demand Forecasts, 2015-2055

Below are tables presenting the base case energy and demand forecasts for each year within the planning period, 2015-2055:[6]

[6]Public Service did not forecast any sales subject to the jurisdiction of other states.

Table 2.2-4 Base Case: Energy/Coincident Summer and Winter Demand (Including Impacts of DSM Programs)

	Energy Sales (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Retail	Wholesale	Retail	Wholesale	Retail	Wholesale
2015	29,078	2,290	6,078	480	4,675.3	572
2016	29,374	2,341	6,130	491	4,728.6	577
2017	29,689	2,322	6,213	499	4,763.2	585
2018	30,079	2,404	6,259	508	4,814.5	593
2019	30,543	2,370	6,366	518	4,930.9	602
2020	31,191	2,425	6,443	527	5,059.7	609
2021	32,046	2,474	6,566	536	5,080.0	618
2022	32,320	2,542	6,615	546	5,116.4	628
2023	32,603	2,596	6,668	557	5,154.1	637
2024	32,971	2,663	6,732	567	5,202.7	648
2025	33,146	2,721	6,776	577	5,226.2	658
2026	33,402	2,790	6,826	587	5,260.0	669
2027	33,693	2,854	6,882	597	5,300.0	680
2028	34,063	2,918	6,949	608	5,351.1	691
2029	34,340	2,982	6,996	619	5,388.0	703
2030	34,645	3,041	7,050	630	5,428.2	714
2031	34,935	3,094	7,096	641	5,468.6	726
2032	35,287	3,149	7,149	653	5,517.4	738
2033	35,504	3,199	7,185	665	5,548.7	750
2034	35,787	3,258	7,225	677	5,590.3	763
2035	36,087	3,311	7,273	689	5,631.6	775
2036	36,460	3,367	7,343	702	5,676.4	788
2037	36,653	3,423	7,384	715	5,696.6	801
2038	36,917	3,479	7,435	728	5,725.3	814
2039	37,190	3,536	7,484	741	5,755.2	827
2040	37,532	3,592	7,544	755	5,793.5	841
2041	37,723	3,648	7,584	768	5,812.9	855
2042	37,992	3,707	7,634	783	5,842.1	869
2043	38,257	3,764	7,684	797	5,870.6	883
2044	38,595	3,821	7,742	812	5,907.7	897
2045	38,877	3,879	7,786	827	5,937.8	912
2046	39,143	3,938	7,828	842	5,965.8	927
2047	39,409	3,996	7,859	858	5,991.6	942
2048	39,772	4,055	7,887	874	6,015.2	957
2049	40,050	4,114	7,912	890	6,036.7	973
2050	40,318	4,175	7,934	907	6,055.9	989
2051	40,585	4,234	7,953	924	6,073.0	1,005
2052	40,960	4,295	7,969	942	6,087.9	1,021
2053	41,208	4,355	7,982	959	6,100.6	1,037
2054	41,448	4,417	7,992	977	6,111.2	1,054
2055	41,690	4,478	8,024	996	6,137.1	1,071

Table 2.2-5A Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class (Including Impacts of DSM Programs)

	Energy Sales (GWh)					Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total
2015	9,243	19,595	240	2,290	31,367	2,479	3,584	15	480	6,559	2,044	2,564	68	572	5,247
2016	9,318	19,797	259	2,341	31,716	2,519	3,590	21	491	6,620	2,066	2,589	74	577	5,306
2017	9,373	20,038	277	2,322	32,011	2,557	3,635	21	499	6,712	2,088	2,600	74	585	5,348
2018	9,498	20,304	278	2,404	32,484	2,585	3,653	21	508	6,768	2,119	2,621	75	593	5,408
2019	9,569	20,692	283	2,370	32,913	2,608	3,735	22	518	6,884	2,141	2,714	76	602	5,533
2020	9,585	21,310	297	2,425	33,617	2,628	3,789	27	527	6,970	2,150	2,830	80	609	5,669
2021	9,603	22,134	309	2,474	34,519	2,645	3,894	27	536	7,102	2,167	2,833	81	618	5,698
2022	9,703	22,308	310	2,542	34,862	2,675	3,913	27	546	7,161	2,194	2,842	81	628	5,744
2023	9,806	22,487	311	2,596	35,200	2,709	3,932	27	557	7,225	2,221	2,852	81	637	5,792
2024	9,959	22,701	312	2,663	35,634	2,748	3,958	27	567	7,299	2,253	2,868	82	648	5,851
2025	10,004	22,829	313	2,721	35,868	2,780	3,969	27	577	7,352	2,275	2,869	82	658	5,885
2026	10,097	22,991	314	2,790	36,192	2,814	3,985	27	587	7,413	2,301	2,877	82	669	5,929
2027	10,206	23,173	315	2,854	36,548	2,852	4,003	27	597	7,479	2,331	2,888	82	680	5,980
2028	10,357	23,391	316	2,918	36,981	2,893	4,028	27	608	7,557	2,364	2,906	82	691	6,043
2029	10,427	23,596	317	2,982	37,321	2,931	4,038	27	619	7,615	2,394	2,913	82	703	6,091
2030	10,517	23,810	318	3,041	37,686	2,970	4,053	27	630	7,680	2,424	2,922	82	714	6,143
2031	10,605	24,011	319	3,094	38,029	3,008	4,061	27	641	7,738	2,455	2,932	82	726	6,195
2032	10,733	24,235	320	3,149	38,436	3,049	4,073	27	653	7,802	2,488	2,947	83	738	6,256
2033	10,777	24,406	321	3,199	38,703	3,082	4,076	27	665	7,850	2,516	2,950	83	750	6,299
2034	10,853	24,612	322	3,258	39,045	3,114	4,084	27	677	7,902	2,547	2,960	83	763	6,353

Table 2.2-5B Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class (Including Impacts of DSM Programs)

	Energy Sales (GWh)					Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total
2035	10,935	24,830	323	3,311	39,399	3,149	4,097	27	689	7,962	2,578	2,970	83	775	6,407
2036	11,086	25,049	324	3,367	39,826	3,197	4,118	27	702	8,045	2,613	2,980	84	788	6,464
2037	11,167	25,160	325	3,423	40,076	3,240	4,116	27	715	8,098	2,643	2,969	84	801	6,497
2038	11,286	25,305	326	3,479	40,396	3,286	4,121	27	728	8,163	2,675	2,966	84	814	6,539
2039	11,406	25,457	327	3,536	40,725	3,332	4,125	28	741	8,225	2,707	2,963	84	827	6,582
2040	11,571	25,633	328	3,592	41,125	3,380	4,136	28	755	8,299	2,743	2,966	85	841	6,634
2041	11,642	25,751	329	3,648	41,371	3,422	4,134	28	768	8,352	2,771	2,957	85	855	6,668
2042	11,758	25,903	330	3,707	41,698	3,467	4,139	28	783	8,416	2,802	2,955	85	869	6,711
2043	11,870	26,056	331	3,764	42,021	3,512	4,144	28	797	8,481	2,833	2,952	85	883	6,753
2044	12,021	26,242	332	3,821	42,416	3,559	4,155	28	812	8,554	2,866	2,956	86	897	6,805
2045	12,138	26,406	332	3,879	42,756	3,609	4,150	28	827	8,613	2,900	2,952	86	912	6,850
2046	12,249	26,562	332	3,938	43,081	3,658	4,142	28	842	8,670	2,933	2,947	85	927	6,893
2047	12,359	26,719	332	3,996	43,406	3,699	4,131	28	858	8,717	2,966	2,940	85	942	6,934
2048	12,495	26,944	332	4,055	43,827	3,740	4,119	28	874	8,761	2,999	2,931	85	957	6,973
2049	12,603	27,115	332	4,114	44,164	3,780	4,104	28	890	8,802	3,031	2,920	85	973	7,009
2050	12,710	27,276	332	4,175	44,492	3,819	4,087	28	907	8,841	3,062	2,908	85	989	7,045
2051	12,816	27,437	331	4,234	44,819	3,857	4,068	28	924	8,877	3,093	2,895	85	1,005	7,078
2052	12,953	27,677	331	4,295	45,255	3,895	4,046	28	942	8,911	3,123	2,880	85	1,021	7,109
2053	13,062	27,815	331	4,355	45,563	3,932	4,022	28	959	8,941	3,153	2,863	85	1,037	7,138
2054	13,166	27,953	330	4,417	45,865	3,968	3,996	28	977	8,970	3,182	2,845	84	1,054	7,165
2055	13,270	28,091	329	4,478	46,168	4,003	3,993	28	996	9,020	3,210	2,840	87	1,071	7,208

Table 2.2-6 Base Case: Energy and Capacity Sales to Other Utilities (at the Time of Coincident Summer and Winter Peak Demand)

	Energy Sales (GWh)	Coincident Summer Demand (MW)	Coincident Winter Demand (MW)
2015	2,290	480	572
2016	2,341	491	577
2017	2,322	499	585
2018	2,404	508	593
2019	2,370	518	602
2020	2,425	527	609
2021	2,474	536	618
2022	2,542	546	628
2023	2,596	557	637
2024	2,663	567	648
2025	2,721	577	658
2026	2,790	587	669
2027	2,854	597	680
2028	2,918	608	691
2029	2,982	619	703
2030	3,041	630	714
2031	3,094	641	726
2032	3,149	653	738
2033	3,199	665	750
2034	3,258	677	763
2035	3,311	689	775
2036	3,367	702	788
2037	3,423	715	801
2038	3,479	728	814
2039	3,536	741	827
2040	3,592	755	841
2041	3,648	768	855
2042	3,707	783	869
2043	3,764	797	883
2044	3,821	812	897
2045	3,879	827	912
2046	3,938	842	927
2047	3,996	858	942
2048	4,055	874	957
2049	4,114	890	973
2050	4,175	907	989
2051	4,234	924	1,005
2052	4,295	942	1,021
2053	4,355	959	1,037
2054	4,417	977	1,054
2055	4,478	996	1,071

Table 2.2-7 Base Case: Intra-Utility Energy and Capacity Use (at the Time of Coincident Summer and Winter Peak Demand)

	Energy Sales (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Interdpt	Company Use	Interdpt	Company Use	Interdpt	Company Use
2015	3	27	1	5	2	4
2016	3	27	1	5	2	4
2017	3	27	1	5	2	4
2018	3	27	1	5	2	4
2019	3	27	1	5	2	4
2020	3	27	1	5	2	4
2021	3	27	1	5	2	4
2022	3	27	1	5	2	4
2023	3	27	1	5	2	4
2024	3	27	1	5	2	4
2025	3	27	1	5	2	4
2026	3	27	1	5	2	4
2027	3	27	1	5	2	4
2028	3	27	1	5	2	4
2029	3	27	1	5	2	4
2030	3	27	1	5	2	4
2031	3	27	1	5	2	4
2032	3	27	1	5	2	4
2033	3	27	1	5	2	4
2034	3	27	1	5	2	4
2035	3	27	1	5	2	4
2036	3	27	1	5	2	4
2037	3	27	1	5	2	4
2038	3	27	1	5	2	4
2039	3	27	1	5	2	4
2040	3	27	1	5	2	4
2041	3	27	1	5	2	4
2042	3	27	1	5	2	4
2043	3	27	1	5	2	4
2044	3	27	1	5	2	4
2045	3	27	1	5	2	4
2046	3	27	1	5	2	4
2047	3	27	1	5	2	4
2048	3	27	1	5	2	4
2049	3	27	1	5	2	4
2050	3	27	1	5	2	4
2051	3	27	1	5	2	4
2052	3	27	1	5	2	4
2053	3	27	1	5	2	4
2054	3	27	1	5	2	4
2055	3	27	1	5	2	4

Table 2.2-8A Base Case: Losses by Major Customer Class

	Energy Losses (million kWh)				Coincident Summer Demand Losses (MW)				Coincident Winter Demand Losses (MW)			
	Residential	**C&I**	**Other**	**FERC**	**Residential**	**C&I**	**Other**	**FERC**	**Residential**	**C&I**	**Other**	**FERC**
2015	699	1,257	17	60	186	238	1	16	157	170	5	26
2016	701	1,275	18	61	189	238	1	17	159	170	5	26
2017	703	1,286	19	61	191	239	1	17	161	171	5	26
2018	710	1,302	19	63	192	240	1	17	163	172	5	27
2019	713	1,320	19	62	193	241	1	17	165	173	5	27
2020	712	1,344	20	63	194	242	1	18	165	173	6	27
2021	711	1,369	20	65	195	242	1	18	167	173	6	27
2022	716	1,380	20	66	196	243	1	18	169	174	6	27
2023	722	1,391	20	68	198	244	1	18	171	175	6	28
2024	731	1,404	21	70	200	245	1	19	173	176	6	28
2025	732	1,412	21	71	202	245	1	19	175	176	6	28
2026	737	1,421	21	73	204	246	1	19	177	176	6	28
2027	744	1,433	21	75	206	246	1	19	179	177	6	29
2028	754	1,447	21	76	209	248	1	20	182	178	6	29
2029	758	1,461	21	78	211	248	1	20	184	179	6	29
2030	763	1,476	21	79	214	249	1	20	186	179	6	30
2031	769	1,491	21	81	217	250	1	21	189	180	6	30
2032	778	1,508	21	82	220	251	1	21	191	181	6	30
2033	782	1,520	21	83	222	251	1	21	193	181	6	30
2034	788	1,535	21	85	225	252	1	21	196	182	6	31

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.2-8B Base Case: Losses by Major Customer Class

	Energy Losses (million kWh)				Coincident Summer Demand Losses (MW)				Coincident Winter Demand Losses (MW)			
	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC
2035	794	1,550	21	86	227	253	1	22	198	183	6	31
2036	806	1,564	21	88	231	254	1	22	201	183	6	31
2037	812	1,571	22	89	234	254	1	22	203	183	6	32
2038	821	1,580	22	91	238	254	1	23	206	182	6	32
2039	830	1,590	22	92	241	254	1	23	208	182	6	32
2040	843	1,601	22	94	245	255	1	23	211	182	6	33
2041	848	1,609	22	95	248	255	1	24	213	182	6	33
2042	857	1,618	22	97	252	255	1	24	215	182	6	33
2043	866	1,628	22	98	255	256	1	25	218	181	6	34
2044	878	1,640	22	100	259	256	1	25	220	182	6	34
2045	887	1,650	22	101	263	256	1	25	223	181	6	35
2046	895	1,660	22	103	267	256	1	26	226	181	6	35
2047	904	1,670	22	104	270	255	1	26	228	181	6	35
2048	914	1,685	22	106	273	254	1	27	231	180	6	36
2049	922	1,696	22	107	276	253	1	27	233	179	6	36
2050	931	1,706	22	109	279	252	1	27	235	178	6	37
2051	939	1,716	22	110	282	251	1	28	238	178	6	37
2052	949	1,731	22	112	285	249	1	28	240	177	6	37
2053	958	1,740	22	113	288	247	1	29	242	175	6	38
2054	966	1,749	22	115	290	246	1	29	245	174	6	38
2055	974	1,758	22	117	293	246	1	30	247	174	6	39

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.2-9 Base Case: Energy and Peak Demand Incremental DSM Savings

	Energy Savings (million kWh)	Coincident Summer Demand Savings (MW)	Coincident Winter Demand Savings (MW)
2015	50	0	1
2016	100	3	2
2017	147	4	4
2018	197	5	5
2019	246	7	6
2020	302	8	7
2021	346	9	8
2022	395	11	10
2023	445	12	11
2024	505	13	12
2025	544	15	13
2026	594	16	14
2027	644	17	16
2028	708	18	17
2029	695	18	17
2030	695	18	17
2031	695	18	17
2032	710	18	17
2033	695	18	17
2034	695	18	17
2035	695	18	17
2036	710	18	17
2037	695	18	17
2038	695	18	17
2039	695	18	17
2040	710	18	17
2041	695	18	17
2042	695	18	17
2043	695	18	17
2044	710	18	17
2045	695	18	17
2046	695	18	17
2047	695	18	17
2048	710	18	17
2049	694	18	17
2050	693	18	17
2051	693	18	17
2052	700	18	17
2053	693	18	17
2054	693	18	17
2055	693	18	17

Forecast Overview

Table 2.2-10 presents the base case forecast of native summer peak demand through the resource acquisition period ending in 2023. The bold line across the table delineates historical from projected information.

Table 2.2-10 Actual and Forecasted Summer Peak Demand

	Retail - Native Summer Peak Demand (MW)	Wholesale - Native Summer Peak Demand (MW)	Total - Native Summer Peak Demand (MW)	Annual Increase (MW)
2010	5,587	737	6,324	168
2011	5,868	1,041	6,909	585
2012	6,167	570	6,737	(171)
2013	5,906	768	6,674	(63)
2014	5,784	468	6,252	(422)
2015	6,078	480	6,559	306
2016	6,130	491	6,620	61
2017	6,213	499	6,712	92
2018	6,259	508	6,768	55
2019	6,366	518	6,884	116
2020	6,443	527	6,970	86
2021	6,566	536	7,102	132
2022	6,615	546	7,161	59
2023	6,668	557	7,225	64

Total native peak demand has varied greatly over the past five years, with overall annual gains averaging just 14 MW. However, retail native peak demand has grown at 2.0% over the time period, with average annual increases of 109 MW per year. The projected retail growth rates through 2023 are slightly weaker at 1.9% or 118 MW. With stabilization in wholesale demand, the growth rate for total native load peak demand is expected to be 1.6%.

For consistency, native energy sales to the wholesale customers were separated from retail energy sales in Table 2.2-11. The growth rates for sales are different in both history and forecast. Native sales to the wholesale customers decreased by 14.6% annually over the past five years, this was due mainly to the expiration of contracts. Retail sales grew 1.0% per year over the same period. Wholesale sales are expected to grow at 1.6% through 2023 while retail sales will grow slightly slower at 1.4%. Total native sales are expected to grow at 1.5% annually through 2023.

Table 2.2-11 Actual and Forecasted Annual Sales

	Retail - Native Sales (GWh)	Wholesale - Native Sales (GWh)	Total - Native Sales (GWh)	Annual Increase (GWh)
2010	28,255	4,891	33,146	(68)
2011	28,616	4,028	32,643	(502)
2012	28,964	2,471	31,435	(1,208)
2013	29,135	2,494	31,630	194
2014	28,910	2,588	31,497	(132)
2015	29,078	2,290	31,367	(130)
2016	29,374	2,341	31,716	348
2017	29,689	2,322	32,011	295
2018	30,079	2,404	32,484	473
2019	30,543	2,370	32,913	429
2020	31,191	2,425	33,617	704
2021	32,046	2,474	34,519	903
2022	32,320	2,542	34,862	343
2023	32,603	2,596	35,200	338

Forecast Methodologies

The following discussion describes the methods Public Service uses to forecast each of the various customer classes, which make up the total Public Service energy and demand forecasts.

Public Service uses monthly historical customer, sales and peak demand data by rate class to develop its forecasts. Forecasted economic and demographic data are obtained from IHS Global Insight, Inc.

Energy Sales Forecast

Public Service's residential sales and commercial and industrial sales forecasts are developed using a Statistically-Adjusted End-Use ("SAE") modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating, cooling, and base use) and the factors that affect these end-use energy requirements.

The SAE residential sales forecast is calculated as the product of average use and customer forecasts. The SAE modeling approach consists of regressions for average use per customer and number of customers. The use per customer regression model is estimated using monthly historical sales per customer, weather, economics, price, and appliance saturation and efficiency trend data. Customer growth is strongly correlated with growth in state housing stock. Therefore, the number of customers is forecasted as a function of housing stock projections.

End-use concepts are incorporated in the average use per customer model. Average use is defined as a function of heating, cooling, and base use requirements, as shown below. The term *e* is the model error term.

Average Use = Heating + Cooling + Base + ***e***

Each of these elements of average use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the stock of appliances, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

Heating = HeatIndex * HeatUse
Cooling = CoolIndex * CoolUse
Base = BaseIndex * BaseUse

The indices are calculated as the ratio of the appliance saturation and average efficiency of the existing stock. To generate a relative index, the ratio is divided by the estimated value for 2009. Thus, the index has a value of 1.0 in 2009. The indices reflect both changes in saturation resulting from end-use competition and improvements in appliance efficiency standards. For example, if gas heating gains market share, the electric heating saturation will decline, resulting in a decline in the heating index variable. Similarly, improvements in electric heating efficiency will also contribute to a lower heating index. The trend towards greater saturation of central air conditioning has the opposite effect, contributing to an increasing cooling index over time. Air conditioning efficiency gains mitigate this increase. Appliance trends in other end-uses such as water heating, cooking, refrigeration, and miscellaneous loads are captured in the base index.

The utilization variables (CoolUse, HeatUse, and BaseUse) are designed to capture energy demand driven by the use of the appliance stock. For the residential sector, the primary factors that impact appliance use are weather conditions (as measured by heating and cooling degree days), electricity prices, household income and household size. The utilization variables are defined as:

COOLUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.2)
*(HOUSEHOLD_SIZE^0.25) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.2)
*(HOUSEHOLD_SIZE^0.25) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.1) *(HOUSEHOLD_SIZE^0..46)

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in the utilization variables (CoolUse, HeatUse, and BaseUse) given a 1% change in the economic variables (Price, Income per Household, and Household Size). The elasticities are provided by Itron as part of the residential end-use model.

The forecast model is estimated by regressing monthly average residential usage on Cooling Use, Heating Use, Base Use, monthly seasonal variables for all months except April, May, October and November, and a single binary variable for February 2014. The regression model effectively calibrates the end-use concepts to actual residential average use. Monthly seasonal variables for are included to account for non-weather-related seasonal factors. The binary variable for February 2014 is included to account for unusual billing activity during this month. The forecast model results are adjusted to reflect the expected incremental impact of residential DSM programs, reductions in sales that can be attributed to distributed solar generation, and the expected impacts from the residential tiered rate structure that is effective from June through September each year.

The same general approach is used to construct the commercial and industrial sales forecast model. For this model, sales can again be decomposed into heating, cooling and base use. The end-use variables Heating, Cooling and Base are structured in a manner similar to those used in the residential model and are defined as the product of a variable that reflects technology stock and efficiency (Index) and a variable that captures stock utilization (Use).

For the commercial and industrial sector, saturation and efficiency trends can be captured by the change in annual energy intensities (kWh per square foot). The Heating Index, Cooling Index, and Base Index have values of 1.0 in 2004. Increasing saturation levels drive an index higher, while improvements in stock efficiency or decreasing saturation levels lower the value of the index.

Stock utilization is a function of electricity prices, business activity (as measured by Colorado Gross State Product), heating degree days and cooling degree days. The utilization variables are specified as:

COOLUSE = (PRICE^(-0.15)) * (Com. Output Index^0.7) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.15)) * (Com. Output Index^0.7) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.15)) * (Com. Output Index^0.7)

The forecast model is then estimated by regressing monthly commercial and industrial sales on Cooling, Heating, Base, monthly billing cycle days, commercial customer counts and a monthly seasonal variable for each month. The regression model effectively calibrates the end-use concepts to actual commercial and industrial sales. The monthly seasonal variables for each month are included to account for non-weather-related seasonal factors. The model results are adjusted to reflect the expected incremental impact of commercial and industrial DSM programs, distributed solar generation, and new load additions as identified by the large commercial and industrial customer account managers.

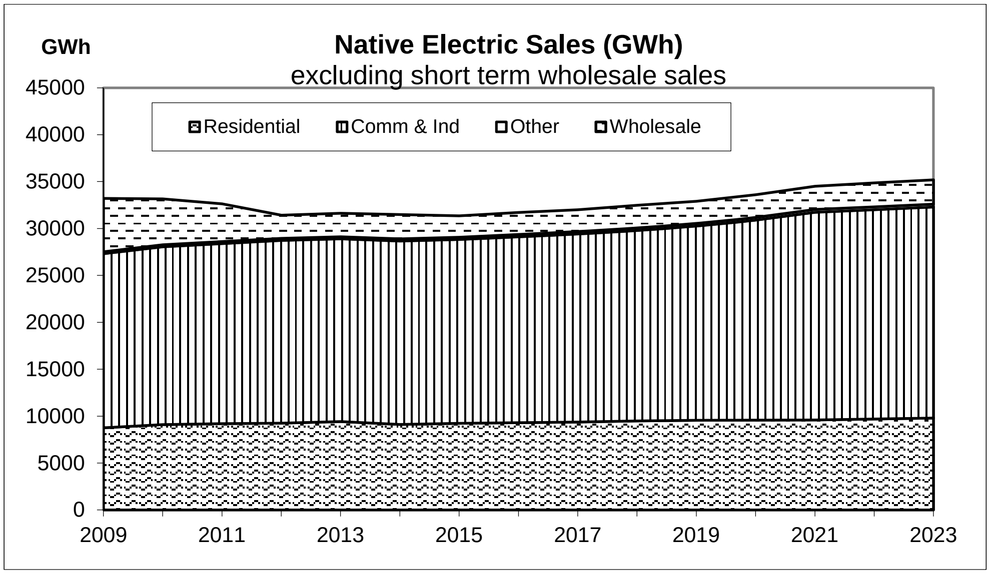
Public authority sales are forecasted using a regression model that is based on the same Base variable developed for the commercial and industrial sector and various monthly binary variables. The public authority model includes a binary variable for the latest extension of light rail service for the Regional Transportation District in 2001, 2002, 2006 and 2013.

Street light sales are forecasted using a regression model that is based on the forecast of the number of residential customers, monthly seasonal variables for all months, binary variables for January and February 2013 and a lagged variable that accounts for changes in the billing system. The monthly seasonal variables account for the differing number of hours per day that street lights are on. The binary variables in January and February 2013 account for the unusual billing activity observed during these months.

The interdepartmental sales forecast is developed as part of the commercial and industrial forecast.

Forecasts for sales to resale customers are received from Public Service's wholesale customers.

Figure 2.2-3 Native Electric Sales (GWh)



Demand Forecast

Residential coincident peak demand is expected to increase in response to changes to residential energy requirements. For the residential demand regression model, residential energy requirements are defined as a 12-month moving average of monthly residential sales. The moving average calculation removes the monthly sales cyclical pattern. Efficiency improvements captured in the residential sales model are assumed to have the same impact on residential peak demand. Since peak demand does not necessarily grow at the same rate as the underlying sales, an end-use saturation term interacting with peak-day weather conditions and customer counts is also included in the model. This variable is defined as:

Peak_Day_Cooling_Degree_Days *Customer Counts* CoolIndex

The cooling index is the same index used in the residential average use per customer model. With the cooling index variable the sensitivity to peak-day weather changes as residential cooling saturation and efficiency changes.

Also included in the residential peak model are peak day heating degree days, seasonal monthly variables (April and May), a linear trend variable and binary variables to remove months with data anomalies (October 2005, April 2006, April 2007, May 2007, October 2007, September 2008, October 2010, October 2011 and September 2008). The model results are adjusted to reflect the expected incremental impact of residential DSM programs and distributed solar generation.

The commercial and industrial (nonresidential) coincident peak demand forecast is developed using a regression model similar to the residential peak model. Historical commercial and industrial coincident peaks are regressed against commercial and industrial energy requirements defined as the 12-month moving average of commercial and industrial sales. Also included in the model is a variable that allows peak demand to change at a different rate than sales. This variable, which interacts peak day weather with commercial-industrial customers, reflects increasing cooling usage as customer counts increase. In addition, the model contains seasonal monthly variables (January, February, November and December), a linear trend variable and binary variables to remove April 2006, April 2007, and April 2012 from the regression. The model results are adjusted to reflect the expected incremental impact of commercial and industrial DSM programs, distributed solar generation and new load additions as identified by the large commercial and industrial customer account managers.

Forecasts of peak demand for each REA and municipality are received from the respective wholesale customers. Forecasts of the capacity required by these customers coincident with the system peak are developed from following sources of information.

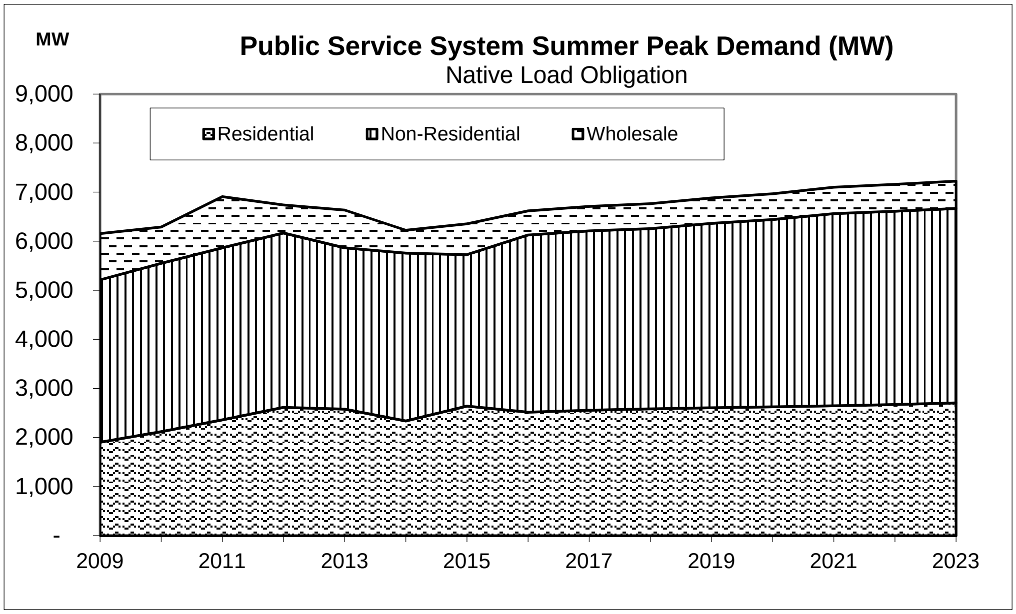
1. Historical loads for Public Service sales to these customers coincident with the Public Service system peak are provided by Xcel Energy's Load Research Department.

2. Monthly billing reports provide historical data of energy and capacity sales itemized by the utility providing the power, the total non-coincident peak demand for the month, and the portion of that peak demand allocated to WAPA.

A forecast of the capacity required by each of these customers coincident with the Public Service system peak is developed using the trends present in the non-coincident peak demand forecasts, the historical coincident loads, and information from the billing reports regarding WAPA capacity allocations and the total load coincident with the Public Service system peak.

Coincident peak demand forecasts for the interruptible load are provided by Xcel Energy's Load Research Department. The components of this forecast are the primary, secondary, and transmission voltage Interruptible contracted loads and the Residential Saver's Switch program.

Figure 2.2-4 Native Peak Demand (MW)



Variability Due to Weather

Weather has an impact on energy sales and an even greater impact on peak demand. The Public Service system usually experiences its annual peak demand during the month of July. The base forecast assumes normal weather based on 30-year average of peak day weather in the future. In order to quantify the possible outcomes of weather variation from the 30-year average weather, Monte Carlo simulations have been developed to establish confidence bands around the base forecast. The probability distributions for the simulation runs for both sales and demand were based on 30 years of historical weather data for Denver. Table 2.2-12 provides the resulting confidence bands at the level of 1.00 standard deviation or 70% probability bandwidth and 1.65 standard deviations or 90% probability bandwidth above and below the base case forecast of native load peak demand. Table 2.2-13 provides the confidence bands above and below the annual native energy sales forecast. Graphs of the peak demand and sales confidence bands are presented in Figure 2.2-4 and Figure 2.2-5.

Table 2.2-12 Native Peak Demand Weather Variability

	Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	+1.65 Std Dev	+1 Std Dev	Base	-1 Std Dev	-1.65 Std Dev	+1.65 Std Dev	+1 Std Dev	Base Case	-1 Std Dev	-1.65 Std Dev
2016	7,138	6,943	6,620	6,308	6,120	5,736	5,578	5,306	5,033	4,870
2017	7,224	7,034	6,712	6,390	6,203	5,775	5,619	5,348	5,079	4,921
2018	7,279	7,094	6,768	6,449	6,266	5,838	5,678	5,408	5,139	4,986
2019	7,389	7,206	6,884	6,560	6,374	5,969	5,807	5,533	5,260	5,099
2020	7,476	7,289	6,970	6,647	6,455	6,110	5,945	5,669	5,387	5,230
2021	7,612	7,430	7,102	6,774	6,587	6,133	5,975	5,698	5,422	5,258
2022	7,685	7,488	7,161	6,840	6,652	6,178	6,019	5,744	5,470	5,304
2023	7,737	7,545	7,225	6,901	6,704	6,227	6,070	5,792	5,513	5,358
2024	7,819	7,629	7,299	6,969	6,780	6,288	6,127	5,851	5,572	5,407
2025	7,866	7,678	7,352	7,026	6,841	6,323	6,161	5,885	5,605	5,445
2026	7,927	7,739	7,413	7,091	6,900	6,371	6,207	5,929	5,653	5,486
2027	7,988	7,792	7,479	7,147	6,955	6,421	6,255	5,980	5,706	5,541
2028	8,077	7,885	7,557	7,233	7,037	6,491	6,326	6,043	5,765	5,598
2029	8,133	7,943	7,615	7,285	7,097	6,542	6,375	6,091	5,817	5,648
2030	8,198	8,010	7,680	7,357	7,161	6,593	6,419	6,143	5,861	5,695
2031	8,256	8,066	7,738	7,408	7,219	6,644	6,479	6,195	5,909	5,744
2032	8,329	8,124	7,802	7,467	7,275	6,713	6,543	6,256	5,966	5,800
2033	8,374	8,176	7,850	7,518	7,324	6,761	6,593	6,299	6,023	5,852
2034	8,418	8,223	7,902	7,573	7,374	6,813	6,645	6,353	6,069	5,899
2035	8,485	8,291	7,962	7,633	7,430	6,869	6,700	6,407	6,112	5,946
2036	8,584	8,385	8,045	7,711	7,521	6,929	6,757	6,464	6,173	6,006
2037	8,633	8,439	8,098	7,765	7,575	6,966	6,792	6,497	6,205	6,032
2038	8,695	8,500	8,163	7,822	7,621	6,996	6,828	6,539	6,240	6,066
2039	8,760	8,559	8,225	7,887	7,688	7,057	6,881	6,582	6,284	6,114
2040	8,834	8,635	8,299	7,958	7,758	7,105	6,930	6,634	6,330	6,158
2041	8,900	8,691	8,352	8,012	7,804	7,147	6,968	6,668	6,368	6,191
2042	8,966	8,757	8,416	8,079	7,874	7,193	7,014	6,711	6,412	6,230
2043	9,015	8,817	8,481	8,134	7,924	7,240	7,064	6,753	6,451	6,271
2044	9,104	8,900	8,554	8,202	7,995	7,295	7,108	6,805	6,501	6,321
2045	9,164	8,955	8,613	8,263	8,059	7,339	7,160	6,850	6,540	6,361
2046	9,220	9,020	8,670	8,319	8,116	7,388	7,207	6,893	6,584	6,404
2047	9,266	9,070	8,717	8,370	8,163	7,432	7,251	6,934	6,623	6,439
2048	9,317	9,108	8,761	8,404	8,201	7,468	7,287	6,973	6,659	6,472
2049	9,371	9,159	8,802	8,455	8,239	7,520	7,331	7,009	6,691	6,512
2050	9,394	9,191	8,841	8,486	8,276	7,550	7,362	7,045	6,722	6,538
2051	9,453	9,231	8,877	8,522	8,309	7,577	7,394	7,078	6,758	6,571
2052	9,475	9,265	8,911	8,550	8,334	7,621	7,429	7,109	6,787	6,596
2053	9,505	9,303	8,941	8,581	8,373	7,644	7,461	7,138	6,817	6,624
2054	9,539	9,333	8,970	8,613	8,405	7,690	7,491	7,165	6,840	6,651
2055	9,588	9,369	9,020	8,660	8,446	7,736	7,541	7,208	6,886	6,684

Table 2.2-13 Annual Native Energy Sales Weather Variability

	Energy Sales (million kWh)				
	+1.65 Std Dev	**+1 Std Dev**	**Base**	**-1 Std Dev**	**-1.65 Std Dev**
2016	34,266	33,319	31,714	30,137	29,215
2017	34,593	33,620	32,009	30,418	29,496
2018	35,047	34,097	32,482	30,895	29,963
2019	35,480	34,514	32,911	31,324	30,395
2020	36,193	35,227	33,615	32,017	31,099
2021	37,140	36,162	34,518	32,896	31,958
2022	37,468	36,507	34,860	33,251	32,305
2023	37,806	36,835	35,198	33,581	32,645
2024	38,224	37,258	35,633	34,012	33,073
2025	38,468	37,492	35,866	34,262	33,316
2026	38,787	37,824	36,191	34,588	33,651
2027	39,142	38,175	36,546	34,954	34,014
2028	39,566	38,602	36,980	35,383	34,459
2029	39,907	38,933	37,321	35,718	34,791
2030	40,267	39,297	37,686	36,085	35,149
2031	40,615	39,653	38,029	36,438	35,510
2032	41,005	40,046	38,435	36,838	35,910
2033	41,269	40,312	38,703	37,114	36,187
2034	41,615	40,654	39,045	37,459	36,528
2035	41,960	41,004	39,399	37,810	36,880
2036	42,399	41,431	39,826	38,242	37,320
2037	42,639	41,682	40,076	38,495	37,572
2038	42,963	41,996	40,396	38,814	37,896
2039	43,276	42,330	40,725	39,135	38,218
2040	43,684	42,723	41,125	39,547	38,635
2041	43,923	42,968	41,371	39,796	38,866
2042	44,248	43,303	41,698	40,114	39,200
2043	44,573	43,617	42,021	40,443	39,527
2044	44,949	44,003	42,416	40,848	39,932
2045	45,282	44,339	42,756	41,189	40,273
2046	45,599	44,661	43,081	41,518	40,601
2047	45,915	44,982	43,406	41,845	40,929
2048	46,333	45,402	43,827	42,267	41,348
2049	46,661	45,735	44,164	42,607	41,688
2050	46,980	46,059	44,492	42,939	42,020
2051	47,297	46,380	44,819	43,270	42,351
2052	47,728	46,815	45,255	43,706	42,786
2053	48,024	47,117	45,563	44,019	43,100
2054	48,314	47,412	45,865	44,327	43,409
2055	48,603	47,708	46,168	44,636	43,719

Figure 2.2-5 Native Peak Demand Weather Confidence Bands (MW)

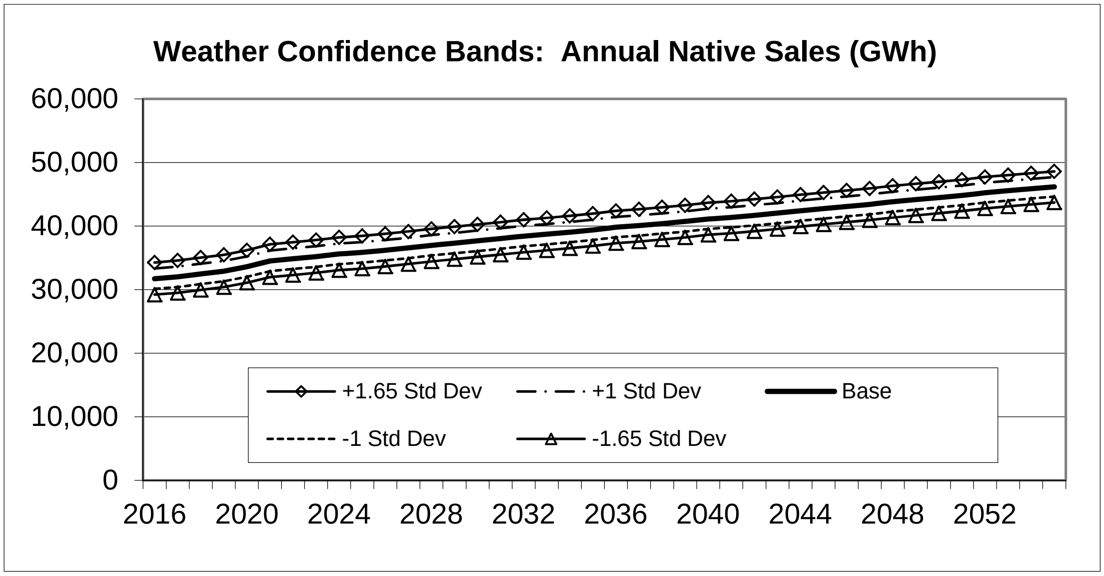
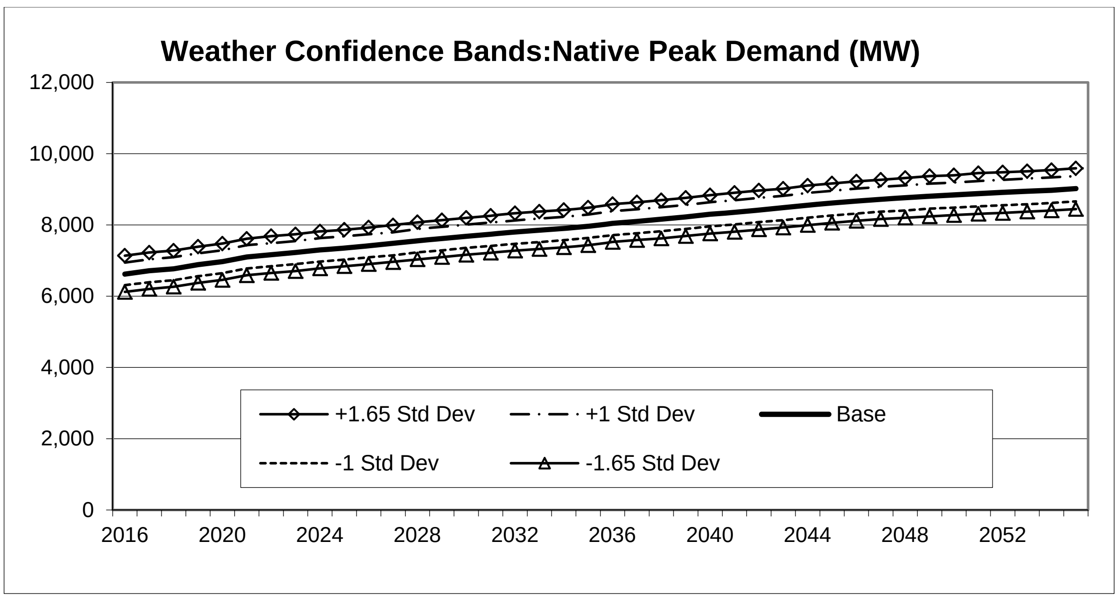


Figure 2.2-6 Native Sales Weather Confidence Bands (GWH)



High Growth Forecast

Public Service's high energy sales forecast is based on a Monte Carlo simulation of the energy sales forecast with probabilistic inputs for the main economic drivers of the forecast model and for model error. The primary component of the high sales scenario is the forecast level from the simulation that represents the upper limit of a one standard deviation wide confidence band.

The resulting high energy sales forecast grows 1.4% annually over the next 40 years, from 31,428 GWh in 2015, to 54,463 GWh in 2055. High energy sales growth over the next 8 years is anticipated to average 2.5% annually with sales of 38,167 GWh in 2023.

Public Service's high summer native load peak demand forecast grows from 6,562 MW in 2015 to 10,514 MW in 2055, an average annual growth rate of 1.2%. Short-term annual growth is expected to be 2.2% over the next 8 years. The Base Case forecast indicates 1.2% annual growth through 2023 and 0.8% through 2055.

The forecasted high peak demands and high sales are contained in Figures 2.2-7 and 2.2-8 and listed in Tables 2.2-14 and 2.2-15.

Low Growth Forecast

Public Service's low energy sales forecast is based on a Monte Carlo simulation of the energy sales forecast with probabilistic inputs for the main economic drivers of the forecast model and for model error. The primary component of the low sales scenario is the forecast level from the simulation that represents the lower limit of a one standard deviation wide confidence band.

The resulting low native energy sales forecast grows 0.5% annually over the next 40 years, from 31,403 GWh in 2015, to 37,828 GWh in 2055. The low scenario energy sales growth over the next 8 years is anticipated to average 0.3% annually with sales of 32,194 GWh in 2023.

Public Service's low summer native load peak demand forecast grows from 6,557 MW in 2015 to 7,556 MW in 2055, an average annual growth rate of 0.4%. The low short-term annual growth is expected to be 0.2% over the next 8 years, with peak demand of 6,667 MW in 2023.

The forecasted low peak demands and low sales are illustrated in Figures 2.2-7 and 2.2-8 and listed in Tables 2.2-14 and 2.2-15.

Figure 2.2-7 Base Case, High and Low Peak Native Sales Forecast Comparison – Base, High, Low

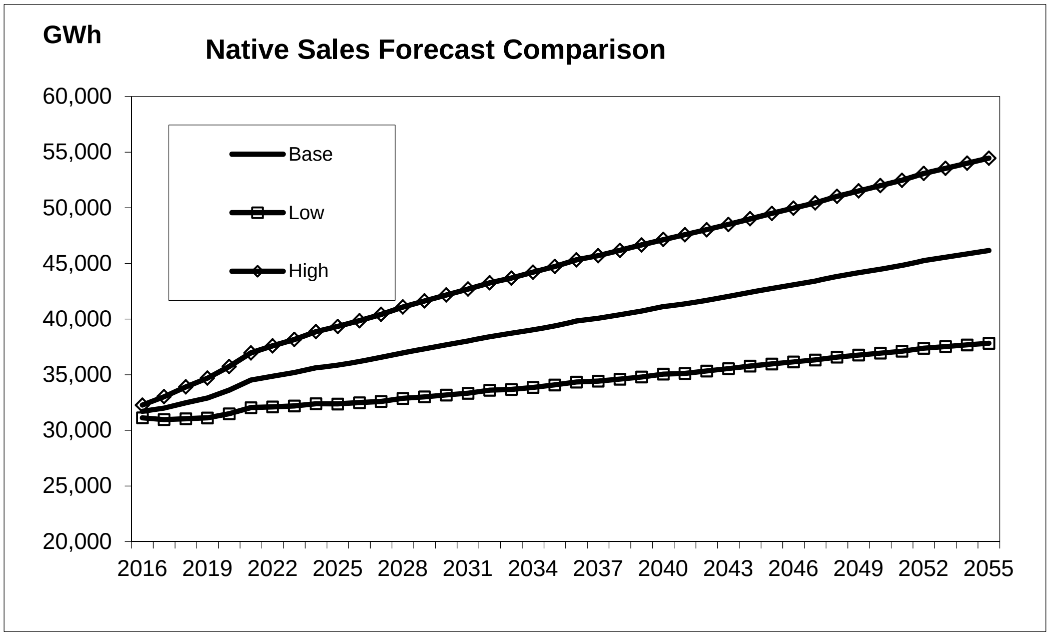


Figure 2.2-8 Base Case, High and Low Peak Demand Forecast

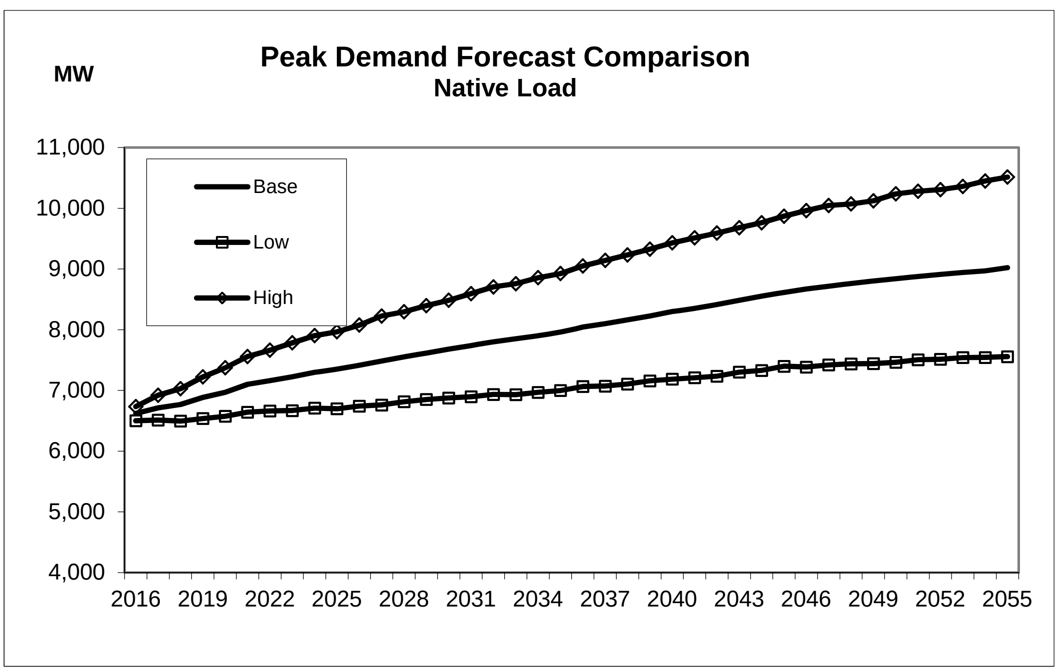


Table 2.2-14 Base Case, High, and Low Sales of Energy (MW) (Including Impacts of DSM Programs)

	Base	Low	High
2016	31,714	31,126	32,270
2017	32,009	30,973	33,031
2018	32,482	31,044	33,904
2019	32,911	31,123	34,697
2020	33,615	31,493	35,737
2021	34,518	32,043	36,965
2022	34,860	32,106	37,598
2023	35,198	32,194	38,167
2024	35,633	32,395	38,867
2025	35,866	32,372	39,337
2026	36,191	32,485	39,853
2027	36,546	32,593	40,423
2028	36,980	32,878	41,084
2029	37,321	33,012	41,635
2030	37,686	33,177	42,165
2031	38,029	33,338	42,696
2032	38,435	33,608	43,255
2033	38,703	33,677	43,680
2034	39,045	33,864	44,216
2035	39,399	34,089	44,728
2036	39,826	34,345	45,323
2037	40,076	34,422	45,694
2038	40,396	34,606	46,175
2039	40,725	34,796	46,655
2040	41,125	35,059	47,160
2041	41,371	35,117	47,584
2042	41,698	35,338	48,025
2043	42,021	35,547	48,500
2044	42,416	35,782	49,011
2045	42,756	35,973	49,496
2046	43,081	36,151	49,967
2047	43,406	36,328	50,439
2048	43,827	36,583	51,025
2049	44,164	36,767	51,514
2050	44,492	36,942	51,995
2051	44,819	37,115	52,475
2052	45,255	37,377	53,086
2053	45,563	37,531	53,548
2054	45,865	37,680	54,004
2055	46,168	37,828	54,463

Table 2.2-15 Base Case, High and Low Coincident Summer and Winter Peak Demand (Including Impacts of DSM Programs)

	Coincident Summer Demand (MW)			Coincident Winter Demand (MW)		
	Base	**Low**	**High**	**Base**	**Low**	**High**
2016	6,620	6,501	6,734	5,306	5,203	5,410
2017	6,712	6,511	6,921	5,348	5,158	5,534
2018	6,768	6,495	7,029	5,408	5,152	5,657
2019	6,884	6,538	7,222	5,533	5,215	5,846
2020	6,970	6,574	7,373	5,669	5,295	6,044
2021	7,102	6,642	7,559	5,698	5,275	6,113
2022	7,161	6,662	7,662	5,744	5,277	6,211
2023	7,225	6,667	7,784	5,792	5,293	6,296
2024	7,299	6,709	7,902	5,851	5,312	6,392
2025	7,352	6,698	7,966	5,885	5,307	6,482
2026	7,413	6,741	8,076	5,929	5,312	6,544
2027	7,479	6,761	8,225	5,980	5,332	6,653
2028	7,557	6,815	8,295	6,043	5,341	6,715
2029	7,615	6,850	8,396	6,091	5,366	6,818
2030	7,680	6,877	8,485	6,143	5,398	6,901
2031	7,738	6,896	8,594	6,195	5,429	6,966
2032	7,802	6,935	8,704	6,256	5,454	7,054
2033	7,850	6,930	8,757	6,299	5,447	7,122
2034	7,902	6,968	8,856	6,353	5,484	7,206
2035	7,962	6,998	8,925	6,407	5,522	7,302
2036	8,045	7,064	9,050	6,464	5,522	7,387
2037	8,098	7,071	9,141	6,497	5,558	7,434
2038	8,163	7,106	9,231	6,539	5,573	7,508
2039	8,225	7,158	9,327	6,582	5,581	7,589
2040	8,299	7,186	9,431	6,634	5,621	7,674
2041	8,352	7,209	9,512	6,668	5,620	7,719
2042	8,416	7,235	9,591	6,711	5,650	7,792
2043	8,481	7,302	9,679	6,753	5,653	7,829
2044	8,554	7,329	9,762	6,805	5,691	7,938
2045	8,613	7,398	9,870	6,850	5,712	8,008
2046	8,670	7,384	9,961	6,893	5,721	8,060
2047	8,717	7,420	10,046	6,934	5,743	8,122
2048	8,761	7,437	10,071	6,973	5,734	8,202
2049	8,802	7,442	10,122	7,009	5,760	8,233
2050	8,841	7,462	10,237	7,045	5,801	8,325
2051	8,877	7,506	10,281	7,078	5,802	8,372
2052	8,911	7,512	10,306	7,109	5,785	8,416
2053	8,941	7,541	10,359	7,138	5,799	8,452
2054	8,970	7,543	10,449	7,165	5,838	8,527
2055	9,020	7,556	10,514	7,208	5,829	8,572

Forecast Accuracy

Public Service reviews its demand and energy forecasts for accuracy annually. Overall, forecast accuracy is better in the short term than in the long term.

Tables 2.2-16 through 2.2-24 on the following pages compare the actual energy sales and demand forecasts to the forecasted sales and system demands, as required by the Electric Resource Planning rules. Figures 2.2-9 through 2.2-13 contain a graphical description of the forecasts.

Table 2.2-16 Native Sales Forecast Comparison (GWh)

	Actual Energy Sales	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010	33,146					33,451
2011	32,643				32,916	33,350
2012	31,435			30,859	31,675	32,186
2013	31,630		30,735	31,092	31,940	32,586
2014	31,497	31,124	30,645	31,290	32,433	33,069

Table 2.2-17 Forecast Sales less Actual Sales (GWh)

	Actual less Forecast (GWh)					Percent Difference				
	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010					-305					-0.92%
2011				-272	-707				-0.83%	-2.17%
2012			577	-240	-751			1.83%	-0.76%	-2.39%
2013		894	537	-310	-956		2.83%	1.70%	-0.98%	-3.02%
2014	373	852	207	-936	-1,571	1.18%	2.71%	0.66%	-2.97%	-4.99%

Table 2.2-18 Coincident Summer Demand Forecast Comparison (MW)

	Actual Demand	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010	6,324					6,490
2011	6,909				6,634	6,539
2012	6,737			6,428	6,397	6,339
2013	6,674		6,510	6,532	6,469	6,477
2014	6,252	6,112	6,546	6,589	6,526	6,600

Table 2.2-19 Forecast Demand less Actual Summer Native Peak Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010					-166					-2.63%
2011				274	370				3.97%	5.35%
2012			309	341	398			4.58%	5.05%	5.91%
2013		165	142	205	197		2.47%	2.13%	3.07%	2.96%
2014	141	-293	-337	-274	-348	2.25%	-4.69%	-5.39%	-4.38%	-5.56%

Table 2.2-20 Weather Normalized Coincident Summer Demand Forecast Comparison (MW)

	Weather Normal Demand	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010	6,562					6,490
2011	6,675				6,634	6,539
2012	6,527			6,428	6,397	6,339
2013	6,570		6,510	6,532	6,469	6,477
2014	6,484	6,112	6,546	6,589	6,526	6,600

Table 2.2-21 Forecast Demand less Actual Summer Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010					72					1.10%
2011				41	137				0.61%	2.05%
2012			99	131	188			1.52%	2.00%	2.88%
2013		60	37	100	93		0.91%	0.57%	1.53%	1.41%
2014	372	-62	-106	-42	-116	5.74%	-0.95%	-1.63%	-0.65%	-1.79%

Table 2.2-22 Coincident Winter Demand Forecast Comparison (MW)

	Actual Demand	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010	5,707					5,607
2011	5,814				5,298	5,760
2012	5,282			5,106	5,075	5,591
2013	5,417		5,078	5,140	5,140	5,762
2014	5,799	5,160	5,104	5,176	5,205	5,902

Table 2.2-23 Forecast Demand less Actual Winter Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	2011 Forecast	2010 Forecast
2010					100					1.76%
2011				516	54				8.88%	0.93%
2012			176	207	-309			3.33%	3.92%	-5.86%
2013		339	276	276	-345		6.26%	5.10%	5.10%	-6.38%
2014	639	695	623	594	-103	11.02%	11.98%	10.75%	10.25%	-1.78%

Figure 2.2-9 Forecast Comparison to Actual Native Energy Sales

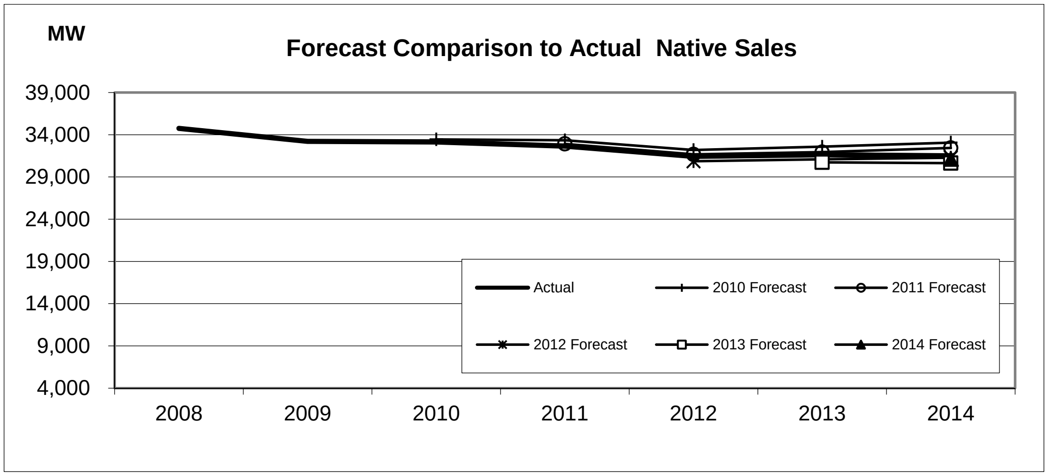


Figure 2.2-10 Forecast Comparison to Actual Summer Native Peak Demand

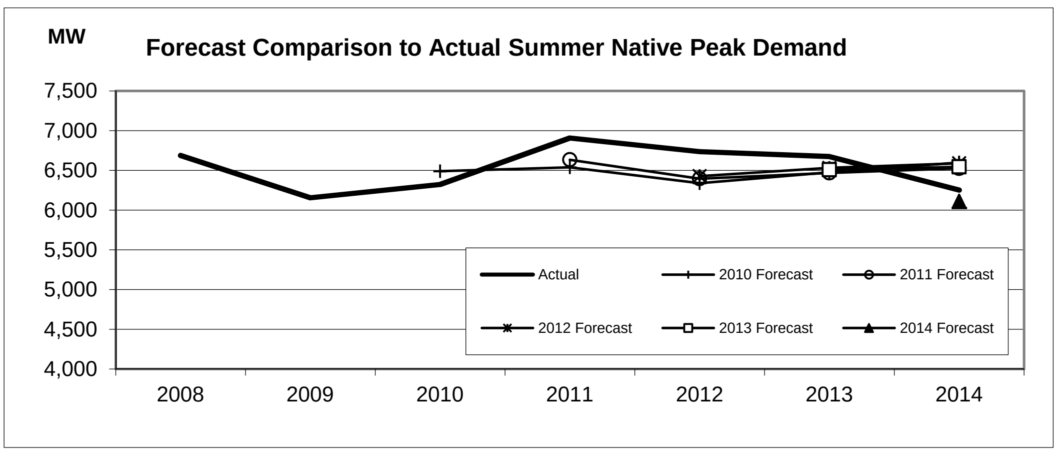


Figure 2.2-11 Forecast Comparison to Actual Winter Native Peak Demand

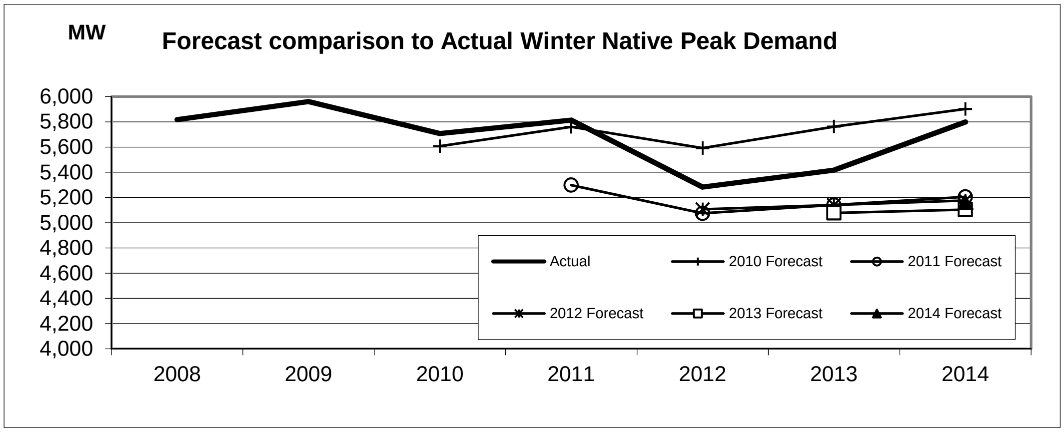


Table 2.2-24 2011 ERP Forecast vs. 2016 ERP Forecast

Year	Summer Coincident Peak Demand (MW)		Annual Energy Sales (GWh)	
	2011 RP Forecast	2016 RP Forecast	2011 RP Forecast	2016 RP Forecast
2011	6,664	6,909	32,774	32,643
2012	6,391	6,737	31,046	31,435
2013	6,464	6,674	31,248	31,630
2014	6,521	6,252	31,550	31,497
2015	6,599	6,559	32,052	31,367
2016	6,682	6,620	32,270	31,716
2017	6,743	6,712	32,635	32,011
2018	6,797	6,768	32,849	32,484
2019	6,854	6,884	33,184	32,913
2020	6,905	6,970	33,652	33,617
2021	6,950	7,102	33,829	34,519
2022	6,918	7,161	33,742	34,862
2023	6,968	7,225	33,745	35,200
2024	7,026	7,299	34,096	35,634
2025	7,082	7,352	34,437	35,868
2026	7,149	7,413	34,900	36,192
2027	7,212	7,479	35,204	36,548
2028	7,280	7,557	35,610	36,981
2029	7,346	7,615	36,007	37,321
2030	7,412	7,680	36,314	37,686
2031	7,472	7,738	36,667	38,029
2032	7,531	7,802	37,109	38,436
2033	7,580	7,850	37,344	38,703
2034	7,636	7,902	37,692	39,045
2035	7,696	7,962	38,129	39,399
2036	7,747	8,045	38,434	39,826
2037	7,797	8,098	38,802	40,076
2038	7,843	8,163	39,260	40,396
2039	7,887	8,225	39,588	40,725
2040	7,928	8,299	39,981	41,125
2041	7,966	8,352	40,457	41,371
2042	8,000	8,416	40,801	41,698
2043	8,032	8,481	41,207	42,021
2044	8,060	8,554	41,692	42,416
2045	8,085	8,613	41,851	42,756
2046	8,107	8,670	42,154	43,081
2047	8,118	8,717	42,537	43,406
2048	8,125	8,761	42,781	43,827
2049	8,132	8,802	43,086	44,164
2050	8,156	8,841	43,472	44,492
2051	8,238	8,877	43,723	44,819

Year	Summer Coincident Peak Demand (MW)		Annual Energy Sales (GWh)	
	2011 RP Forecast	2016 RP Forecast	2011 RP Forecast	2016 RP Forecast
2052		8,911		45,255
2053		8,941		45,563
2054		8,970		45,865
2055		9,020		46,168

Figure 2.2-12 Energy Sales Forecast Comparison – 2011 ERP & 2016 ERP

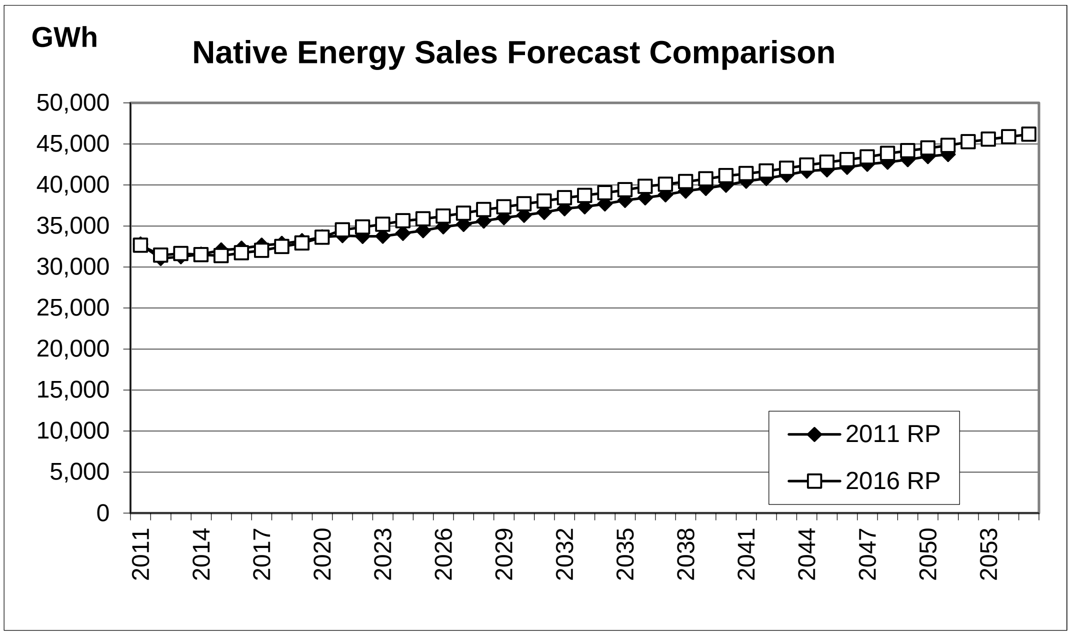
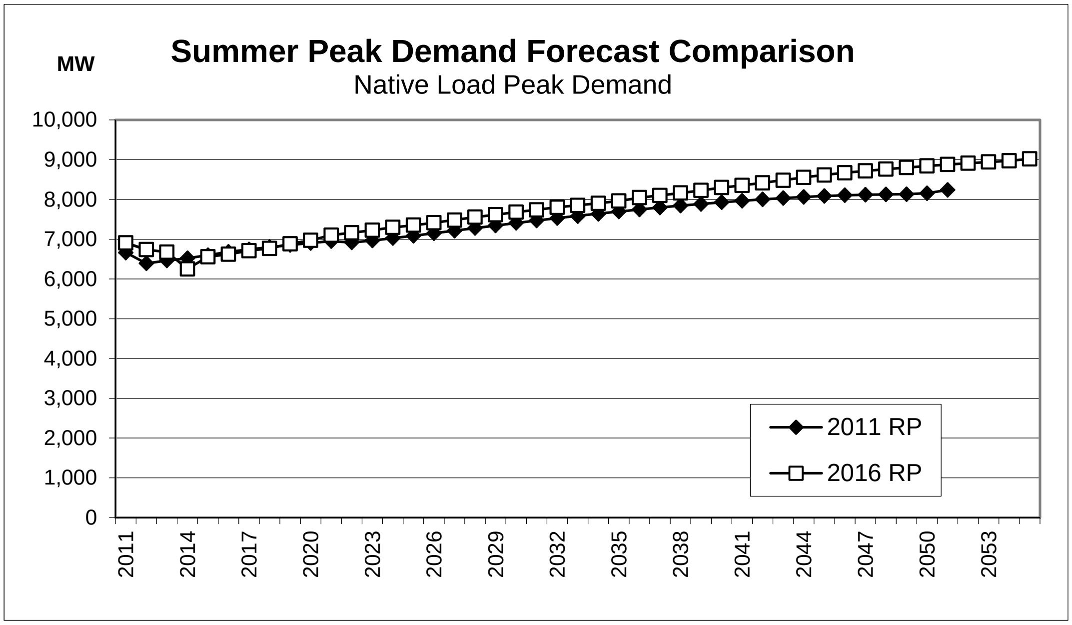


Figure 2.2-13 Summer Native Load Peak Demand Forecast Comparison – 2011 ERP & 2016 ERP



Description and Justification

The following tables show the parameters associated with Public Service's econometric forecasting models.

Table 2.2-25 Number of Residential Electric Customers

REGRESSION PERIOD: Jan 2005- Jun 2015				
NUMBER OF OBSERVATIONS: 126				
LINEAR LEAST SQUARES MODEL WITH ARIMA ERRORS				
Residential Customers = C1*HousingStock				
ARIMA(2,0,0)x(1,0,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	526.2315	0.498483	1055.666	0.00%
AR(1)	1.203817	0.085804	14.02991	0.00%
AR(2)	-0.3169	0.083805	-3.78137	0.03%
SAR(1)	0.480854	0.074765	6.43154	0.00%

Table 2.2-26 Residential Electric Customers – Regression Statistics

Regression Statistics	
Iterations	14
Adjusted Observations	112
Deg. of Freedom for Error	108
R-Squared	0.999
Adjusted R-Squared	0.999
AIC	13.197
BIC	13.294
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(893.96)
Model Sum of Squares	96,216,517,823.37
Sum of Squared Errors	56,183,403.73
Mean Squared Error	520,216.70
Std. Error of Regression	721.26
Mean Abs. Dev. (MAD)	510.87
Mean Abs. % Err. (MAPE)	0.00
Durbin-Watson Statistic	1.98
Durbin-H Statistic	#NA
Ljung-Box Statistic	41.79
Prob (Ljung-Box)	0.014
Frequency of historical data is monthly	

Table 2.2-27 Residential Electric Customers – Definitions and Sources

Variable Name	Definition/Source
Residential Customers	Public Service residential electric customers / Public Service
Housing Stock	Colorado housing Stock / IHS Global Insight Inc.

Table 2.2-28 Residential Electric Sales per Customer

SAMPLE PERIOD: Jan 2005 through Jun 2015				
NUMBER OF OBSERVATIONS: 126				
LINEAR LEAST SQUARES MODEL WITH ARIMA ERRORS				
AvgRes_Use = C1*Heating + C2*Cooling +C3*Base +				
C4*Jan + C5*Feb + C6*Mar + C7*Jun +				
C8*Jul + C9*Aug +C10*Sep + C11*Dec +				
C12*Feb14				
ARIMA(1,0,0)x(0,0,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	2.0229476	0.1714943	11.796008	0.00%
C2	0.2801042	0.0161852	17.306212	0.00%
C3	1.0884831	0.0113278	96.089636	0.00%
C4	130.21706	8.7415685	14.896304	0.00%
C5	34.758215	6.7368513	5.1594155	0.00%
C6	13.45829	5.6560635	2.3794447	1.90%
C7	44.959732	5.5660839	8.0774442	0.00%
C8	89.857237	11.161622	8.0505537	0.00%
C9	61.372569	13.122068	4.6770502	0.00%
C10	69.529198	7.9596299	8.73523	0.00%
C11	89.325203	6.1322168	14.566544	0.00%
C12	37.048936	13.512121	2.7419039	0.71%
AR(1)	0.3558785	0.0903547	3.9386821	0.01%

Table 2.2-29 Residential Electric Sales per Customer – Regression Statistics

Regression Statistics	
Iterations	17
Adjusted Observations	125
Deg. of Freedom for Error	112
R-Squared	0.979
Adjusted R-Squared	0.977
AIC	5.33
BIC	5.63
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(497.71)
Model Sum of Squares	975,805.29
Sum of Squared Errors	21,031.55
Mean Squared Error	187.78
Std. Error of Regression	13.70
Mean Abs. Dev. (MAD)	10.20
Mean Abs. % Err. (MAPE)	0.02
Durbin-Watson Statistic	2.10
Durbin-H Statistic	#NA
Ljung-Box Statistic	34.71
Prob (Ljung-Box)	0.073
Frequency of historical data is monthly	

Table 2.2-30 Residential Electric Sales per Customer – Definition and Sources

Variable Name	Definition/Source
AvgRes_Use	Residential kWh sales per customer/Public Service
Cooling	CoolIndex * CoolUse CoolUse = (Price^(-0.15))*(Income per Household^0.2)*(Household Size^0.25)*Cooling Degree Days/ Public Service, IHS Global Insight Inc.
Heating	HeatIndex * HeatUse HeatUse = (Price^(-0.15))*(Income per Household^0.2)*(Household Size^0.25)*Heating Degree Days/ Public Service, IHS Global Insight Inc.
Base	BaseIndex*BaseUse BaseUse = (Price^(-0.15))*(Income per Household^0.1)*(Household Size^0.46))/ Public Service, IHS Global Insight Inc.
Jan-Dec	Binary variables for each month except April, May, October and November
Feb14	Binary variable = 0 for all months except February 2014 = 1

Table 2.2-31 Commercial / Industrial Electric Sales

SAMPLE PERIOD: Jan 2006 through Jun 2015				
NUMBER OF OBSERVATIONS: 114				
LINEAR LEAST SQUARES MODEL				
Mwh.gs = C1*Heating + C2*Cooling + C3*Base + C4*Jan + C5*Feb + C6*Mar + C7*Apr + C8*May + C9*Jun + C10*Jul + C11*Aug + C12*Sep + C13*Oct + C14*Nov + C15*Dec + C16*BillCycles + C17*GS_Cust				
No ARIMA process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	0.67	0.34	1.95	5.36%
C2	0.54	0.10	5.25	0.00%
C3	0.03	0.01	2.51	1.37%
C4	(1,121,499.80)	398,259.14	(2.82)	0.59%
C5	(1,277,029.10)	396,560.92	(3.22)	0.17%
C6	(1,243,132.64)	396,702.68	(3.13)	0.23%
C7	(1,260,157.46)	394,887.80	(3.19)	0.19%
C8	(1,243,588.48)	393,975.44	(3.16)	0.21%
C9	(1,164,739.31)	394,165.17	(2.95)	0.39%
C10	(1,118,497.77)	395,339.92	(2.83)	0.57%
C11	(1,173,325.65)	397,913.67	(2.95)	0.40%
C12	(1,135,449.03)	395,559.61	(2.87)	0.50%
C13	(1,200,623.81)	395,918.20	(3.03)	0.31%
C14	(1,244,775.42)	395,085.75	(3.15)	0.22%
C15	(1,140,181.00)	397,610.41	(2.87)	0.51%
C16	40,317.41	4,982.37	8.09	0.00%
C17	8.75	1.56	5.60	0.00%

Table 2.2-32 Commercial/Industrial Electric Sales – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	114
Deg. of Freedom for Error	97
R-Squared	0.89
Adjusted R-Squared	0.88
AIC	21.35
BIC	21.76
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(1,361.57)
Model Sum of Squares	1,341,542,932,112
Sum of Squared Errors	157,940,663,482
Mean Squared Error	1,628,254,263
Std. Error of Regression	40,351.63
Mean Abs. Dev. (MAD)	29,539.35
Mean Abs. % Err. (MAPE)	0.02
Durbin-Watson Statistic	2.32
Durbin-H Statistic	#NA
Ljung-Box Statistic	44.853
Prob (Ljung-Box)	0.006
Frequency of historical data is monthly	

Table 2.2-33 Commercial & Industrial Electric Sales – Definitions and Sources

Variable Name	Definition/Source
MWh.gs	Commercial/Industrial electric sales/Public Service
Cooling	CoolIndex * CoolUse CoolUse = (Price^(-0.15))*(Com. Output Index^0.7)*Cooling Degree Days/ Public Service, IHS Global Insight Inc.
Heating	HeatIndex * HeatUse HeatUse = (Price^(-0.15))*(Com. Output Index^0.7)*Heating Degree Days/ Public Service, IHS Global Insight Inc.
Base	BaseIndex*BaseUse BaseUse = (Price^(-0.15))*(Com. Output Index^0.7))/ Public Service, IHS Global Insight Inc.
BillCycleDays	Average number of days in the monthly billing period
Jan-Dec	Binary variables for each month
GS_Cust	Historical and forecasted Commercial/Industrial customers/ Public Service

Table 2.2-34 Electric Sales to Other Public Authorities

SAMPLE PERIOD: Jan 2000 through Jun 2015				
NUMBER OF OBSERVATIONS: 186				
LINEAR LEAST SQUARES MODEL WITH ARIMA ERRORS				
Public Authority = C1*BaseUse + C2*LightRail1 + C3*LightRail2 + C4*LightRail3 + C5*LightRail4				
ARIMA(1,0,0)x(0,0,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	498.50	113.47	4.39	0.00%
C2	335.29	193.18	1.74	8.44%
C3	839.90	174.64	4.81	0.00%
C4	2,241.91	95.69	23.43	0.00%
C5	1,287.87	116.53	11.05	0.00%
AR(1)	0.28	0.07	3.83	0.02%

Table 2.2-35 Electric Sales to Other Public Authorities – Regression Statistics

Regression Statistics	
Iterations	7
Adjusted Observations	185
Deg. of Freedom for Error	179
R-Squared	0.95
Adjusted R-Squared	0.95
AIC	11.94
BIC	12.04
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(1,360.54)
Model Sum of Squares	490,510,633.19
Sum of Squared Errors	26,455,430.28
Mean Squared Error	147,795.70
Std. Error of Regression	384.44
Mean Abs. Dev. (MAD)	220.98
Mean Abs. % Err. (MAPE)	0.09
Durbin-Watson Statistic	2.08
Durbin-H Statistic	#NA
Ljung-Box Statistic	29.45
Prob (Ljung-Box)	0.20
Frequency of historical data is monthly	

Table 2.2-36 Electric Sales to Other Public Authorities – Definitions and Sources

Variable Name	Definition/Source
Public Authority	Public Authority electric sales /Public Service
Base	BaseUse = (Price^(-0.15))*(Com. Output Index^0.7))/ Public Service, IHS Global Insight Inc.
LightRail1	Binary variable = 0 for all months until December 2001, = 1 after
LightRail2	Binary variable = 0 for all months until October 2002, = 1 after
LightRail3	Binary variable = 0 for all months until November 2006, = 1 after
LightRail4	Binary variable = 0 for all months until April 2013, = 1 after

Table 2.2-37 Electric Street and Highway Lighting Sales

REGRESSION PERIOD: Jan 2000 - Jun 2015				
NUMBER OF OBSERVATIONS: 186				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
StreetLight = C1*ResCustomers + C2*Jan + C3*Feb + C4*Mar + C5*Apr + C6*May + C7*Jun + C8*Jul + C9*Aug + C10*Sep + C11*Oct + C12*Nov + C13*Dec + C14*CRSph2+ C15*Feb13 + C16*Jan13				
ARIMA(2,0,0)x(0,0,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	0.004	0.002	2.25	2.58%
C2	14,128.88	1,795.91	7.87	0.00%
C3	13,648.15	1,797.66	7.59	0.00%
C4	11,552.65	1,797.34	6.43	0.00%
C5	11,450.87	1,797.49	6.37	0.00%
C6	9,627.27	1,796.56	5.36	0.00%
C7	8,469.94	1,797.34	4.71	0.00%
C8	8,021.22	1,785.70	4.49	0.00%
C9	8,629.92	1,786.84	4.83	0.00%
C10	9,499.93	1,786.51	5.32	0.00%
C11	10,381.07	1,789.27	5.80	0.00%
C12	12,019.58	1,790.83	6.71	0.00%
C13	12,794.12	1,793.18	7.13	0.00%
C14	(580.07)	203.68	(2.85)	0.50%
C15	(9,100.96)	311.01	(29.26)	0.00%
C16	(2,951.25)	311.18	(9.48)	0.00%
AR(1)	0.318	0.074	4.32	0.00%
AR(2)	0.307	0.071	4.35	0.00%

Table 2.2-38 Electric Street and Highway Lighting Sales – Regression Statistics

Regression Statistics	
Iterations	10
Adjusted Observations	184
Deg. of Freedom for Error	166
R-Squared	0.977
Adjusted R-Squared	0.975
AIC	11.659
BIC	11.974
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(1,315.714)
Model Sum of Squares	746,757,553.343
Sum of Squared Errors	17,510,357.518
Mean Squared Error	105,484.081
Std. Error of Regression	324.783
Mean Abs. Dev. (MAD)	211.736
Mean Abs. % Err. (MAPE)	0.015
Durbin-Watson Statistic	2.062
Durbin-H Statistic	#NA
Ljung-Box Statistic	36.539
Prob (Ljung-Box)	0.049
Frequency of historical data is monthly	

Table 2.2-39 Electric Street and Highway Lighting Sales – Definitions and Sources

Variable Name	Definition/Source
StreetLight	Public Service street and highway lighting electric sales/ Public Service
ResCustomers	Historical and forecasted residential customers/Public Service
Jan-Dec	Binary variables for each month except July
CRSPh2(-2 lag)	Binary variable for the timing of CRS Phase II lagged 2 periods
Feb13	Binary variable = 0 for all months except February 2013 = 1
Jan13	Binary variable = 0 for all months except January 2013 = 1

Table 2.2-40 Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2002 through Dec 2014				
NUMBER OF OBSERVATIONS: 156				
LINEAR LEAST SQUARES MODEL				
Res_Coincident = C1*Res_SalesTrend + C2*ResCoolTrend_CDD_Cust_Jun + C3*ResCoolTrend_CDD_Cust_Jul + C4*ResCoolTrend_CDD_Cust_Aug + C5*Dec_HDD + C6*Jan_HDD + C7*Feb_HDD + C8*Sep08 + C9*Oct10 + C10*Oct05 + C11*Apr06 + C12*Apr07 + C13*May07 + C14*Sep13 + C15*Oct07 + C16*Apr12 + C17*Oct11 + C18*TrendVar + C19*Apr + C20*May				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	2.00	0.12	16.89	0.00%
C2	0.00	0.00	9.78	0.00%
C3	0.00	0.00	12.92	0.00%
C4	0.00	0.00	10.15	0.00%
C5	0.00	0.00	7.48	0.00%
C6	0.00	0.00	6.27	0.00%
C7	0.00	0.00	4.53	0.00%
C8	507.56	149.29	3.40	0.09%
C9	(729.54)	149.45	(4.88)	0.00%
C10	(515.62)	149.35	(3.45)	0.08%
C11	(565.61)	155.05	(3.65)	0.04%
C12	(559.29)	155.02	(3.61)	0.04%
C13	(408.96)	153.88	(2.66)	0.88%
C14	596.58	150.32	3.97	0.01%
C15	(590.66)	149.43	(3.95)	0.01%
C16	(549.70)	155.51	(3.53)	0.06%
C17	(391.43)	149.67	(2.62)	0.99%
C18	7.06	4.25	1.66	9.92%
C19	(101.92)	51.17	(1.99)	4.84%
C20	(157.11)	47.48	(3.31)	0.12%

Table 2.2-41 Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	156.000
Deg. of Freedom for Error	136.000
R-Squared	0.840
Adjusted R-Squared	0.817
AIC	10.110
BIC	10.501
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(989.928)
Model Sum of Squares	15,552,249.594
Sum of Squared Errors	2,967,876.563
Mean Squared Error	21,822.622
Std. Error of Regression	147.725
Mean Abs. Dev. (MAD)	101.871
Mean Abs. % Err. (MAPE)	0.060
Durbin-Watson Statistic	1.746
Durbin-H Statistic	#NA
Ljung-Box Statistic	45.556
Prob (Ljung-Box)	0.005
Frequency of historical data is monthly	

Table 2.2-42 Residential Contribution to System Peak Demand – Definition and Sources

Variable Name	Definition/Source
Res_Coincident	Residential class contribution to system peak, MW/Public Service
Res_SalesTrend	12 month moving average of actual and forecast Residential kWh sales/ Public Service (calculated internally in the energy sales model)
ResCoolTrend_ CDD_Cust	Cooling Degree Days (base 65) * Residential Cooling Index*Customer Counts for the months of June, July, and August/ the National Weather Service, Denver, Colorado, Public Service
HDD	Heating Degree Days (base 55) for months December-February/ calculated from data from the National Weather Service, Denver, Colorado
TrendVar	Simple linear trend variable
Apr-May	Binary variable for April and May
Sep08	Binary variable = 0 for all months except September 2008 = 1
Oct10	Binary variable = 0 for all months except October 2010 = 1
Apr06	Binary variable = 0 for all months except April 2006 = 1
Apr07	Binary variable = 0 for all months except April 2007 = 1
May07	Binary variable = 0 for all months except May 2007 = 1
Sep13	Binary variable = 0 for all months except September 2013 = 1
Oct05	Binary variable = 0 for all months except October 2005 = 1
Oct07	Binary variable = 0 for all months except October 2007 = 1
Apr12	Binary variable = 0 for all months except April 2012 = 1
Oct11	Binary variable = 0 for all months except October 2011 = 1

Table 2.2-43 Non-residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2004 through Dec 2014				
NUMBER OF OBSERVATIONS: 132				
LINEAR LEAST SQUARES MODEL WITH ARIMA ERRORS				
NonRes_Coincident = C1*NonRes_SalesTrend + C2*May_PDMaxTemp + C3*Jun_PDMaxTemp_Cust+ C4*Jul_PDCDD_Cust + C5*Aug_PDCDD_Cust + C6*Sep_PDMaxTemp+ C7*Oct_PDMaxTemp + C8*Sep_08 + C9*Jan + C10*Feb + C11*Nov + C12*Dec + C13*Apr12 + C14*Apr06 + C15*TrendVar + C16*Apr07				
ARIMA(1,0,0)x(0,0,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	0.00	0.00	19.70	0.00%
C2	7.57	0.68	11.21	0.00%
C3	0.00	0.00	16.08	0.00%
C4	0.00	0.00	18.99	0.00%
C5	0.00	0.00	17.64	0.00%
C6	10.14	0.71	14.20	0.00%
C7	4.81	0.94	5.11	0.00%
C8	(911.18)	164.30	(5.55)	0.00%
C9	228.71	62.97	3.63	0.04%
C9	219.43	57.46	3.82	0.02%
C9	341.79	61.36	5.57	0.00%
C9	347.47	61.66	5.64	0.00%
C9	698.31	161.58	4.32	0.00%
C9	630.16	160.35	3.93	0.02%
C9	(24.99)	6.64	(3.76)	0.03%
C9	710.57	160.24	4.43	0.00%
AR(1)	0.17	0.09	1.78	7.83%

Table 2.2-44 Non-residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	11
Adjusted Observations	131
Deg. of Freedom for Error	114
R-Squared	0.878
Adjusted R-Squared	0.860
AIC	10.266
BIC	10.639
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(841.273)
Model Sum of Squares	20,796,923.640
Sum of Squared Errors	2,902,782.105
Mean Squared Error	25,463.001
Std. Error of Regression	159.571
Mean Abs. Dev. (MAD)	114.417
Mean Abs. % Err. (MAPE)	0.042
Durbin-Watson Statistic	2.020
Durbin-H Statistic	#NA
Ljung-Box Statistic	29.238
Prob (Ljung-Box)	0.211
Frequency of historical data is monthly	

Table 2.2-45 Non-residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
NonRes_Coincident	Commercial and industrial class contribution to system peak, MW/ Public Service
NonRes_SalesTrend	12 month moving average of actual and forecast Non-Residential kWh sales/ Public Service (calculated internally in the energy sales model)
PDMaxTemp_Cust	Peak day maximum temperature*Commercial-Industrial Customers for months May, June, September, and October/ the National Weather Service, Denver, Colorado, Public Service
PDCDD_Cust	Peak day Cooling Degree Days (base 65)*Commercial-Industrial Customers for months July and August/ the National Weather Service, Denver, Colorado, Public Service
Jan-Dec	Binary variables for January, February, November, and December
Trendvar	Simple linear trend variable
Sep08	Binary variable = 0 for all months except September 2008 = 1
Apr12	Binary variable = 0 for all months except April 2012 = 1
Apr06	Binary variable = 0 for all months except April 2006 = 1
Apr07	Binary variable = 0 for all months except April 2007 = 1

2.3 HOURLY LOAD PROFILES

Introduction

This section contains typical day load patterns on a system-wide basis for each major customer class (by voltage level) provided for peak day, average day and representative off-peak days for each calendar month.

The following monthly class load shapes are developed from Company load research data for the year 2014. The following statistics were used for each requirement:

REQUIREMENT	STATISTIC
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The residential and commercial and industrial profiles were developed from aggregated load research classes. These profiles were calculated using the population weighted average load of all the rate classes in each group.

The following pages contain "figures" with tables and graphs for each of the load patterns described above.

Residential	Figures 2.3-1 through 2.3-12
Commercial & Industrial (Secondary)	Figures 2.3-13 through 2.3-24
Commercial & Industrial (Primary)	Figures 2.3-25 through 2.3-36
Commercial & Industrial (Transmission)	Figures 2.3-37 through 2.3-48
Wholesale	Figures 2.3-49 through 2.3-60

Please note that the wholesale data provided for two customers who are part owners in Comanche 3 contains their total load (what is served by both Xcel Energy and Comanche 3). Public Service is required to serve their total load in the event that Comanche 3 is not on line. In addition, the WAPA allocations for the wholesale data are not subtracted from the total load provided because hourly WAPA data is not available.

Figure 2.3-1 Residential January

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9512	0.8044	0.8110
2	0.8845	0.7701	0.7612
3	0.8450	0.7502	0.7276
4	0.8537	0.7454	0.7263
5	0.8361	0.7641	0.7261
6	0.8502	0.8332	0.7477
7	0.8896	0.9388	0.7816
8	0.9263	0.9606	0.8284
9	1.0129	0.8900	0.8905
10	1.0627	0.8708	0.9646
11	1.1589	0.8553	0.9767
12	1.2233	0.8331	1.0027
13	1.2154	0.8077	1.0107
14	1.1584	0.7858	0.9940
15	1.2506	0.7902	0.9944
16	1.2889	0.8147	1.0033
17	1.4124	0.9355	1.0954
18	1.5311	1.1376	1.2310
19	1.6721	1.2848	1.3385
20	1.6646	1.3064	1.3368
21	1.5077	1.2510	1.2954
22	1.3660	1.1738	1.1859
23	1.2040	1.0164	1.0429
24	1.0075	0.8730	0.8859

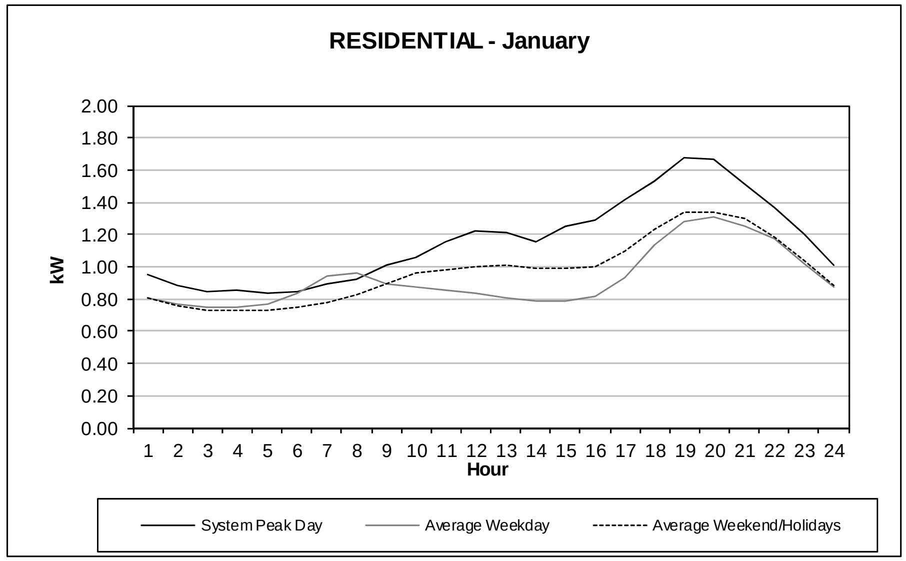


Figure 2.3-2 Residential February

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9280	0.8008	0.8367
2	0.8977	0.7697	0.7925
3	0.8973	0.7567	0.7569
4	0.9179	0.7569	0.7495
5	0.9478	0.7695	0.7485
6	1.0185	0.8474	0.7699
7	1.1512	0.9485	0.8178
8	1.1834	0.9588	0.8691
9	1.1566	0.8989	0.9441
10	1.0893	0.8600	1.0001
11	1.0094	0.8496	1.0159
12	1.0393	0.8392	1.0053
13	1.0369	0.8166	1.0047
14	1.0823	0.8011	0.9617
15	1.0568	0.7847	0.9416
16	1.0276	0.8152	0.9693
17	1.1338	0.9126	1.0308
18	1.3275	1.0798	1.1586
19	1.5819	1.2602	1.2574
20	1.6135	1.2882	1.2807
21	1.4730	1.2422	1.2393
22	1.4182	1.1730	1.1707
23	1.2450	1.0057	1.0376
24	1.0990	0.8656	0.9080

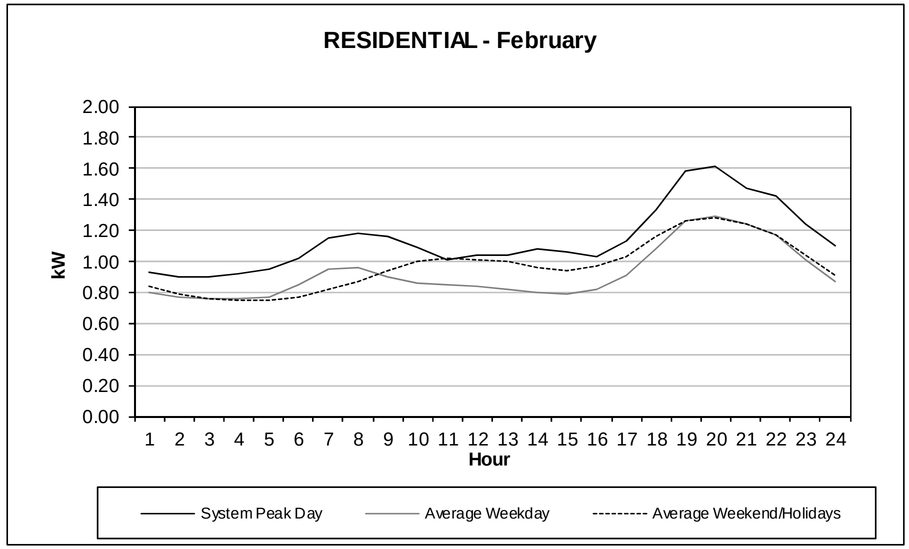


Figure 2.3-3 Residential March

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8042	0.7100	0.7747
2	0.7556	0.6681	0.7189
3	0.7125	0.6546	0.7004
4	0.6823	0.6476	0.6838
5	0.6722	0.6677	0.6770
6	0.6935	0.7459	0.7011
7	0.7640	0.8507	0.7478
8	0.8489	0.8515	0.8153
9	0.9431	0.8132	0.8873
10	0.9292	0.7805	0.9413
11	0.9691	0.7634	0.9957
12	1.0090	0.7482	0.9464
13	0.9889	0.7249	0.9459
14	0.9510	0.7028	0.9170
15	0.9481	0.6894	0.9035
16	1.0240	0.7101	0.8930
17	1.1332	0.7742	0.9292
18	1.1345	0.8876	0.9959
19	1.2406	1.0207	1.0778
20	1.3682	1.0989	1.1901
21	1.2761	1.1204	1.1971
22	1.1533	1.0635	1.1280
23	1.0407	0.9277	0.9929
24	0.9767	0.8004	0.8412

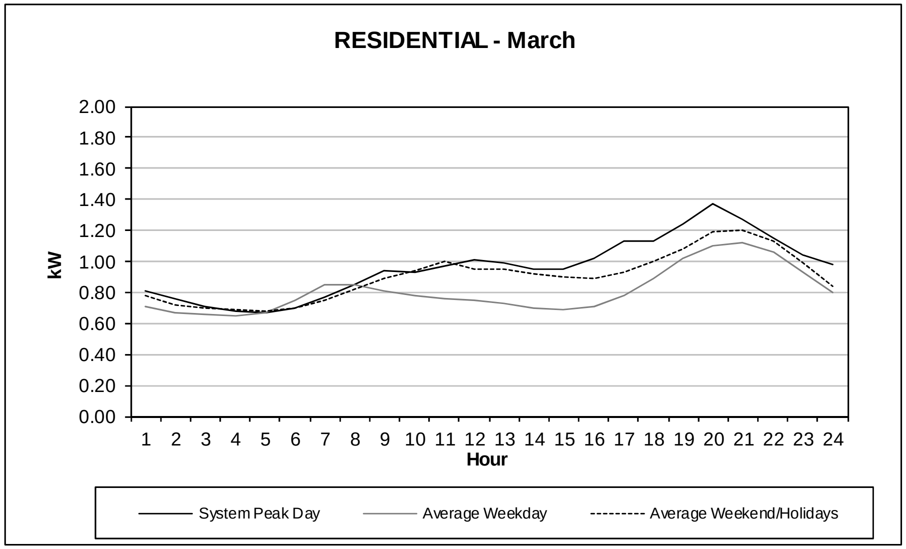


Figure 2.3-4 Residential April

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6677	0.6383	0.6662
2	0.6155	0.6002	0.6074
3	0.5960	0.5796	0.5808
4	0.5780	0.5757	0.5654
5	0.5739	0.5883	0.5541
6	0.5829	0.6607	0.5869
7	0.6377	0.7663	0.6434
8	0.7034	0.7494	0.6936
9	0.8405	0.7021	0.7695
10	0.9267	0.6892	0.8366
11	0.9589	0.6722	0.8467
12	0.9813	0.6711	0.8616
13	1.0127	0.6651	0.8612
14	1.0160	0.6429	0.8512
15	1.0179	0.6415	0.8403
16	1.0788	0.6675	0.8587
17	1.0856	0.7291	0.8859
18	1.1433	0.8207	0.9361
19	1.2579	0.8980	0.9862
20	1.3641	0.9676	1.0563
21	1.2776	1.0319	1.0885
22	1.2110	1.0042	1.0518
23	1.0398	0.8708	0.9216
24	0.8464	0.7351	0.7721

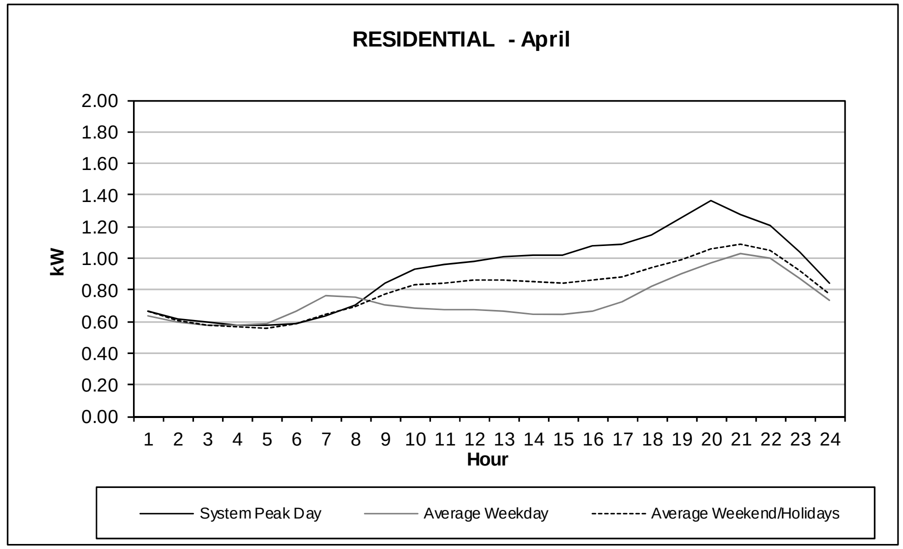


Figure 2.3-5 Residential May

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6991	0.6600	0.6542
2	0.6166	0.5921	0.5871
3	0.5824	0.5665	0.5509
4	0.5695	0.5559	0.5290
5	0.5437	0.5606	0.5223
6	0.5895	0.6158	0.5417
7	0.6767	0.7047	0.5827
8	0.6787	0.6918	0.6209
9	0.6889	0.6698	0.6958
10	0.7292	0.6660	0.7509
11	0.7748	0.6725	0.8161
12	0.8078	0.6774	0.8007
13	0.9129	0.6960	0.8087
14	0.9904	0.6982	0.8278
15	1.0520	0.7241	0.8441
16	1.1589	0.7515	0.8812
17	1.3327	0.8415	0.9074
18	1.4083	0.9294	0.9494
19	1.4906	0.9805	0.9987
20	1.5672	1.0357	1.0052
21	1.4412	1.0485	1.0243
22	1.4109	1.0253	1.0067
23	1.2857	0.9148	0.9285
24	1.0326	0.7694	0.7679

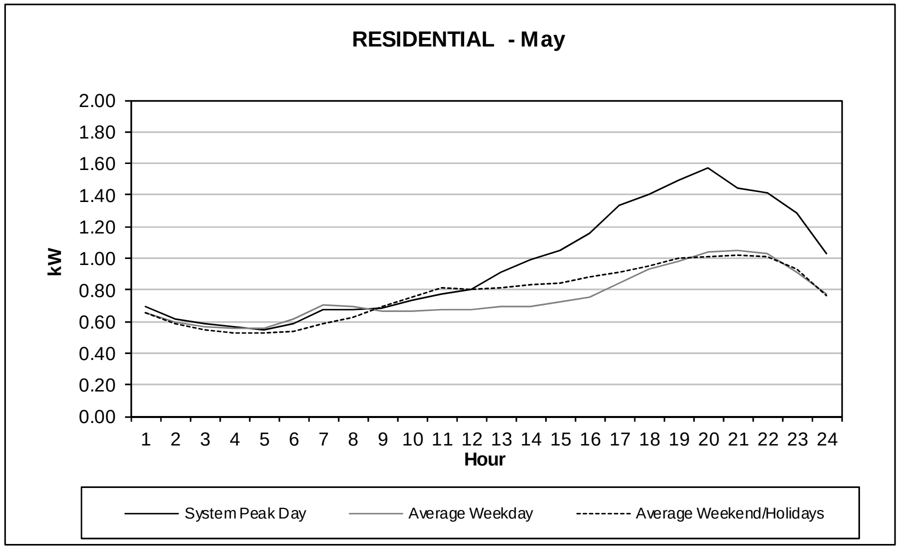


Figure 2.3-6 Residential June

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9099	0.7178	0.7265
2	0.7912	0.6223	0.6392
3	0.7393	0.5753	0.5905
4	0.6942	0.5525	0.5613
5	0.6577	0.5435	0.5398
6	0.6730	0.5753	0.5393
7	0.6896	0.6267	0.5779
8	0.7311	0.6386	0.6085
9	0.8078	0.6540	0.6631
10	0.8220	0.6998	0.7339
11	0.9409	0.7664	0.8041
12	1.0256	0.8163	0.8642
13	1.1486	0.8633	0.9195
14	1.2913	0.9345	0.9807
15	1.3778	0.9885	1.0139
16	1.4741	1.0579	1.0595
17	1.6005	1.1522	1.1238
18	1.6277	1.2435	1.1555
19	1.6608	1.3002	1.1904
20	1.6093	1.2799	1.1860
21	1.5455	1.2113	1.1311
22	1.4475	1.1799	1.1042
23	1.2204	1.0503	0.9851
24	1.0275	0.8705	0.8248

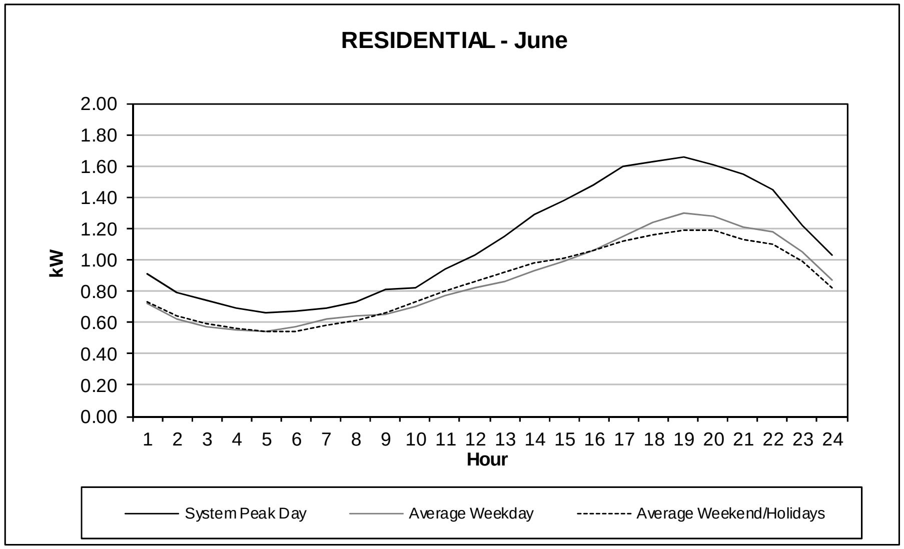


Figure 2.3-7 Residential July

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0190	0.8526	0.8963
2	0.8821	0.7456	0.7701
3	0.7822	0.6858	0.7081
4	0.7262	0.6486	0.6568
5	0.6930	0.6314	0.6374
6	0.6949	0.6560	0.6277
7	0.7685	0.6950	0.6550
8	0.7687	0.7196	0.6991
9	0.8080	0.7424	0.7757
10	0.9555	0.8011	0.9094
11	1.1417	0.8967	1.0377
12	1.2689	0.9721	1.1911
13	1.4118	1.0649	1.2846
14	1.5115	1.1522	1.3778
15	1.6083	1.1998	1.4640
16	1.6910	1.2599	1.5226
17	1.7751	1.3353	1.5336
18	1.8240	1.4108	1.5262
19	1.7906	1.4567	1.5085
20	1.7236	1.4278	1.4719
21	1.6623	1.3739	1.3911
22	1.4983	1.3334	1.3334
23	1.3191	1.1889	1.2119
24	1.1159	0.9968	1.0525

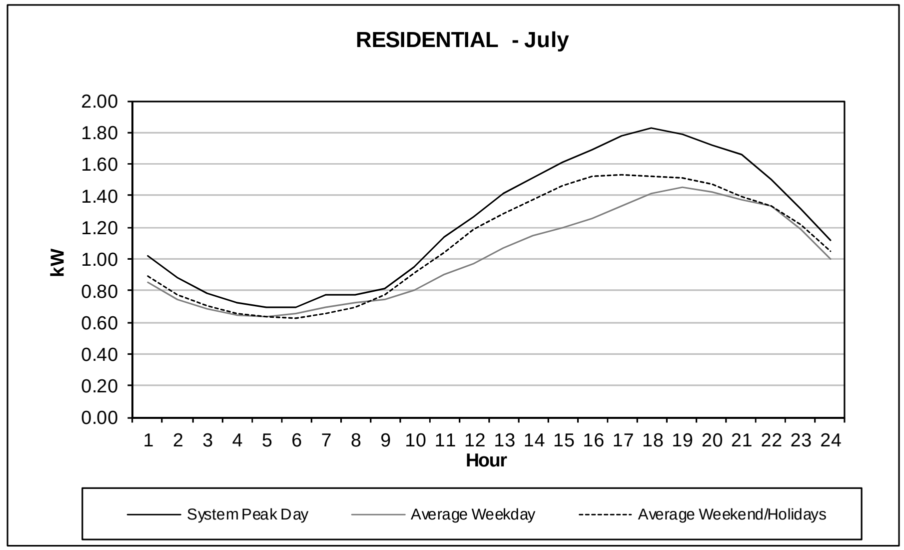


Figure 2.3-8 Residential August

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8546	0.7635	0.7262
2	0.7763	0.6751	0.6399
3	0.7290	0.6301	0.5940
4	0.7037	0.5962	0.5595
5	0.6857	0.5894	0.5482
6	0.6725	0.6213	0.5471
7	0.7195	0.6840	0.5780
8	0.7215	0.6970	0.6197
9	0.7169	0.6619	0.6650
10	0.7823	0.6899	0.7685
11	0.9062	0.7645	0.8480
12	0.9851	0.8288	0.9208
13	1.0933	0.9074	1.0026
14	1.2723	0.9799	1.1060
15	1.3641	1.0277	1.1973
16	1.5222	1.0830	1.2394
17	1.6972	1.1661	1.3039
18	1.7042	1.2297	1.3340
19	1.6643	1.3074	1.3248
20	1.5556	1.2769	1.3196
21	1.5198	1.2411	1.2900
22	1.4835	1.1951	1.2246
23	1.3055	1.0452	1.0751
24	1.0830	0.8645	0.8935

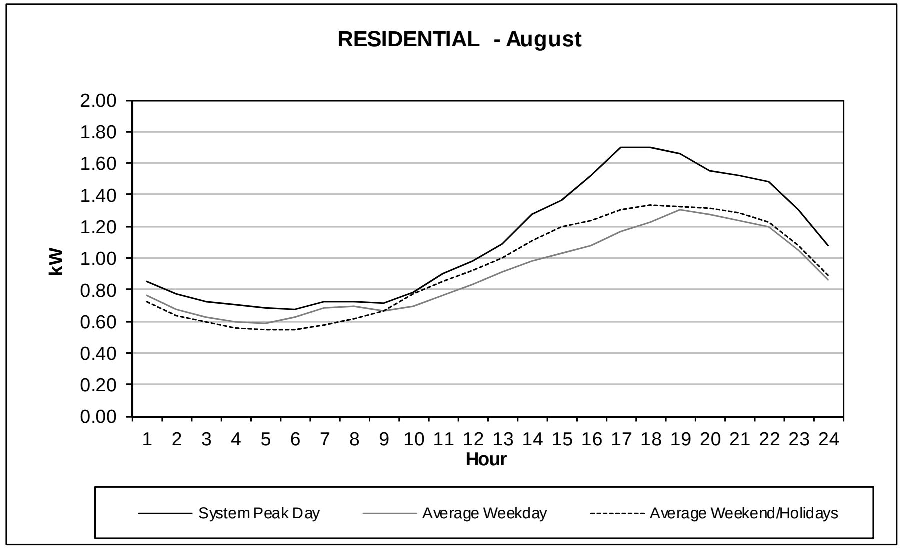


Figure 2.3-9 Residential September

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7132	0.6368	0.6701
2	0.6364	0.5721	0.5984
3	0.5945	0.5418	0.5621
4	0.5637	0.5225	0.5351
5	0.5696	0.5308	0.5231
6	0.5760	0.5765	0.5294
7	0.6783	0.6793	0.5684
8	0.6748	0.6844	0.6098
9	0.6418	0.6418	0.6702
10	0.6785	0.6336	0.7125
11	0.7931	0.6474	0.7708
12	0.9669	0.6927	0.8179
13	1.0914	0.7266	0.8729
14	1.2264	0.7880	0.9345
15	1.3362	0.8376	0.9891
16	1.4380	0.9005	1.0409
17	1.5624	0.9959	1.1042
18	1.6632	1.1134	1.1221
19	1.7021	1.1672	1.1406
20	1.6506	1.1845	1.1340
21	1.5619	1.1377	1.1219
22	1.4309	1.0657	1.0631
23	1.2353	0.9165	0.9348
24	0.9969	0.7501	0.7573

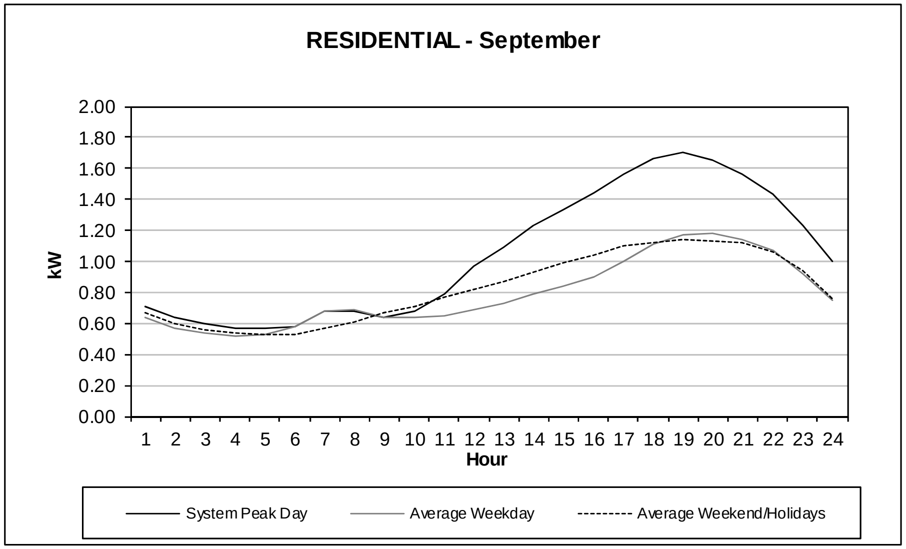


Figure 2.3-10 Residential October

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.5931	0.5787	0.6152
2	0.5319	0.5415	0.5675
3	0.5061	0.5261	0.5451
4	0.4974	0.5229	0.5313
5	0.5103	0.5472	0.5372
6	0.5698	0.6095	0.5548
7	0.6592	0.7246	0.6121
8	0.6845	0.7610	0.6803
9	0.6290	0.6861	0.7351
10	0.6120	0.6456	0.7760
11	0.6085	0.6352	0.8112
12	0.6181	0.6283	0.8234
13	0.6392	0.6258	0.8328
14	0.6694	0.6271	0.8600
15	0.6948	0.6378	0.8562
16	0.7619	0.6716	0.8876
17	0.8684	0.7598	0.9546
18	0.9466	0.8582	0.9769
19	1.0323	0.9732	1.0327
20	1.0872	1.0254	1.0668
21	0.9857	1.0073	1.0374
22	0.9622	0.9457	0.9501
23	0.8094	0.8062	0.8331
24	0.6719	0.6732	0.6856

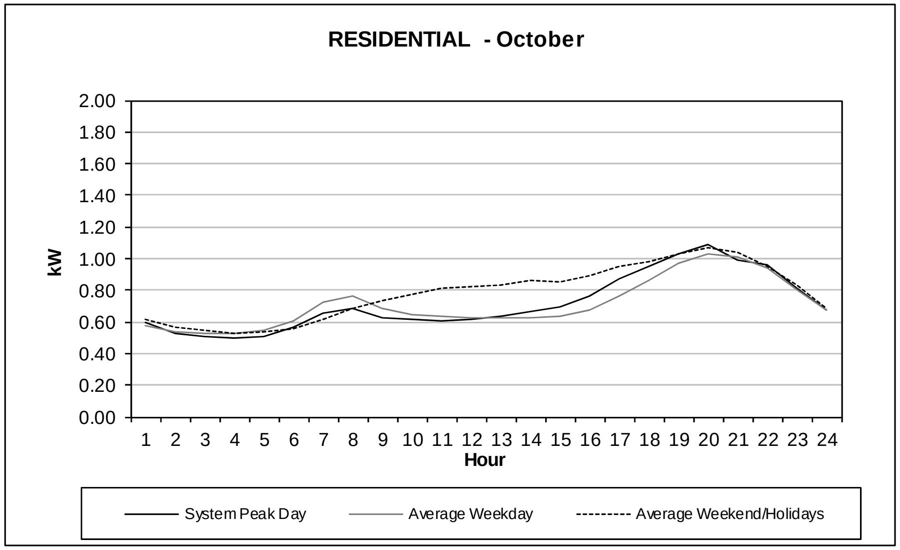


Figure 2.3-11 Residential November

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8025	0.7128	0.7179
2	0.7515	0.6824	0.6697
3	0.7425	0.6717	0.6375
4	0.7637	0.6706	0.6274
5	0.8034	0.6933	0.6290
6	0.8658	0.7620	0.6649
7	0.9250	0.8525	0.7340
8	0.9842	0.8805	0.7948
9	0.9521	0.8212	0.8520
10	0.9342	0.7949	0.9334
11	0.9452	0.7718	0.9392
12	0.9153	0.7534	0.9215
13	0.9237	0.7601	0.9442
14	0.9762	0.7455	0.9259
15	0.9685	0.7434	0.9618
16	0.9218	0.7806	0.9677
17	1.1011	0.9152	1.0297
18	1.2976	1.1102	1.1435
19	1.3404	1.1931	1.1671
20	1.2750	1.1964	1.1553
21	1.2748	1.1427	1.0978
22	1.2705	1.0791	1.0208
23	1.0328	0.9204	0.8892
24	0.9059	0.7798	0.7609

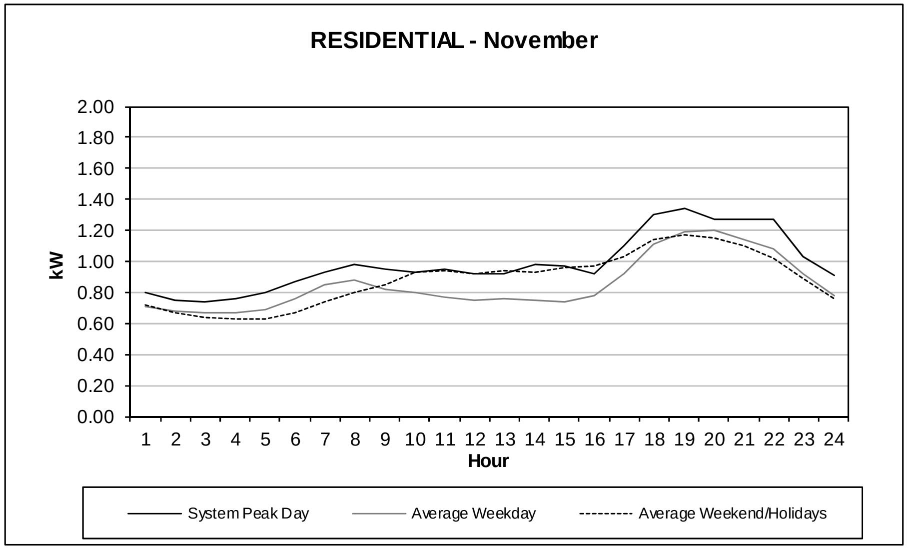


Figure 2.3-12 Residential December

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9795	0.8051	0.8255
2	0.8669	0.7492	0.7488
3	0.8522	0.7251	0.7259
4	0.8422	0.7192	0.7024
5	0.8784	0.7442	0.7118
6	0.9268	0.8168	0.7403
7	0.9757	0.8887	0.7994
8	1.0111	0.9589	0.8837
9	1.0362	0.9034	0.9209
10	1.0865	0.8613	0.9799
11	1.0995	0.8487	1.0089
12	1.0839	0.8338	1.0049
13	1.1208	0.8223	1.0181
14	1.0960	0.8111	0.9938
15	1.1317	0.8171	1.0005
16	1.1151	0.8495	1.0272
17	1.2552	1.0052	1.1188
18	1.4565	1.2089	1.2601
19	1.5958	1.3109	1.2980
20	1.5728	1.3055	1.2911
21	1.5088	1.2752	1.2431
22	1.3713	1.1916	1.1551
23	1.2362	1.0426	1.0210
24	1.1119	0.8992	0.8900

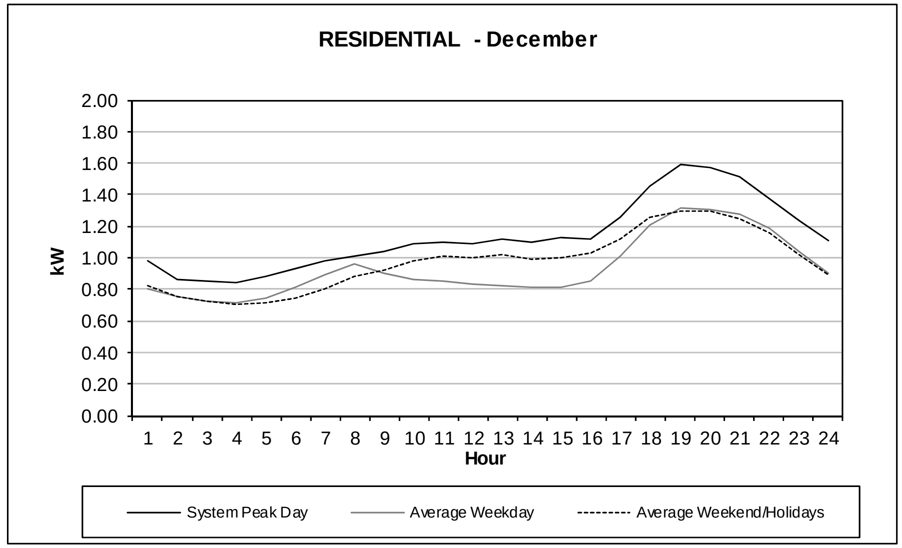


Figure 2.3-13 Commercial & Industrial (Secondary) January

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.4652	8.6356	8.2156
2	8.5096	8.6204	8.1915
3	8.4298	8.5302	8.0977
4	8.3880	8.5534	8.0669
5	8.4953	8.8566	8.1875
6	8.5786	9.6274	8.3672
7	8.8744	10.7021	8.7498
8	9.0802	11.4000	8.8116
9	8.9105	11.8328	8.7398
10	9.1496	12.0728	8.8977
11	9.2683	12.1669	9.0376
12	9.4208	12.1409	9.0851
13	9.4728	12.0437	9.0255
14	9.5233	12.0574	8.9725
15	9.2900	11.9598	8.8854
16	9.3503	11.7174	8.8656
17	9.5187	11.3662	8.9209
18	9.8791	11.1660	9.2681
19	9.6704	10.6153	9.1009
20	9.5153	10.2824	8.9880
21	9.3808	9.9119	8.8494
22	9.1245	9.4223	8.5970
23	8.9988	9.0304	8.4057
24	8.8764	8.8388	8.2388

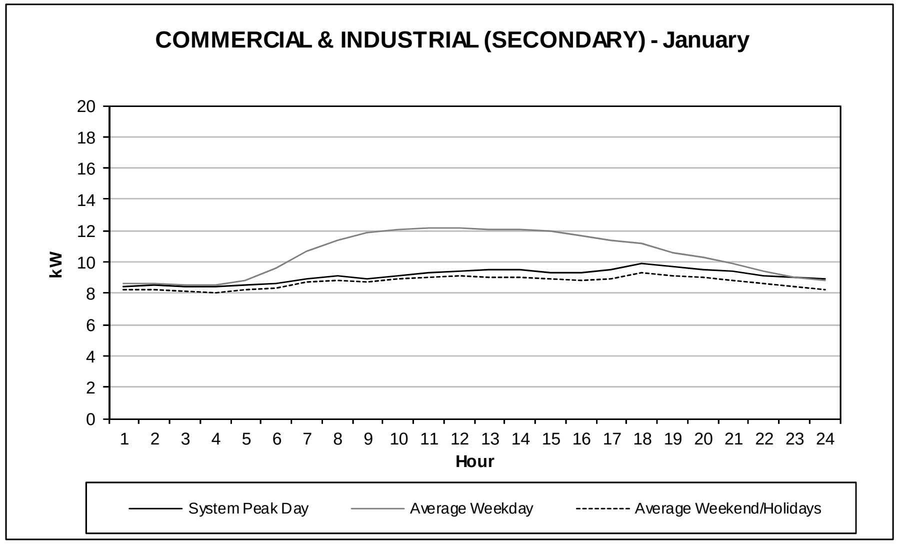


Figure 2.3-14 Commercial & Industrial (Secondary) February

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10.1657	8.8529	8.4240
2	10.1486	8.8444	8.3191
3	10.1549	8.7841	8.2411
4	10.0168	8.8213	8.2419
5	10.2052	9.1008	8.3397
6	10.9217	9.8098	8.4838
7	11.9938	10.8896	8.8353
8	12.5747	11.4175	8.7922
9	13.1531	11.9223	8.8668
10	13.4905	12.2066	8.9994
11	13.5096	12.3692	9.1444
12	13.3545	12.3259	9.0936
13	13.2768	12.2348	9.0020
14	13.3467	12.2481	8.9091
15	13.3074	12.1421	8.8888
16	13.1342	11.8781	8.8375
17	12.8171	11.4453	8.8694
18	12.6185	11.0495	8.9879
19	12.3359	10.7339	9.0743
20	12.0544	10.4568	9.0120
21	11.7877	10.1280	8.8672
22	11.2584	9.6579	8.6316
23	10.6768	9.2351	8.4258
24	10.5453	9.0378	8.3067

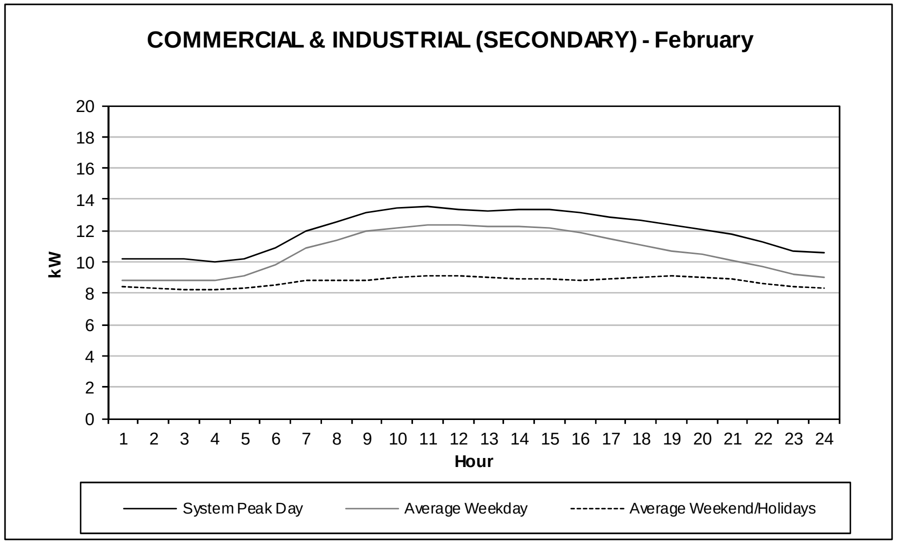


Figure 2.3-15 Commercial & Industrial (Secondary) March

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.2571	8.1357	8.0160
2	8.1204	8.1357	7.9468
3	8.0857	8.0607	7.8917
4	8.0488	8.0934	7.8311
5	8.1610	8.3861	7.9462
6	8.3807	9.0571	8.1295
7	8.8152	10.1102	8.4657
8	9.0919	10.6808	8.5031
9	9.4262	11.1866	8.5694
10	9.6293	11.4698	8.7045
11	9.9252	11.6430	8.8766
12	9.7341	11.7254	8.8847
13	9.5339	11.6641	8.8563
14	9.3126	11.7073	8.7547
15	9.1780	11.6392	8.7073
16	9.1080	11.4227	8.6647
17	9.2381	10.9743	8.6317
18	9.2943	10.2490	8.5226
19	9.5358	9.6987	8.4590
20	9.4853	9.6712	8.6205
21	9.3397	9.4079	8.5339
22	9.1142	8.9724	8.3209
23	8.7998	8.5359	8.0680
24	8.6210	8.3466	7.9353

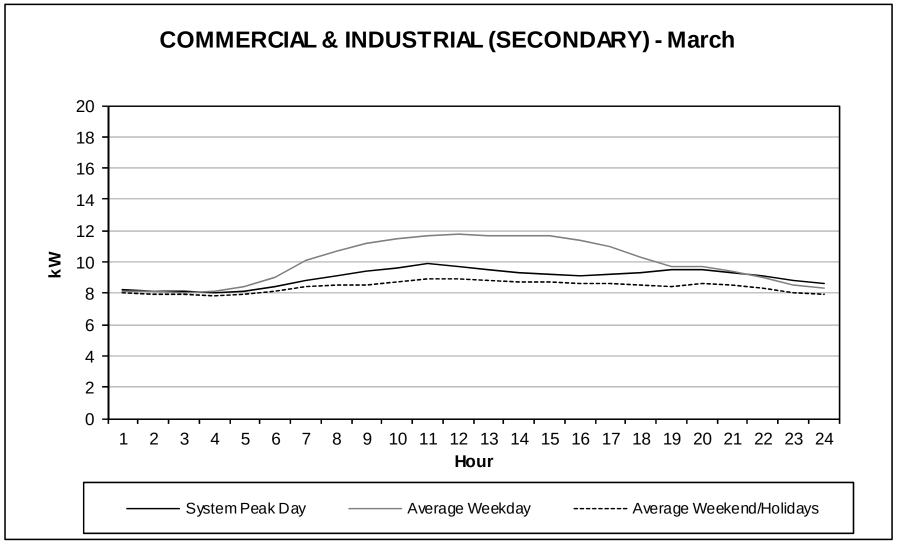


Figure 2.3-16 Commercial & Industrial (Secondary) April

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.2965	8.0005	7.6832
2	7.2075	7.9168	7.5637
3	7.2073	7.8718	7.4683
4	7.1745	7.9036	7.4079
5	7.2698	8.1723	7.4976
6	7.4236	8.8874	7.6791
7	7.6936	9.7249	7.8961
8	7.7430	10.3257	7.9009
9	7.6994	10.9136	8.0440
10	7.8944	11.3554	8.2821
11	7.9985	11.6419	8.5054
12	8.2187	11.7773	8.6425
13	8.2752	11.7794	8.6354
14	8.1710	11.9254	8.6381
15	8.3084	11.9160	8.6288
16	8.3429	11.6769	8.5855
17	8.3967	11.1643	8.4691
18	8.1144	10.3997	8.2694
19	8.0099	9.7404	8.0666
20	8.1962	9.5903	8.2133
21	8.4083	9.4459	8.2852
22	8.3038	9.0611	8.0903
23	8.1071	8.5483	7.7868
24	8.0031	8.2841	7.6153

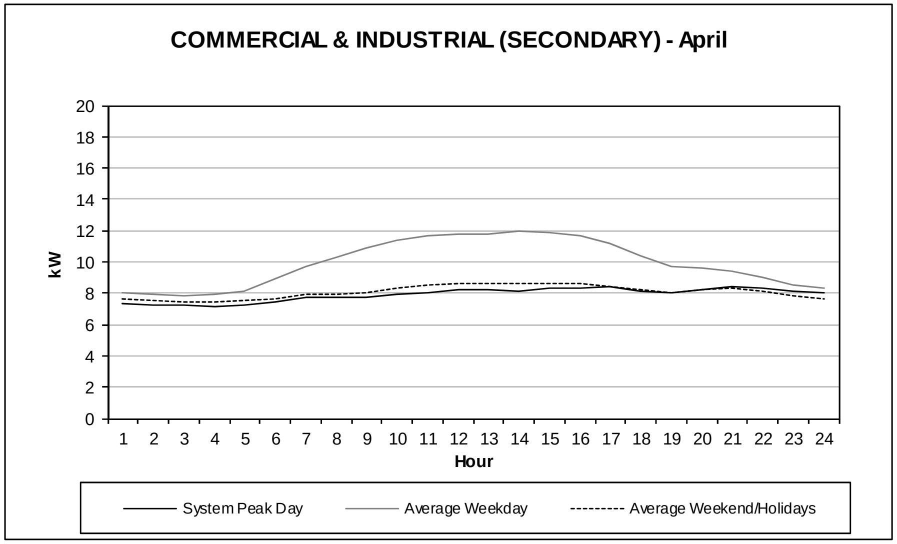


Figure 2.3-17 Commercial & Industrial (Secondary) May

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.1489	7.9296	7.5339
2	7.8889	7.8083	7.4212
3	7.7838	7.7095	7.2989
4	7.8039	7.7208	7.2334
5	7.9933	7.9769	7.2657
6	8.6524	8.6322	7.3701
7	10.0676	9.6962	7.4843
8	11.4069	10.8529	7.7008
9	12.3000	11.7487	8.1444
10	13.2245	12.2971	8.6023
11	14.0065	12.7084	8.8869
12	14.6474	12.9538	9.0808
13	14.7800	13.0896	9.1812
14	15.1015	13.2491	9.2219
15	15.2350	13.1884	9.0500
16	15.0285	12.8390	8.9568
17	14.5937	12.2753	8.8086
18	12.8677	10.9117	8.5771
19	11.8697	10.0494	8.3574
20	11.2662	9.7018	8.2897
21	10.6028	9.4256	8.3952
22	10.1406	9.0479	8.2064
23	9.3428	8.4875	7.8295
24	8.7948	8.1513	7.5960

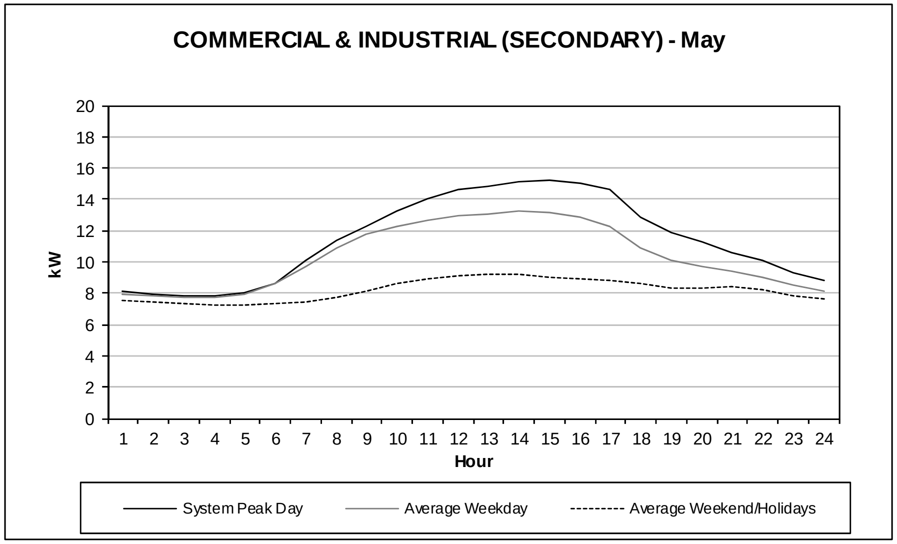


Figure 2.3-18 Commercial & Industrial (Secondary) June

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.8593	8.4047	8.0679
2	8.6821	8.2510	7.8632
3	8.5565	8.0310	7.6470
4	8.5645	7.9788	7.5395
5	8.7452	8.1895	7.5057
6	9.2213	8.7586	7.4647
7	11.0081	10.0406	7.5437
8	12.1796	11.2298	7.9353
9	13.2411	12.0827	8.6396
10	14.1556	12.8685	9.0915
11	14.7823	13.5163	9.3669
12	15.2424	13.9768	9.7500
13	15.5748	14.1983	9.9001
14	16.0079	14.4203	9.8820
15	16.0049	14.5295	9.7205
16	15.7737	14.3299	9.6412
17	15.0501	13.7444	9.5170
18	13.1320	12.1660	9.2845
19	11.9692	11.1917	8.9270
20	11.2074	10.6247	8.7124
21	10.6427	10.1551	8.7977
22	10.4035	9.9444	8.7883
23	9.6155	9.2373	8.3609
24	9.0906	8.8097	8.0561

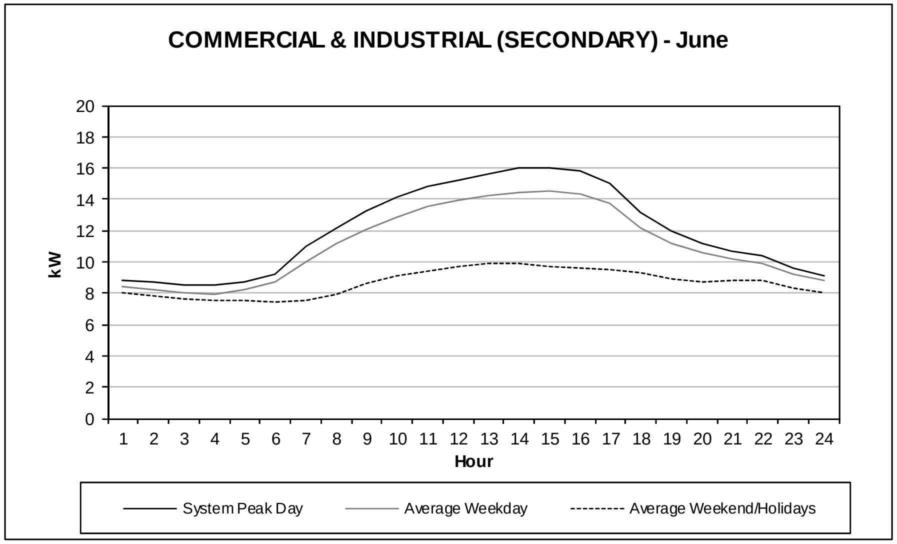


Figure 2.3-19 Commercial & Industrial (Secondary) July

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.6625	8.7578	8.4804
2	8.5083	8.5853	8.2269
3	8.4795	8.4060	8.0480
4	8.5011	8.4140	7.9175
5	8.5983	8.6457	7.8808
6	9.1753	9.5502	7.8701
7	10.8556	10.7142	8.0276
8	12.3587	11.6769	8.3632
9	13.5633	12.6048	8.8741
10	14.7634	13.4563	9.4619
11	15.5793	14.0692	10.0368
12	16.0389	14.5318	10.3946
13	16.2543	14.7386	10.6246
14	16.6579	14.9690	10.7373
15	16.5335	14.9702	10.7258
16	16.4178	14.6432	10.7361
17	15.5644	13.9719	10.5584
18	13.6172	12.7480	10.1929
19	12.4052	11.4101	9.7905
20	11.6476	10.8652	9.5443
21	10.9429	10.4831	9.5236
22	10.4532	10.1179	9.4947
23	9.7640	9.4523	9.0421
24	9.2383	9.0393	8.7203

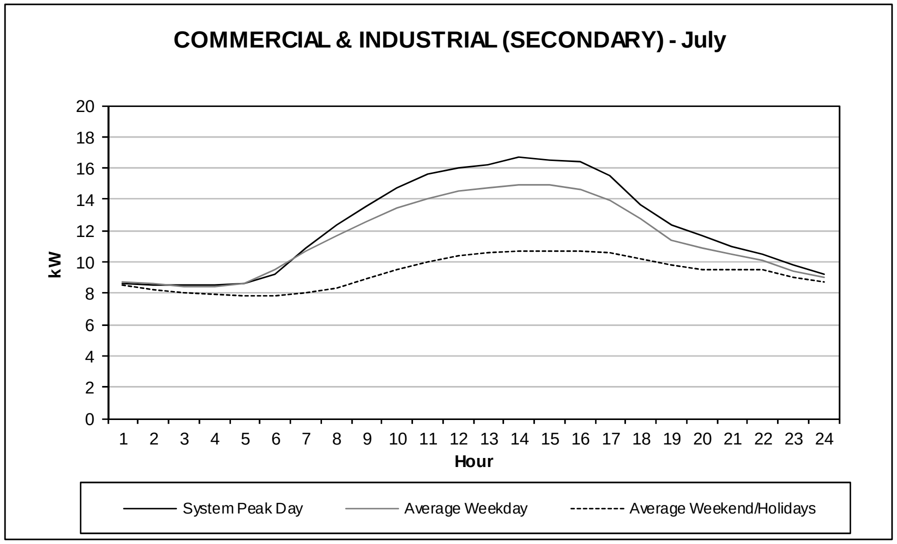


Figure 2.3-20 Commercial & Industrial (Secondary) August

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.0350	8.7452	8.1319
2	8.8069	8.5291	7.9392
3	8.6505	8.3319	7.7452
4	8.6572	8.3410	7.6646
5	8.8678	8.5867	7.6536
6	9.6892	9.5203	7.6987
7	11.1830	10.7478	7.8415
8	11.7854	11.6169	8.0923
9	12.8372	12.5952	8.5699
10	13.8287	13.4054	9.1861
11	14.5921	14.0703	9.6423
12	15.1756	14.5811	9.9976
13	15.6154	14.8164	10.2205
14	16.1181	15.0447	10.3087
15	16.2589	15.0013	10.2548
16	16.0008	14.6007	10.1945
17	15.4395	13.7954	10.1353
18	14.0626	12.6214	9.8433
19	12.2029	11.3056	9.5582
20	11.5784	10.7326	9.3409
21	11.1679	10.3198	9.3302
22	10.7721	9.8928	9.1414
23	9.8947	9.2471	8.7132
24	9.6151	8.9109	8.3740

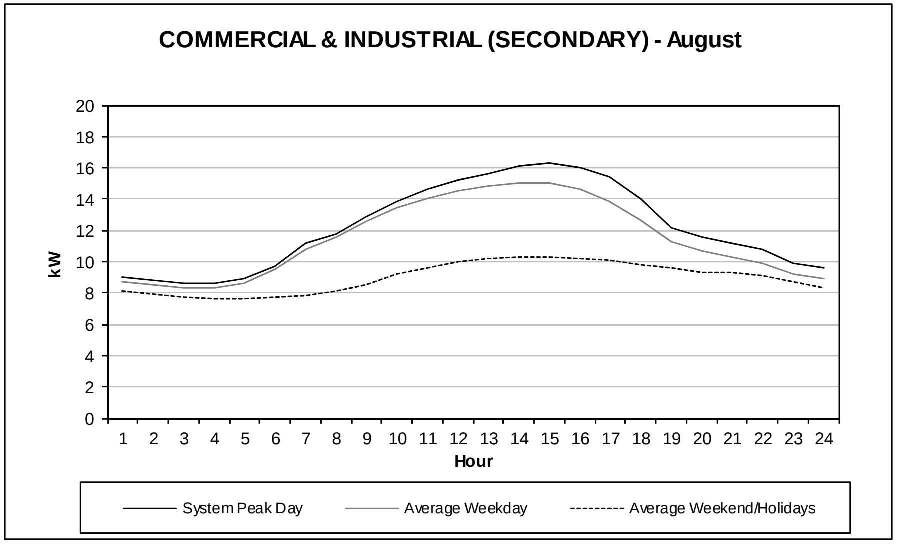


Figure 2.3-21 Commercial & Industrial (Secondary) September

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.9305	8.1176	7.8218
2	8.7270	7.9362	7.6133
3	8.3998	7.8046	7.4670
4	8.2122	7.8149	7.3594
5	8.3244	8.0417	7.3592
6	9.5864	8.9037	7.4746
7	10.5337	10.1993	7.7855
8	11.1984	10.8614	7.8411
9	12.4069	11.8268	8.2484
10	13.3920	12.6076	8.6892
11	14.3347	13.1965	9.0892
12	14.9840	13.6126	9.4757
13	15.3965	13.8448	9.6728
14	15.7489	14.0578	9.7313
15	15.7992	14.0761	9.7731
16	15.6441	13.7527	9.6804
17	14.9086	13.1019	9.6147
18	13.8149	11.7550	9.3173
19	12.2336	10.7416	8.9538
20	11.5569	10.4480	8.9964
21	10.8887	9.8588	8.8394
22	10.3332	9.3527	8.5605
23	9.5328	8.7488	8.2074
24	9.0990	8.4028	7.9504

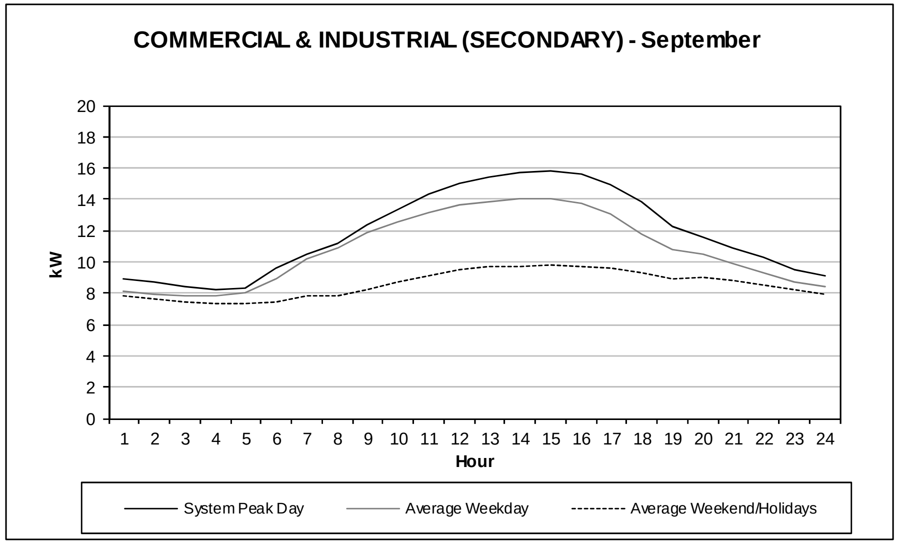


Figure 2.3-22 Commercial & Industrial (Secondary) October

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.8943	7.6948	7.4144
2	7.8524	7.6039	7.3244
3	7.6822	7.5228	7.2035
4	7.5524	7.5261	7.1427
5	7.8542	7.7725	7.1959
6	8.3528	8.4406	7.3116
7	9.3051	9.4241	7.6481
8	9.9087	10.1203	7.6907
9	10.5911	10.6267	7.8136
10	11.3511	11.0552	8.0801
11	11.9998	11.3799	8.3592
12	12.4804	11.6371	8.6073
13	12.8013	11.7715	8.8218
14	12.9277	11.9258	8.7749
15	12.8862	11.9392	8.7899
16	12.9119	11.7153	8.7704
17	12.4932	11.1830	8.7034
18	11.5478	10.4261	8.5219
19	10.7616	9.9369	8.4917
20	10.2429	9.5960	8.4005
21	9.6062	9.1614	8.1665
22	9.3281	8.7024	7.9511
23	8.7818	8.1651	7.6212
24	8.2999	7.8695	7.4285

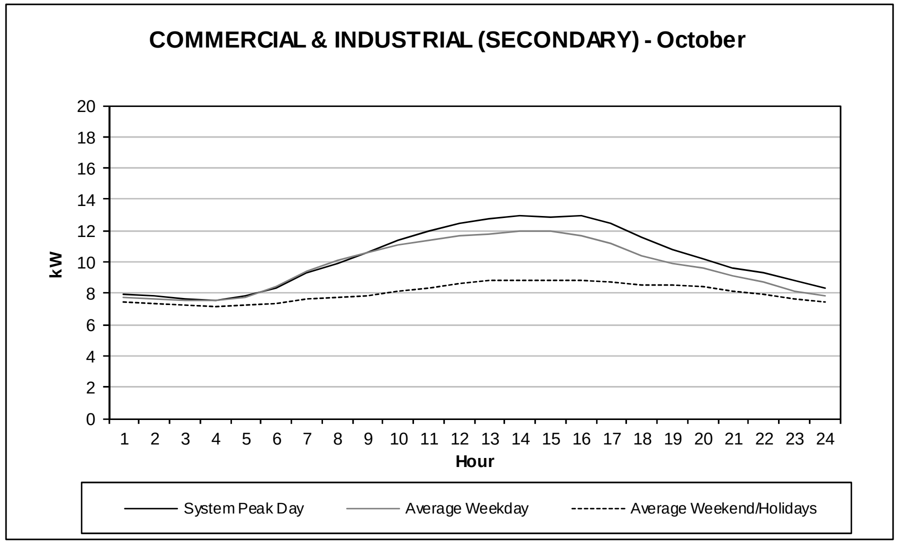


Figure 2.3-23 Commercial & Industrial (Secondary) November

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.0387	8.2219	7.7184
2	9.2097	8.2006	7.6173
3	9.1901	8.1287	7.5126
4	9.0268	8.1597	7.4884
5	9.3428	8.4403	7.5596
6	10.1554	9.1866	7.7399
7	10.9129	10.1338	8.0200
8	11.4969	10.6739	7.9512
9	12.2228	11.1660	7.9851
10	12.6792	11.4995	8.1209
11	12.9066	11.5871	8.3464
12	12.8973	11.7003	8.3772
13	12.7671	11.6315	8.3562
14	12.7528	11.6682	8.3118
15	12.6699	11.5965	8.2415
16	12.2238	11.3809	8.2201
17	11.9254	11.0072	8.2934
18	11.7763	10.8037	8.5840
19	11.2252	10.1951	8.4329
20	10.8196	9.8468	8.3211
21	10.6004	9.6190	8.2068
22	10.3336	9.2109	7.9552
23	10.1780	8.7583	7.7156
24	10.1178	8.5700	7.6178

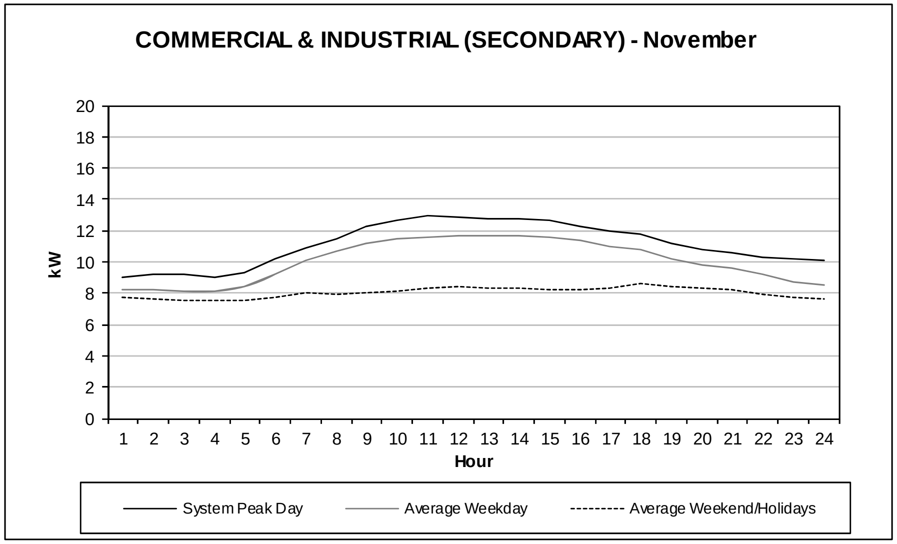


Figure 2.3-24 Commercial & Industrial (Secondary) December

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10.0372	8.7457	8.2027
2	10.0222	8.6626	8.0974
3	10.1193	8.5954	7.9889
4	10.0719	8.6317	7.9809
5	10.4364	8.9580	8.0577
6	10.8931	9.6513	8.2848
7	11.7762	10.5945	8.5985
8	12.4319	11.2196	8.5746
9	12.8176	11.7134	8.5594
10	12.9911	11.8917	8.6032
11	13.2651	11.9421	8.6730
12	13.2472	12.0297	8.6728
13	13.1139	11.9712	8.5823
14	12.9257	11.9576	8.5164
15	12.9076	11.8178	8.4619
16	12.9283	11.6634	8.4762
17	12.6594	11.4536	8.6636
18	12.5268	11.1831	8.9763
19	11.9701	10.5815	8.8267
20	11.7445	10.2945	8.7228
21	11.5333	10.0133	8.6291
22	11.4148	9.6214	8.4752
23	10.9661	9.1922	8.2565
24	10.7932	9.0469	8.1946

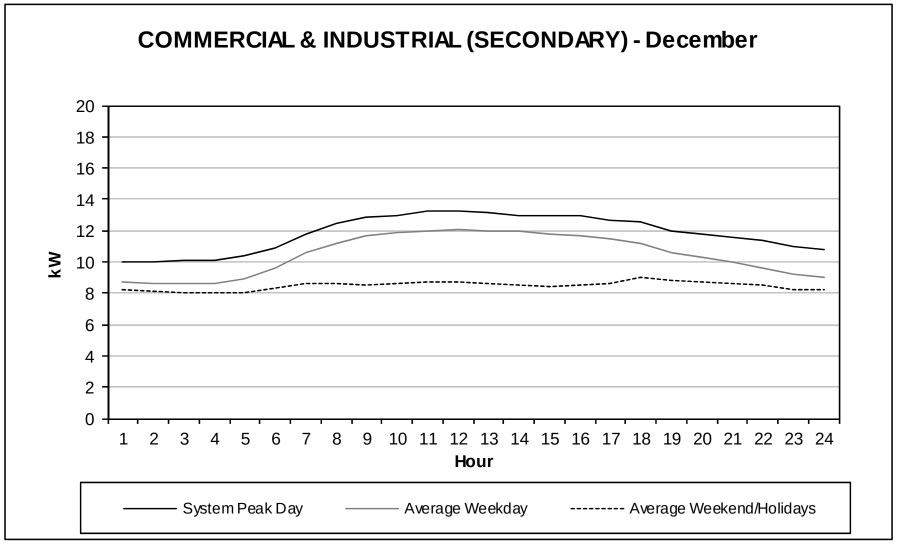


Figure 2.3-25 Commercial & Industrial (Primary) January

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	590.8311	584.7413	565.8601
2	589.6907	578.8488	561.3549
3	586.4673	575.3337	559.0492
4	587.7042	578.5708	557.0345
5	589.8373	594.6234	561.0477
6	594.3722	619.5161	567.8762
7	601.6597	653.7963	578.1285
8	604.5643	682.8382	582.8529
9	607.7085	698.2578	583.8262
10	611.6682	702.6821	587.8105
11	614.1583	703.6904	592.2780
12	611.8769	703.4922	594.8097
13	607.7815	700.3968	594.2508
14	604.3324	701.2049	592.7105
15	604.3942	701.0096	589.6184
16	606.3404	689.6719	586.6771
17	606.8419	669.3249	582.6161
18	617.0541	661.3004	590.3859
19	613.4824	646.0966	587.8902
20	616.2440	635.2461	585.1256
21	610.9943	626.3130	580.6208
22	603.0864	615.9922	576.3436
23	599.8280	603.6484	570.5633
24	600.8266	593.0552	566.6494

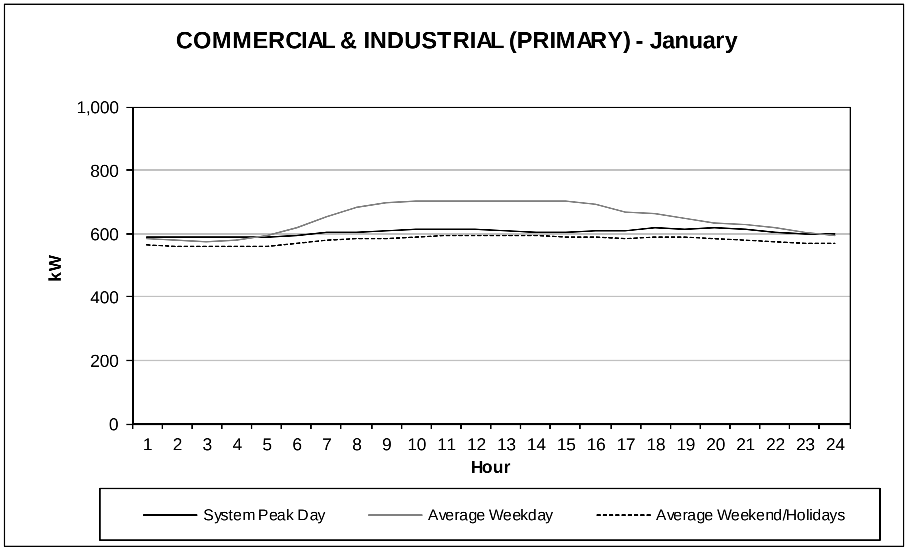


Figure 2.3-26 Commercial & Industrial (Primary) February

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	625.8037	597.9627	576.6086
2	619.2388	591.4638	571.4253
3	612.2467	588.2726	568.1593
4	610.3700	590.3384	566.2253
5	622.2067	605.9188	568.9792
6	648.9662	630.9985	576.8381
7	681.7396	667.1193	585.3925
8	698.7646	691.3933	589.5960
9	716.7498	710.2613	597.6458
10	725.3461	718.1453	604.1210
11	731.3823	723.1051	609.1320
12	733.6601	724.5835	609.2716
13	729.8630	721.0687	606.7966
14	735.5439	722.0556	603.1961
15	731.6176	718.3618	597.8676
16	717.3539	705.6003	592.8904
17	701.4845	684.6651	585.5678
18	699.8473	673.7117	588.1034
19	686.8784	662.8984	591.5798
20	679.5678	650.7449	589.4136
21	671.8758	641.7345	586.0909
22	664.4348	631.6748	582.9768
23	650.4610	618.1741	577.4342
24	639.0821	607.1757	571.8944

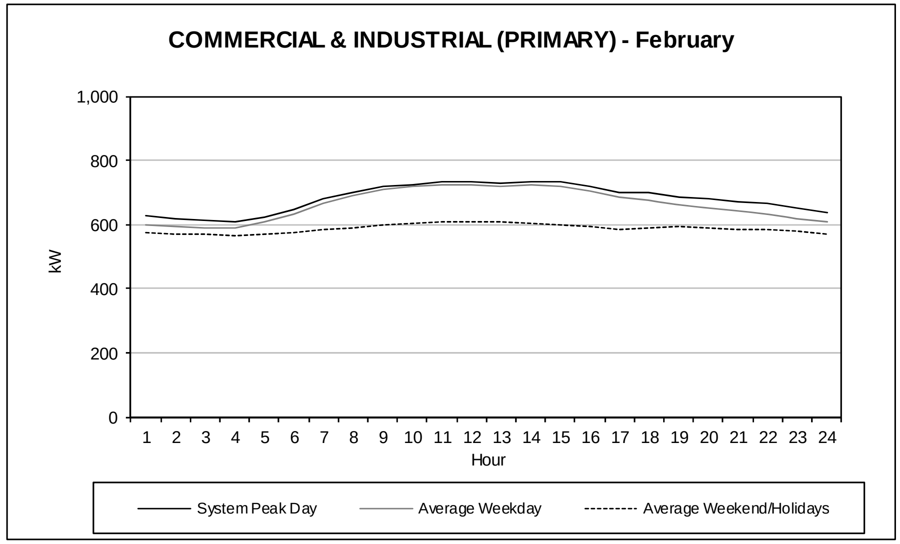


Figure 2.3-27 Commercial & Industrial (Primary) March

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	569.4634	579.2080	566.3981
2	563.2702	573.1527	560.9365
3	563.6188	569.9390	559.3451
4	559.8207	572.5050	556.1504
5	563.3008	587.9592	558.7349
6	574.2145	614.3256	566.8234
7	587.6674	652.2954	576.4038
8	601.0636	682.4006	581.2002
9	612.0111	701.4066	588.3110
10	620.4114	710.0706	593.7319
11	622.9414	713.9108	595.2251
12	623.6137	714.9244	595.3111
13	620.0156	712.3314	594.8515
14	616.1268	715.1213	593.6751
15	613.1113	713.1661	590.2712
16	606.9155	696.1264	584.6864
17	600.8249	669.0848	577.5128
18	606.2724	651.1046	576.5239
19	612.4231	639.0594	578.8726
20	609.0568	633.1985	581.3155
21	605.0042	624.5075	578.9714
22	601.3351	613.9275	574.6622
23	596.1024	601.1816	568.0393
24	588.9729	589.1876	563.2595

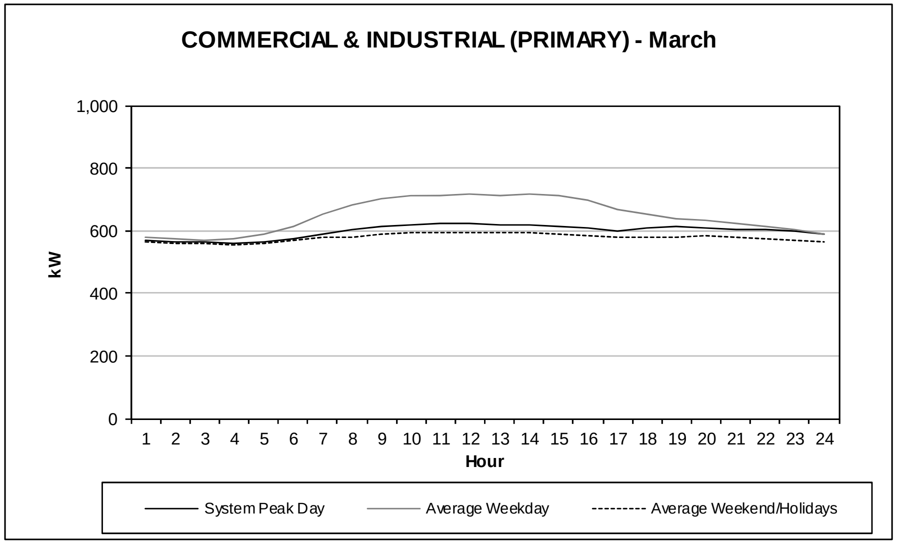


Figure 2.3-28 Commercial & Industrial (Primary) April

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	549.4717	582.6462	563.7528
2	545.0222	574.4200	555.6027
3	546.0023	570.3709	552.0831
4	543.6280	571.9354	548.4416
5	546.5047	587.9438	551.0972
6	551.2774	614.9364	558.5338
7	562.6139	649.2682	565.8680
8	566.6047	679.5263	568.0665
9	574.7910	702.8149	576.6096
10	581.6983	713.1599	584.6621
11	586.7455	719.9644	591.3927
12	589.3113	723.6958	595.4321
13	587.3623	723.1551	597.3211
14	586.8309	727.1602	598.3303
15	588.3928	726.5957	595.2179
16	588.7000	717.3619	590.7908
17	585.8638	692.1634	585.7506
18	584.2402	672.1859	582.4415
19	579.5332	652.4730	577.6540
20	588.0370	643.2404	578.3031
21	594.3194	637.6855	579.6790
22	591.5152	625.6507	574.2479
23	588.4398	609.1264	566.9253
24	583.1873	594.9244	560.9978

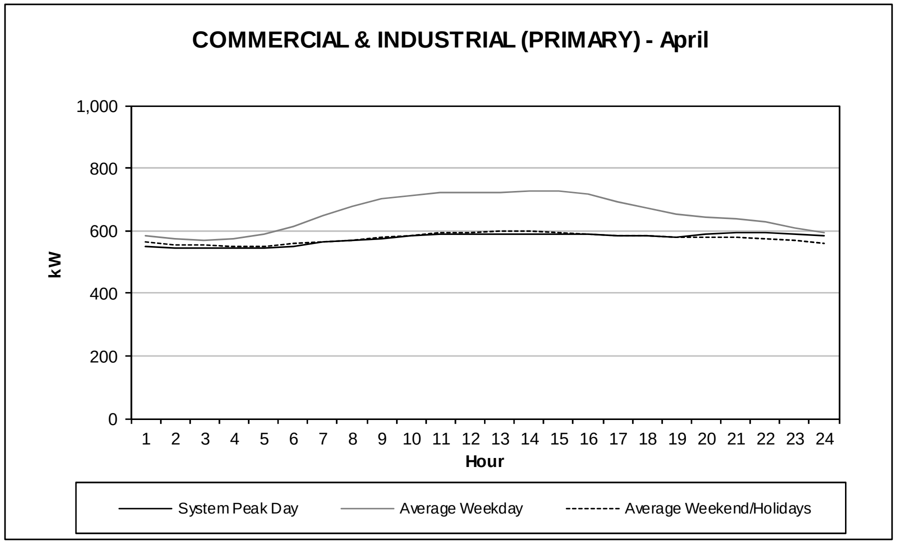


Figure 2.3-29 Commercial & Industrial (Primary) May

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	605.7470	581.2161	560.4900
2	593.3857	573.3127	552.6277
3	588.4888	569.2643	549.1672
4	583.3158	569.5781	545.9159
5	598.2548	584.3559	548.2983
6	625.1039	611.3026	555.8271
7	659.1766	642.8233	558.5614
8	702.6956	675.0901	564.1332
9	716.4762	695.5554	571.6342
10	740.3792	707.9990	578.9753
11	750.2757	715.5111	586.8679
12	754.7412	717.3120	594.1593
13	759.6503	719.9586	597.5234
14	763.7386	725.0974	598.8049
15	758.0256	725.3984	599.3947
16	749.0394	716.6302	595.5728
17	746.6770	697.5898	593.2748
18	734.9393	674.2733	589.4342
19	711.9416	653.4134	583.7539
20	697.6609	639.9632	579.2904
21	677.7999	633.6116	579.6431
22	667.4235	622.6518	575.3736
23	647.0974	606.9300	567.0905
24	632.0638	593.0456	559.3299

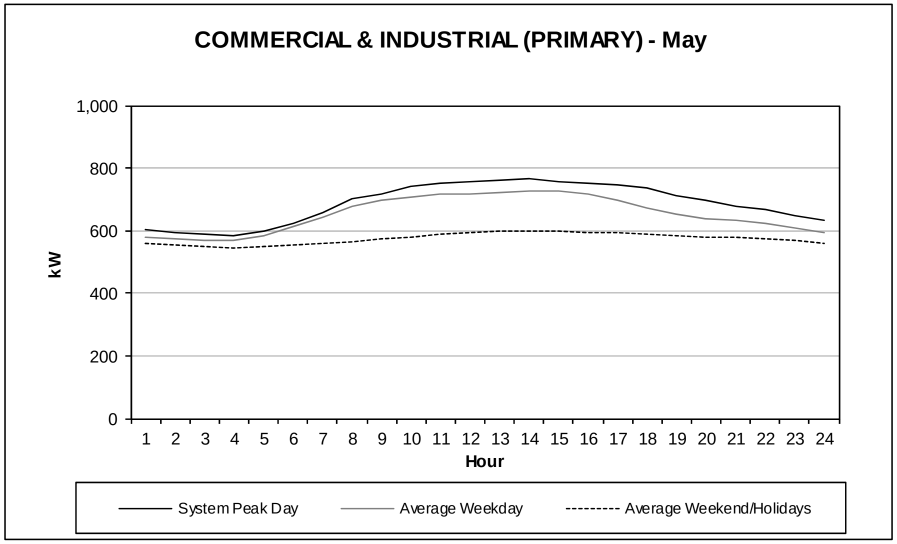


Figure 2.3-30 Commercial & Industrial (Primary) June

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	611.1286	602.4117	585.4349
2	602.7452	594.0937	577.7370
3	598.0931	589.0408	572.4398
4	600.3710	589.4510	567.2830
5	622.3084	605.3643	570.5951
6	650.7509	631.5692	576.7105
7	688.2599	662.4151	579.7010
8	723.1600	699.4065	589.7760
9	761.6954	728.9937	600.5366
10	777.7640	744.5057	609.6267
11	788.2368	754.3472	617.9398
12	798.4877	763.2938	625.4782
13	804.3310	765.4656	628.6526
14	811.4160	771.7193	628.9733
15	810.8267	774.0347	628.4387
16	806.9634	767.9836	622.6478
17	786.5683	744.2221	618.7617
18	757.4770	718.9437	614.7840
19	726.1510	696.3391	607.8324
20	703.2015	679.0346	601.9308
21	686.7074	665.4536	598.5922
22	677.5814	655.5466	598.0676
23	653.1151	635.7541	589.1637
24	635.7337	620.3521	582.1728

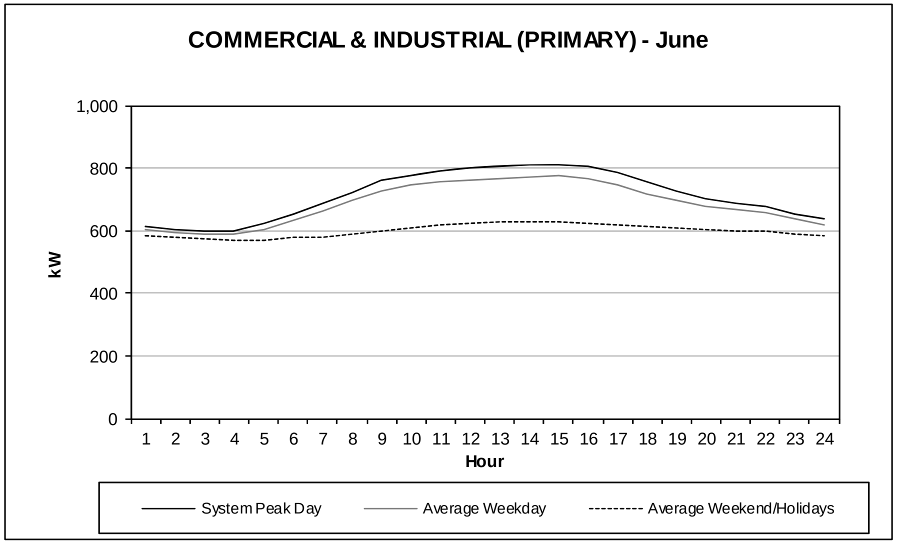


Figure 2.3-31 Commercial & Industrial (Primary) July

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	618.1000	631.9881	608.0783
2	613.5362	621.7867	598.2048
3	610.8023	616.9897	592.6878
4	614.0746	617.3149	588.0160
5	632.3299	633.6610	589.9857
6	661.1280	661.4699	596.5337
7	698.2627	696.1730	600.4644
8	746.2146	734.8267	613.1541
9	779.6770	758.9082	631.1278
10	794.2223	770.0953	644.8226
11	800.1116	778.2230	652.9989
12	810.7682	785.1818	656.0516
13	812.9644	788.8511	659.3575
14	815.0066	794.1851	661.8600
15	823.2163	797.1231	660.0306
16	816.3627	789.2644	660.6729
17	790.3394	765.5110	657.0852
18	763.9108	742.6309	650.5939
19	738.6874	717.9862	642.2580
20	720.6506	699.5038	637.2529
21	711.0508	689.1620	633.7321
22	698.8478	678.9503	632.1361
23	683.0187	659.5993	622.7064
24	665.8853	644.5972	613.3867

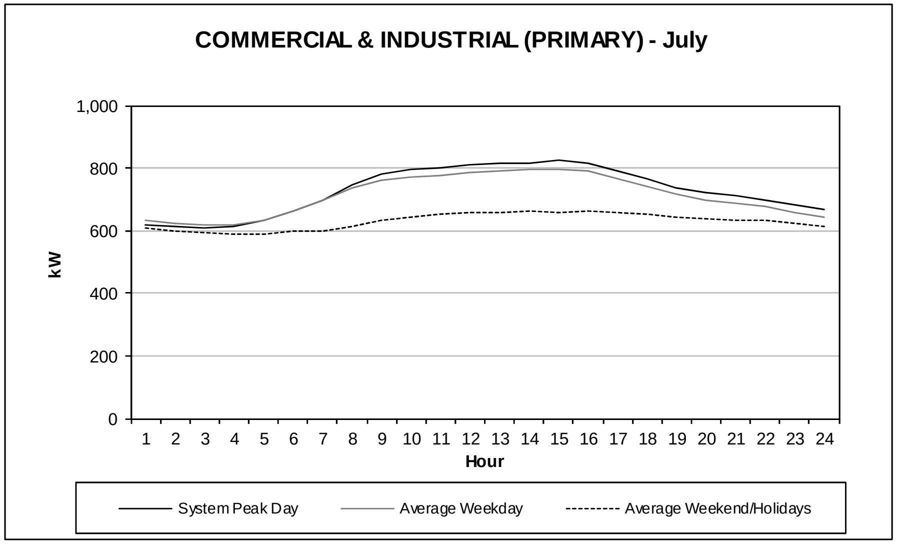


Figure 2.3-32 Commercial & Industrial (Primary) August

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	668.4277	636.2407	611.1853
2	658.1682	626.8211	601.8499
3	649.7858	620.6291	596.4841
4	646.0128	622.3827	592.4063
5	658.5577	636.4414	593.5802
6	684.5810	667.0133	601.1534
7	724.9337	703.6118	602.9964
8	770.6880	739.7052	607.1690
9	806.6799	768.6670	619.4856
10	818.3030	784.7148	631.6810
11	823.2655	794.8710	641.8504
12	834.3873	804.3625	648.2366
13	837.9807	807.9397	653.2558
14	847.3981	814.0169	657.0548
15	854.1150	813.4927	654.9112
16	844.3892	800.5143	654.1292
17	826.1704	777.6491	653.3030
18	788.6710	751.3727	649.6482
19	754.9233	726.1339	642.8800
20	730.8246	708.7767	636.8965
21	724.5679	700.5955	634.8694
22	713.5980	687.0709	628.7678
23	697.1593	667.6722	618.8985
24	682.4262	651.7401	607.5465

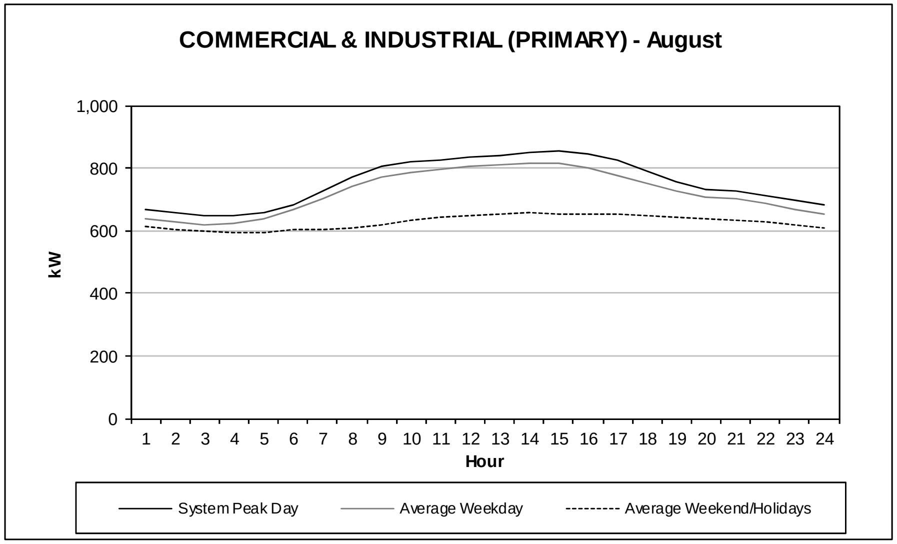


Figure 2.3-33 Commercial & Industrial (Primary) September

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	638.7252	606.8853	588.3799
2	627.6574	598.1345	579.4035
3	617.7196	593.2598	573.8987
4	616.9200	592.8509	569.4191
5	627.6098	607.7577	573.6336
6	655.5624	637.4157	582.5094
7	693.0203	677.7244	590.7027
8	728.8718	707.6650	590.2116
9	761.2480	732.6742	597.0883
10	784.6362	749.7506	607.6391
11	806.0725	762.0555	620.8957
12	821.5582	772.4041	630.4990
13	822.0142	777.2440	638.2547
14	826.3220	784.2331	642.8400
15	827.9407	784.0592	645.4417
16	825.2259	774.6889	644.9586
17	805.5335	755.8453	642.6237
18	784.1617	727.6025	637.0420
19	750.8794	702.3522	630.0157
20	731.8916	688.9051	627.4209
21	715.2427	673.9938	618.7592
22	698.2823	659.5840	610.9366
23	674.5852	640.6768	602.0078
24	656.9112	623.0582	592.7657

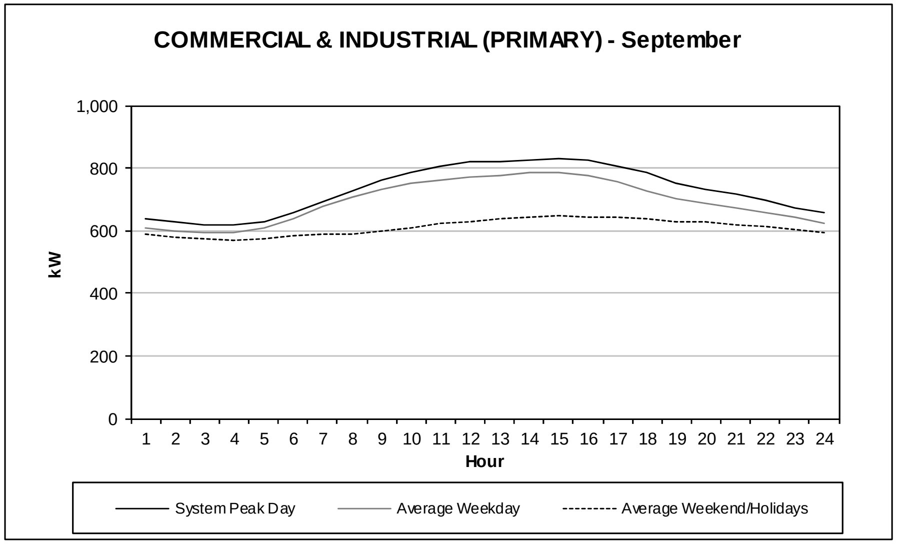


Figure 2.3-34 Commercial & Industrial (Primary) October

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	609.9891	603.6494	579.1989
2	603.7378	595.6741	574.1332
3	599.9330	592.4772	569.0402
4	600.0831	593.5185	565.6021
5	615.2132	609.6606	569.4461
6	648.4786	638.9003	578.2131
7	690.9721	679.9328	588.6285
8	715.9673	710.3111	592.9893
9	736.3155	722.3760	592.9331
10	747.6355	726.9079	594.4760
11	767.0394	732.5946	602.5049
12	779.3415	739.1022	611.6527
13	783.4868	742.7888	616.7566
14	788.7906	750.9106	619.8493
15	794.2141	753.1588	619.4696
16	789.2821	745.8520	618.8841
17	770.5970	725.1168	618.5209
18	739.7875	697.0606	612.9313
19	712.5993	678.4675	610.4558
20	693.8821	665.3815	605.7258
21	674.5458	652.3326	598.1474
22	656.9327	641.1571	592.5750
23	640.3355	627.4337	587.4223
24	626.1230	613.8611	579.9520

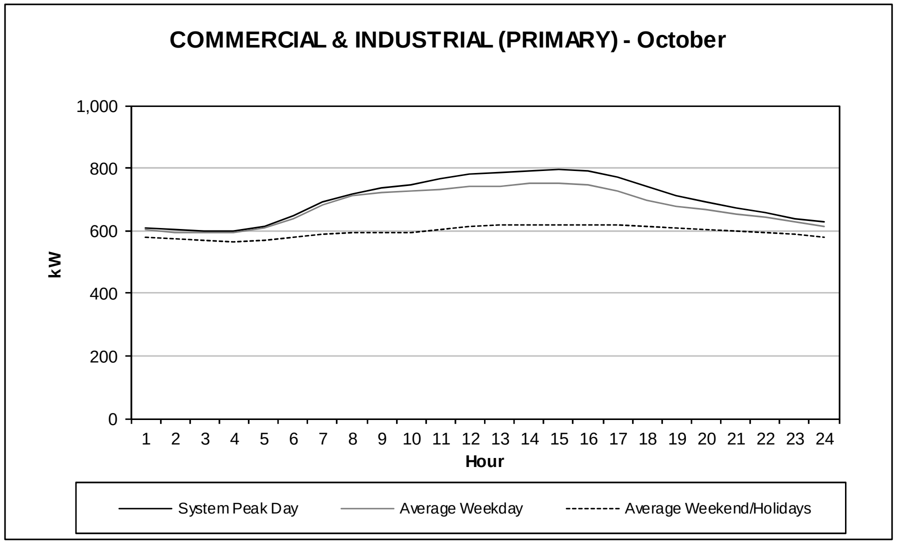


Figure 2.3-35 Commercial & Industrial (Primary) November

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	668.5017	631.9785	606.8568
2	662.1930	626.3396	601.2485
3	657.6108	624.2435	599.3686
4	654.5018	626.3690	598.1402
5	661.1626	640.8860	602.1944
6	688.8953	667.5357	609.6580
7	721.8271	698.8663	616.6510
8	747.3988	720.5097	616.4405
9	764.6829	734.6621	617.1281
10	772.5335	737.7550	615.9746
11	776.5982	735.8603	614.7416
12	777.4334	735.8663	617.2604
13	781.9765	735.0782	617.8764
14	778.2570	739.9659	618.5175
15	775.0743	740.1544	619.3995
16	739.1653	730.5719	618.8072
17	713.9836	715.5742	620.4212
18	698.6958	703.8549	626.3652
19	684.3281	688.3893	624.7815
20	677.3682	677.9039	622.4323
21	677.5678	668.8757	618.4321
22	676.8859	661.7588	615.9036
23	699.9622	654.3879	613.1089
24	698.8287	643.8833	608.0092

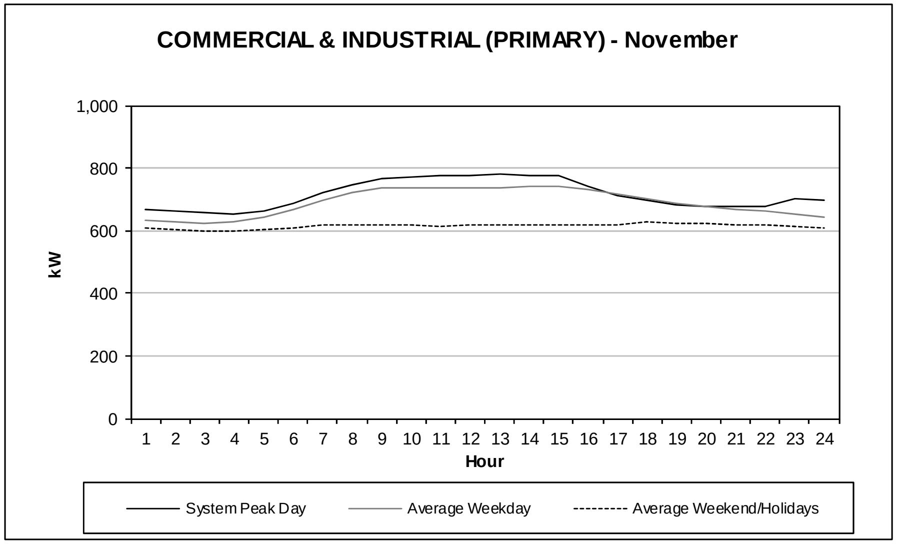


Figure 2.3-36 Commercial & Industrial (Primary) December

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	637.8168	623.9765	598.8736
2	634.0490	618.2085	593.6506
3	631.2956	615.8617	592.3322
4	631.9318	618.4825	589.7916
5	642.2634	633.5897	594.2378
6	663.5562	658.6175	602.8565
7	687.2859	690.0005	611.2633
8	707.6219	715.7135	617.7598
9	724.9404	732.1376	621.3386
10	729.9640	736.0279	623.8234
11	735.7439	734.3041	624.9021
12	732.6812	730.9293	623.3888
13	736.1444	725.2995	618.7207
14	742.1983	726.6863	616.1334
15	738.7982	724.7821	614.5736
16	721.3774	716.8244	611.9958
17	701.5774	700.9602	612.1954
18	692.4659	688.6780	616.8605
19	679.7649	674.3790	616.6424
20	670.9419	666.2888	614.2791
21	663.6863	657.7351	610.0364
22	657.1926	649.7632	607.5773
23	648.0337	640.6481	604.6577
24	637.8057	631.0763	600.4910

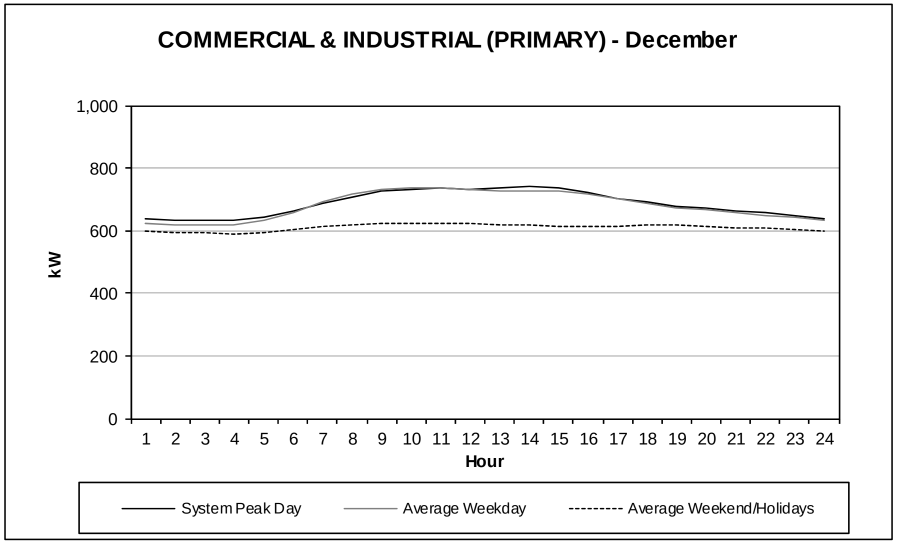


Figure 2.3-37 Commercial & Industrial (Transmission) January

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7151.7718	7535.0209	6915.4076
2	7220.0033	7583.3684	7184.4287
3	7171.1371	7492.6934	7327.9325
4	7203.3549	7443.9864	7366.2376
5	7074.3616	7392.6825	7198.0515
6	7151.9931	7424.0501	6949.8575
7	6945.2254	7404.9676	6963.4661
8	5458.3640	7168.6439	6919.4269
9	5672.8013	7234.6885	6434.3423
10	6521.3690	7330.9283	6830.1693
11	7035.7062	7334.9067	6865.8075
12	6710.7613	7341.1745	6722.1534
13	6678.9101	7464.6326	6781.9896
14	6822.8685	7445.7923	6768.6482
15	5998.6323	7513.2169	6623.5969
16	6244.8742	7560.6326	6756.9669
17	6109.6578	7688.7736	6871.2736
18	6909.9738	7606.4331	6884.5433
19	6924.3109	7447.3374	6933.4805
20	6773.0791	7496.4247	6933.1576
21	6762.0553	7532.4778	6763.0760
22	6895.8457	7444.6709	6794.8077
23	6850.2173	7437.6596	6932.6808
24	6122.2449	7561.1044	6827.1582

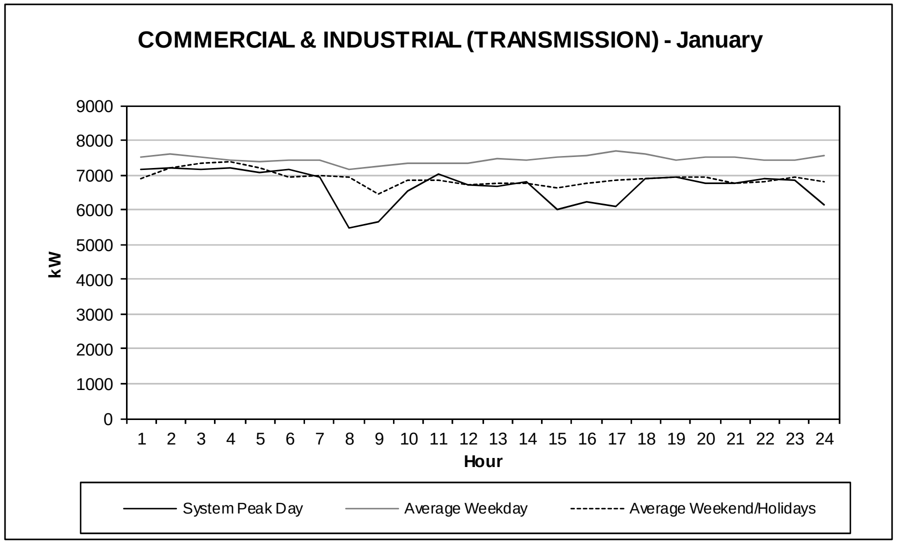


Figure 2.3-38 Commercial & Industrial (Transmission) February

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8100.8571	7345.5766	7353.8223
2	8262.4631	7425.3037	7258.2752
3	8211.4475	7387.3491	7281.8659
4	7930.9618	7384.4888	7361.0951
5	8426.0975	7374.7605	7084.6712
6	8333.1008	7232.5188	7118.2769
7	7616.9922	7225.1448	6972.7816
8	6807.2084	7139.5609	6643.4599
9	7054.0781	7203.2127	6962.9654
10	8463.2375	7147.8130	6781.3712
11	7669.2723	7225.0740	6675.0291
12	8211.2840	7103.6230	6686.5918
13	8359.2006	7200.1796	6936.5139
14	8588.1823	7353.9934	6929.1975
15	8262.2754	7386.0995	6629.3744
16	8409.6955	7460.4404	6641.7064
17	8643.4731	7513.4473	6895.4026
18	8062.0382	7304.4563	6889.1419
19	8406.0213	7365.8102	6825.3707
20	8293.5978	7412.3100	6441.1238
21	8146.2981	7416.5932	6765.8582
22	8458.6035	7471.9192	7036.9428
23	8560.5249	7563.4901	7121.1372
24	7210.4663	7462.7201	7087.4048

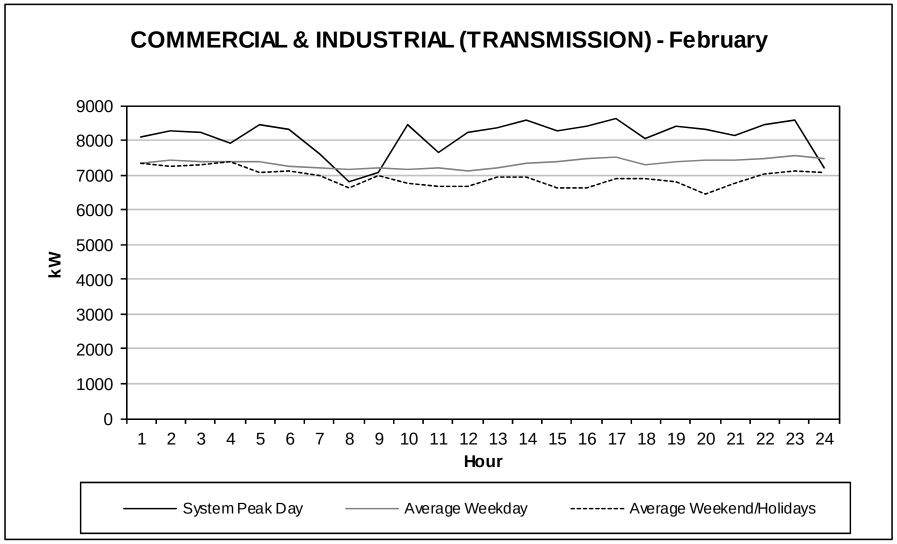


Figure 2.3-39 Commercial & Industrial (Transmission) March

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6707.0803	7203.6424	6935.1263
2	7245.3498	7328.7940	6986.5042
3	7010.9328	7380.8481	6623.2277
4	7210.5628	7396.7836	6779.5840
5	7254.3467	7350.8324	6815.9586
6	7182.5763	7182.1317	6902.4806
7	6948.0191	7186.3825	6758.6823
8	5479.6100	6948.9872	6218.7547
9	5358.5062	6819.6223	6362.9974
10	6108.2303	6849.9843	6552.8337
11	6886.7602	7027.9283	6671.6994
12	6774.2106	7002.4561	6427.8096
13	6534.2961	7026.2678	6336.8033
14	6803.5947	7078.9392	6429.9153
15	6697.6925	7142.4552	6383.4262
16	6854.8068	7089.2170	6376.2317
17	6743.8997	7063.2816	6465.5999
18	6005.0329	7098.4925	6494.4803
19	6684.7962	7099.5277	6366.6704
20	6959.4389	7051.1719	6506.9905
21	6965.6220	7143.9155	6502.5323
22	7030.5140	7262.9150	6615.8956
23	7077.8778	7253.4624	6822.6001
24	6853.3212	7170.4407	7047.4104

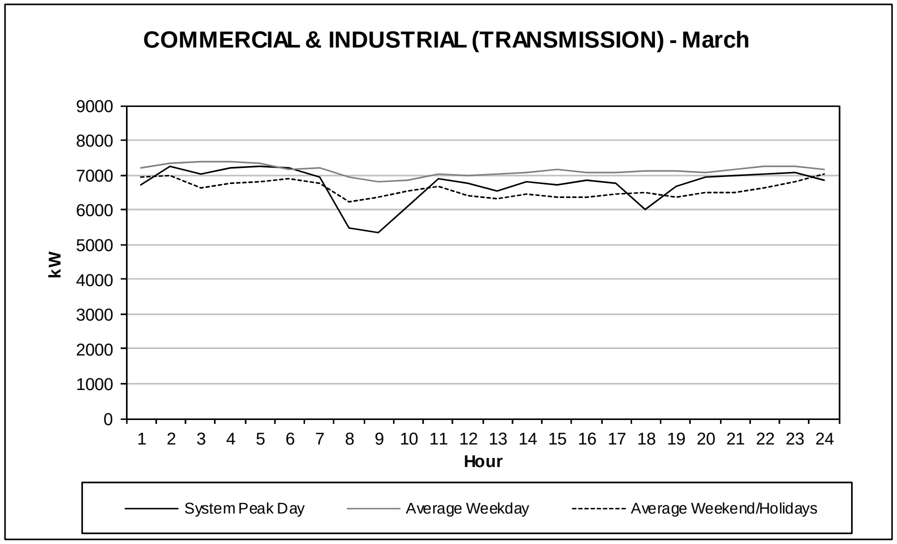


Figure 2.3-40 Commercial & Industrial (Transmission) April

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5469.9255	7594.1051	6871.9087
2	6863.6527	7655.7287	6758.6898
3	7038.1001	7656.4375	6507.3504
4	6776.4795	7644.6615	6923.0098
5	7076.2069	7708.6397	6892.0643
6	6597.7969	7583.2846	6730.2298
7	6894.7109	7432.0448	6527.0232
8	6823.4546	7348.8137	6469.3916
9	4667.1356	7202.3304	6076.4848
10	4864.4112	7235.2289	5904.9070
11	5338.8047	7450.3707	5901.3127
12	5515.9876	7434.8181	6103.6933
13	5350.1893	7548.5714	6347.8285
14	5312.2859	7502.0916	6528.8167
15	5327.4768	7423.3836	6413.3651
16	5452.6675	7561.2221	6430.8783
17	5431.1888	7553.7633	6411.8543
18	5231.6967	7581.7121	6281.8239
19	5324.3598	7470.3407	6239.7450
20	5311.8415	7444.5939	6606.3298
21	5220.6425	7616.5605	6661.8079
22	5181.5193	7647.1653	6494.5562
23	5055.5973	7755.9155	6293.1262
24	5183.1815	7633.5712	6486.4085

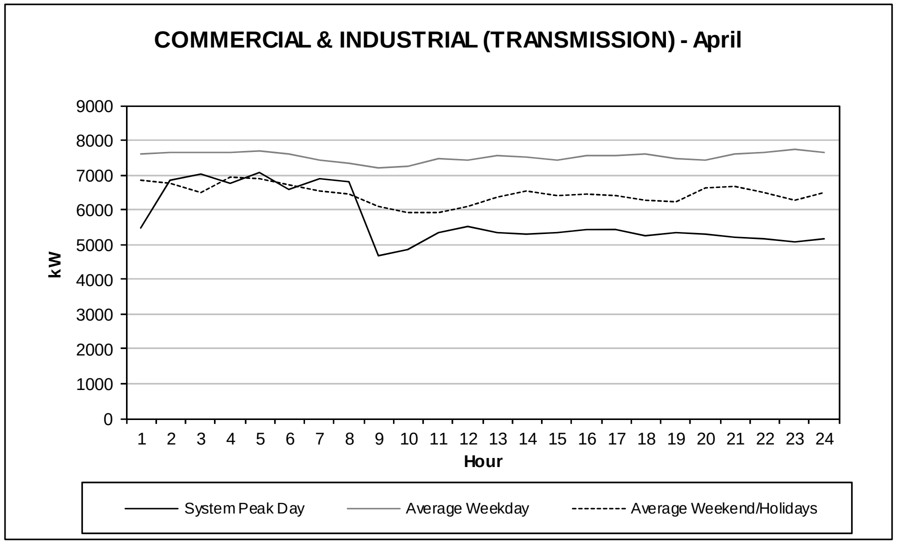


Figure 2.3-41 Commercial & Industrial (Transmission) May

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7855.2663	7328.1271	6894.6502
2	8190.0319	7380.9903	6966.0338
3	7526.8525	7399.1939	7059.0626
4	7763.6121	7338.3044	6995.5464
5	7751.9536	7326.2189	6964.2383
6	7690.9746	7185.1734	7092.9272
7	6744.9299	7119.3038	7023.8450
8	6892.9052	7106.5806	6766.6406
9	5999.3483	7073.9310	6572.5855
10	5853.8942	7034.3539	6690.7263
11	5677.8976	7171.8538	6606.4356
12	6237.6376	7169.9924	6686.6923
13	7291.2620	7348.7254	6839.4328
14	7230.2931	7437.6692	6871.4413
15	7526.7076	7410.4195	6825.1150
16	6455.5014	7377.2593	6873.7453
17	7806.2216	7250.7002	6751.8100
18	7519.7459	7248.1602	6601.1316
19	7845.2166	7326.4758	6650.3831
20	7695.4883	7355.9377	6599.7115
21	6430.6555	7387.7056	6771.5408
22	6195.8927	7329.5280	6626.0359
23	7651.4208	7539.4789	6817.9969
24	8033.2119	7571.5238	6829.9029

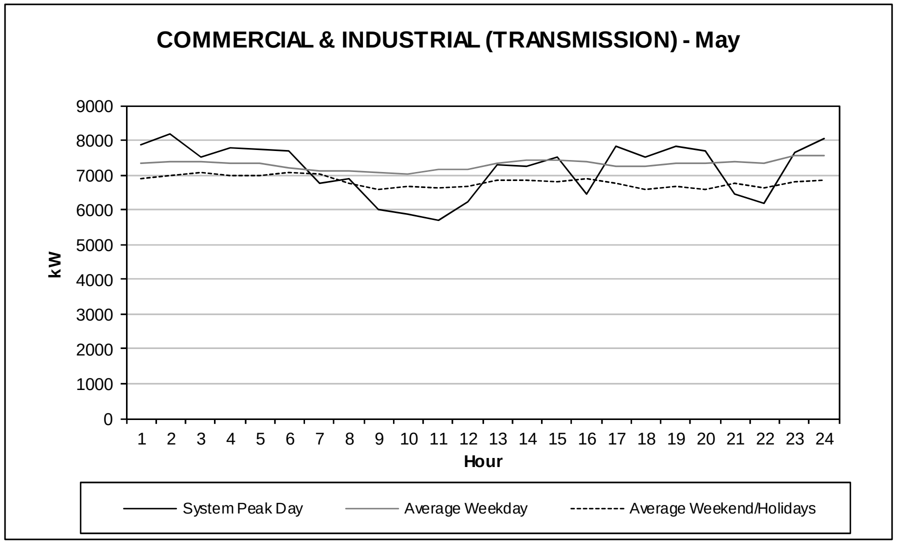


Figure 2.3-42 Commercial & Industrial (Transmission) June

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7377.0950	7450.2590	6854.2136
2	7151.5453	7266.9066	6753.7954
3	7362.9787	7277.7037	6749.8539
4	7326.1344	7298.4948	6681.9481
5	6907.2517	7441.4907	6757.8538
6	6811.3392	7267.6589	6599.2030
7	7165.1949	7279.4058	6597.9693
8	7348.6549	7113.1184	6607.9099
9	6541.7395	7118.0039	6474.2797
10	7088.6043	7143.3261	6654.9748
11	7490.8350	7193.0945	6588.6787
12	7809.6933	7414.6418	6635.9760
13	7837.7775	7459.6247	6917.3035
14	7620.4463	7373.1845	6664.1100
15	8026.7055	7454.5912	6622.9827
16	7591.8635	7315.7723	6481.1798
17	7781.2431	7518.7055	6665.7164
18	7318.1612	7316.9042	6545.9242
19	7556.3130	7397.1430	6784.0336
20	7280.9381	7494.5274	6680.3666
21	7477.9755	7480.9817	6832.2415
22	7671.9902	7532.3899	6871.0573
23	7630.2930	7582.3502	6800.6981
24	7665.2997	7488.2737	6843.9693

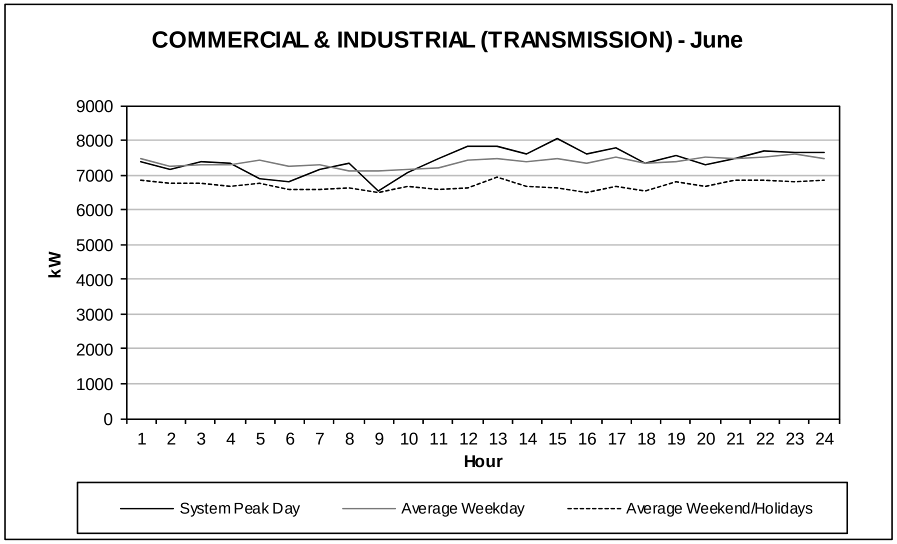


Figure 2.3-43 Commercial & Industrial (Transmission) July

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6536.5574	7343.0465	7015.2268
2	6919.7021	7398.0114	7148.7012
3	6794.1830	7413.0521	6923.1784
4	6731.5097	7499.6354	7058.8841
5	5961.9063	7472.7534	6975.0038
6	6872.7384	7264.3030	6701.7840
7	6961.0076	7270.3219	6518.6576
8	6964.4238	7192.8769	6193.1895
9	7322.7715	7145.0577	6176.5485
10	6923.9369	7175.7192	6735.8755
11	7511.5773	7327.6289	6799.9321
12	7411.5393	7508.1142	6807.9041
13	7398.1835	7487.9796	6645.3233
14	7500.2693	7534.6776	6614.7790
15	6481.5370	7405.8714	6842.1405
16	6567.6201	7478.1336	6681.5430
17	7597.4244	7521.1068	6898.8396
18	7333.1223	7354.5777	6889.7457
19	7491.7093	7219.0631	6932.8254
20	6438.8555	7231.8780	6763.8882
21	7539.4885	7363.2218	6640.5865
22	7252.1399	7388.5202	6749.7447
23	7889.0640	7714.8008	6774.5488
24	7473.2597	7534.5867	6484.9531

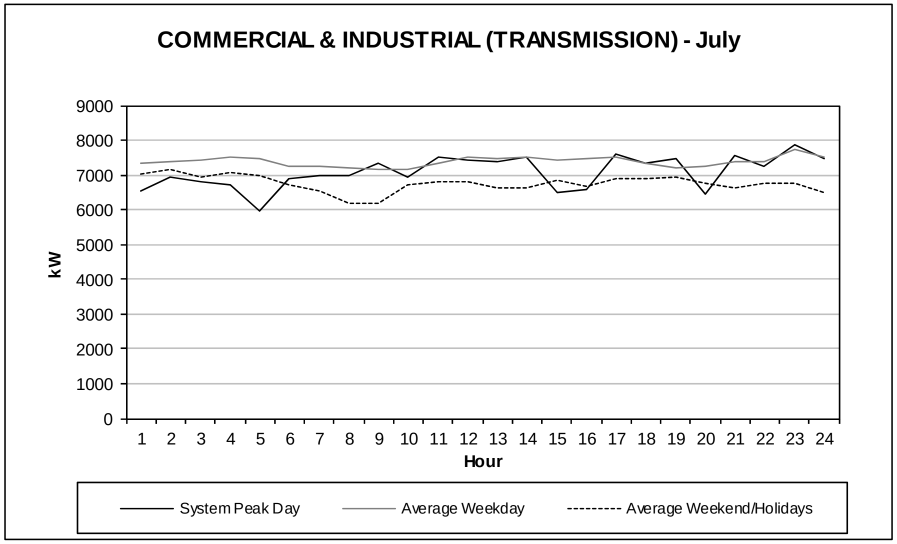


Figure 2.3-44 Commercial & Industrial (Transmission) August

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7025.8440	7466.6072	6931.9341
2	7871.0041	7573.0500	6920.3784
3	7687.2460	7571.2182	7106.7043
4	7680.2130	7517.9616	6887.4548
5	7628.4216	7532.3009	6936.6180
6	7709.6321	7471.9755	6925.8682
7	7513.6043	7323.7644	6713.9260
8	7816.6972	7143.1403	6632.6031
9	7823.3327	7252.5907	6385.5705
10	7699.2756	7315.3691	6584.4222
11	7900.1057	7213.7151	6511.3772
12	7508.5586	7283.2359	6564.3642
13	8016.5922	7277.4409	6533.2680
14	8201.4118	7487.1441	6658.2750
15	7891.3867	7311.6817	6685.0075
16	8111.5915	7351.1618	6865.1014
17	7953.5529	7406.9765	6671.3986
18	8011.9049	7205.5117	6702.2516
19	7782.1676	7202.9118	6683.1782
20	7991.1813	7182.2479	6844.8730
21	8062.8164	7320.0212	6690.6036
22	7986.2133	7295.3721	6623.9858
23	8334.5587	7364.5360	6716.6133
24	7738.4527	7405.6777	6649.9121

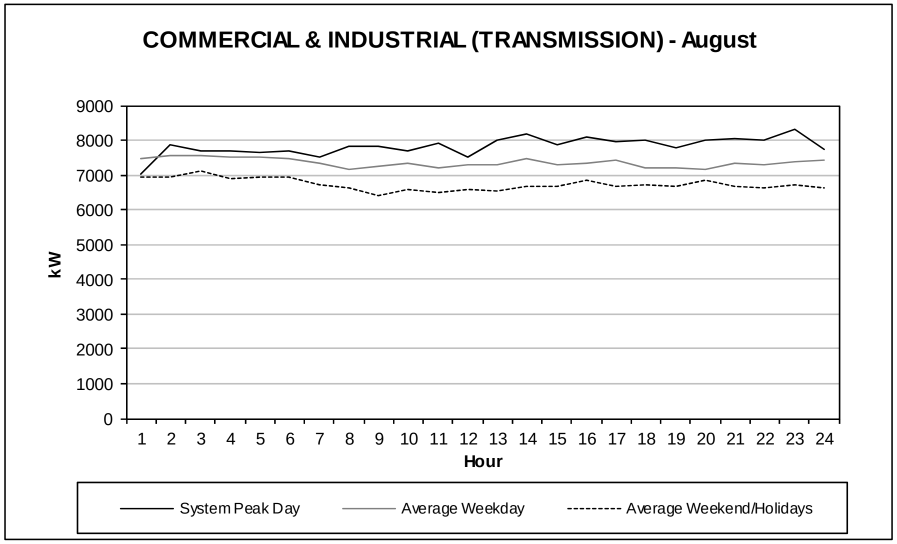


Figure 2.3-45 Commercial & Industrial (Transmission) September

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7400.1763	7058.1277	7017.2191
2	6162.5426	7011.8262	6809.8312
3	5932.5558	7031.9735	6811.4351
4	5854.2653	7011.5340	6817.5327
5	5766.2057	7040.0447	6884.2174
6	5882.2015	6921.7574	6834.8226
7	5994.8581	6948.4910	6590.9122
8	6010.5212	6825.6619	6884.3468
9	6267.4527	6932.0037	6824.0103
10	6291.8685	7045.0012	6556.9850
11	6231.1235	7035.4128	6806.4616
12	6052.6901	7193.2171	6733.6662
13	6419.1045	7174.1550	6637.4234
14	6402.3988	7233.4282	6546.9596
15	6581.8680	7202.1887	6639.2056
16	6491.0975	7212.2763	6534.3580
17	6444.6048	7060.4991	6635.3504
18	6350.2155	7059.2347	6619.0162
19	6252.4002	6921.7046	6463.1783
20	6361.3522	6937.3823	6533.2916
21	6432.5570	7117.5723	6708.8875
22	7795.1235	7355.5732	6611.7504
23	7603.2549	7459.6152	6511.7733
24	7667.7796	7285.1611	6545.3718

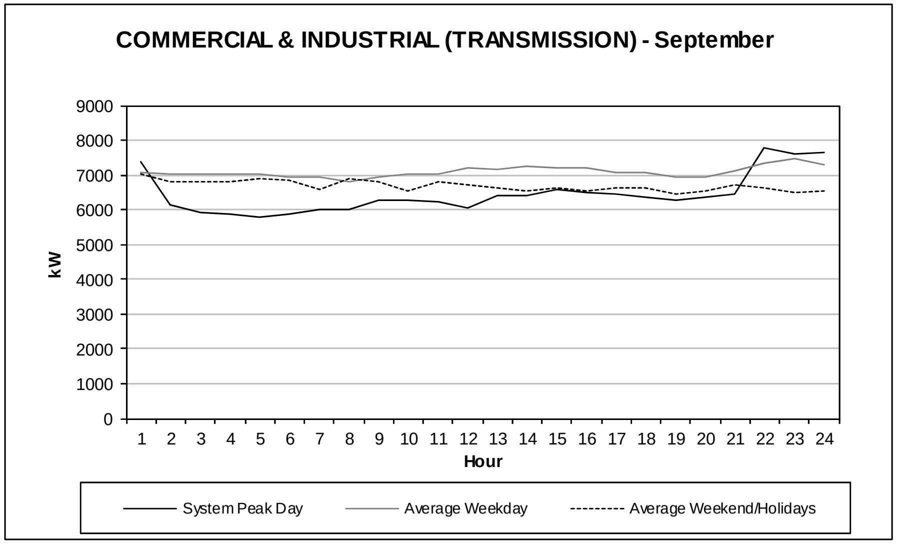


Figure 2.3-46 Commercial & Industrial (Transmission) October

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7646.1338	6933.2740	6909.1013
2	7035.5370	6960.0880	7015.8894
3	6973.5168	6987.7204	6792.1194
4	7467.8683	7082.4050	6750.8815
5	7466.1643	7088.4985	6644.6646
6	7336.5203	7014.0771	6742.5045
7	7401.4052	7007.3822	6573.7498
8	6236.6048	6936.2796	6738.1624
9	6128.2792	6823.1192	6593.9811
10	6193.7652	6695.4825	6441.1913
11	6187.8646	6675.5946	6401.9195
12	6323.0643	6702.8006	6639.8236
13	6464.0110	6703.7537	6668.6109
14	7590.1408	6891.7844	6686.3843
15	7952.0414	6915.3854	6509.7095
16	7517.2002	6996.8842	6616.0420
17	7562.8949	6906.2824	6841.0019
18	7703.8125	6888.6975	6641.4817
19	7656.7406	6856.0280	6666.8921
20	7824.1014	6870.8470	6721.5824
21	7177.6480	6854.2845	6795.9655
22	6567.7631	6968.4603	6703.1998
23	6498.8510	6988.3224	6684.4259
24	6370.3598	6989.9483	6676.0681

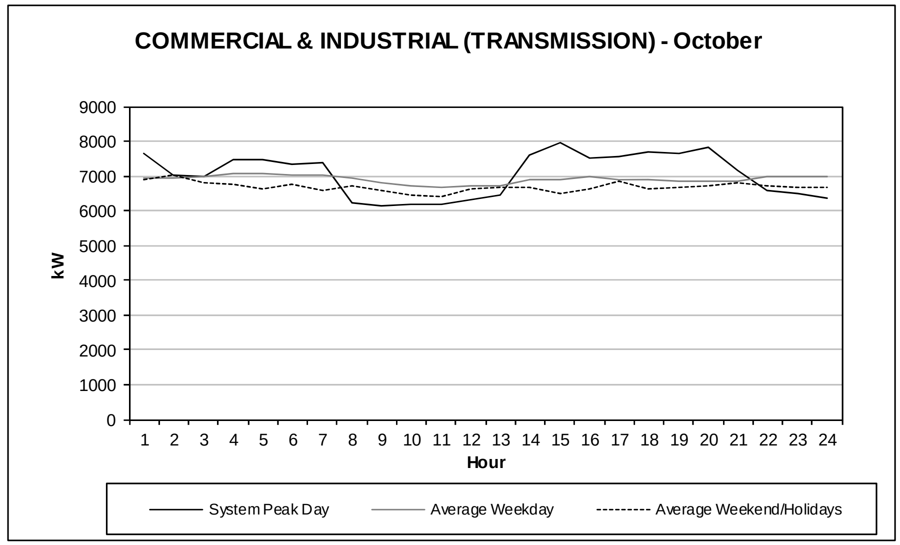


Figure 2.3-47 Commercial & Industrial (Transmission) November

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7014.7703	7076.7722	6925.3371
2	7124.6470	7123.1941	6937.4583
3	7462.8254	7081.7612	6897.7629
4	7617.2080	7103.0312	6781.3578
5	7582.6753	7190.7019	6772.3524
6	7267.9103	7119.1899	6678.3577
7	7493.0959	7110.3766	6420.0859
8	7562.4148	6864.2480	6425.1013
9	7839.6307	6832.6704	6457.5953
10	7693.3740	6754.9871	6259.7177
11	7173.9867	6909.1043	6468.3480
12	7584.6273	6932.6936	6204.8701
13	7961.6672	6886.1981	6107.1663
14	7505.2088	6911.8026	6297.3484
15	7642.9546	7103.0605	6240.4303
16	7792.8100	7161.3066	6508.3651
17	7184.2442	7174.1294	6475.2588
18	7017.8012	7142.5228	6511.9443
19	7235.3990	7036.0472	6462.7051
20	6375.0469	7054.3906	6651.6113
21	7606.7490	7093.6674	6811.3294
22	7356.0135	7257.4130	6851.7535
23	7697.0054	7267.9360	6689.6594
24	7555.7339	7215.6523	6557.5028

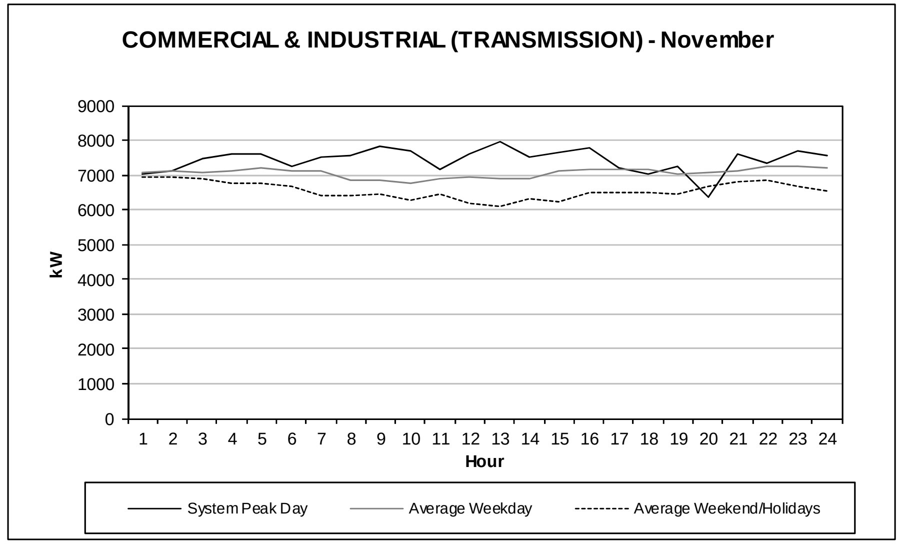


Figure 2.3-48 Commercial & Industrial (Transmission) December

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7339.5047	6933.7538	6277.5460
2	7379.7700	7007.7332	6295.6838
3	7002.8180	7029.4202	6375.0375
4	7496.8980	6878.8376	6228.0746
5	7267.9791	6893.0234	6142.5635
6	7306.8505	6718.9696	6111.5238
7	7325.0971	6838.6565	6098.1704
8	8029.5865	6808.5808	5935.1118
9	8019.3242	6807.9143	5932.8534
10	7420.1182	6868.0289	5875.1232
11	7432.7162	6783.5694	6014.3083
12	8117.7484	6703.2011	6003.5977
13	8030.0981	6740.3681	6000.0862
14	8201.9820	6715.4401	5886.8638
15	6765.8157	6392.1445	6275.2864
16	7014.3290	6544.4546	6143.4878
17	8113.7797	6803.8933	6188.7921
18	7796.2631	6784.1295	6066.0920
19	7812.4564	6619.7536	5993.8996
20	7809.9104	6685.0456	6094.0351
21	7818.2635	6992.1642	5952.4283
22	7920.3846	6977.8882	6136.6281
23	7733.8746	6888.7549	6068.7292
24	7923.6422	6901.3523	6275.1948

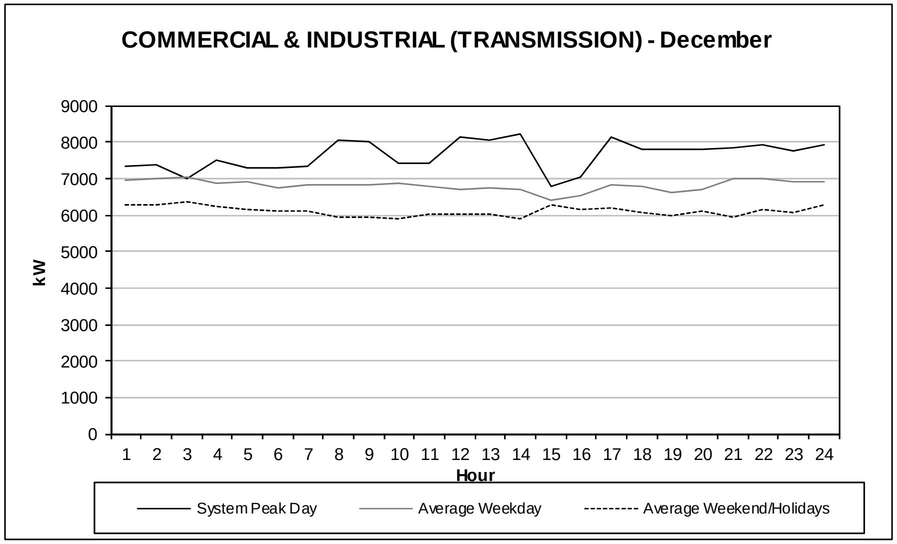


Figure 2.3-49 FERC Jurisdictional January

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	80389	72697	73571
2	79012	71416	71628
3	78583	71223	70942
4	78700	71648	70776
5	79015	73459	71654
6	80703	78007	73526
7	84530	85844	77325
8	89842	90302	82483
9	96223	89950	86260
10	99061	88765	87753
11	99466	87138	87611
12	99458	85279	86662
13	98931	83288	85292
14	98019	81861	83814
15	97533	81301	83236
16	98400	81598	83403
17	102982	85244	87282
18	113408	95654	97251
19	115659	99589	100621
20	113874	98304	98737
21	109812	95696	96080
22	102735	90025	91156
23	95558	82309	83869
24	88438	76015	77431

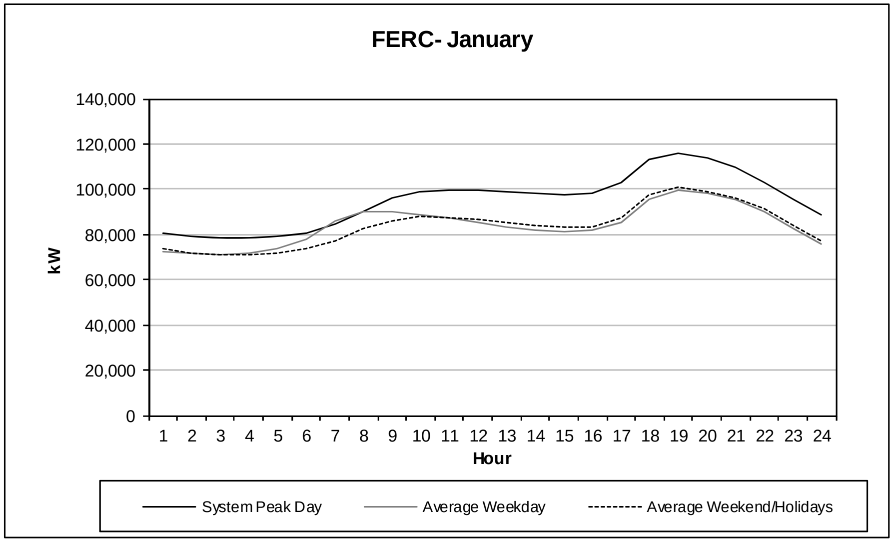


Figure 2.3-50 FERC Jurisdictional February

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	81436	69417	69818
2	80562	68279	68040
3	81281	68209	67520
4	81611	68681	67702
5	83027	70459	68572
6	88181	75308	70592
7	95893	83287	74707
8	100995	86540	79687
9	102001	85954	83637
10	99228	84774	85094
11	97237	83264	84321
12	95413	81597	82971
13	92861	79840	81587
14	91184	78584	80314
15	90229	77850	79837
16	89587	77662	80151
17	94639	79929	82032
18	103164	87539	88990
19	109565	94700	94757
20	108612	93979	93616
21	105856	91546	91570
22	99936	86193	87039
23	92355	78542	79652
24	86794	72289	73163

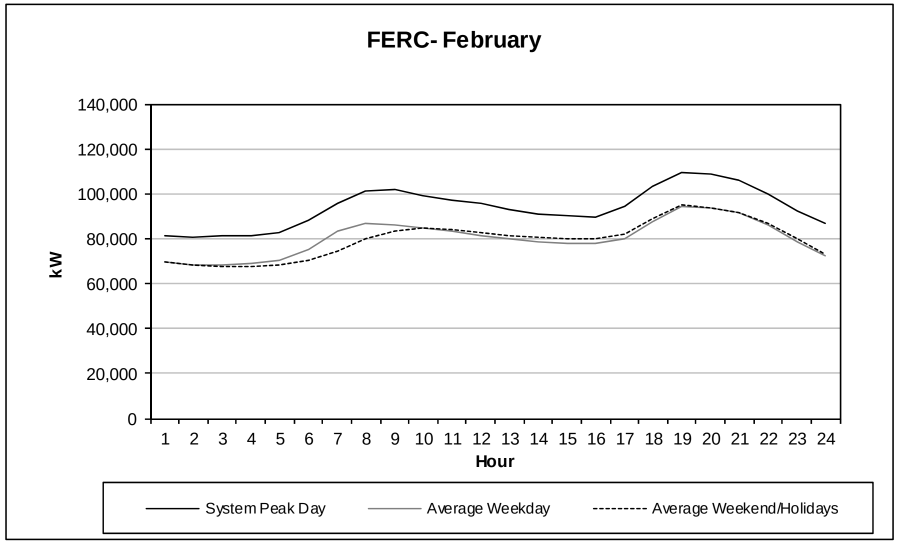


Figure 2.3-51 FERC Jurisdictional March

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	61500	61979	64231
2	59726	60949	62803
3	58794	60820	61998
4	58990	61284	62326
5	59915	62773	63105
6	62613	67033	64845
7	67225	74833	68885
8	73181	79417	74133
9	79032	79837	78101
10	82136	79166	79531
11	82288	78035	79131
12	81740	76268	77811
13	79748	74179	76133
14	77607	72660	74289
15	77777	71336	73298
16	79555	70350	72855
17	81003	70695	73092
18	85558	73720	75816
19	90037	77619	79494
20	88867	81842	83012
21	85879	82515	83058
22	82362	78595	79342
23	76459	71731	72971
24	71494	65423	67107

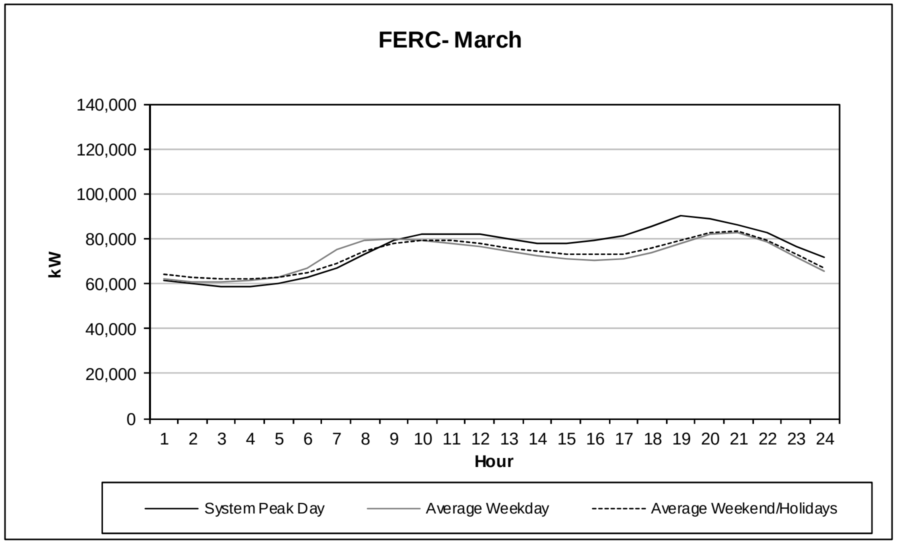


Figure 2.3-52 FERC Jurisdictional April

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	53488	56033	54772
2	51783	54868	53062
3	51264	54716	52402
4	51102	55214	52417
5	51607	56771	52973
6	53515	60961	54267
7	57951	68046	57834
8	63105	70787	62185
9	68808	70350	66106
10	72798	69644	68058
11	74962	68921	68302
12	76684	67927	67864
13	77853	66495	67434
14	78682	65355	67223
15	78376	64399	67207
16	78944	63939	67132
17	81334	64084	67983
18	83043	65855	69616
19	82258	67775	70833
20	84716	71127	73577
21	86491	74500	76237
22	82101	71081	72888
23	74245	64539	66536
24	67755	58608	60193

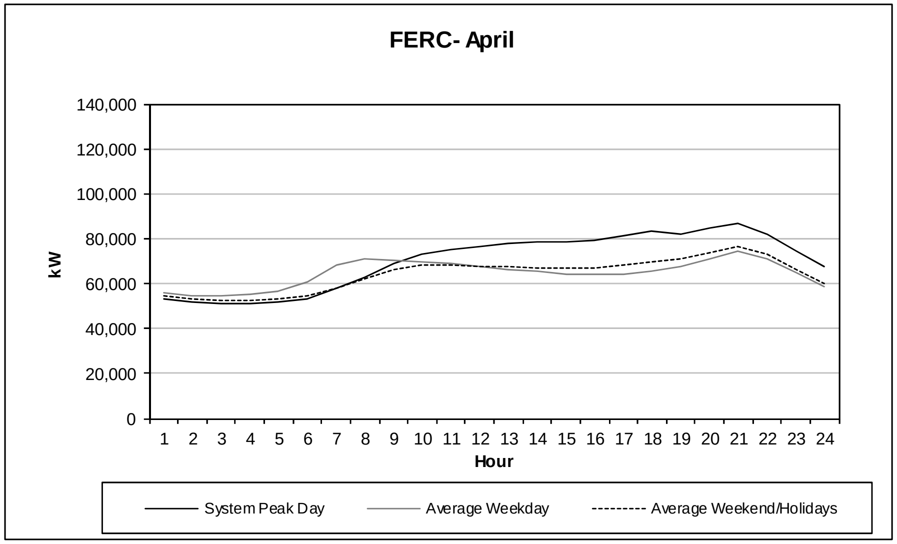


Figure 2.3-53 FERC Jurisdictional May

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	52492	52244	51477
2	49977	50515	49471
3	49241	49983	48609
4	48796	49928	48457
5	49775	51024	48851
6	51001	54569	49817
7	55341	60121	52077
8	59544	63386	55855
9	61943	63993	59446
10	63745	64141	61203
11	65612	64468	61717
12	67617	64468	62116
13	69582	64304	62204
14	72618	64283	62200
15	75126	63962	62793
16	76467	64031	63620
17	79412	65024	64865
18	81507	66415	66522
19	80923	66969	66844
20	80452	67738	67496
21	80950	70682	70078
22	78587	68926	68394
23	69209	62143	62204
24	59886	55580	55635

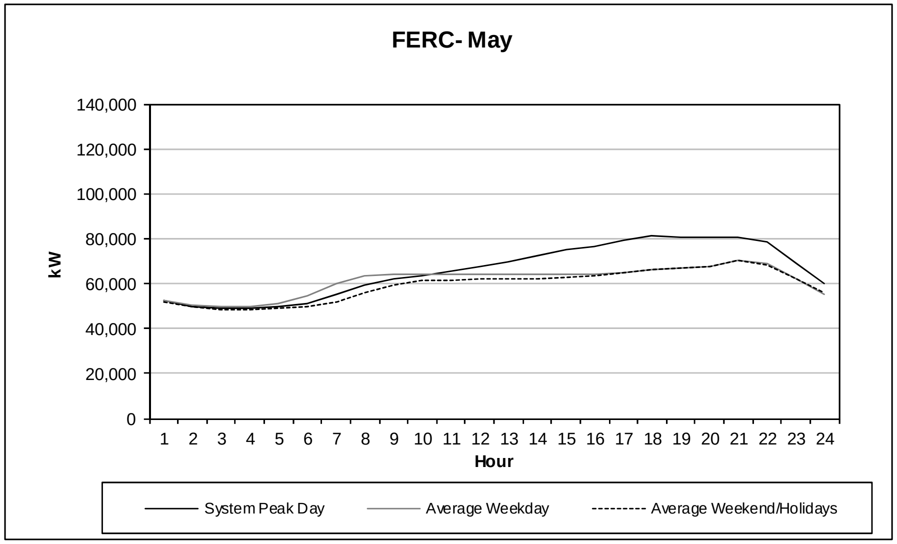


Figure 2.3-54 FERC Jurisdictional June

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	60722	53152	53808
2	56498	50519	50869
3	53627	49130	49268
4	51737	48515	48294
5	51599	48903	48100
6	53533	51105	48362
7	57905	55273	50344
8	64238	60322	54771
9	69904	63535	59395
10	75087	65920	62801
11	79934	68091	64964
12	84313	69956	66552
13	87435	71373	68058
14	89771	72681	69198
15	90837	73793	70543
16	93093	75411	71752
17	95749	77285	73975
18	97494	78958	75915
19	96646	78802	76111
20	91835	77040	75099
21	87028	76387	74820
22	84080	75416	74164
23	74283	67573	66697
24	63662	58971	58501

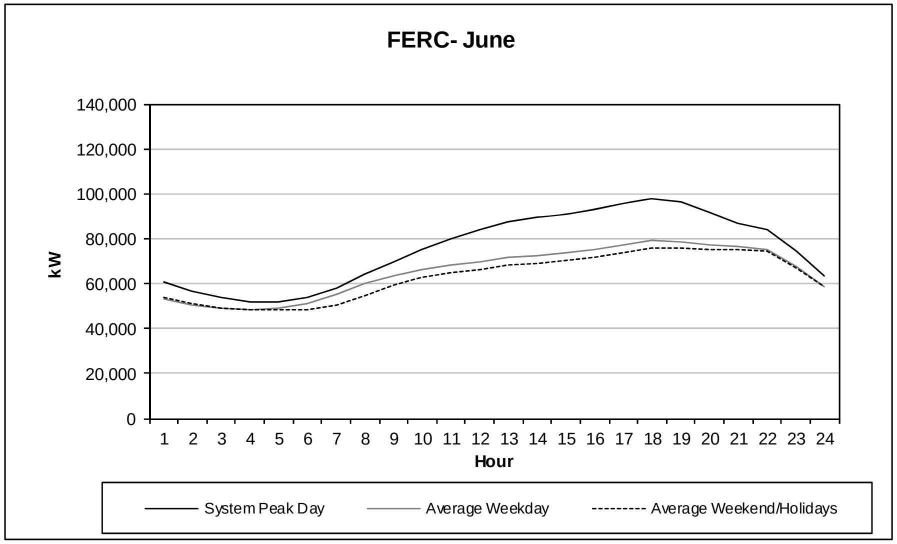


Figure 2.3-55 FERC Jurisdictional July

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	61910	58370	59021
2	57379	54694	55069
3	55231	52614	52935
4	54134	51568	51747
5	53802	51730	50961
6	54882	53773	51292
7	59399	57986	53202
8	67093	63653	58500
9	74557	68611	65121
10	81810	72787	70973
11	88055	76659	76273
12	94150	80017	80615
13	97831	82583	84464
14	100806	84783	87728
15	103418	86152	89650
16	105124	86681	91048
17	106005	87581	91687
18	104952	88237	90929
19	101939	87390	88495
20	96015	84647	85337
21	92261	83202	83268
22	88483	81225	81605
23	77928	72985	74177
24	67087	64010	65482

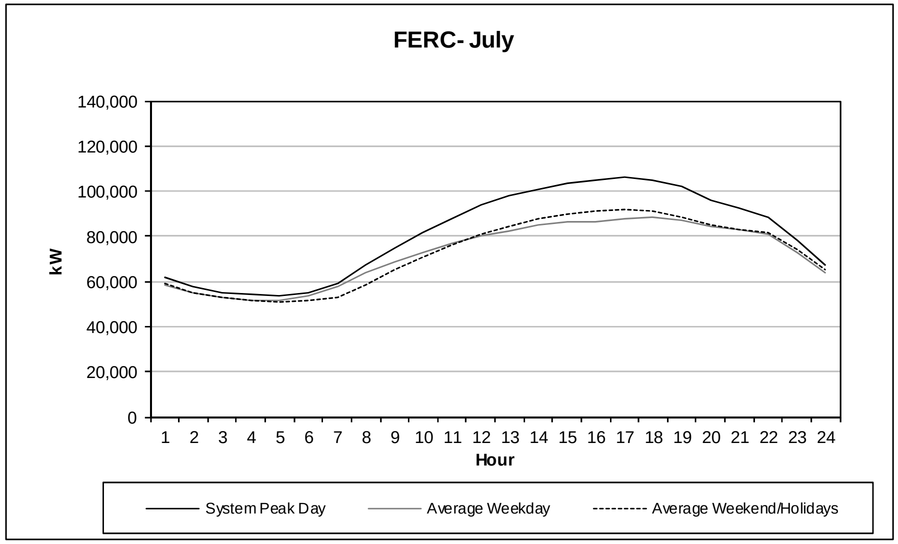


Figure 2.3-56 FERC Jurisdictional August

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	59562	54544	54324
2	55892	51503	51016
3	53576	49979	49178
4	51678	49322	48418
5	52300	49633	48141
6	53400	52143	48586
7	58662	57786	50735
8	63909	62430	55463
9	68201	66011	61230
10	72255	68876	65668
11	76641	71508	68680
12	80280	73948	71192
13	84507	76159	73734
14	89607	77768	75976
15	92668	78725	77774
16	94729	79093	79458
17	97051	79801	81526
18	96516	80987	83334
19	93088	81020	82758
20	88439	79310	80593
21	87663	79960	80672
22	82771	76011	76572
23	74049	67815	68124
24	64880	59461	59648

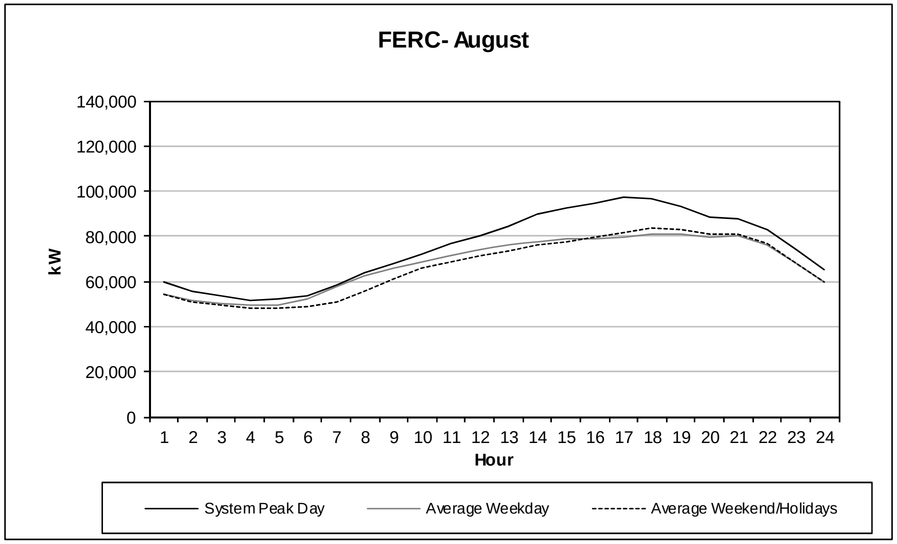


Figure 2.3-57 FERC Jurisdictional September

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	55142	50642	51994
2	51922	48426	49468
3	50491	47233	47794
4	49891	46872	47076
5	50036	47644	47215
6	52757	50920	48202
7	59873	58272	50913
8	64144	61760	54271
9	66803	62938	58681
10	69193	64070	61530
11	73322	65441	63217
12	76934	66600	64371
13	79156	67698	65648
14	83145	68735	66946
15	87433	69943	68622
16	91540	71221	70727
17	94793	73140	73043
18	96005	74998	74422
19	94415	75514	74914
20	91677	76970	76184
21	89522	75903	75522
22	81306	70335	70357
23	69745	62505	62288
24	59950	55139	54920

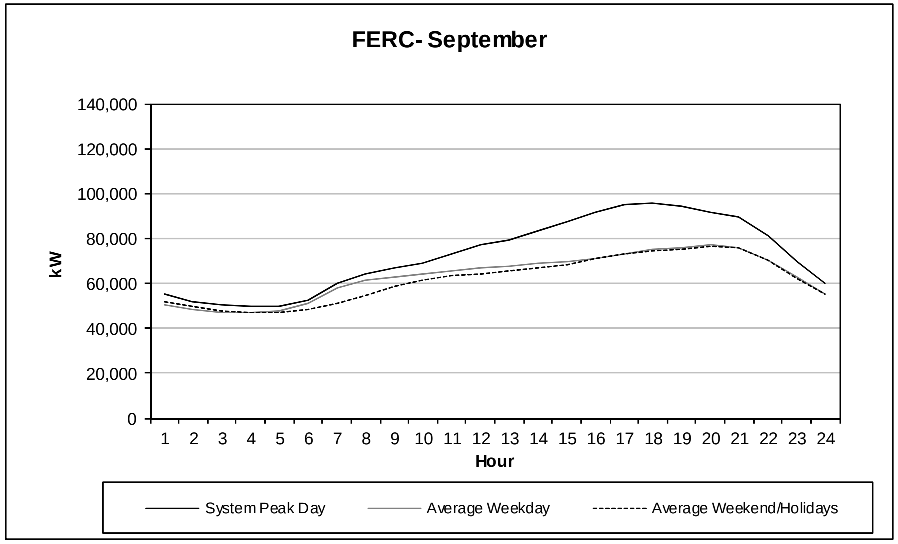


Figure 2.3-58 FERC Jurisdictional October

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	47372	49226	49252
2	46204	47947	47414
3	45739	47607	46626
4	45764	47722	46465
5	47211	49194	47063
6	51774	53562	48885
7	59658	61522	52360
8	62549	65319	56382
9	61971	64691	59637
10	61453	63801	61270
11	61100	63043	61450
12	61305	62288	61069
13	61153	61347	60731
14	60712	60184	60349
15	60670	59521	60323
16	61377	59386	60866
17	62597	60405	62395
18	64351	62873	64688
19	67875	68185	68950
20	71976	70919	70914
21	69757	69023	68743
22	64125	64292	64340
23	57083	58114	57896
24	50787	52572	52087

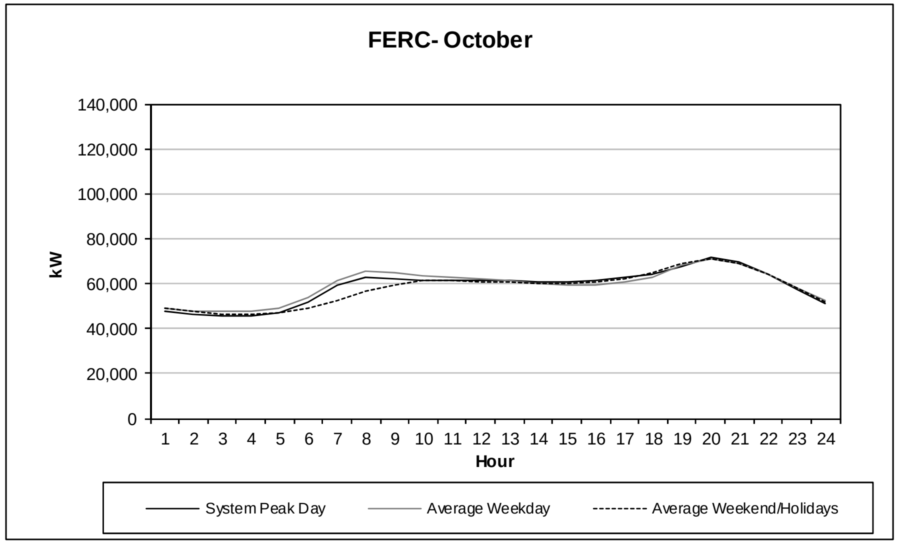


Figure 2.3-59 FERC Jurisdictional November

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	70076	67623	63553
2	70544	66770	62082
3	71615	66741	61671
4	72536	67450	61839
5	73783	69068	62482
6	78511	73066	64058
7	86299	80570	68066
8	89890	82936	72556
9	91079	81964	75775
10	91618	80584	76590
11	91544	79120	76068
12	90762	77547	75258
13	89172	75936	74496
14	88652	74368	73760
15	87987	73524	73519
16	87937	74000	74114
17	93422	78764	78435
18	102756	88205	85778
19	104563	90062	86750
20	103148	88986	85402
21	100175	86695	83307
22	94132	81719	79014
23	86878	75697	72462
24	81702	70617	67199

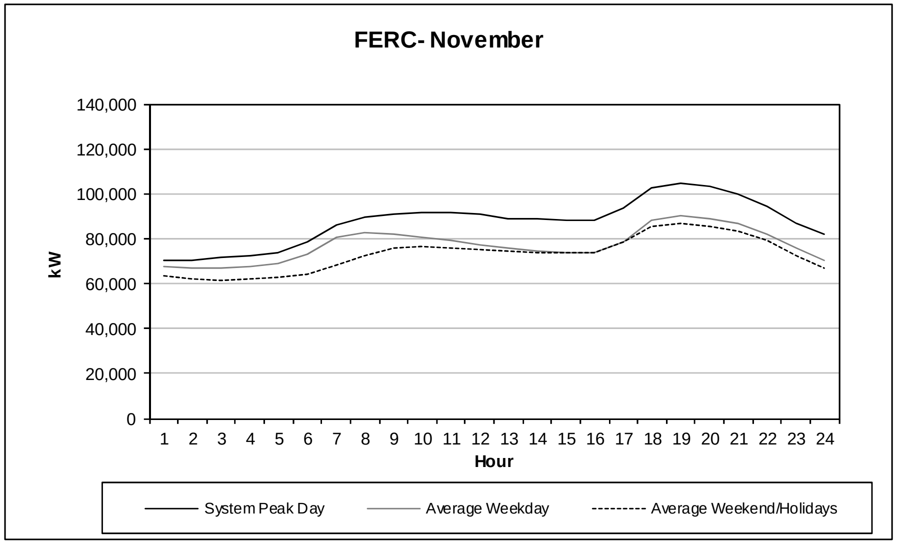
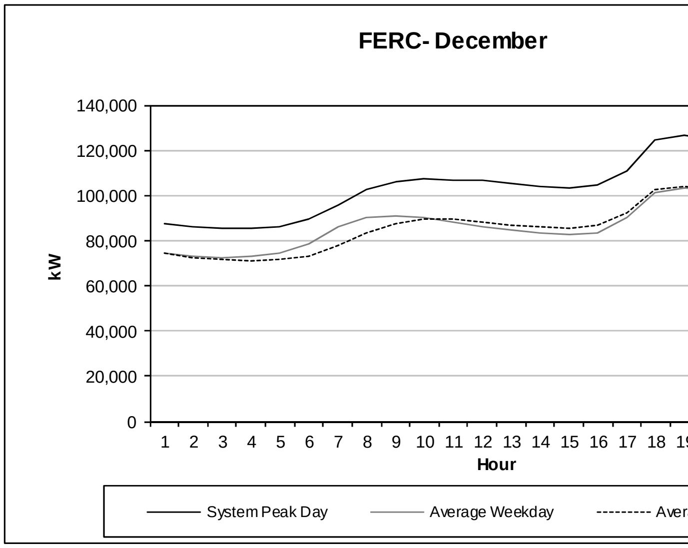


Figure 2.3-60 FERC Jurisdictional December

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	87843	74433	74751
2	85813	72834	72275
3	85173	72498	71466
4	85249	72791	71370
5	86305	74221	71627
6	89471	78278	73302
7	95608	85956	77715
8	102280	90493	83347
9	106088	90944	87785
10	107598	90045	89658
11	107038	88363	89271
12	106418	86418	88096
13	105247	84435	86822
14	103814	83070	85800
15	103533	82615	85749
16	104616	83496	86485
17	110622	89913	92483
18	124276	101558	102914
19	126844	103466	103900
20	124802	102389	102366
21	121912	100076	100194
22	116299	95032	95166
23	106988	86948	86938
24	98441	79537	79159



2.4 EVALUATION OF EXISTING RESOURCES

Company Owned Resources

Table 2.4-1 lists the names and locations of generation facilities owned by Public Service.

Table 2.4-1 Name and Location of Public Service Owned Generation Facilities

Facility Name	Unit	Location
Alamosa	1,2	One mile South of the city of Alamosa, CO, in the San Luis Valley
Ames	1	South Fork of the San Miguel River, approximately ten miles south-southwest of Telluride, CO
Blue Spruce	1,2	N Powhaton Rd, Aurora, CO
Cabin Creek	1,2	South of Georgetown, CO
Cherokee	4,5,6,7	Commerce City, CO. Near intersection of Washington St. and 61st
Comanche	1,2,3	South end of Pueblo, CO, east of I-25
Craig	1,2	Near Craig, CO
Fruita	1	Ten miles northwest of Grand Junction, CO, near the Town of Fruita
Ft. Lupton	1,2	Two miles northeast of Ft. Lupton, CO
Ft. St. Vrain	1,2,3,4,5,6	Three miles northwest of Platteville, CO
Georgetown	1,2	On South Clear Creek in Georgetown, CO
Hayden	1,2	On the Yampa River, two miles east of Hayden in western CO
Pawnee	1	Four miles southwest of Brush, CO
Rocky Mtn Energy Center	1,2,3	County Road 51, Keenesburg, CO
Salida	1,2	On the South Arkansas River, six miles east of Poncha Springs, CO
Shoshone	A,B	On the Colorado River in Glenwood Canyon, six miles east of Glenwood Springs, CO
Tacoma	1,2	On the Animas River, eighteen miles north of Durango, CO
Valmont	5,6	East Boulder, CO off of Arapahoe Road

Table 2.4-2 contains the following info for Public Service owned generation facilities:

1) Gross Maximum Capacity
2) Summer Net Dependable Capacity
3) Fuel Type
4) Heat Rate
5) Estimated retirement year without significant new investment or maintenance expense

Table 2.4- 2 Public Service Owned Generation Facilities (MW)

Facility Name	Unit	Gross Maximum Capacity (MW)	Summer Net Dependable Capcity (MW)	Fuel Type	Availability Factor % (1)	Heat Rate (2)	Estimated Retirement Year
Alamosa	1	17	13	Gas	96.85	-	2026
Alamosa	2	18	14	Gas	97.04	-	2026
Ames	1	3.8	3.8	Hydro	70.22	-	2050
Blue Spruce	1	146	130	Gas	93.30	-	2050
Blue Spruce	2	150	134	Gas	92.37	-	2050
Cabin Creek (8)	A	162	105	Pumped Hydro	89.13	-	2054
Cabin Creek (8)	B	162	105	Pumped Hydro	90.15	-	2054
Cherokee	4	383	352	Gas (2018)	84.85	-	2028
Cherokee	5	182	168	Gas	81.32	-	2055
Cherokee	6	182	168	Gas	91.17	-	2055
Cherokee	7	248	240	Gas	91.15	-	2055
Comanche	1	360	325	Coal	86.03	-	2033
Comanche	2	365	335	Coal	88.09	-	2035
Comanche (3)	3	536	500	Coal	75.37	-	2070
Craig (4)(5)	1	43	42	Coal	83.58	-	2040
Craig (4)(5)	2	43	42	Coal	89.72	-	2039
Fruita	1	18	14	Gas	97.39	-	2026
Ft. Lupton	1	50	45	Gas	83.20	-	2026
Ft. Lupton	2	50	45	Gas	89.70	-	2026
Ft. St. Vrain	1	312	301	Gas	94.97	-	2041
Ft. St. Vrain	2	138	123	Gas	91.12	-	2041
Ft. St. Vrain	3	143	128	Gas	92.77	-	2041
Ft. St. Vrain	4	143	128	Gas	93.02	-	2041
Ft. St. Vrain	5	163	145	Gas	96.47	-	2049
Ft. St. Vrain	6	162	144	Gas	97.24	-	2049
Georgetown	1	0.8	0.6	Hydro	95.82	-	2036
Georgetown	2	0.8	0.6	Hydro	79.86	-	2036
Hayden (6)	1	153	139	Coal	87.38	-	2030
Hayden (7)	2	106	98	Coal	89.08	-	2036
Pawnee	1	536	505	Coal	82.31	-	2041
Rocky Mountain Energy Center	1	159	145	Gas	80.50	-	2050
Rocky Mountain Energy Center	2	159	145	Gas	80.56	-	2050
Rocky Mountain Energy Center	3	303	290	Gas	82.59	-	2050
Salida	2	0.6	0.6	Hydro	83.13	-	2027
Salida	1	0	0	Hydro	0.00	-	2027
Shoshone	A	7.5	7.5	Hydro	71.73	-	2058
Shoshone	B	7.5	7.5	Hydro	81.19	-	2058
Tacoma	1	2.3	2.3	Hydro	85.33	-	2050
Tacoma	2	2.3	2.3	Hydro	60.53	-	2050
Valmont	5	196	184	Coal	83.48	-	2017
Valmont	6	51	43	Gas	72.09	-	2026

(1) Based on Historical 2011 - 2015 Data
(2) Unit Heat Rates are Considered Confidential Information
(3) PSCo Capacity Only (66.66% of Total Unit)
(4) PSCo Capacity Only (9.72% of Total Unit)
(5) Represents Equivalent Availability Factor (EAF) as this is the only metric available from unit operator.
(6) PSCo Capacity Only (75.5% of Total Unit)
(7) PSCo Capacity Only (37.5% of Total Unit)
(8) Current Capacity. Does not include anticipated additional capacity from upgrade approved in CPUC Decision No. C15-0955.

Table 2.4-3 shows the projected capacity factors of Public Service-owned generation facilities under Alternative Plan 2 discussed in Section 1.5 of Volume 1.

Table 2.4-3 Projected Capacity Factors

	2016	2017	2018	2019	2020	2021	2022	2023
Coal								
Cherokee 4	55.12%	51.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Comanche 1	80.47%	77.34%	86.74%	82.00%	76.24%	82.28%	82.47%	83.28%
Comanche 2	67.51%	82.70%	80.09%	75.54%	83.44%	79.57%	79.72%	80.54%
Comanche 3	88.28%	76.63%	89.86%	83.98%	89.41%	83.13%	83.32%	83.83%
Craig 1	78.45%	84.61%	88.63%	88.17%	88.91%	85.35%	85.60%	87.15%
Craig 2	76.90%	84.53%	88.15%	87.55%	88.13%	85.24%	85.85%	86.98%
Hayden 1	54.35%	56.93%	52.42%	62.02%	74.94%	81.16%	82.05%	83.67%
Hayden 2	43.16%	55.92%	61.33%	63.33%	67.88%	82.53%	82.86%	84.25%
Pawnee 1	66.08%	81.20%	82.26%	72.67%	81.59%	78.28%	78.68%	79.32%
Valmont 5	48.21%	48.21%	48.21%	48.21%	48.21%	48.21%	48.21%	48.21%
Gas Combined Cycle/Steam								
Fort St. Vrain CC	56.92%	55.45%	60.32%	61.41%	57.02%	60.03%	60.89%	64.41%
Rocky Mountain CC	28.56%	31.09%	32.37%	32.94%	32.08%	34.73%	36.10%	40.20%
Cherokee CC	30.16%	34.87%	37.90%	37.24%	36.71%	41.55%	43.74%	48.76%
Cherokee 4	0.00%	0.00%	5.07%	5.04%	3.03%	2.53%	4.28%	7.07%
Combustion Turbine								
Alamosa 1	0.05%	0.11%	0.19%	0.28%	0.23%	0.31%	0.25%	0.23%
Alamosa 2	0.05%	0.09%	0.19%	0.27%	0.23%	0.33%	0.26%	0.23%
Blue Spruce 1	0.18%	0.29%	0.54%	0.69%	0.64%	0.91%	1.63%	2.92%
Blue Spruce 2	0.29%	0.47%	0.73%	0.92%	0.96%	1.25%	2.08%	3.72%
Fruita 1	0.05%	0.11%	0.20%	0.29%	0.24%	0.34%	0.27%	0.24%
Ft. Lupton 1	0.23%	0.32%	0.40%	0.51%	0.43%	0.59%	1.05%	1.80%
Ft. Lupton 2	0.24%	0.33%	0.40%	0.53%	0.44%	0.61%	1.10%	1.87%
Ft. St. Vrain 5	1.59%	2.34%	3.04%	3.70%	5.92%	7.96%	11.51%	14.16%
Ft. St. Vrain 6	0.58%	0.92%	2.29%	2.45%	3.47%	5.70%	8.44%	9.00%
Valmont 6	0.07%	0.13%	0.22%	0.31%	0.27%	0.39%	0.31%	0.27%
Hydro								
Ames	28.46%	28.54%	28.54%	28.54%	28.46%	28.54%	28.54%	28.54%
Georgetown	31.52%	31.61%	31.61%	31.61%	31.52%	31.61%	31.61%	31.61%
Salida	32.53%	32.62%	32.62%	32.62%	32.53%	32.62%	32.62%	32.62%
Shoshone	64.51%	64.69%	64.69%	64.69%	64.51%	64.69%	64.69%	64.69%
Tacoma	24.01%	24.08%	24.08%	24.08%	24.01%	24.08%	24.08%	24.08%
Pumped Storage								
Cabin Creek	14.21%	14.62%	18.51%	18.19%	14.30%	13.94%	14.31%	14.33%

In-Service Date for Facilities Granted a CPCN

The only utility-owned generation facility for which a CPCN has been granted, but is not in service at the time of filing this 2016 ERP, involves upgrades at the Company's Cabin Creek facility. The upgrades include: (1) increasing the existing pump turbine unit capacity from 324 MW to 360 MW and (2) expanding the size of the upper reservoir to provide an additional 75 acre-feet of storage capacity. Together, these upgrades will provide an additional 112 MWh of energy generation per storage cycle and 36.6 MW of capacity, and the round-trip overall storage efficiency will be improved from 64.4 to 72.4 percent. A CPCN was granted on August 19, 2015 in Decision No. C15-0955, Proceeding No. 15A-0304E. The estimated in-service date for Unit A is May 11, 2019; the estimated in-service date for Unit B is May 11, 2020. The estimated Commercial Operation dates are June 1, 2019, and June 1, 2020, respectively.

Purchased Power

Public Service buys a significant amount of firm capacity and energy through PPAs with various agreement term lengths and fuel resource types. These PPAs contain provisions that detail the amount and type of capacity available to Public Service. Some are "unit contingent," meaning that the delivered capacity is contingent upon the availability of certain generating facilities. If one of these facilities is not available for operation, the supplying counterparty can reduce the amount of capacity provided to Public Service.

Table 2.4-4 summarizes the following for all PPAs to which Public Service currently purchases firm capacity:

1) Resource Type
2) Firm Summer Capacity
3) Anticipated PPA Expiration Date

Table 2.4-4 PPA Summer Capacity

PPA Name	Resource Type	Firm Summer MW	Expires (1)
Arapahoe 5,6,7-Southwest Gen	Gas	118	2023
Brush 1/3	Gas	76	2025
Brush 4D	Gas	132	2022
Fountain Valley--Southwest Gen	Gas	238	2031
Manchief Power	Gas	256	2021
PacifiCorp Exchange	Coal	150	2022
Plains End I	Gas	109	2027
Plains End II	Gas	110	2027
Spindle Hill Energy	Gas	280	2026
Thermo Cogeneration	Gas	129	2018
Tri-State 2	Coal	100	2016
WM Renewable Energy, LLC	Biomass	3.3	2022
City of Boulder (Betasso) (2)	Hydro	1.3	2017
City of Boulder (Kohler) (2)	Hydro	0.1	2017
City of Boulder (Lakewood) (2)	Hydro	1.8	2016
City of Boulder (Maxwell) (2)	Hydro	0.1	2016
City of Boulder (Orodell) (2)	Hydro	0.1	2017
City of Boulder (Silverlake) (2)	Hydro	1	2016
City of Boulder (Sunshine) (2)	Hydro	0.4	2017
The City and County of Denver (Foothills) (2)	Hydro	1.2	2026
The City and County of Denver (Strontia Springs) (2)	Hydro	0.6	2026
The City and County of Denver (Dillon Dam) (2)	Hydro	1	2026
The City and County of Denver (Roberts Tunnel) (2)	Hydro	3.1	2026
The City and County of Denver (Hillcrest) (2)	Hydro	1.2	2026
The City and County of Denver (Gross Reservoir) (2)	Hydro	4.1	2026
Orchard Mesa/Grand Valley (2)	Hydro	1.5	2020
Redlands Water and Power (2)	Hydro	0.7	2024
Ute Hydro (2)	Hydro	0.1	2019
STS Hydropower, Ltd. (Mt. Elbert) (2)	Hydro	1.3	2019
SunE Alamosa1, LLC (3)	Solar	4	2027
Greater Sandhill I, LLC (3)	Solar	10	2030
SunE GIL1, LLC (SolarTAC) (3)	Solar	0.2	2016
San Luis Solar, LLC (3)	Solar	17	2036
Cogentrix of Alamosa, LLC (3)	Solar	17	2031
Solar Star Colorado III (3)	Solar	28	2036
Comanche Solar PV LLC (5)	Solar	56	2040
Ridge Crest Wind Partners, LLC (4)	Wind	5	2016
Colorado Green Holdings, LLC (4)	Wind	26	2018
Spring Canyon Energy LLC (4)	Wind	10	2025
PPM Twin Buttes Wind (4)	Wind	12	2026
Cedar Creek Wind Energy, LLC (4)	Wind	48	2027
Peetz Table Wind Energy, LLC (4)	Wind	32	2032
Logan Wind Energy LLC (4)	Wind	32	2027
Northern Colorado Wind Energy, LLC (I) (4)	Wind	24	2034
Northern Colorado Wind Energy, LLC (II) (4)	Wind	4	2029
Cedar Creek II, LLC (4)	Wind	40	2036
Cedar Point Wind, LLC (4)	Wind	40	2031
Limon Wind, LLC (4)	Wind	32	2037
Limon Wind II, LLC (4)	Wind	32	2037
Limon Wind III, LLC (4)	Wind	32	2039
Golden West Power Partners, LLC (4)	Wind	40	2040

(1) Final Year in Which Capacity is Available to Serve Peak Summer Load
(2) Firm Capacity Reflects 50% Effective Load Carrying Capability
(3) Firm Capacity Reflects 55% Effective Load Carrying Capability
(4) Firm Capacity Reflects 16% Effective Load Carrying Capability
(5) Firm Capacity Reflects 47% Effective Load Carrying Capability

Table 2.4-5 below summarizes all contract provisions that allow for modification of the amount of capacity or energy purchased for current Public Service PPAs.

Table 2.4-5 PPA Duration and Contract Modification Terms

Power Purchase Agreement	Contract Duration (Termination Year)	Contract Modification Terms
Arapahoe-Southwest Gen	2023	PSCo has the first right to any Excess Capacity and Excess Energy at a mutually agreeable price.
Brush 1/3 (2005 PPA)	2017	PSCo has the first right to any Excess Capacity and Excess Energy at the price offered by Seller.
Brush 1/3 (2014 PPA)	2025	PSCo has the first right to any Excess Capacity and Excess Energy at the price offered by Seller.
Cedar Creek II	2036	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
Cedar Point	2031	PSCo has the right to accept or decline any Excess Renewable Energy produced during any commercial operation year.
Cogentrix of Alamosa	2032	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Comanche Solar	2041	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Fountain Valley-Southwest Gen	2032	PSCo has the first right to any Excess Capacity and Excess Energy at a mutually agreeable price.
Greater Sandhill	2030	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Limon	2037	PSCo has the right to accept or decline any Excess Renewable Energy produced during any commercial operation year.
Limon II	2037	PSCo has the right to accept or decline any Excess Renewable Energy produced during any commercial operation year.
Manchief	2022	PSCo has the first right to any Excess Capacity and Excess Energy at the price offered by Seller.
Northern Colorado Wind II	2029	PSCo has the right to accept or decline any Excess Renewable Energy produced during any commercial operation year.
PacifiCorp Exchange	2022	PacifiCorp has the right annually to reduce the amount of capacity and energy made available to PSCo in 25 MW increments on a rolling 3 year term.
San Luis Solar	2031	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Solar Star Colorado III	2036	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Spindle Hill	2027	PSCo has the first right to any Excess Capacity and Excess Energy at the price offered by Seller.
Thermo Cogeneration	2019	PSCo is only required to purchase excess capacity to support operation in severe cold weather conditions.
Tri-State 2	2017	PSCo has the right to purchase any Excess Capacity for the upcoming season at a mutually agreeable price.

Tables 2.4-6 and Table 2.4-7 identify Public Service owned units identified as affected in the final version of EPA's Clean Power Plan, released in August 2015.

Table 2.4-6 Clean Power Plan Affected Units (Public Service Owned)

111(d) Affected Units - PSCo Owned				
Plant	**Unit**	**PSCo NDC MW**	**Fuel**	**Retirements [1]**
Arapahoe	3,4	153	Coal	2013
Cherokee	1	107	Coal	2012
Cherokee	3	152	Coal	2015
Cherokee	4	352	Coal/Gas [2]	2027
Cherokee	567	576	Gas	2055
Comanche	1	325	Coal	2033
Comanche	2	335	Coal	2035
Comanche	3	500	Coal	2070
Craig	1	42	Coal	2040
Craig	2	42	Coal	2039
Fort St Vrain	1234	680	Gas	2041
Hayden	1	139	Coal	2030
Hayden	2	98	Coal	2036
Pawnee	1	505	Coal	2041
Rocky Mountain Energy Cente	123	580	Gas	2050
Valmont	5	184	Coal	2017
Zuni	2	60	Coal	2015

(1) Retirement dates after 2015 reflect assumed retirement dates for modeling purposes

(2) Coal unit scheduled to be converted to natural gas usage in 2017

Table 2.4-7 Clean Power Plan Affected Units
(Affected Units Under Public Service PPA Post 2022)

111(d) Affected Units - PSCo PPAs Expiring Within 2022 - 2030 Compliance Window				
Plant	**Unit**	**PSCo NDC MW**	**Fuel**	**Scheduled PPA Exp**
Arapahoe Combustion Turbine Project	UN5, UN6, UN7	118	Gas	2023
Brush Generation Facility	1345 GT, 124 ST	132	Gas	2022
PacifiCorp Purchase	Craig/Hayden	150	Coal	2022

Demand Side Management

On June 17, 2013, the Company filed an application for approval of a number of strategic issues relating to its Demand Side Management (DSM) plan, including long-term electric energy savings and demand response goals. Per the Commission's decision (Decision No. C14-0731) in the 2013 Strategic Issues proceeding (Proceeding No. 13A-0686EG), the Company has used the approved demand response targets for purposes of determining resource need. Since the approved goals extend only through 2020, the current assumption is that levels of demand response remain constant after 2020 for purposes of resource need determination. Table 2.4-8 reflected the demand response targets only, with the additional ordered 65 MW of DSM reductions reflected directly in the load forecast.

Table 2.4-8 Demand Response Goals (MW)

Demand Response	2016	2017	2018	2019	2020	2021	2022	2023
Strategic Issues DR Goal	537	555	575	598	623	623	623	623

As with the DSM related demand reductions, the energy savings goals specified in the Commission decision are also reflected directly in the load forecast.

Among the issues addressed by the Commission in the 2010 DSM Strategic Issues Decision was whether the Company should be required to use competitive solicitation(s) to acquire all DSM resources. The Commission refused to require the Company to acquire DSM resources through competitive solicitation(s) but directed the Company "to make a more robust and transparent application of competitive bidding *as it implements an approved DSM plan"* (emphasis added). Accordingly, while the Company will continue to use competitive bidding to solicit vendors to assist in implementing its approved DSM plans, the Company does not intend to solicit DSM resources as part of the competitive solicitation made as a result of the 2016 ERP.

To incorporate the impacts of future DSM, the Company has reduced its sales forecast assuming achievement of the energy savings goals for energy efficiency programs through 2020 that the Commission established in the DSM Strategic Issues Decision C14-0731 of 400 GWh. For each year after 2020, the Company assumed continued achievement of the 400 GWh goal. For the demand forecast, the Company has assumed achievement of the DSM Strategic Issues Decision C14-0731 demand goals for energy efficiency of 65 MW from 2016-2020, and has assumed continued achievement of this goal for each year after 2020. Additionally, the demand impacts of the most recent forecast of load management achievements are also included.

Utility Coordination

In accordance with Rule 3607(b), utilities are required to coordinate their Resource Plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Below are the Company's coordination letters sent to: (1) Tri-State, and (2) Black Hills, requesting confirmation that the transaction information stated by Public Service is consistent with that which each respective utility plans to use in any resource plan filing or reporting.

March 14, 2016

Mr. Rob Wolaver
Senior Manager of Energy Resources
Tri-State Generation & Transmission
P.O. Box 33695
Denver, CO 80233

Subject: Public Service Company of Colorado's 2016 Electric Resource Plan

Dear Rob,

The Colorado Public Utilities Commission's Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service requests that Tri-State confirm that the transaction information listed below is consistent with that which Tri-State plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:
Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

The capacities shown in the following table reflect the amount of power that Public Service purchases from Tri-State to help meet our firm load obligation. The listed capacities are included in our resource planning and modeling assumptions. The listed capacities are subject to all of the terms and conditions of each of the individual contracts. This letter is not intended to limit Public Service or Tri-State in any manner regarding future administration of these or other contracts.

	Contract	**Summer**	**Contract**	
Contract	**Source**	**Capacity (MW)**	**Start**	**Expiration**
TSGT #2	LRS, Craig	100	4/1/1987	3/31/2017
Thermo Cogen	J M Shafer	129	9/1/2002	6/30/2019

If you agree with this contract information, please reply with a letter of acknowledgement. We anticipate that we will include your reply letter, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me at (303) 571-2749 with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
1800 Larimer Street
Suite 1400
Denver, CO 80202

From: Wolaver, Rob [mailto:rwolaver@tristategt.org]
Sent: Wednesday, March 16, 2016 9:14 AM
To: Bowman, Jon M
Subject: RE: Coordination Letter for Public Service 2016 ERP

XCEL ENERGY SECURITY NOTICE: This email originated from an external sender. Exercise caution before clicking on any links or attachments and consider whether you know the sender. For more information please visit the Phishing page on XpressNET.

Jon:

I have reviewed the letter that you attached to the email, and can confirm that the information you provided regarding transactions between Public Service Company of Colorado and Tri-State is correct.

Rob

Robert Wolaver, P.E.
Senior Manager, Energy Resources
Tri-State Generation and Transmission Association, Inc.
303 254 3447

March 15, 2016

Mr. Eric Egge
Director Generation Dispatch & Power Marketing
Black Hills Corporation
625 Ninth Street
P.O. Box 1400
Rapid City, South Dakota 57709-1400

Subject: Public Service Company of Colorado’s 2016 Electric Resource Plan

Dear Mr. Egge,
The Colorado Public Utilities Commission’s Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service requests that Black Hills Colorado confirm that the transaction information listed below is consistent with that which Black Hills Colorado plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:
Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

Currently, Public Service has no firm purchases or sales with Black Hills as counterparty. As such, Public Service is not including any transactions with Black Hills in its determination of resource need.

If you agree with this information, please reply with a letter of acknowledgement. We anticipate that we will include your reply letter, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me at (303) 571-2749 with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
1800 Larimer Street
Suite 1600
Denver, CO 80202

Black Hills Energy
Eric M. Egge
Director, Generation Dispatch & Power Marketing
eric.m.egge@blackhillscorp.com

2828 Plant Street, Suite B
Rapid City, SD 57702
P: 605.721.2646
F: 605.721.2567

March 22, 2016

Jim Hill
Director Resource Planning and Bidding
1800 Larimer Street, Suite 1600
Denver, CO 80202

Dear Mr. Hill:

This letter is in response to your request to coordinate the reporting of purchases and sales of firm electricity between Black Hills Colorado Electric (Black Hills) and Public Service Company of Colorado (PSCo). I confirm that there are currently no firm purchases or sales between and PSCo and Black Hills.

Please contact me with any further questions.

Sincerely,

Eric M. Egge

Improving life with energy
www.blackhillsenergy.com

2.5 TRANSMISSION RESOURCES

Electric Transmission System Overview

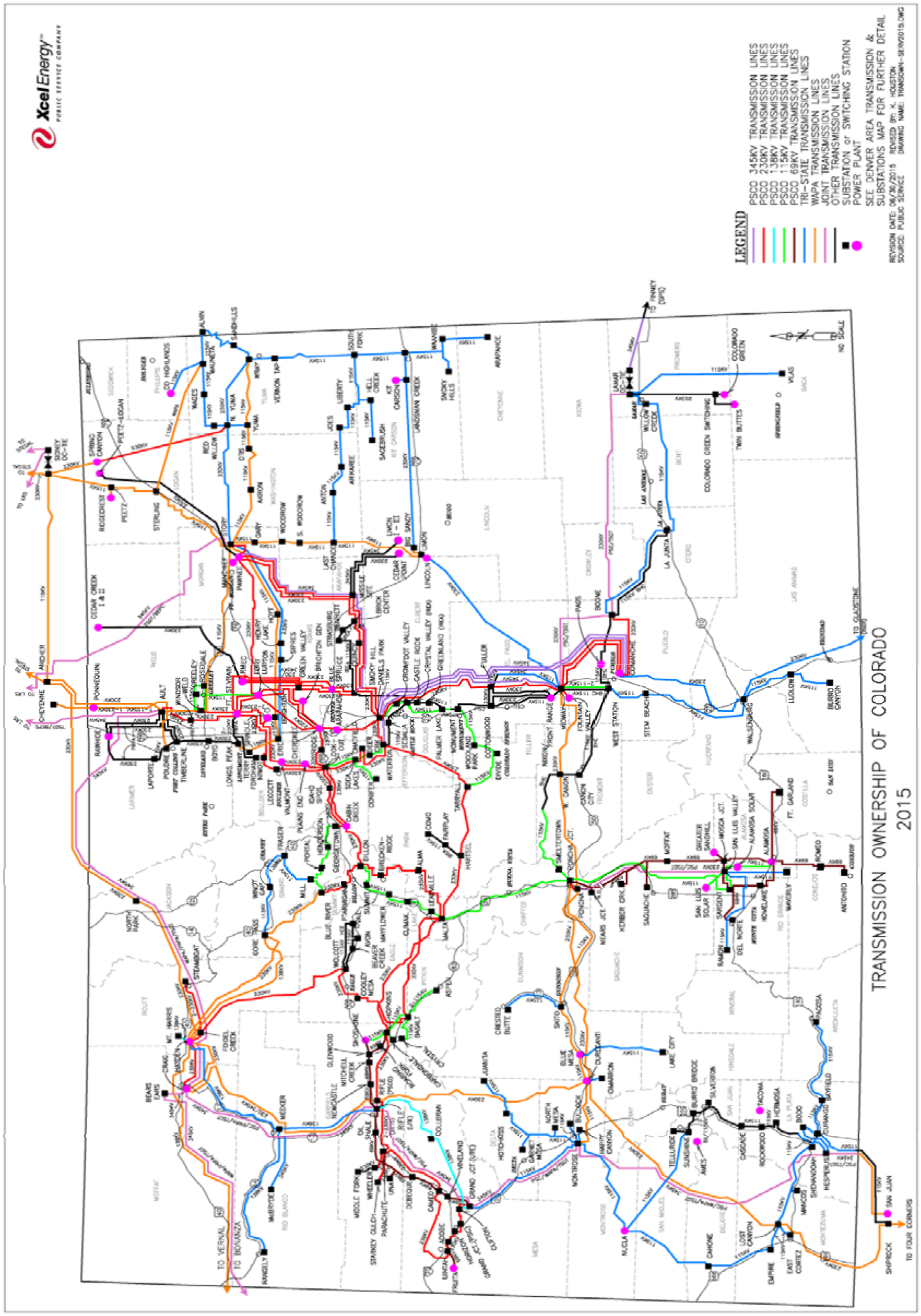
Public Service owns and maintains approximately 4,670 circuit-miles of transmission lines, all of which are located inside Colorado. The transmission lines are rated 44 kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also uses 223 transmission and distribution substations to transform and deliver electric energy.

Colorado is on the eastern edge of the Western Electric Interconnection, which operates asynchronously from the Eastern Electric Interconnection. The Public Service–Southwestern Public Service Company Tie-line and 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station, in-service since December 31, 2004, provides the first link in Colorado between the two interconnections.

Public Service has ownership in the jointly owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado south to the Four Corners area.

Figure 2.5-1 shows a map of the Colorado Transmission System including Public Service's transmission facilities.

Figure 2.5-1 Colorado Transmission Map



TOT Transmission System Operating Limitations

Public Service shares ownership in four jointly-owned transmission corridors within the Colorado/Wyoming/Utah/New Mexico area. These jointly-owned transmission corridors are called TOTs which is an acronym for "total of transmission." These TOTs are numbered 2A, 3, 5, and 7. The System Operating Limit ("SOL") across these TOTs is developed regularly by coordination and agreement by the owners of the TOT facilities.

The North American Electric Reliability Corporation ("NERC") is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. Public Service also participates in Peak Reliability ("Peak"). This organization provides situational awareness and real-time monitoring of the Reliability Coordinator ("RC") Area within the Western Interconnection. Peak is listed on the NERC Compliance Registry to perform the RC function as a statutory activity.

The Peak Reliability sub-regional study group Rocky Mountain Operating Study Group ("RMOSG"), of which Public Service is a participating member, reviews and approves the SOLs. The RMOSG is one of four Regional Study Groups in the Western Electricity Coordinating Council ("WECC") that performs SOL related seasonal studies. Each study group is responsible for reviewing and approving SOLs and submitting the results to Peak Reliability.

Presently, Public Service transmission capacities on these transfer paths are committed to serve Public Service native load. Public Service posts available transmission capability ("ATC") on the WestTrans OASIS node at http://www.oatioasis.com. Transmission tariffs, including transmission terms, conditions and pricing, are posted on the WestTrans OASIS node.

The bulk power transmission system within the Denver/Boulder metro area consists primarily of a double-circuit 230 kV loop around the Denver metro region. This outer belt loop feeds into the 230 kV and 115 kV load-serving networks at various points on the system. 345 kV transmission helps serve the Denver metro loads with generation resources from the Pawnee and Pueblo areas. Public Service is adding an additional 345 kV transmission line from the Pawnee area into the Denver/Boulder metro area at Daniels Park Substation.

Figure 2.5-2 illustrates the TOT locations. The power transferred across these TOT paths is continuously monitored by the designated operating agent for each TOT to ensure that the path limits are not exceeded. All TOTs have been rated by WECC and the Transmission Providers that jointly own the TOTs. Public Service shows

TOT1A in Figure 2.5-2 but does not further describe the TOT in this report as Public Service does not own any portion of the TOT and has no rights on the TOT.

Figure 2.5-2 Colorado TOT Transmission Path Map

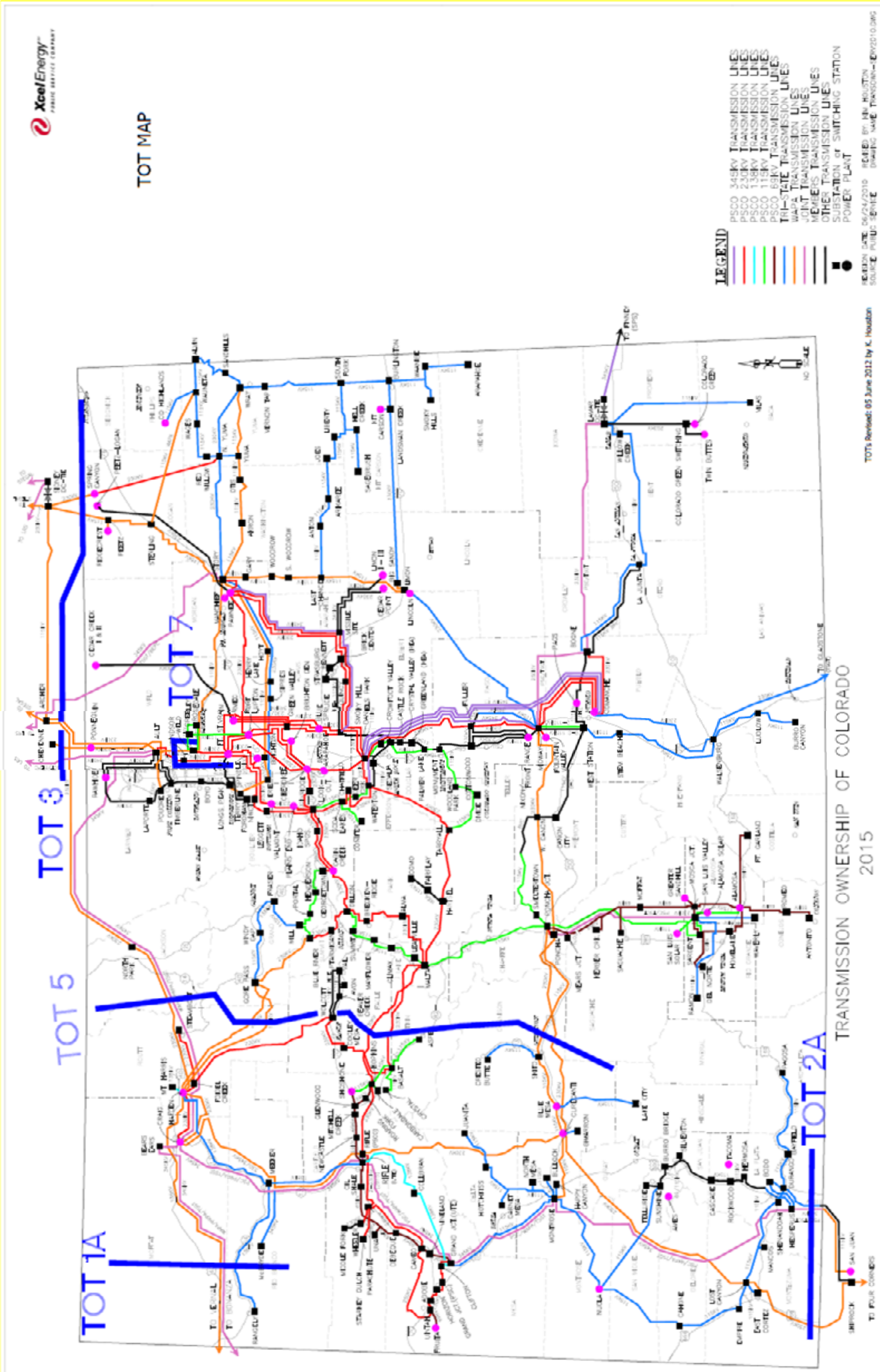


Table 2.5-1 shows Public Service's TOT capability on each path.

Table 2.5-1 TOT Transmission Transfer Capability Limitations (2015)

Path	Transmission Lines	Public Service Firm Path Transfer Capability (MW)		Public Service Capability Committed (MW)
TOT 2A	Waterflow-San Juan 345 kV Hesperus-Glade Tap 115 kV Lost Canyon-Shiprock 230 kV	135 north-south	200 south-north	135 north-south 200 south-north
TOT 3	Archer-Ault 230 kV LRS-Ault 345 kV LRS-Story 345 kV Cheyenne-Owl Creek 115 kV Sidney-Sterling 115 kV Sidney-Spring Canyon 230 kV Cheyenne-Ault 230 kV	56 north-south	56 south-north	56 north-south 0 south-north
TOT 5	North Park-Archer 230 kV Craig-Ault 345 kV Hayden-Gore Pass 230 kV Hayden-Gore Pass 138 kV Gunnison – Poncha 115 kV Curecanti-Poncha 230 kV Hopkins-Malta 230 kV Basalt-Malta 230 kV	480 west-east	480 east-west	480 west-east 480 east-west
TOT 7	Weld-Fort St. Vrain 230 kV Longs Peak -FSV 230 kV Ault-Fort St. Vrain 230 kV	516 north-south	516 south-north	516 north-south 2 south-north

TOT 2A

TOT 2A represents the transmission path that connects southwestern Colorado with New Mexico and Arizona. This path is comprised of three transmission lines and has a north to south limit of 690 MW minus net load in the Montrose-Curecanti-San Juan-Shiprock area of southwest Colorado. The limit is based on a single contingency of the Hesperus - San Juan 345 kV line. The path is jointly owned by Western Area Power Administration ("WAPA"), Tri-State Generation & Transmission ("TSGT" or "Tri-State"), and Public Service. The south to north limit is not defined, but Public Service has ownership rights to 200 MW of transfer capability in the south to north direction on this path and a 135 MW share of the maximum north to south transfer capability of 690 MW. However, the limit is dynamic and monitored continuously. The limit is also highly dependent on local southwest Colorado loads and drops significantly as the loads increase and when southwest Colorado generation is off-line.

TOT 3

TOT 3 is essentially the transmission path that connects Wyoming and Nebraska with northeastern Colorado. This path is comprised of seven transmission lines and presently has a maximum north to south transfer limit of 1,680 MW that is adjusted seasonally to account for load and local generation variations.

WAPA, TSGT, Basin Electric Power Cooperative and Public Service jointly own the TOT 3 transmission lines. Public Service owns 56 MW of firm transfer capability on TOT 3 but presently depends on this TOT path for delivery of approximately 400 MW of purchased power from northwestern Colorado and southern Wyoming.

Operationally, TOT 3 is the most constraining transmission path used to import power into eastern Colorado. Once the TOT 3 capacity limit is reached, further schedules into eastern Colorado over TOT 5 result in the overloading of TOT 3. In this condition the overloading of TOT 3 is due to the increased flow on TOT 5's North Park-Terry Ranch Road 230 kV line into Wyoming resulting in an increase on TOT 3's Terry Ranch Road-Ault 230 kV line into Colorado.

TOT 5

TOT 5 represents the transmission path that connects western Colorado to eastern Colorado. The TOT 5 path is comprised of eight transmission elements and presently has a west to east operating transfer limit of 1,680 MW. The west to east rating of the path is defined through established operating practices. WAPA, Tri-State, Poudre River Power Authority ("PRPA"), and Public Service jointly own the TOT 5 transmission lines. Public Service owns 480 MW of firm transfer capability on TOT 5 (west-east) and, since the path is not formally rated in that direction, the same 480 MW east to west. The east to west limit is not defined at this time.

Public Service's 480 MW firm transfer capability in the west to east direction on TOT 5 is fully committed to transmitting capacity and associated energy from the Company's purchased power resources and from Company-owned resources located in western Colorado. Public Service has committed the east to west direction as backup for western Colorado loads and for counter-scheduling needs.

TOT 7

TOT 7 is south of the TOT 3 path and consists of three transmission lines that transfer power to the north Denver-metro area. The TOT 7 path has a north to south transfer limit of 890 MW. The south to north transfer limit is not defined at this time.

Public Service and PRPA jointly own TOT 7. Public Service owns 516 MW of firm transfer capability on TOT 7. Since TOT 7 is located east of TOT 5 and south of TOT 3, TOT 7 use generally requires coordinated use of both the TOT 3 and TOT 5 paths.

SB07-100 New Transmission Additions

Senate Bill 07-100 ("SB07-100"), which is codified at § 40-2-126, requires rate-regulated electric utilities such as Public Service to do the following on a biennial basis:[7]

- Designate Energy Resource Zones ("ERZs");
- Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such ERZs;
- Consider how transmission can be provided to encourage local ownership of renewable energy facilities, whether through renewable energy cooperatives as provided in section 7-56-210, Colorado Revised Statutes, or otherwise; and
- Submit proposed plans, designations, and applications for certificates of public convenience and necessity to the Commission for simultaneous review.

Public Service filed its first SB07-100 Report on October 31, 2007. On October 31, 2015, the Company filed its most recent SB07-100 Report. The report is available on the Commission's e-filing system under Proceeding No. 15M-0856E and also on Xcel Energy's Transmission website.[8]

[7] SB07-100 required regulated Colorado electric utilities to submit their biennial transmission plans "[o]n or before October 31 of each odd-numbered year," however, the General Assembly recently passed House Bill 16-1091 in March 2016, which amends this timeline to require regulated electric utilities to submit plans "[b]iennally, on or before a date determined by the Commission, commencing in 2016."

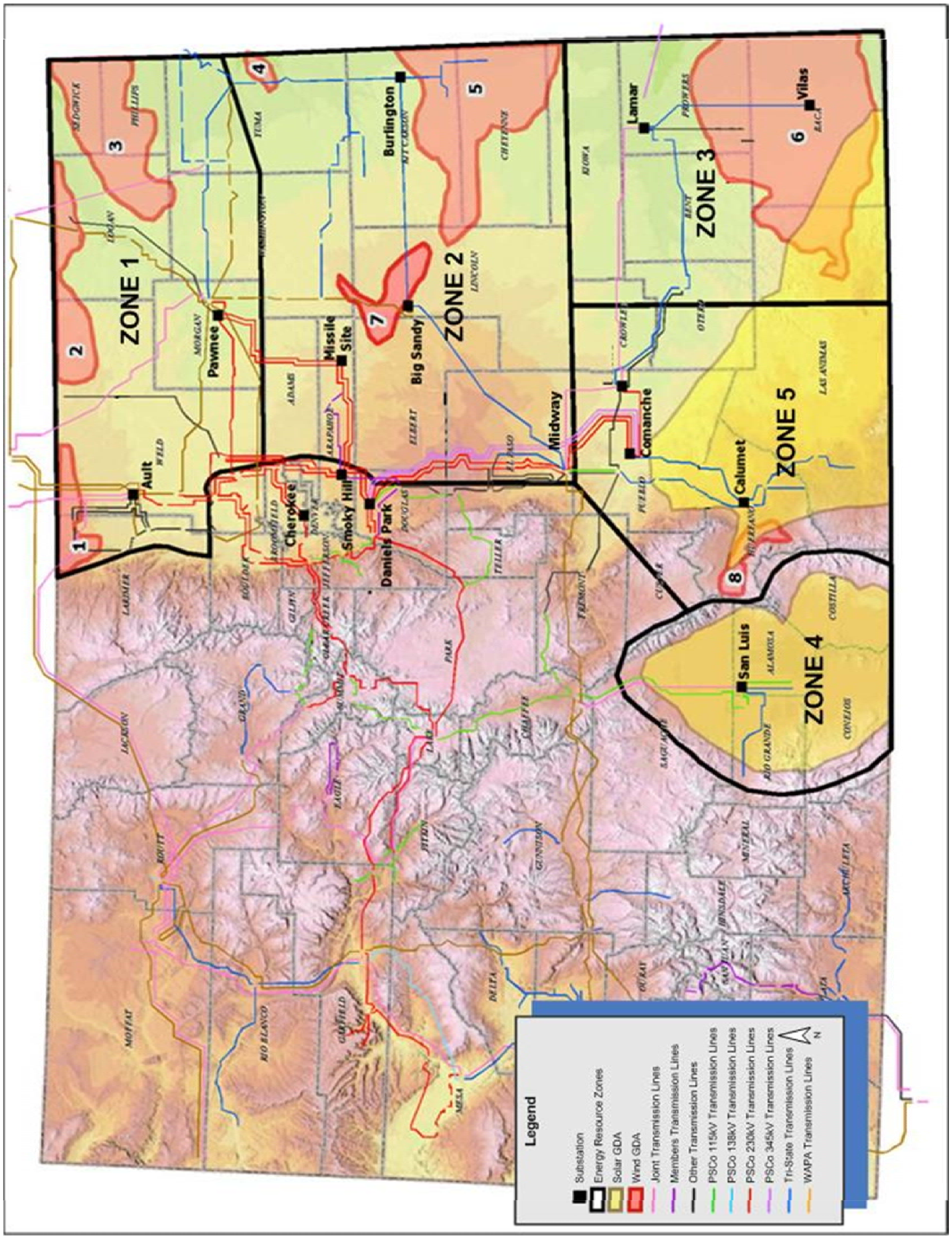
[8] http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado.

The ERZs were established in 2007 and revised by the 2008 Informational Report and the 2009 Report to the number and status described below.

> ERZ 1: In Northeast Colorado, ERZ 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. The geography of this ERZ is similar to the way it was described in the 2007 Report, but it has been redrawn to provide clarity so that major metropolitan areas (particularly the greater Denver area) are not included in any ERZ.
>
> ERZ 2: ERZ 2 is in East Central Colorado, and includes all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa and Cheyenne Counties. The geography of this ERZ is also similar to that described in the 2007 Report but has been redrawn to remove the greater Denver area as well as parts of Colorado Springs.
>
> ERZ 3: ERZ 3 is in Southeast Colorado, and includes all of parts of Baca, Prowers, Kiowa, Crowley, Otero, Bent and Las Animas Counties. This ERZ is somewhat smaller than the ERZ 3 that was described in the 2007 Report; its western portion is now in ERZ 5, as is more fully described in the ERZ 5 description.
>
> ERZ 4: ERZ 4 is in the San Luis Valley, and includes all or parts of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. This ERZ is somewhat smaller than the ERZ 4 created for the 2007 Report, as it now includes only the San Luis Valley region, and does not include any of Wind Generation Development Area ("GDA") 8 which is now located wholly within the new ERZ 5.
>
> ERZ 5: ERZ 5 is in South-Central Colorado, and includes all or parts of Huerfano, Pueblo, Otero, Crowley, Custer and Las Animas Counties.

Figure 2.5-3 illustrates the five ERZs overlaid upon the wind and solar GDAs that were identified in the Senate Bill 07-091 Task Force Report.

Figure 2.5-3 Energy Resource Zones with Generation Development Areas



The SB07-100 project that is likely to be placed in service during the proposed Resource Acquisition Period (Pawnee-Daniels Park) is summarized below consistent with Commission Rule 3608(b). The project is described in more detail in the SB07-100 report filed by the Company on October 31, 2015 and Proceeding No. 14A-0287E.[9]

Table 2.5-2 SB07-100 Projects Likely to be In-Service During the RAP

Project	ERZ	CPCN Status	Currently Scheduled In-Service Date	Estimated Cost ($ Millions)	Injection Capability	Length (Miles)
Pawnee-Daniels Park 345 kV Transmission Project	1	Granted: April 2015	December 2022[10]	180	Estimated 1,000 MW	125

<u>Implemented SB07-100 Transmission Projects Since the 2011 ERP</u>

1. Pawnee – Smoky Hill 345 kV Transmission Project (ERZ 1)
   Description: This project was filed in the 2007 Report and consists of developing approximately 95 miles of 345 kV transmission between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project allows for approximately 500 MW of additional resources in ERZ 1, interconnected at or near the Pawnee and Missile-Site Substations. The Missile Site 345 kV substation bisects the Pawnee – Smoky Hill 345 kV Project.

   Status: An application for a CPCN was presented to the Commission for this project in October 2007. The CPCN for that project was approved by the Commission on February 26, 2009 (Decision No. C09-0048). The project was placed in service in June 2013.

2. Missile Site 345 kV Substation (ERZ 2)
   Description: The Missile Site 345 kV Substation expands the Missile Site 230 kV Switching Station to allow additional generator and transmission interconnections at the 345 kV voltage level. The

[9] In Re Application of Public Service Company of Colorado (A) For a Certificate of Public Convenience and Necessity for the Pawnee to Daniels Park 345 kV Transmission Project, and (B) For Specific Findings with Respect to EMF and Noise (Mar. 28, 2014).

[10] The Company has filed a petition with the Commission to move the in-service date from 2022 to 2019 (Proceeding No. 16V-0314E)

Substation bisects the Pawnee – Smoky Hill 345 kV Transmission Project. The Missile Site 345 kV Substation allows additional generation from ERZ 2. In addition to connecting the Pawnee – Smoky Hill 345 kV line, the station also allows for future 345 kV transmission connections. These will include connections to the Pawnee – Daniels Park 345 kV Project and potential future connections to high voltage transmission to the south, such as to Big Sandy and Lamar.

Status: Public Service submitted a petition for a declaratory order on April 16, 2010 (Docket No: 10D-240E) that an application for a CPCN is not required to expand the Missile Site substation, or in the alternative, application for a CPCN for the expansion of the Missile Site substation. The Commission issued an order on June 8, 2010 (Decision No. C10-0552) evaluating these filings and granting the CPCN for the expansion of the Missile Site Substation. The Missile site 345 kV substation has been completed with an in service date in 2013. Missile Site 345 kV Substation consists of several 345 kV terminations including one for a 600 MW wind project. The wind project is made up of three individual 200 MW projects of which the third project (Limon III) began operations in October of 2014.

Other Transmission Additions

The Company has plans for numerous transmission system facilities and upgrades to the Public Service system. Some were completed in 2015. Some projects are under construction. The planned transmission line and substation projects are as follows:

Transmission Facilities completed in 2015 and scheduled for completion in 2016:

1) Malta 230/115 kV transformer addition (Completed in 2015)
2) Leetsdale 230/115 kV transformer addition (Completed in 2015)
3) Mount Harris 138/69 kV transformer replacement (Completed in 2015)
4) Rosedale Substation interconnection (Completed in 2015)
5) Beaver Creek – Brush 115 kV line upgrade (Completed in 2015)
6) Monfort – DCP (Completed in 2015)
7) Rifle – Parachute 230 kV #2 line (To be completed in 2016)
8) Cherokee – Ridge 230kV Conversion (To be completed 2016)
9) Happy Canyon Substation (To be completed in 2016)

Transmission projects planned through 2022:

1) Avery Substation
2) Thornton Substation
3) Moon Gulch Substation

4) Bluestone Valley Substation
5) Southwest Weld Expansion Project (SWEP) Participation
6) Avon – Gilman 115 kV line
7) Ault – Cloverly 115/230 kV line
8) Milton – Rosedale 230 kV line
9) Weld – Rosedale 230 kV line
10) Pawnee-Daniels Park 345 kV Line

Please see Commission Proceeding Nos. 15M-0043E and 16M-0039E (2015 and 2016 Rule 3206 Filings) or Commission Proceeding No.16M-0063E (Rule 3627) 10-Year Transmission Plan for greater detail.

Transmission Injection Capability

LGIA and Transmission Planning Studies

Public Service performs transmission studies for Large Generator Interconnection Procedures("LGIP")requests. The LGIP requests are made to determine the feasibility, cost, time to construct and injection capability for the transmission system interconnection of an electric generating resource. The Company posts the results of these studies on its OASIS website.[11] The Company performs other transmission studies for purposes of transmission planning which determine similar information.

The transmission system is interconnected as a network and generation injection at one point on the system likely changes the injection capability at other points, e.g., generation injections at Pawnee could decrease the generation injection level at Missile Site and vice versa. The generation injection capability values provided below are approximations based on the stand-alone transmission studies performed for the LGIP requests in the past. Table 2.5-3 is not a comprehensive representation of the injection capability on the entire Public Service transmission system, but rather is limited to locations for which an LGIP request was received and analyzed or for which other transmission studies were performed for planning purposes. Furthermore, the MW injection capabilities listed do not necessarily represent the maximum injection capability at a particular location but instead represent either the MW value requested to be studied in the LGIP process or the MW value studied for planning purposes. The generation injection capability values can change when Public Service performs additional specific resource and resource portfolio transmission studies whether for resource evaluation or for an LGIP request or simply when conditions change on the system. Table 2.5-3 lists the study determined injection capabilities. In all locations a

[11] http ://www.rmao.com/wtpp/PUBLIC SERVICE_Studies.html

subsequent generator interconnection study will be required to determine future injection capability for a specific interconnection.

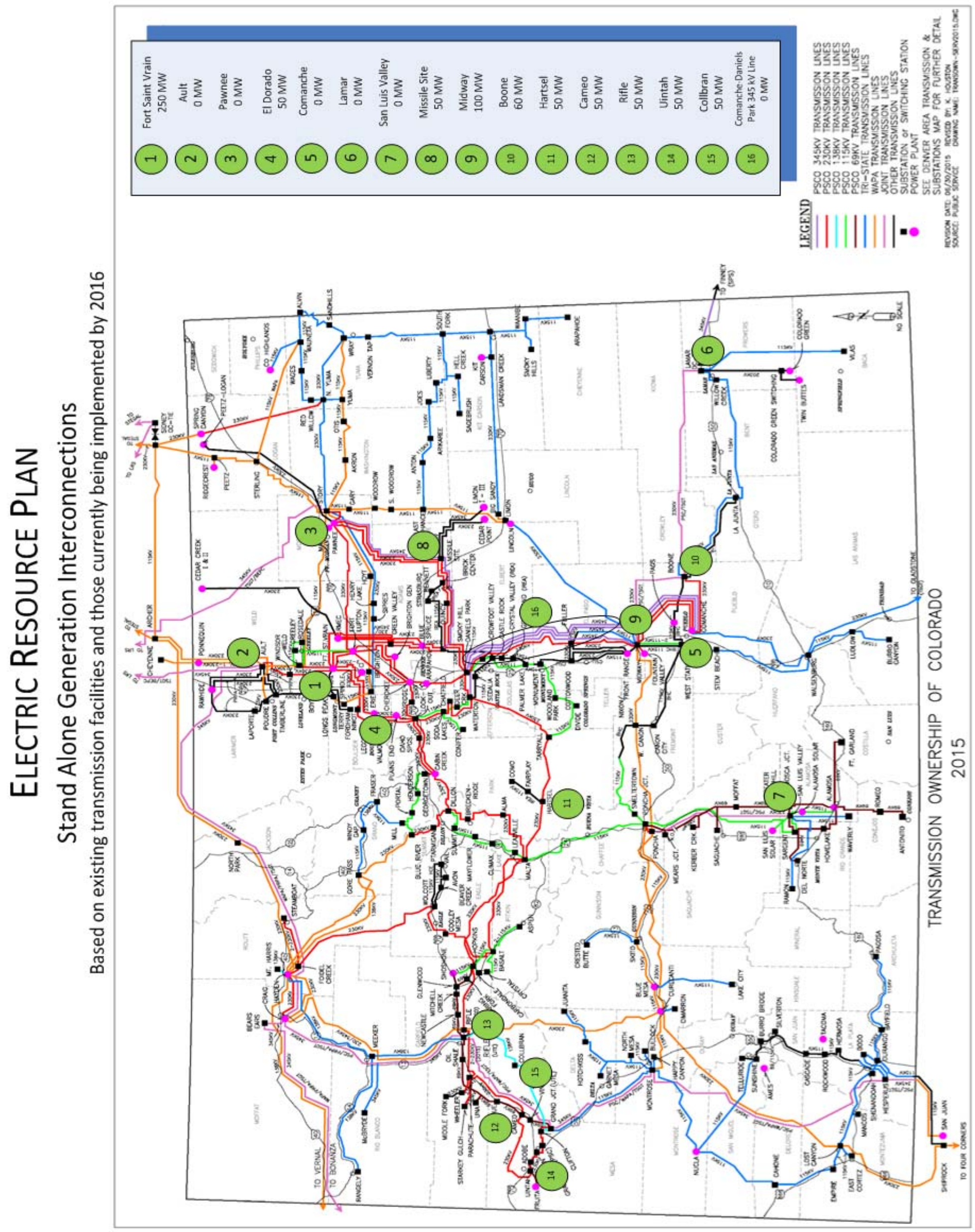
Table 2.5-3 Potential Injection Capabilities

Location	LGIP Study	Injection Capability (MW)	Time to Construct
Fort Saint Vrain 230 kV	G1-2008-29	250	18 months
Ault 230 kV	GI-2008-30	0	30 months
Pawnee 230 kV	GI-2010-5	0	48 months
El Dorado 115 kV	GI-2012-2	50	30 months
Lamar 230 kV	GI-2012-4	0	24 months
Comanche 230 kV	GI-2013-1	0	Not Available
San Luis Valley 115 KV	GI-2014-14	0	18 months
Missile Site 230 kV	GI-2014-5	50	18 months
Midway 115 kV	GI-2014-6	100	12 months
Boone 230 kV	GI-2014-8	60	18 months
San Luis Valley 230 kV	GI-2014-13	0	18 months
Boone 115 kV	GI-2014-12	53	18 months
Hartsel 230 kV	NQ-2014-1	50	Not Available
Cameo 230 kV	NQ-2014-1	50	Not Available
Rifle 230 kV	NQ-2014-1	50	Not Available
Uintah 230 kV	NQ-2014-1	50	Not Available
Collbran 138 kV	NQ-2014-1	50	Not Available
Comanche-Daniels Park 345 kV	GI-2015-1	0	Not Available
Missile Site 345 kV	GI-2016-3	0	24 months

The values in this table are based on the most recent LGIP studies performed consistent with the FERC LGIP. Public Service generally performs these studies on a stand-alone basis. Thus, for a given interconnection study, only the specified resource for that particular request is modeled; resources submitted in prior requests, sometimes referred to as lower queue number requests, are not included. Accordingly, this table should not be used to draw conclusions regarding the cumulative capability of any combination of stand-alone results. Moreover, one must take into account the fact that the results displayed only reflect the results achieved at the time the study was performed.

Figure 2.5-4 shows the injection points and values on a Public Service electric transmission system map.

Figure 2.5-4 Potential Injection Values and Locations



Transmission Service Agreements

Public Service is party to a number of transmission service or "wheeling" agreements that are not specifically tied to PPAs. For example, Public Service has a number of retail and wholesale load centers residing within the Platte River Power Authority ("PRPA"), Western Area Power Administration ("WAPA") and Tri-State Generation and Transmission Association ("Tri-State") systems, and acquires network integration transmission service from each of these utilities pursuant to their open access transmission tariffs ("OATT").

The vast majority of Public Service's owned and purchased resources are located within the Public Service transmission system and have no specific wheeling agreement associated with them. Rather, in accordance with the requirements of the FERC, the transmission function of Public Service maintains a list, posted on its OASIS website, of designated network resources that are delivered to the Public Service native load customers. This list is updated when a new resource has completed the required transmission study processes and placed in service, and when a PPA terminates or a generator is retired.

Public Service has a long-term firm point to point service agreement with the transmission function of Public Service for the purchase of 188 MW of transmission service from the San Juan/Four Corners/Shiprock region to the Craig switchyard. This path is used to purchase capacity and energy at the Four Corners/San Juan marketplace. This contract terminates on January 31, 2020, and may be renewed in accordance with the OATT.

Public Service also maintains short-term firm and non-firm transmission service agreements with over 30 transmission service providers, pursuant to the providers' OATTs. These agreements are not transaction specific and have no specified MW quantity or term. Rather, these "umbrella" agreements allow (and are required in order for) Public Service to request and purchase short-term transmission services via the providers' OASIS Internet home pages. Such purchased transmission services are used to transmit short-term purchased resources to the Public Service system, or to facilitate off-system sales.

In addition to Public Service's wheeling agreements, a few of the Company's firm utility PPAs have transmission service provisions contained within the PPAs. These transmission service provisions are not specific wheeling agreements per se; however, they do affect Public Service's ability to import power into its system and ability to use PPA resources. Currently, Public Service pays Tri-State for wheeling contract-associated capacity and energy. This contract terminates March 31, 2017.

Coordination Agreements

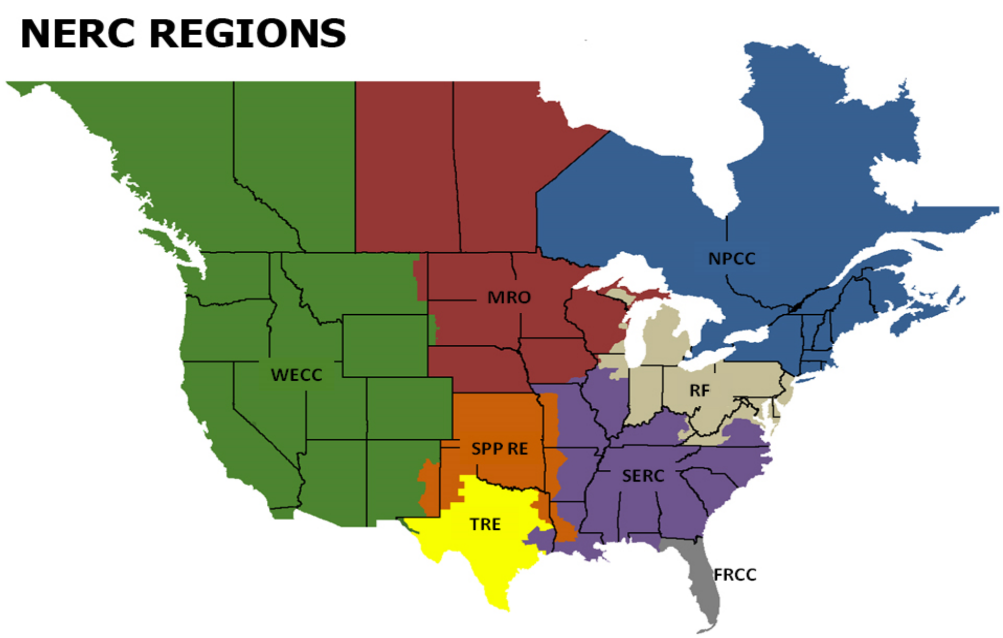
Public Service purchases short-term energy and capacity under two coordination agreements: the Western Systems Power Pool ("WSPP") Agreement and the Rocky Mountain Reserve Group ("RMRG") Agreement. The WSPP Agreement represents a marketing pool involving many supplier organizations throughout the United States. Many of Public Service's short-term firm and economy purchases are made under, and pursuant to the terms of, the WSPP Agreement. The RMRG Agreement provides for sharing of contingency operating reserves among interconnected electric utilities operating in the Rocky Mountain Region. There are presently nine members in the RMRG. By pooling their contingency reserves, these utilities are required to maintain less contingency reserve capacity than if they operated independently. Under the RMRG Agreement, Public Service can call on and purchase contingency reserves (spinning and non-spinning) and the energy associated with such reserves when they are activated in response to a sudden system disturbance. Typically the system disturbance is unplanned loss of generation. Public Service can also purchase emergency assistance under the RMRG Agreement.

2.6 RESERVE MARGINS AND CONTINGENCY PLANS

Planning Reserve Background

The reliability of the electrical system of North America is guided and coordinated by the North American Electric Reliability Corporation ("NERC"). NERC is comprised of eight separate regional entities.

Figure 2.6-1 Regional Reliability Councils of NERC



Public Service is a member of and regularly participates in the activities of the following groups:

- Western Electricity Coordinating Council ("WECC")
- Peak Reliability
- Rocky Mountain Reserve Group ("RMRG")
- WestConnect

The WECC is one of the eight current NERC regional councils established to promote the reliable operation of the interconnected bulk power system of the western United States and Canada. The WECC does not publish recommended or required planning reserve criteria for its member systems, but rather allows individual member systems (including regulatory Commissions) to adopt their own planning reserve criteria. WECC does, however, perform Power Supply Assessments ("PSA") of its member systems annually. The purpose of the PSAs is to identify WECC subregions that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. During these annual PSA reviews Public Service provides WECC with detailed information regarding the Company's electric supply system including:

- Generation rating data
- Actual and forecasts of demand
- Characteristics of demand
- General system data

WECC combines this data with that of other member systems to model the interconnected systems and assess the reliability for the upcoming summer and winter seasons.

As part of each PSA, the WECC determines both a summer and winter "building block" reserve margin ("BBM") for each subregion. These BBM targets are designed to represent the level of available generation resources required for each subregion to maintain acceptable system reliability. For each subregion, the seasonal BBM is determined by adding estimates for required Contingency Reserves, Regulating Reserves, Forced Outages, and Temperature Variation to the baseline demand (1 in 2) forecast.[12] In the most recently released PSA (2015), the WECC determined the BBM for the RMRG subregion to be 13.9% for summer and 11.9% for winter for the 2016 - 2025 study period[13]. This BBM does not reflect the planning reserve margins approved for use by individual utilities (including Public Service) and is not intended to supplant these approved planning reserve margins; however, it does provide a useful crosscheck for comparison.

Reliability Planning at Public Service

Public Service strives to provide electric service at all times to our firm customers. To accomplish this, the Company works to maintain an adequate supply of electric generation to meet the expected maximum demand of our customers (i.e., the "peak" demand or load) for a reasonable set of unforeseen events (power plant outages, higher than expected load etc.) To maintain service to firm customers, Public Service utilizes a combination of measures and practices, each focusing different time horizons - real-time, mid-term, and long-term.

[12] Details of this process can be found in the "Loads and Resources Data Manual" available at https://www.wecc.biz/ReliabilityAssessment/Pages/Default.aspx

[13] Report available at: https://www.wecc.biz/Reliability/2015PSA.pdf

Real-time

Ultimately it is the real-time status of the system that determines whether supply is sufficient to maintain service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system. These entail carrying sufficient operating reserves to ensure that ample resources are available to serve load. Operating reserves are generation capacity that is either on-line and unloaded, i.e., spinning, or that can be brought on-line and synchronized to the grid in short order.

As a member of the RMRG, Public Service carries operating reserves in accord with the RMRG established methodology. As of April 2016, Public Service's RMRG obligation for the summer of 2016 has been set at 418 MW. For long term planning, the slightly higher level of 420 MW is assumed based on historical obligation levels.

As a part of managing the real-time balance between load and generation on the system, the Company continuously monitors the current level of wind generation and ensures that a sufficient level of flexible resources are available to maintain system reliability in the case of a large wind ramping event. The level of flexible resources required for this purpose is a function of the amount of wind generation.

Operating Reserve is a general term used to define the combination of various reserves that are needed to perform in the duty of balancing generation and load. Operating Reserve for Public Service is made up of Contingency Reserve, Regulating Reserve, and Flex Reserve. Contingency Reserve is the reserve maintained to respond to the unplanned trip of generators. Contingency reserve is provided by resources that can respond very quickly to an event, within 10 minutes. Contingency reserves are split between spinning (i.e. connected to the grid) and non-spinning resources. The amount of contingency reserve that is to be carried by the Company is determined by the RMRG.

Regulating Reserve is the reserve maintained to intra-hour changes in load, non-VER generation output and VER, and it is also comprised of various types of service. The two types of regulating reserve are "fast moving reserve" and "load following reserve." To manage minute to minute changes in load, non-VER generation and VER on the system, Public Service carries fast-moving regulation reserve. To manage changes over a 15-minute period, the Company carries load following regulation reserve. The Company recently studied the amount of fast moving and load following regulating reserve required to reliably manage its system and has updated its Open Access Transmission Tariff accordingly.

The last type of Operating Reserve that Public Service carries on its system to maintain reliable service to customers is Flex Reserve. Flex Reserve is held on Public Service generating units to address the impacts of large downward ramping events caused by reductions in wind speed within the Public Service BAA. The Company determines the amount of Flex Reserve required to operate reliably with the wind it has, or will have, on its system. The calculation has evolved over time due to the increasing size of the wind generation on the system and our experience of performing efficient, reliable system dispatch with increasing levels of installed wind generation.

Mid-term

To better ensure sufficient resources are available to meet the real-time needs of the system, Public Service evaluates the need for short-term capacity and energy several months in advance of each summer and winter peak season. In the event that this mid-term supply adequacy evaluation determines that the installed or purchased generation for the upcoming summer or winter peak periods are likely insufficient to achieve desired reserve margin, the Company will pursue purchasing short-term capacity.

Long-term

Long-term activities involve the acquisition of additional generation resources or demand reduction to meet the long-term electric demand projections. The amount of installed generation capacity in excess of the annual system peak demand is commonly referred to as “planning reserve margin” or “planning reserves.” Long-term in this context refers to a future period up to 10 years (or longer) over which the Company acquires additional resources through the Commission’s ERP process. The reserve margin target used in the long-term planning of the system influences the Company’s ability to meet the future mid-term and, ultimately, the real-time capacity needs of the system. The remaining discussion will focus on the “planning reserve margin” Public Service proposes to employ in the acquisition of future resources in the 2016 ERP.

Planning Reserves for the 2016 ERP

For the 2016 ERP, Public Service proposes to utilize a planning reserve margin target of 16.3% in assessing the need for additional power supply resources. This 16.3% value will be applied to the Company’s projection of annual firm peak demand[14] over the RAP to determine the amount of additional power supply the Company should seek to acquire in this ERP in order to maintain acceptable long-term system reliability. The appropriateness of a 16.3% planning reserve target for the Public Service system was established through a collaborative study effort between the Commission Staff, the Office of Consumer Counsel, and the Company. The study determined that a 16.3% planning reserve margin for the Public Service system would result in a “loss of load

[14] Annual firm peak demand to which the 16.3% reserve margin target will be applied is represented by taking the 50th percentile forecast of total peak demand projection and subtracting the effects of the Company’s energy efficiency and firm interruptible load programs.

probability” (“LOLP”) of 1-day in 10-years, a common industry standard for an acceptable level of system reliability. A copy of the study is included for reference in Section 2.13 of Volume 2.

Contingency Plan

Public Service recognizes that matching electric generation with customer demand will not always proceed according to plan. Problems can arise as a result of delays in the in-service dates of new generation facilities, contract negotiations with suppliers can breakdown, and unanticipated increases in the customer demand can arise that Public Service is obligated to serve. While it is impossible to anticipate everything that can occur in the resource acquisition process, we can anticipate the more common contingencies and develop plans to address them. This section of the 2016 ERP identifies what the Company believes to be the most likely situations it might face in the resource acquisition process and identifies contingency alternatives available to Public Service to address them. The discussion will focus on events or situations that create the potential for a capacity shortfall if corrective action is not taken.

Contingency Events

We anticipate that the more relevant and probable contingency events will include, but are not limited to:

1. Failed contract negotiations with winning bidders
2. Bidders withdrawing proposals
3. Bidders seeking revised terms from those in their bid
4. Project development delays or cancellation
5. Transmission development delays
6. Higher than anticipated electric demand

Contingency Plan Options

The following is a list of options available to Public Service to remedy any unanticipated resource shortfall:

1. Initiate negotiations with other / replacement bidder(s)
2. Hold a targeted RFP to replace a selected project that has failed
3. Advance the in-service date of other selected projects
4. Purchase short-term capacity from off system, existing generation supplies
5. Issue additional non-targeted RFP(s) to satisfy anticipated shortfalls
6. Construct and own additional new generation capacity
7. Arrange temporary generation
8. Implement interim Load Management / Customer generation plans
9. Modify contracts with existing suppliers

10. Sole source with an IPP to construct additional generation
11. Increase Demand Side Management
12. Some combination of (1) through (11)

Critical Factors

Two critical factors dictate whether a corrective action provides a viable solution for a particular contingency event. These factors are:

1. The magnitude of the potential resource shortfall, and
2. The timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

The magnitude of an anticipated capacity shortfall dictates the available options Public Service can pursue. For example, a capacity shortfall of 50-100 MW might be addressed through contracting short-term purchases from existing generation supplies. Short-term capacity purchases would likely be ineffective in addressing a 500 MW shortfall.

Similarly, the timing of an anticipated capacity shortfall dictates the number of available options Public Service can pursue. Timing in this case includes both the duration of the shortfall and when it is expected to occur. Capacity shortfalls projected to occur within a year for example would likely exclude the option of constructing new generation and transmission facilities. By contrast, a capacity shortfall projected to occur several years in the future could be addressed through a variety of actions including new construction, initiating negotiations with other bidders or issuing an RFP.

Likewise, a delay of a new generation resource or of the transmission needed for a new resource might best be addressed by a temporary or interim solution, like temporary generation facilities, short-term purchases, or interim load management, as opposed to the permanent addition of another new generation project or new Company constructed and owned generation facilities – unless there were a long-term need for additional resources.

Corrective Actions

In the event Public Service faces a capacity shortfall situation, the appropriate course of action will depend largely on the specifics of the shortfall itself, i.e., magnitude and timing, as well as a variety of other factors, e.g., market conditions, other acquisition activities underway. As such, Public Service will always need to apply judgment as to how we should proceed when deciding what corrective action to pursue. For this reason, the Public Service contingency plan reflects a large degree of flexibility in how we plan to address various contingencies. Table 1.8-1, Hierarchy of Contingency Plan Alternatives, lists several possible approaches for addressing contingencies that might require corrective action over the acquisition period. This hierarchy depends on how long before the event Public Service becomes aware of the contingency, the expected duration of the contingency, e.g., a delay versus the permanent loss of a planned resource, and the magnitude of the contingency.

Table 2.6-1 Hierarchy of Contingency Plan Alternatives

1.	Short-term capacity purchases	Save for "late breaking" contingencies for which there might not be time to use one of the following corrective actions
2.	Use alternative bids	If the contingency becomes known before Public Service has released bidders from their obligation, Public Service would use this corrective action. This corrective action is most appropriate for replacing 1st winning bids that drop out soon after selection or do not reach successful contract completion.
3.	Accelerate in service date of resources for which contracts have been executed or for self-build projects already been approved	If the contingency becomes known sufficiently ahead of time, negotiate an earlier in service date for a resource planned for later in the acquisition period. This corrective action is most appropriate for a one to two year delay in another resource.
4.	Public Service builds back-up bids	If the contingency becomes known in time for Public Service to build its own facility, Public Service will self-build a facility to cover the contingency through the use of the back-up bid that will be filed with the Commission at the time the bids for the RFP are due to be submitted to the Company.
5.	Sole source with reliable supplier	This option could substitute for Public Service building its back-up bid if time does not permit the Company to complete the necessary construction in a timely manner. Effectively, Public Service would approach an IPP with whom it has had a good working relationship and sole source a new supply either from an existing facility or possibly an expansion of an existing facility..
6.	Install Temporary Generation	The Company or an IPP can implement this measure with somewhat less lead-time than the installation of new permanent generation and it is well suited to cover a generation project or transmission delay that may last a year or possibly two.
7.	Implement interim Load Management or Customer Generation Programs	Similar to the installation of temporary generation, this measure can be implemented in a relatively short lead-time, e.g. within 6 months, and is well suited to address resource delays.
8.	Reduced reserve margin	If the contingency became known too late to add new resources in time and insufficient short-term purchases were available to cover the contingency, Public Service could operate with a reduced planning reserve margin but with the required operating reserve margin for a summer season until one or a combination of the other corrective actions could be put into place.

Public Service and other Xcel Energy Inc. electric operating companies have successfully applied many of these contingency actions in the past. Xcel Energy Inc.'s other utility operating companies also have experience with many of these measures and Public Service can draw upon a wide range of resources, experience and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP for the 2016 ERP.

2.7 PHASE I PLAN DEVELOPMENT AND MODELING DETAILS

Strategist Model Description

Public Service used the Strategist electric utility planning model to represent the various costs of the Least-Cost Baseline Case and all alternative plans discussed in Volume 1 of this 2016 ERP.

Strategist is a computer based model specifically designed to represent the many characteristics of an electric utility's power supply system and to simulate economic dispatch of the generating resources in that system to meet customer demand for electric power (i.e., load) in the lowest cost manner. The model also has the capability to determine the least-cost mix of generation resources that should be added to an electric system to help serve future load growth. Public Service has used Strategist in developing its last three electric resource plans submitted to the Commission.

Strategist incorporates a wide range of variables that can be used to represent various types of electric generating facilities, e.g. coal, gas, wind, solar and storage facilities. Strategist contains four basic modules ("LFA," "GAF," "CER," "PROVIEW") that work in concert to simulate the operation of the existing units as well as the new units that are added to the system in future years to meet load growth. The model tracks and reports capital costs (and the associated revenue requirements), operations and maintenance costs, fuel costs, emissions and associated costs, integration costs for solar and wind and coal cycling costs.

Modeling Assumptions

On February 29, 2016 as required in Commission Decision No. C16-0127, the Company filed as Attachment A in Proceeding No. 16A-0138E, a summary of 32 key modeling assumptions for use in several interrelated proceedings. In that Attachment A, the Company also noted that several of the assumptions would be further clarified or updated in the 2016 ERP filing. This section summarizes the assumptions provided in the February 29th Attachment A filing and updates those assumptions which were identified as requiring an update in this ERP filing.

The Company's Attachment A filed in Proceeding No. 16A-0138E also indicated that several study reports supporting the assumptions would be filed at a later date. These study reports have been filed as follows:

- **Wind ELCC Study:** Filed in Proceeding No. 16A-0117E.
- **Coal Cycling Study:** Filed in Proceeding No. 16A-0117E.
- **Solar Integration Study:** Filed in 2016 ERP as Attachment KLS-1.
- **Solar ELCC Study:** Filed in 2016 ERP as Attachment KLS-2.

1. Capital Structure and Discount Rate

The rates shown in Table 1 are used to calculate the capital revenue requirements of generic resources. The after tax weighted average cost of capital ("WACC") of 6.78% is also used as the discount rate to determine the present value of revenue requirements.

Table 2.7-1 Capital Structure

Public Service			**Decision No. C15-0292**	
Component	Capital Structure	Allowed Return	Before Tax WACC	After Tax WACC
L-T Debt	44.00%	4.67%	2.05%	1.27%
Common Equity	56.00%	9.83%	5.50%	5.50%
Total	**100%**		**7.55%**	**6.78%**
Income Tax rate	38.01%			

2. Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of the latest market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates ("CERA") and Petroleum Industry Research Associates ("PIRA"). The four sources are combined to develop the composite forecast. Data from the various sources may not extend through the end of the modeling period. As the source data ends, the latest value is escalated at a GDP/inflation proxy rate to extend the forecast through the end of the modeling period.

For the basis differentials to Henry Hub of the various regional gas hubs needed for the analysis, the settlement price for the ICE-traded basis swap for the relevant hub is used. The last reported year's profile is extended through the modeling period.

While the forecasts themselves are proprietary, information regarding the three forecasting services can be found on their respective websites:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

The annual average base gas price and relevant sensitivities are summarized in Table 2.7-.2. Gas price sensitivities will be run in Phase I of the 2016 ERP. High and low gas price sensitivities adjust the growth rate up and down by 50 percent from the base gas price starting in year 2018.

Table 2.7-2 Fuel and Market Price Inputs

	CIG Rocky Mountain Gas Price Forecast ($/mmBtu)			4-Corners Electric Market Price Forecast ($/MWh)		Coal Price Forecast ($/mmBtu)
	Low	Base	High	On-Peak	Off-Peak	Base
2016	2.13	2.13	2.13	23.35	18.68	1.68
2017	2.46	2.46	2.46	26.80	22.79	1.73
2018	2.53	2.61	2.68	28.22	23.22	1.75
2019	2.64	2.83	3.02	30.81	24.27	1.80
2020	2.94	3.46	4.04	35.73	27.91	1.79
2021	3.12	3.88	4.77	36.49	28.48	1.84
2022	3.18	4.05	5.08	36.98	29.04	1.88
2023	3.26	4.24	5.44	37.46	29.57	1.92
2024	3.31	4.37	5.69	39.68	31.63	1.97
2025	3.37	4.53	6.00	41.21	33.33	2.01
2026	3.43	4.68	6.30	43.19	37.08	2.04
2027	3.51	4.91	6.76	44.72	38.52	2.08
2028	3.60	5.17	7.29	46.60	40.39	2.11
2029	3.68	5.40	7.78	48.75	42.53	2.16
2030	3.73	5.54	8.09	49.60	43.78	2.20
2031	3.82	5.81	8.69	52.11	45.99	2.25
2032	3.90	6.06	9.24	54.27	47.93	2.30
2033	3.96	6.25	9.67	55.88	49.40	2.35
2034	4.02	6.42	10.06	57.32	50.73	2.41
2035	4.07	6.58	10.44	58.59	52.11	2.47
2036	4.11	6.71	10.75	59.74	53.14	2.52
2037	4.15	6.84	11.08	60.92	54.19	2.58
2038	4.19	6.98	11.41	62.13	55.26	2.63
2039	4.23	7.12	11.75	63.35	56.35	2.70
2040	4.28	7.26	12.10	64.61	57.47	2.76
2041	4.32	7.41	12.47	65.88	58.60	2.83
2042	4.36	7.56	12.84	67.18	59.76	2.89
2043	4.41	7.71	13.23	68.51	60.94	2.96
2044	4.45	7.86	13.62	69.86	62.14	3.03
2045	4.49	8.02	14.03	71.24	63.37	3.11
2046	4.54	8.18	14.45	72.65	64.62	3.18
2047	4.58	8.34	14.89	74.08	65.90	3.25
2048	4.63	8.51	15.33	75.55	67.20	3.32
2049	4.68	8.68	15.79	77.04	68.52	3.39
2050	4.72	8.85	16.27	78.56	69.88	3.46
2051	4.77	9.03	16.75	80.11	71.26	3.53
2052	4.82	9.21	17.25	81.69	72.67	3.60
2053	4.87	9.39	17.77	83.31	74.10	3.67
2054	4.91	9.58	18.30	84.95	75.56	3.74

3. Gas Transportation Costs

A balancing fee of $0.0532 per MMBtu will be added to all generation resources not directly connected to the Colorado Interstate Gas High Plains Pipeline system.

4. Firm Fuel Charges

In the current 2017 RE Plan modeling, the Company applied a levelized charge of $6.16/kW-yr to generic gas fired resources to represent an estimate of the fixed costs associated with acquiring firm fuel supply to these generators either through firm gas supply or fuel oil backup infrastructure. The Company is currently examining this assumption and may provide an updated value in its 2016 ERP Phase I filing.

5. Market Prices

In addition to resources that exist within Colorado, the Company has access to markets located outside its service territory. External markets include Craig, Four Corners and the Southwest Power Pool (through the Lamar tie).

Market power prices are developed using a blend of market information from the NYMEX and fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Regional prices relevant to Public Service are not generally available publicly; therefore, regional prices used for modeling are based on Palo Verde forward prices, where publicly available price information exists, multiplied by a scalar regional price differentials developed using 1) 2 year historical linear regression model between Palo Verde and the regional hub and 2) fundamentally based forecasts where available. Prices at Palo Verde are based on the average of the implied heat rates from the Wood Mackenzie, CERA and PIRA forecasts multiplied by the natural gas Four-Source blend. If data from the various sources does not extend through the end of the modeling period, data is extrapolated as needed. As the source data ends, implied heat rates from the last year of each forecast are carried forward through the end of the modeling period.

Detailed information regarding the three forecasting services can be found on the respective websites for PIRA, CERA, and Wood Mackenzie, as discussed above. However, the forecasts are available only via paid subscription.

Annual average values for the Four Corners Market are summarized in Table 2.7-2.

6. Gas Price Volatility Mitigation ("GPVM") Adder

A GPVM Adder is added to the base natural gas forecast to account for potential volatility in the future price of natural gas for use in evaluating the total cost of a natural gas-fired generating facility. The Company is using $0.61/MMBtu which is the recent cost of an "at the money" NYMEX call option covering the 10-year period starting in 2016 as the proxy for a GPVM Adder. The utilization of the GPVM will be further discussed in Phase I of the 2016 ERP.

7. Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current coal contract volumes and prices combined with current estimates of required spot market coal volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed by averaging price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent RFP responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required. The simple average annual coal price forecast is summarized in Table 2.7-2.

8. Reserve Margin

As in the 2011 ERP, the Company will utilize the existing Planning Reserve Margin of 16.3% applied to the 50th Percentile demand forecast based on the Loss of Load Probability (LOLP) study completed by Ventyx and filed with the Commission in 2008. This study is provided for reference in Section 2.13 of Volume 2.

9. Surplus Capacity Credit

For the period up to the year in which the Company's loads and resources table shows firm generation capacity in excess of the planning reserve margin (i.e. the periods in which the Company is currently long capacity), surplus capacity will be credited $2.79/kW-mo up to an excess of 200 MW in the Phase I alternative plan analysis and during Phase II portfolio creation. The surplus capacity credit price is based on bids received by Southwestern Public Service for seasonal capacity for the 2011 summer season. This credit will be applied for the four summer months of June through September. After this period, surplus capacity credit for up to 500 MW will be priced at the cost of a generic combustion turbine for all twelve months of a year. The utilization of a Surplus Capacity Credit is discussed further in Section 2.11 of Volume 2.

10. Seasonal Capacity Purchases

The Company does not currently anticipate that Seasonal Capacity Purchases will play a part in the Phase I alternative plan analysis.

11. CO_2 Price Forecasts

Base modeling assumptions are a $0/ton CO_2 proxy price. Consistent with Decision No. C13-1566 in Proceeding No. 11A-869E (consolidated), the utilization of a CO_2 sensitivity case(s) is discussed further in Section 2.11 of Volume 2.

12. Inflation / Construction Escalation Rates

The inflation rate used for construction (capital) costs, non-fuel variable O&M, fixed O&M and any other escalation factor related to general inflationary trends is the long-term forecast from Global Insight for the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015. This rate is 2.0% and will be applied throughout the entire planning period as a base assumption.

13. Demand Side Management Forecasts

As directed by the Commission, the DSM goals approved in the 2013 Strategic Issues docket (Decision No. C14-0731) will be used in determination of the resource need in this 2016 ERP.

The approved Demand Reduction goals have two components:

1) An annual 65 MW target of Demand Reduction to be achieved through the Company's Energy Efficiency programs within the Company's DSM portfolio for 2015-2020, and
2) A remaining level of dispatchable Demand Reduction to be achieved through the Company's Demand Response programs (such as Saver's Switch and ISOC) for 2015-2020.

The 65 MW of required annual Energy Efficiency reductions are accounted for in the Company's load forecast. The remaining Demand Reduction levels (to be achieved through growth in the Company's dispatchable Demand Response programs) are subtracted directly from the Company's forecasted Obligation Load to determine resource need. A summary of the Demand Reduction target levels used to determine the resource need is summarized in Table 2.7-3:

Table 2.7-3: Demand Reduction Goals

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Dispatchable DR Goal (MW)	537	555	575	598	623	623	623	623	623	623

Since the specified goals currently only extend through 2020, the current assumption is that dispatchable Demand Response levels remain flat after 2020 for purposes of resource need determination.

14. Transmission Delivery Costs

Estimates of transmission delivery costs of the generic resources are included in the cost estimates in this 2016 ERP. In Phase II, the Company will allocate or assign transmission delivery costs on a pro-rata share of transmission upgrades needed for each individual Phase II bid. The Company will not assign transmission delivery costs to projects that will utilize existing transmission capacity or that will utilize transmission projects for which the Company has been granted a Certificate of Public Convenience and Necessity at the time of the bid evaluation. This is consistent with the approached used in the 2011 ERP and approved in Paragraph 237 of Decision No. C13-0094.

15. Transmission Interconnection Costs

Estimates of transmission interconnection costs of the generic resources are included in the cost estimates for this 2016 ERP.

16. ELCC Capacity Credit for Wind Resources

The ELCC of the Company's existing wind portfolio is assigned a rate of 16.0% based on the Company's most recent wind ELCC study. Incremental wind is assigned an ELCC rate dependent upon the level of the incremental wind (MW) and the location of the wind based on Table 2.7-4 below. Table 2.7-4 values are based on the Company's most recent wind ELCC study.

Table 2.7-4: Average ELCC to Apply to Incremental Wind

Incremental Wind (MW_AC)	Northern	Limon	Lamar
250	10.0%	9.8%	18.8%
500	9.7%	9.2%	16.9%
1000	9.1%	8.4%	14.0%

The Company has filed its most recent wind ELCC study report in Proceeding No. 16A-0117E. The wind ELCC study report is also attached for reference in Section 2.13 of Volume 2.

17. ELCC Capacity Credit for Solar Resources

The ELCC of the Company's existing utility-scale solar portfolio is assigned a rate of 55.0% (MW_AC basis) and the ELCC of the Company's existing distribution-interconnected solar portfolio is assigned a rate of 37.0% (MW_AC basis) based on the Company's most recent solar ELCC study. Incremental solar is assigned an ELCC rate dependent upon the level of the incremental solar generation (MW_AC), the location of the solar generation, and whether the generation can track or is mounted fixed based on Table 2.7-5 below. Table 2.7-5 values are based on the Company's most recent solar ELCC study. The solar ELCC study report is provided as Attachment KLS-2.

Table 2.7-5: Average ELCC to Apply to Incremental Solar

Incremental Solar (MW_AC)	Northern Front Range		San Luis Valley		Western Slope	
	Fixed	Tracking	Fixed	Tracking	Fixed	Tracking
50	37.0%					
100	37.0%	41.5%	43.5%	52.5%	41.5%	53.0%
250	35.8%	40.2%	42.2%	50.4%	41.0%	52.0%
500	33.9%	37.8%	39.1%	47.1%	39.0%	49.5%
1000	30.3%	33.2%				
1500	27.7%	29.1%				

18. Resource Acquisition Period

As discussed above, Public Service specifies an 8-year RAP that will run from May 2016 to May 2024, thereby addressing the summer peak needs of our system for years 2016 through 2023. In addition, for the 2017 RE Plan filing, the Company proposes programs to acquire additional resources for calendar years 2017-2019.

19. Planning Period

Planning Period means the future period for which a utility develops its ERP and the period over which net present value of revenue requirements for resources are calculated. Pursuant to Rule 3602(k), the planning period is 20 to 40 years and begins from the date the utility files its plan with the Commission. The planning period is from June 1, 2016 – June 1, 2054.

20. SO_2 Effluent Costs and Allocations

SO_2 is controlled through the Acid Rain program in Colorado. Through this program, the Company has excess SO_2 allowances because of the use of low sulfur coal and scrubber retrofits at the Arapahoe, Cherokee, Hayden, and Valmont units. Therefore, the Company does not anticipate that it will have to purchase any allowances for SO_2 under current or reasonably foreseeable legislation. In addition, Acid Rain allowances are trading for less than $1.00 per ton so the value of the excess allowances that the Company owns is very little. Therefore, the Company assigns no effluent costs or allocations to SO_2. SO_2 effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

21. NO_x Effluent Costs and Allocations

There is no trading program for sources of NO_x in Colorado; therefore, no cost is applied to NO_x emissions. The primary programs that reduce NO_x are the Regional Haze Rule through the application of the Best Available Retrofit Technology program, which seeks to achieve further reasonable progress towards long term visibility goals in Class I areas like national parks and wilderness areas. The Denver ozone State Implementation Plan ("SIP") is also another driver for NO_x reductions. As a result, the costs of NO_x reductions are embedded in capital and operating costs of the resources included in the SIP (e.g., the Selective Catalytic Reduction additions to Pawnee and Hayden). NO_x effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

22. Mercury Effluent Costs and Allocations

Mercury is also controlled as a command and control rule through the Colorado Mercury Rule. Therefore, there is no cap and trade for mercury either and effluent costs and allocations will be assigned a zero cost in the Phase I alternative plan analysis. As with SO_2 and NO_x, costs associated with controlling these emissions were captured in the resource costs. Mercury effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

23. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled was consistent with the Company's Rocky Mountain Reserve Group ("RMRG") requirements. The cost of spinning reserve was estimated in the Strategist model by assigning a spin requirement and the spinning capability of each resource.

The spinning reserve requirement is modeled as 210 MW consistent with the newest value from RMRG.

24. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at an arbitrary cost ($500/MWh) which is far above the cost of the most expensive resource. Emergency energy costs occur only in rare instances.

25. Dump Energy / Wind Curtailment Costs

When wind energy is curtailed within the Strategist model in order to maintain the balance between load and generation, the Company accounts for the potential lost Production Tax Credit ("PTC") value. These potential costs are captured by multiplying the levels of the "dump energy" variable in the model (which is assumed to be curtailed wind generation) times the grossed-up value of the PTC (PTC/(1-tax rate)).

26. Wind Integration Costs (**UPDATED**)

Wind integration costs are priced based upon the results of the *2 GW and 3 GW Wind Integration Cost Study* completed in August 2011 included for reference in Section 2.13 of Volume 2. Average annual wind integration costs applied in each of the scenarios considered in the Phase I analysis are presented in Table 2.7-6.

Table 2.7-6 Wind Integration Costs by Scenario

	UPDATED Average Wind Integration Costs ($/MWh by Scenario)[1]							
	Run 1[2]	Run 2[2]	Run 3	Run 4	Run 4A	Run 4B	Run 4C	Run 4D
2016	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93
2017	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93
2018	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93
2019	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93	$2.93
2020	$3.06	$3.09	$3.12	$3.09	$3.09	$3.09	$3.09	$3.09
2021	$3.30	$3.41	$3.49	$3.41	$3.41	$3.41	$3.41	$3.41
2022	$3.39	$3.53	$3.63	$3.53	$3.53	$3.53	$3.53	$3.53
2023	$3.50	$3.68	$3.80	$3.68	$3.68	$3.68	$3.68	$3.68
2024	$3.58	$3.78	$3.92	$3.78	$3.78	$3.85	$3.85	$3.85
2025	$3.67	$3.90	$4.06	$3.90	$3.90	$3.98	$3.98	$4.06
2026	$3.73	$3.99	$4.17	$3.99	$3.99	$4.08	$4.17	$4.26
2027	$3.84	$4.15	$4.35	$4.15	$4.15	$4.25	$4.45	$4.45
2028	$3.78	$4.01	$4.24	$4.01	$4.01	$4.48	$4.48	$4.60
2029	$3.89	$4.15	$4.41	$4.15	$4.15	$4.68	$4.68	$4.81
2030	$3.95	$4.21	$4.49	$4.21	$4.21	$4.78	$4.78	$5.06
2031	$4.07	$4.36	$4.67	$4.36	$4.36	$4.99	$4.99	$5.31
2032	$4.18	$4.28	$4.63	$4.28	$4.28	$5.32	$5.32	$5.67
2033	$4.26	$4.26	$4.55	$4.26	$4.26	$5.48	$5.67	$6.04
2034	$4.34	$4.34	$4.65	$4.34	$4.34	$5.63	$5.83	$6.22
2035	$4.41	$4.41	$4.58	$4.41	$4.41	$5.61	$6.23	$6.64
2036	$4.47	$4.47	$4.64	$4.47	$4.47	$5.72	$6.37	$6.79
2037	$4.53	$4.53	$4.53	$4.53	$4.53	$5.99	$6.66	$7.11
2038	$4.59	$4.59	$4.59	$4.59	$4.59	$6.11	$6.81	$7.27
2039	$4.65	$4.65	$4.65	$4.65	$4.65	$6.23	$6.95	$7.43
2040	$4.71	$4.71	$4.71	$4.71	$4.71	$6.34	$7.08	$7.58
2041		$4.78	$4.78	$4.78	$4.78	$6.41	$6.93	$7.45
2042		$4.84	$4.84	$4.84	$4.84	$6.53	$7.07	$7.60
2043		$4.91	$4.91	$4.91	$4.91	$6.66	$7.22	$7.77
2044			$4.98		$4.98	$6.79	$6.50	$7.08
2045					$5.05	$6.92	$6.63	$7.22
2046					$5.12	$7.06	$6.75	$7.37
2047					$5.19	$7.19	$6.87	$7.51
2048					$5.26	$7.32	$7.00	$7.65
2049					$5.34	$7.48	$6.80	$7.48
2050					$5.42	$7.63	$6.92	$7.63
2051					$5.49	$7.76	$6.68	$7.40
2052					$5.57	$7.91	$6.43	$7.54
2053					$5.66	$8.08	$6.16	$6.93
2054					$5.74	$8.23	$6.26	$7.05

(1) Represents the average cost applied to all applicable annual MWh of generation. Blank cells indicate no applicable generation in given year due to lack of long term "tail" assumption.

(2) Costs unchanged from results filed in Proceeding No. 16A-0173E

The wind integration cost study is included in Section 2.13 of Volume 2. In response to concerns raised by Commission Staff in Proceeding No. 16A-0138E, Public Service assumed a minimum gas price of $3.24/MMBtu (the minimum gas price studied in the original study) in determination of the wind integration costs in all scenarios. In addition, the Company is currently performing an expansion of the original study to measure the impact of higher levels of installed wind resources. This study will be filed upon completion in the 2016 ERP.

27. Wind Induced Coal Plant Cycling Costs (**UPDATED**)

For the 2017 RE Plan, wind-induced coal cycling costs were priced as described in *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study completed in August 2011 and updated in April 2013 (see Attachment 2.12-1 in the Company's 2011 ERP filing). The study addressed both coal plant cycling costs and wind curtailment costs. Wind curtailment costs are estimated within the Strategist model (see Assumption #25) and therefore, this component of cycling costs from the study was not included in the Strategist modeling

In Proceeding No. 16A-0117E, the Company has filed its most recent coal plant cycling study, which evaluates higher penetrations of wind and solar generation. The results of this study are used in the modeling in this 2016 ERP Phase I and will be used in the Phase II bid evaluation. The study report is included for reference in Section 2.13 of Volume 2. Updated average coal cycling costs applied in each scenario studied in the Phase I modeling are summarized in Table 2.7-7 below.

Table 2.7-7 Average Coal Cycling Costs by Scenario

	UPDATED							
	Average Coal Cycling Cost ($/MWh by Scenario)[1]							
	Run 1[2]	Run 2[2]	Run 3	Run 4	Run 4A	Run 4B	Run 4C	Run 4D
2016	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69
2017	$0.59	$0.59	$0.59	$0.59	$0.59	$0.59	$0.59	$0.59
2018	$0.24	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23	$0.23
2019	$0.19	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
2020	$0.17	$0.31	$0.37	$0.31	$0.31	$0.31	$0.31	$0.31
2021	$0.12	$0.27	$0.33	$0.28	$0.28	$0.28	$0.28	$0.28
2022	$0.14	$0.28	$0.35	$0.30	$0.30	$0.30	$0.30	$0.30
2023	$0.08	$0.22	$0.29	$0.24	$0.24	$0.24	$0.24	$0.24
2024	$0.08	$0.22	$0.28	$0.24	$0.24	$0.27	$0.27	$0.28
2025	$0.06	$0.20	$0.27	$0.23	$0.23	$0.26	$0.27	$0.33
2026	$0.06	$0.18	$0.27	$0.21	$0.21	$0.26	$0.31	$0.36
2027	$0.06	$0.18	$0.26	$0.22	$0.22	$0.26	$0.33	$0.36
2028	$0.02	$0.09	$0.17	$0.14	$0.14	$0.28	$0.32	$0.39
2029	$0.02	$0.08	$0.14	$0.12	$0.12	$0.24	$0.29	$0.38
2030	$0.03	$0.08	$0.14	$0.12	$0.12	$0.25	$0.32	$0.41
2031	$0.01	$0.05	$0.09	$0.08	$0.08	$0.18	$0.26	$0.34
2032		$0.02	$0.05	$0.05	$0.05	$0.20	$0.28	$0.36
2033		$0.01	$0.04	$0.05	$0.05	$0.21	$0.31	$0.36
2034		$0.00	$0.02	$0.02	$0.02	$0.13	$0.21	$0.26
2035		$0.01	$0.02	$0.02	$0.02	$0.10	$0.21	$0.27
2036			$0.01	$0.01	$0.01	$0.05	$0.14	$0.19
2037						$0.05	$0.13	$0.16
2038						$0.05	$0.13	$0.17
2039						$0.05	$0.13	$0.17
2040						$0.04	$0.13	$0.16
2041						$0.03	$0.09	$0.11
2042						$0.01	$0.03	$0.04
2043						$0.01	$0.03	$0.04
2044						$0.01	$0.03	$0.04
2045						$0.01	$0.02	$0.03
2046						$0.01	$0.02	$0.04
2047						$0.01	$0.02	$0.03
2048							$0.02	$0.04
2049							$0.01	$0.03
2050							$0.01	$0.03
2051							$0.01	$0.02
2052								$0.02
2053								$0.01
2054								$0.01

(1) Represents the average cost applied to all applicable annual MWh of generation. Blank cells indicate zero values.

(2) Costs unchanged from results filed in Proceeding No. 16A-0117E

28. Solar Integration Costs (**UPDATED**)

For the 2017 RE Plan, solar integration costs were priced upon the results of the *Solar Integration Study* completed in February 2009; see Attachment JFH-4 filed in Proceeding No. 16A-0055E. Updated average solar integration costs applied in Phase I modeling are summarized in Table 2.7-8 below.

Table 2.7-8 Average Solar Integration Costs (All Scenarios)

	UPDATED $/MWh (All Scenarios)
2016	$0.41
2017	$0.41
2018	$0.41
2019	$0.41
2020	$0.41
2021	$0.41
2022	$0.41
2023	$0.41
2024	$0.41
2025	$0.42
2026	$0.43
2027	$0.44
2028	$0.46
2029	$0.47
2030	$0.48
2031	$0.50
2032	$0.52
2033	$0.53
2034	$0.54
2035	$0.55
2036	$0.56
2037	$0.57
2038	$0.58
2039	$0.58
2040	$0.59
2041	$0.60
2042	$0.61
2043	$0.62
2044	$0.63
2045	$0.64
2046	$0.65
2047	$0.66
2048	$0.67
2049	$0.68
2050	$0.70
2051	$0.71
2052	$0.72
2053	$0.73
2054	$0.74

(1) Represents the average cost applied to all applicable annual MWh of generation. Solar Integration costs do not vary by scenario.

The Company has filed its most recent solar integration cost study report as Attachment KLS-1 in the 2016 ERP Phase I. The update study report evaluates: 1) higher penetrations of solar generation, and 2) lower gas costs than assumed in the 2009 study. The results of this most recent solar integration study will be used in the 2016 ERP Phase I modeling and Phase II bid evaluation.

29. Owned Unit Modeled Operating Characteristics and Costs

Company-owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of operating and cost inputs for each company-owned resource:

a. Maximum Capacity
b. Minimum Capacity Rating
c. Seasonal Deration
d. Heat Rate Profiles
e. Variable O&M
f. Fixed O&M
g. Maintenance Schedule
h. Forced Outage Rate
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
j. Contribution to spinning reserve
k. Fuel prices
l. Fuel delivery charges

30. Thermal PPA Operating Characteristics and Costs

Power Purchase Agreements (“PPA”) are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each thermal purchase power contract:

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

31. Renewable Energy PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each renewable energy purchase power contract:

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity Payments
g. Energy Payments
h. Integration Costs
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM if applicable

Integration and cycling costs will be updated as addressed elsewhere in this document.

32. Load Forecast

The same load forecast that was used in the 2017 RE Plan modeling was used in the Company's 2016 ERP Phase I analyses. A complete discussion of the load forecast and methodology is available in Section 2.2 of Volume 2, and a complete discussion of the resource need assessment is available in Section 1.4 of Volume 1. Table 2.7-9 below summarizes the Company's Phase I projection of resource need. This assessment includes the anticipated impact of the Company's proposed Rush Creek Wind Project (Proceeding No. 16A-0117E). A more detailed load and resource table is included in Section 2.12 of Volume 2.

Table 2.7-9 Public Service Resource Need Forecast

	2016	2017	2018	2019	2020	2021	2022	2023
Resource Need (MW)	0	0	0	0	0	0	(284)	(615)

Generic Resource Costs and Performance

In addition to modeling the existing electric system, generic resources are added to the model to serve future firm obligation load and to maintain an acceptable planning reserve margin as well as to meet energy needs in a cost effective manner. The cost and performance information for the generic resources included in the alternative plans are summarized in Tables 2.7-10, 2.7-11, and 2.7-12.

Table 2.7-10 Generic Dispatchable Resource Cost and Performance

Dispatchable Resources 1,2	2x1 CC [6,7]	1x1 CC [6,8]	Large CT [9]	LMS CT [10]	Aeroder. CT [11]
Nameplate Capacity (MW)	700	329	205	94	40
Summer Duct Firing Capacity (MW)	101	44	NA	NA	NA
Summer Peak Capacity (MW)	658	289	192	80	31
Fuel Source [3]	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Cooling	Dry	Dry	Dry	Dry	Dry
Capital Cost ($/kW) [4]	$843	$1,145	$610	$1,375	$1,988
Book Life	40	40	40	40	40
Fixed O&M Cost ($000/yr) [4]	$5,650	$3,421	$464	$640	$414
Variable O&M Cost ($/MWh)	$0.39	$0.44	$1.28	$1.17	$2.08
Ongoing Capital Expenditures	$3,509	$1,892	$1,692	$192	$110
Heat Rate with Duct Firing	7,839	NA	NA	NA	NA
Heat Rate 100 % Loading	6,925	8,492	9,955	9,146	9,635
Heat Rate ~75 % Loading	7,011	7,004	11,079	10,145	11,456
Heat Rate ~50 % Loading	7,149	7,391	14,661	11,761	14,904
Heat Rate ~30 % Loading	8,139	7,732	NA	16,092	23,291
Forced Outage Rate	3%	3%	3%	2%	3%
Maintenance (wks/yr)	3	3	2	2	2
Typical Capacity Factor	37%	37%	9%	10%	10%
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118

Notes:

(1) All Costs in year 2015 dollars

(2) Thermal unit cost and performance characteristics are from Xcel Energy Services and other sources such as CERA, EPRI, and EIA

(3) For all units, a firm fuel charge of $6.16/kW-yr (levelized) has been applied

(4) Estimates of generic capital and fixed O&M costs are based on the midpoint between the costs of a greenfield EPC facility and those of a brownfield facility. Brownfield costs are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. To estimate the midpoint costs for combined cycle units, greenfield capital and fixed O&M costs have beem reduced by 7.5% and 20% respectively from greenfield costs. To estimate the midpoint costs for combustion turbine units, greenfield capital and fixed O&M costs have been reduced by 12.5% and 20% respectively.

(5) For combined cycle units, modeled heat rates are the average of winter and summer values. For combustion turbine units, modeled heat rates represent the summer values.

(6) For all combined cycle units, a levelized $25/kW-yr charge has been applied to estimate transmission interconnection costs

(7) Based on Siemens 5000F 2x1 CC

(8) Based on GE 7FA 1x1 CC

(9) Based on Siemens 5000F SC

(10) Based on GE LMS 100

(11) Based on GE LMS 6000

Table 2.7-11 Total Capacity Costs of RAP Dispatchable Generic Resources

	Unit Fixed Costs ($/kW-mo)				
	2x1 Combined Cycle[2]	1x1 Combined Cycle[3]	Large CT[4]	LMS CT[5]	Aeroder. CT[6]
2015	$9.23	$12.38	$5.86	$12.03	$18.60
2016	$9.41	$12.63	$5.97	$12.26	$18.97
2017	$9.60	$12.89	$6.09	$12.51	$19.35
2018	$9.79	$13.15	$6.22	$12.76	$19.74
2019	$9.99	$13.41	$6.34	$13.02	$20.13
2020	$10.19	$13.67	$6.47	$13.28	$20.54
2021	$10.39	$13.94	$6.60	$13.54	$20.95
2022	$10.60	$14.23	$6.73	$13.81	$21.37
2023	$10.81	$14.51	$6.86	$14.09	$21.80
2024	$11.03	$14.80	$7.00	$14.37	$22.23
2025	$11.25	$15.10	$7.14	$14.66	$22.68
2026	$11.47	$15.40	$7.28	$14.95	$23.12
2027	$11.70	$15.71	$7.43	$15.25	$23.59
2028	$11.93	$16.02	$7.58	$15.55	$24.07
2029	$12.17	$16.34	$7.73	$15.87	$24.54
2030	$12.42	$16.67	$7.88	$16.18	$25.03
2031	$12.66	$17.00	$8.04	$16.51	$25.53
2032	$12.92	$17.34	$8.20	$16.84	$26.04
2033	$13.18	$17.69	$8.36	$17.18	$26.56
2034	$13.44	$18.05	$8.53	$17.52	$27.10
2035	$13.71	$18.41	$8.70	$17.87	$27.64
2036	$13.98	$18.77	$8.88	$18.23	$28.19
2037	$14.26	$19.15	$9.05	$18.59	$28.75
2038	$14.55	$19.53	$9.24	$18.96	$29.33
2039	$14.84	$19.92	$9.42	$19.34	$29.92
2040	$15.14	$20.32	$9.61	$19.73	$30.52
2041	$15.44	$20.72	$9.80	$20.12	$31.12
2042	$15.75	$21.14	$10.00	$20.53	$31.74
2043	$16.06	$21.56	$10.20	$20.94	$32.38
2044	$16.38	$21.99	$10.40	$21.36	$33.03
2045	$16.71	$22.44	$10.61	$21.78	$33.69
2046	$17.05	$22.88	$10.82	$22.21	$34.37
2047	$17.39	$23.34	$11.04	$22.66	$35.05
2048	$17.73	$23.81	$11.26	$23.12	$35.75
2049	$18.09	$24.29	$11.48	$23.58	$36.47
2050	$18.45	$24.77	$11.71	$24.05	$37.19
2051	$18.82	$25.27	$11.95	$24.53	$37.94
2052	$19.20	$25.77	$12.19	$25.02	$38.70
2053	$19.58	$26.28	$12.43	$25.52	$39.47
2054	$22.27	$26.81	$12.68	$26.04	$40.26

Notes:

(1) Capacity costs are based on summer ratings. All values are inclusive of FOM as well as transmission costs and firm fuel charges where applicable.

(2) Based on Siemens 5000F 2x1 CC

(3) Based on GE7FA 1x1 CC

(4) Based on Siemens 5000F SC

(5) Based on GE LMS 100

(6) Based on GE LMS 6000

Table 2.7-12 Generic Renewable Resource Cost and Performance

	RAP Renewables			Post - RAP Renewables	
Renewable Resources	**100% PTC Wind (1)**	**80% PTC Wind**	**30% ITC Solar**	**0% PTC Wind**	**10% ITC Solar**
Nameplate Capacity (MW)	600	400	50	200	50
ELCC Capacity Credit (%)	8.2%	9.0%	25.0%	9.0%	25.0%
Levelized Variable Cost ($/MWh) (2)	$28.68	$37.35	$53.82	$61.05	$61.62
Capital Cost ($/kW) in 2015 Dollars	$1,525 (3)	$1,450	$1,393	$1,450	$1,313
Transmission Cost ($/kW) in 2015 Dollars	$187	$92	$87	$92	$82
Capacity Factor	43.6%	41.5%	29.6%	41.5%	29.6%
Book Life (Years)	25	25	30	25	30
Assumed COD	2019	2020	2022	2023	2025

Notes:
(1) 100% PTC Wind cost and performance represented using the Rush Creek Wind Project
(2) Includes captial cost to construct & transmission to interconnect and deliver. Costs levelized over the book life.
(3) In 2019 Dollars

Projected Emissions

Tables 2.7-13 through 2.7-22 show the projected SO_2, NO_x, PM, Mercury, and CO_2 emissions from existing and generic resources.

Table 2.7-13 Projected SO_2 Emissions (Tons) From Existing Resources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	11,011	11,011	11,011	11,011	11,011	11,011	11,011	11,011	11,011	11,011	11,011
2017	9,170	9,170	9,170	9,170	9,170	9,170	9,170	9,170	9,170	9,170	9,170
2018	9,316	9,316	9,316	9,316	9,316	9,316	9,316	9,316	9,316	9,316	9,316
2019	7,518	7,453	7,455	7,456	7,457	7,453	7,453	7,453	7,453	7,453	7,453
2020	7,267	7,063	7,068	7,071	7,077	7,063	7,063	7,063	7,063	7,063	7,063
2021	7,818	7,614	7,620	7,623	7,628	7,427	7,579	7,579	7,579	7,579	7,579
2022	7,710	7,549	7,553	7,556	7,561	7,386	7,524	7,524	7,524	7,524	7,524
2023	7,634	7,485	7,489	7,492	7,494	7,336	7,430	7,430	7,430	7,430	7,430
2024	7,198	7,085	7,089	7,091	7,094	6,958	7,042	7,042	7,042	7,042	7,042
2025	7,218	7,120	7,124	7,126	7,129	6,991	7,081	7,081	7,009	7,009	6,975
2026	7,202	7,102	7,105	7,108	7,111	6,985	7,062	7,062	6,999	6,981	6,837
2027	7,214	7,125	7,135	7,137	7,140	7,011	7,082	7,082	7,021	6,911	6,782
2028	7,231	7,145	7,148	7,150	7,153	7,038	7,102	7,102	7,046	6,870	6,757
2029	7,274	7,230	7,231	7,232	7,234	7,159	7,201	7,201	6,999	6,904	6,674
2030	7,254	7,218	7,219	7,220	7,222	7,162	7,199	7,199	7,015	6,877	6,626
2031	7,255	7,224	7,226	7,226	7,228	7,171	7,204	7,204	7,033	6,870	6,566
2032	6,463	6,451	6,452	6,453	6,453	6,411	6,433	6,433	6,326	6,181	5,926
2033	6,482	6,475	6,476	6,476	6,477	6,454	6,465	6,465	6,302	6,132	5,864
2034	6,464	6,462	6,462	6,462	6,462	6,453	6,453	6,453	6,277	6,039	5,757
2035	5,550	5,552	5,552	5,552	5,552	5,551	5,550	5,550	5,462	5,310	5,094
2036	5,550	5,552	5,552	5,552	5,552	5,551	5,551	5,551	5,475	5,204	4,970
2037	4,547	4,549	4,549	4,549	4,549	4,548	4,549	4,551	4,517	4,339	4,164
2038	4,020	4,022	4,022	4,022	4,022	4,021	4,021	4,022	3,994	3,799	3,625
2039	4,022	4,023	4,023	4,023	4,024	4,022	4,023	4,023	3,988	3,788	3,629
2040	4,022	4,024	4,024	4,024	4,024	4,023	4,023	4,022	3,993	3,768	3,586
2041	3,923	3,925	3,925	3,925	3,925	3,924	3,924	3,925	3,901	3,685	3,521
2042	3,805	3,807	3,807	3,807	3,807	3,805	3,806	3,807	3,788	3,635	3,517
2043	1,374	1,376	1,376	1,376	1,376	1,375	1,375	1,376	1,374	1,344	1,313
2044	1,373	1,376	1,376	1,376	1,376	1,374	1,375	1,375	1,373	1,347	1,319
2045	1,377	1,381	1,381	1,381	1,381	1,380	1,380	1,379	1,376	1,358	1,335
2046	1,373	1,377	1,377	1,377	1,377	1,377	1,376	1,375	1,372	1,356	1,334
2047	1,373	1,377	1,377	1,377	1,377	1,377	1,376	1,376	1,373	1,359	1,336
2048	1,374	1,377	1,377	1,377	1,377	1,377	1,376	1,376	1,374	1,359	1,338
2049	1,378	1,382	1,382	1,382	1,382	1,382	1,381	1,380	1,378	1,365	1,343
2050	1,374	1,375	1,375	1,375	1,375	1,375	1,374	1,373	1,374	1,362	1,338
2051	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,372	1,374	1,368	1,345
2052	1,368	1,368	1,368	1,368	1,368	1,368	1,367	1,368	1,368	1,366	1,345
2053	1,372	1,372	1,372	1,372	1,372	1,372	1,372	1,373	1,372	1,372	1,357
2054	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,369	1,368	1,368	1,364

Table 2.7-14 Projected SO2 Emissions (Tons) from Generic Resources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	2	1	1	1	1	1	1	1	1	1	1
2024	5	3	3	3	3	3	2	2	2	2	2
2025	6	5	5	5	5	4	4	4	3	3	3
2026	6	6	6	6	6	5	4	4	4	4	3
2027	7	7	7	7	7	6	5	5	5	4	3
2028	10	15	15	15	15	12	11	11	10	7	6
2029	52	39	40	40	40	68	70	70	43	36	27
2030	74	48	49	49	49	97	100	100	64	50	39
2031	81	53	54	54	54	104	108	108	70	54	40
2032	59	74	75	75	76	73	76	76	94	71	52
2033	67	54	54	54	55	82	87	87	104	78	58
2034	80	55	56	56	56	98	105	105	106	73	56
2035	80	97	98	98	99	92	99	99	96	120	92
2036	76	108	109	110	110	88	94	94	91	107	84
2037	75	98	98	99	99	81	87	145	140	96	124
2038	87	118	118	119	120	97	105	120	158	89	131
2039	108	148	149	149	150	120	132	132	160	92	134
2040	116	159	160	161	162	130	142	120	171	93	137
2041	94	123	124	124	125	100	111	122	119	108	98
2042	108	143	144	143	143	117	128	157	126	134	109
2043	156	196	197	198	199	168	181	213	171	183	152
2044	132	172	173	173	174	147	158	169	154	166	138
2045	142	223	223	223	223	190	204	200	166	211	175
2046	152	240	240	240	240	240	220	215	178	226	188
2047	157	250	250	250	250	250	229	224	186	235	195
2048	163	261	261	261	261	261	238	232	193	244	203
2049	169	271	271	271	271	271	247	225	201	252	210
2050	180	200	200	200	200	200	184	167	212	200	168
2051	187	188	188	188	188	188	180	150	220	196	164
2052	193	193	193	193	193	193	186	219	224	214	179
2053	184	184	184	184	184	184	184	238	214	223	175
2054	191	191	191	191	191	191	191	248	223	248	206

Table 2.7-15 Projected NO_x Emissions (Tons) from Existing Sources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	20,690	20,690	20,690	20,690	20,690	20,690	20,690	20,690	20,690	20,690	20,690
2017	15,959	15,959	15,959	15,959	15,959	15,959	15,959	15,959	15,959	15,959	15,959
2018	15,101	15,101	15,101	15,101	15,101	15,101	15,101	15,101	15,101	15,101	15,101
2019	11,508	11,378	11,381	11,383	11,384	11,378	11,378	11,378	11,378	11,378	11,378
2020	11,437	10,919	10,930	10,937	10,948	10,919	10,919	10,919	10,919	10,919	10,919
2021	11,736	11,251	11,262	11,269	11,279	10,930	11,134	11,134	11,134	11,134	11,134
2022	11,730	11,264	11,274	11,281	11,290	10,954	11,150	11,150	11,150	11,150	11,150
2023	11,554	11,019	11,030	11,037	11,047	10,711	10,792	10,792	10,792	10,792	10,792
2024	9,413	9,540	9,555	9,563	9,574	9,200	9,272	9,272	9,272	9,272	9,272
2025	9,408	9,717	9,730	9,737	9,750	9,350	9,432	9,432	9,245	9,245	9,124
2026	9,428	9,746	9,760	9,768	9,781	9,383	9,456	9,456	9,284	9,220	8,856
2027	9,493	9,836	9,853	9,861	9,877	9,472	9,546	9,546	9,367	9,059	8,769
2028	9,669	10,089	10,103	10,112	10,126	9,715	9,797	9,797	9,607	9,081	8,813
2029	9,250	9,130	9,134	9,137	9,141	9,136	9,210	9,210	8,801	8,623	8,263
2030	9,147	9,008	9,012	9,015	9,019	9,027	9,088	9,088	8,740	8,517	8,136
2031	9,156	9,026	9,030	9,032	9,036	9,049	9,106	9,106	8,770	8,504	8,051
2032	8,556	8,581	8,585	8,587	8,589	8,494	8,539	8,539	8,396	8,126	7,707
2033	8,490	8,448	8,450	8,451	8,453	8,438	8,461	8,461	8,198	7,939	7,536
2034	8,474	8,428	8,430	8,430	8,431	8,444	8,454	8,454	8,156	7,793	7,371
2035	6,879	6,904	6,905	6,906	6,906	6,885	6,895	6,895	6,746	6,551	6,223
2036	6,878	6,912	6,913	6,914	6,915	6,885	6,894	6,894	6,764	6,400	6,048
2037	4,684	4,725	4,726	4,727	4,727	4,702	4,708	4,767	4,700	4,439	4,262
2038	4,410	4,449	4,450	4,451	4,451	4,426	4,432	4,444	4,413	4,099	3,916
2039	4,438	4,473	4,474	4,475	4,475	4,449	4,456	4,456	4,406	4,090	3,922
2040	4,444	4,481	4,482	4,482	4,483	4,459	4,465	4,439	4,421	4,061	3,872
2041	3,895	3,931	3,931	3,932	3,933	3,909	3,917	3,930	3,879	3,610	3,421
2042	3,390	3,422	3,423	3,426	3,427	3,402	3,408	3,432	3,369	3,207	3,064
2043	1,491	1,527	1,528	1,529	1,530	1,504	1,510	1,535	1,497	1,468	1,413
2044	1,466	1,520	1,521	1,521	1,522	1,495	1,502	1,510	1,484	1,462	1,406
2045	1,455	1,529	1,529	1,529	1,529	1,505	1,511	1,500	1,464	1,470	1,423
2046	1,449	1,518	1,518	1,518	1,518	1,518	1,501	1,491	1,455	1,461	1,416
2047	1,455	1,523	1,523	1,523	1,523	1,523	1,507	1,495	1,459	1,466	1,422
2048	1,460	1,525	1,525	1,525	1,525	1,525	1,512	1,499	1,464	1,470	1,426
2049	1,470	1,534	1,534	1,534	1,534	1,534	1,521	1,497	1,472	1,478	1,435
2050	1,467	1,478	1,478	1,478	1,478	1,478	1,464	1,449	1,473	1,450	1,406
2051	1,471	1,470	1,470	1,470	1,470	1,470	1,462	1,434	1,474	1,453	1,409
2052	1,395	1,395	1,395	1,395	1,395	1,395	1,389	1,406	1,400	1,393	1,357
2053	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,418	1,401	1,405	1,367
2054	1,394	1,394	1,394	1,394	1,394	1,394	1,394	1,419	1,400	1,410	1,387

Table 2.7-16 Projected NOx Emissions (Tons) from Generic Sources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	2	0	0	0	0	0	0	0	0	0	0
2023	7	5	5	5	5	5	2	2	2	2	2
2024	50	14	14	14	14	12	9	9	9	9	9
2025	60	22	22	22	23	18	15	15	14	14	12
2026	62	25	25	25	25	21	17	17	16	15	11
2027	66	30	31	31	31	25	22	22	20	17	13
2028	83	62	63	63	64	49	48	48	42	30	25
2029	281	207	209	210	212	284	293	293	181	148	113
2030	373	255	257	258	260	403	416	416	268	207	165
2031	404	277	279	280	282	433	450	450	292	223	166
2032	359	372	375	377	379	348	364	364	394	296	218
2033	409	327	329	331	333	403	424	424	432	324	242
2034	473	349	351	353	355	473	502	502	443	306	235
2035	551	560	563	565	569	517	548	548	450	499	382
2036	550	610	613	615	619	514	542	542	444	447	349
2037	603	629	632	634	637	547	574	769	658	447	517
2038	683	735	739	741	746	637	675	727	732	427	545
2039	780	868	873	875	879	747	796	796	738	438	558
2040	818	917	922	925	929	788	840	737	786	443	569
2041	781	828	831	833	837	724	770	747	625	505	447
2042	862	933	937	932	936	817	863	901	666	622	508
2043	1,215	1,304	1,309	1,312	1,316	1,180	1,234	1,287	1,001	955	808
2044	1,139	1,236	1,239	1,241	1,244	1,123	1,171	1,128	958	910	775
2045	1,186	1,455	1,455	1,455	1,455	1,312	1,373	1,259	1,002	1,113	945
2046	1,228	1,527	1,527	1,527	1,527	1,527	1,439	1,325	1,058	1,177	1,001
2047	1,253	1,568	1,568	1,568	1,568	1,568	1,477	1,362	1,091	1,215	1,033
2048	1,279	1,614	1,614	1,614	1,614	1,614	1,514	1,399	1,124	1,253	1,066
2049	1,308	1,658	1,658	1,658	1,658	1,658	1,554	1,367	1,158	1,292	1,099
2050	1,354	1,423	1,423	1,423	1,423	1,423	1,351	1,177	1,204	1,131	974
2051	1,384	1,389	1,389	1,389	1,389	1,389	1,353	1,118	1,242	1,134	976
2052	1,468	1,469	1,469	1,469	1,469	1,469	1,433	1,415	1,316	1,268	1,097
2053	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,501	1,287	1,332	1,097
2054	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,547	1,328	1,444	1,246

Table 2.7-17 Projected PM Emissions (Tons) from Existing Sources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	505	505	505	505	505	505	505	505	505	505	505
2017	545	545	545	545	545	545	545	545	545	545	545
2018	544	544	544	544	544	544	544	544	544	544	544
2019	554	542	542	543	543	542	542	542	542	542	542
2020	575	528	529	530	531	528	528	528	528	528	528
2021	590	543	544	545	546	513	532	532	532	532	532
2022	595	550	552	552	553	521	541	541	541	541	541
2023	606	561	562	563	564	532	541	541	541	541	541
2024	617	587	588	588	589	558	568	568	568	568	568
2025	620	592	593	593	594	563	573	573	558	558	547
2026	622	595	596	597	598	566	576	576	561	556	526
2027	627	602	603	603	604	573	583	583	568	543	518
2028	636	615	616	616	617	586	595	595	580	540	519
2029	633	608	608	609	610	609	617	617	564	542	504
2030	634	605	606	607	607	608	617	617	566	538	498
2031	636	609	610	610	611	612	620	620	570	537	490
2032	588	588	588	589	589	573	579	579	556	521	476
2033	593	577	577	577	578	582	587	587	548	513	467
2034	600	580	580	581	581	592	597	597	546	498	453
2035	523	536	537	537	538	529	533	533	510	496	454
2036	520	542	542	542	543	527	531	531	510	476	434
2037	463	484	485	485	485	471	475	508	492	438	426
2038	453	475	476	476	477	462	466	473	476	409	402
2039	467	489	489	490	490	476	479	479	475	409	402
2040	472	493	494	494	495	480	484	470	480	405	397
2041	451	473	473	473	474	460	464	471	458	413	383
2042	457	479	479	480	481	466	470	484	459	433	400
2043	316	336	336	337	337	323	327	340	320	314	294
2044	303	332	332	332	333	318	322	327	315	310	290
2045	303	347	347	347	347	334	337	332	311	322	303
2046	306	348	348	348	348	348	339	333	312	322	304
2047	309	351	351	351	351	351	341	336	315	325	306
2048	312	353	353	353	353	353	344	338	317	327	308
2049	316	356	356	356	356	356	347	336	320	330	311
2050	319	326	326	326	326	326	317	308	323	313	296
2051	321	320	320	320	320	320	316	298	323	312	294
2052	250	250	250	250	250	250	247	256	253	250	238
2053	248	248	248	248	248	248	248	261	252	254	240
2054	250	250	250	250	250	250	250	263	253	258	248

Table 2.7-18 Projected PM Emissions (Tons) from Generic Sources

	Alternative Plan										
Year	1	2	2A	2B	2C	3	4	4A	4B	4C	4D
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	1	1	1	1	1	1	0	0	0	0	0
2024	27	2	2	2	2	2	1	1	1	1	1
2025	32	3	3	3	3	2	2	2	2	2	2
2026	33	3	3	3	3	3	2	2	2	2	2
2027	35	4	4	4	4	3	3	3	3	2	2
2028	39	8	8	9	9	7	6	6	6	4	3
2029	81	58	59	59	59	38	40	40	25	20	15
2030	95	71	72	72	72	54	56	56	36	28	22
2031	100	75	76	76	76	58	61	61	39	30	22
2032	127	93	93	94	94	79	82	82	53	40	29
2033	145	115	116	116	117	95	99	99	58	44	33
2034	159	129	130	130	131	108	113	113	60	41	32
2035	224	183	183	184	184	163	168	168	96	67	52
2036	234	191	192	192	193	172	177	177	104	60	47
2037	283	238	238	239	239	218	224	217	139	92	70
2038	313	268	269	269	270	248	254	253	149	95	74
2039	333	291	292	293	293	270	277	277	150	97	75
2040	340	299	300	300	301	277	284	263	157	97	77
2041	373	329	330	330	331	308	315	265	173	107	88
2042	401	358	359	359	359	337	344	293	188	127	106
2043	552	511	512	513	513	489	497	448	333	261	229
2044	561	524	524	525	525	503	510	443	347	275	242
2045	569	560	560	560	560	537	545	465	350	311	275
2046	576	569	569	569	569	569	554	474	359	320	285
2047	581	575	575	575	575	575	560	480	365	327	290
2048	586	582	582	582	582	582	566	486	371	333	296
2049	592	590	590	590	590	590	573	481	377	339	302
2050	599	599	599	599	599	599	584	491	384	356	320
2051	605	605	605	605	605	605	598	492	392	370	334
2052	655	655	655	655	655	655	646	538	441	430	389
2053	662	662	662	662	662	662	662	555	446	456	402
2054	667	667	667	667	667	667	667	561	453	477	434

Table 2.7-19 Projected Mercury Emissions (lbs) from Existing Resources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	150	150	150	150	150	150	150	150	150	150	150
2017	142	142	142	142	142	142	142	142	142	142	142
2018	148	148	148	148	148	148	148	148	148	148	148
2019	140	139	139	139	139	139	139	139	139	139	139
2020	132	129	129	129	129	129	129	129	129	129	129
2021	142	139	139	139	139	135	138	138	138	138	138
2022	138	135	135	135	135	132	135	135	135	135	135
2023	138	136	136	136	136	133	135	135	135	135	135
2024	139	137	137	137	137	135	136	136	136	136	136
2025	139	137	138	138	138	135	137	137	136	136	135
2026	139	137	137	137	137	135	136	136	135	135	133
2027	139	137	138	138	138	135	137	137	136	134	132
2028	139	138	138	138	138	136	137	137	136	133	131
2029	140	139	139	139	139	138	139	139	136	134	130
2030	140	139	139	139	139	138	139	139	136	133	129
2031	140	139	139	139	139	138	139	139	136	133	128
2032	133	133	133	133	133	132	133	133	131	128	123
2033	134	134	134	134	134	133	133	133	130	127	122
2034	133	133	133	133	133	133	133	133	130	125	120
2035	112	112	112	112	112	112	112	112	110	107	103
2036	112	112	112	112	112	112	112	112	110	105	101
2037	100	100	100	100	100	100	100	100	99	96	92
2038	96	96	96	96	96	96	96	96	95	91	86
2039	96	96	96	96	96	96	96	96	95	90	87
2040	96	96	96	96	96	96	96	96	95	90	86
2041	96	96	96	96	96	96	96	96	95	90	86
2042	96	96	96	96	96	96	96	96	95	91	89
2043	42	42	42	42	42	42	42	42	42	41	40
2044	42	42	42	42	42	42	42	42	42	41	40
2045	42	42	42	42	42	42	42	42	42	41	41
2046	42	42	42	42	42	42	42	42	42	41	41
2047	42	42	42	42	42	42	42	42	42	41	41
2048	42	42	42	42	42	42	42	42	42	41	41
2049	42	42	42	42	42	42	42	42	42	41	41
2050	42	42	42	42	42	42	42	42	42	41	41
2051	42	42	42	42	42	42	42	42	42	42	41
2052	42	42	42	42	42	42	42	42	42	42	41
2053	42	42	42	42	42	42	42	42	42	42	41
2054	42	42	42	42	42	42	42	42	42	42	42

Table 2.7-20 Projected Mercury Emissions (lbs) from Generic Resources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0	0
2051	0	0	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0	0	0

Table 2.7-21 Projected CO_2 Emissions (Tons) from Existing Resources

	Alternative Plan										
Year	**1**	**2**	**2A**	**2B**	**2C**	**3**	**4**	**4A**	**4B**	**4C**	**4D**
2016	25,155	25,155	25,155	25,155	25,155	25,155	25,155	25,155	25,155	25,155	25,155
2017	22,868	22,868	22,868	22,868	22,868	22,868	22,868	22,868	22,868	22,868	22,868
2018	23,202	23,202	23,202	23,202	23,202	23,202	23,202	23,202	23,202	23,202	23,202
2019	22,040	21,699	21,707	21,712	21,718	21,699	21,699	21,699	21,699	21,699	21,699
2020	22,057	20,725	20,755	20,773	20,802	20,725	20,725	20,725	20,725	20,725	20,725
2021	23,049	21,705	21,735	21,754	21,783	20,840	21,404	21,404	21,404	21,404	21,404
2022	23,250	21,934	21,964	21,983	22,011	21,080	21,639	21,639	21,639	21,639	21,639
2023	23,241	21,923	21,953	21,971	21,997	21,078	21,342	21,342	21,342	21,342	21,342
2024	21,793	21,430	21,459	21,477	21,505	20,585	20,855	20,855	20,855	20,855	20,855
2025	21,766	21,576	21,606	21,623	21,652	20,730	21,006	21,006	20,570	20,570	20,273
2026	21,803	21,641	21,670	21,689	21,717	20,803	21,074	21,074	20,649	20,499	19,618
2027	21,950	21,830	21,864	21,882	21,910	20,993	21,260	21,260	20,835	20,109	19,384
2028	22,120	22,012	22,040	22,057	22,084	21,201	21,461	21,461	21,050	19,926	19,312
2029	21,933	21,389	21,404	21,416	21,433	21,420	21,644	21,644	20,303	19,729	18,690
2030	21,744	21,154	21,170	21,180	21,194	21,199	21,406	21,406	20,199	19,483	18,403
2031	21,789	21,222	21,238	21,248	21,262	21,283	21,473	21,473	20,306	19,460	18,160
2032	20,190	20,221	20,236	20,242	20,255	19,880	20,036	20,036	19,504	18,627	17,416
2033	20,215	19,904	19,914	19,921	19,934	19,970	20,082	20,082	19,148	18,277	17,076
2034	20,291	19,935	19,944	19,949	19,956	20,126	20,210	20,210	19,063	17,865	16,651
2035	17,284	17,521	17,531	17,536	17,543	17,382	17,458	17,458	16,919	16,440	15,387
2036	17,252	17,607	17,616	17,622	17,630	17,360	17,432	17,432	16,950	15,940	14,858
2037	14,312	14,685	14,693	14,698	14,706	14,467	14,526	15,091	14,760	13,583	13,129
2038	13,603	13,990	13,998	14,002	14,009	13,764	13,823	13,947	13,949	12,496	12,128
2039	13,854	14,221	14,228	14,234	14,242	13,991	14,054	14,055	13,923	12,490	12,146
2040	13,927	14,294	14,302	14,306	14,316	14,076	14,133	13,897	14,013	12,383	11,986
2041	13,180	13,544	13,553	13,557	13,565	13,329	13,400	13,522	13,255	12,171	11,438
2042	12,860	13,214	13,223	13,243	13,251	13,003	13,065	13,310	12,843	12,190	11,475
2043	6,290	6,636	6,644	6,649	6,657	6,422	6,477	6,705	6,355	6,235	5,873
2044	6,064	6,569	6,575	6,578	6,584	6,330	6,395	6,480	6,260	6,166	5,804
2045	6,035	6,776	6,776	6,776	6,776	6,552	6,605	6,512	6,161	6,327	5,990
2046	6,062	6,772	6,772	6,772	6,772	6,772	6,608	6,511	6,158	6,319	5,991
2047	6,118	6,818	6,818	6,818	6,818	6,818	6,656	6,554	6,198	6,358	6,032
2048	6,174	6,850	6,850	6,850	6,850	6,850	6,703	6,598	6,242	6,393	6,071
2049	6,243	6,909	6,909	6,909	6,909	6,909	6,765	6,555	6,297	6,447	6,127
2050	6,271	6,392	6,392	6,392	6,392	6,392	6,244	6,087	6,336	6,169	5,857
2051	6,301	6,295	6,295	6,295	6,295	6,295	6,214	5,922	6,330	6,148	5,827
2052	5,131	5,131	5,131	5,131	5,131	5,131	5,083	5,230	5,180	5,125	4,911
2053	5,090	5,090	5,090	5,090	5,090	5,090	5,090	5,312	5,162	5,196	4,944
2054	5,124	5,124	5,124	5,124	5,124	5,124	5,124	5,338	5,179	5,267	5,085

Table 2.7-22 Projected CO_2 Emissions (Tons) from Generic Resources

	Alternative Plan										
Year	1	2	2A	2B	2C	3	4	4A	4B	4C	4D
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	7	0	0	0	0	0	0	0	0	0	0
2023	23	18	18	18	18	16	8	8	8	8	8
2024	667	46	47	47	47	42	29	29	29	29	29
2025	790	75	76	76	76	60	51	51	47	47	42
2026	818	83	84	84	84	72	57	57	53	50	39
2027	856	102	104	104	105	85	74	74	68	56	44
2028	954	211	212	213	215	165	161	161	142	100	86
2029	2,017	1,444	1,455	1,461	1,470	963	993	993	615	503	384
2030	2,353	1,762	1,773	1,780	1,791	1,365	1,409	1,409	908	703	558
2031	2,477	1,863	1,873	1,880	1,892	1,467	1,525	1,525	991	758	564
2032	3,151	2,303	2,315	2,324	2,338	1,956	2,031	2,031	1,335	1,004	739
2033	3,588	2,853	2,867	2,876	2,887	2,360	2,465	2,465	1,464	1,100	821
2034	3,941	3,188	3,203	3,213	3,229	2,673	2,801	2,801	1,503	1,039	796
2035	5,539	4,517	4,534	4,544	4,562	4,023	4,161	4,161	2,394	1,691	1,297
2036	5,783	4,729	4,746	4,757	4,773	4,250	4,390	4,390	2,582	1,517	1,182
2037	6,980	5,874	5,891	5,902	5,919	5,385	5,535	5,368	3,453	2,297	1,754
2038	7,713	6,627	6,645	6,656	6,674	6,123	6,286	6,260	3,720	2,372	1,848
2039	8,234	7,211	7,231	7,242	7,260	6,679	6,856	6,855	3,736	2,414	1,892
2040	8,409	7,404	7,424	7,436	7,452	6,851	7,036	6,515	3,918	2,413	1,931
2041	9,213	8,136	8,153	8,165	8,182	7,615	7,783	6,548	4,277	2,664	2,197
2042	9,893	8,852	8,870	8,860	8,877	8,315	8,489	7,246	4,663	3,158	2,632
2043	13,634	12,635	12,654	12,665	12,684	12,084	12,274	11,070	8,230	6,478	5,665
2044	13,830	12,933	12,946	12,955	12,968	12,417	12,590	10,944	8,579	6,799	5,998
2045	14,043	13,836	13,836	13,836	13,836	13,265	13,467	11,488	8,657	7,698	6,825
2046	14,218	14,073	14,073	14,073	14,073	14,073	13,693	11,722	8,888	7,946	7,054
2047	14,337	14,225	14,225	14,225	14,225	14,225	13,838	11,869	9,032	8,098	7,195
2048	14,458	14,392	14,392	14,392	14,392	14,392	13,984	12,017	9,172	8,251	7,336
2049	14,615	14,578	14,578	14,578	14,578	14,578	14,161	11,895	9,334	8,417	7,490
2050	14,781	14,782	14,782	14,782	14,782	14,782	14,415	12,137	9,512	8,824	7,928
2051	14,932	14,941	14,941	14,941	14,941	14,941	14,763	12,142	9,702	9,168	8,272
2052	16,159	16,160	16,160	16,160	16,160	16,160	15,953	13,292	10,902	10,627	9,614
2053	16,330	16,330	16,330	16,330	16,330	16,330	16,330	13,708	11,033	11,284	9,938
2054	16,470	16,470	16,470	16,470	16,470	16,470	16,470	13,882	11,214	11,795	10,724

2.8 WATER RESOURCES

Use of Water in Electric Generation

Water is consumed during electric generation in a variety of ways:

1. Steam/water cycle. Steam generation is typically a closed-loop system, but boiler feed make-up water is required to replace minor losses.
2. Circulating water cooling. Circulating water is used to cool steam in the steam/water cycle. Circulating water is evaporatively-cooled in the cooling towers and reused until its water quality is no longer suitable. Blowdown rejected from the cooling tower is treated prior to discharge or stored and evaporated, depending on plant design. Cooling typically represents the vast majority of plant water usage and consumption.
3. Other usage. Relatively small volumes of water are used in a number of other important plant capacities, such as dust suppression, fire control, bottom ash removal, and emissions control.
4. Hydro-electric generation. Water consumed is through evaporation while stored in reservoirs at Public Service-owned hydropower facilities in Colorado.

Public Service's Water Consumption and Intensity

Table 2.8-1 shows the 2014 water consumption as well as average use for the Public Service system.

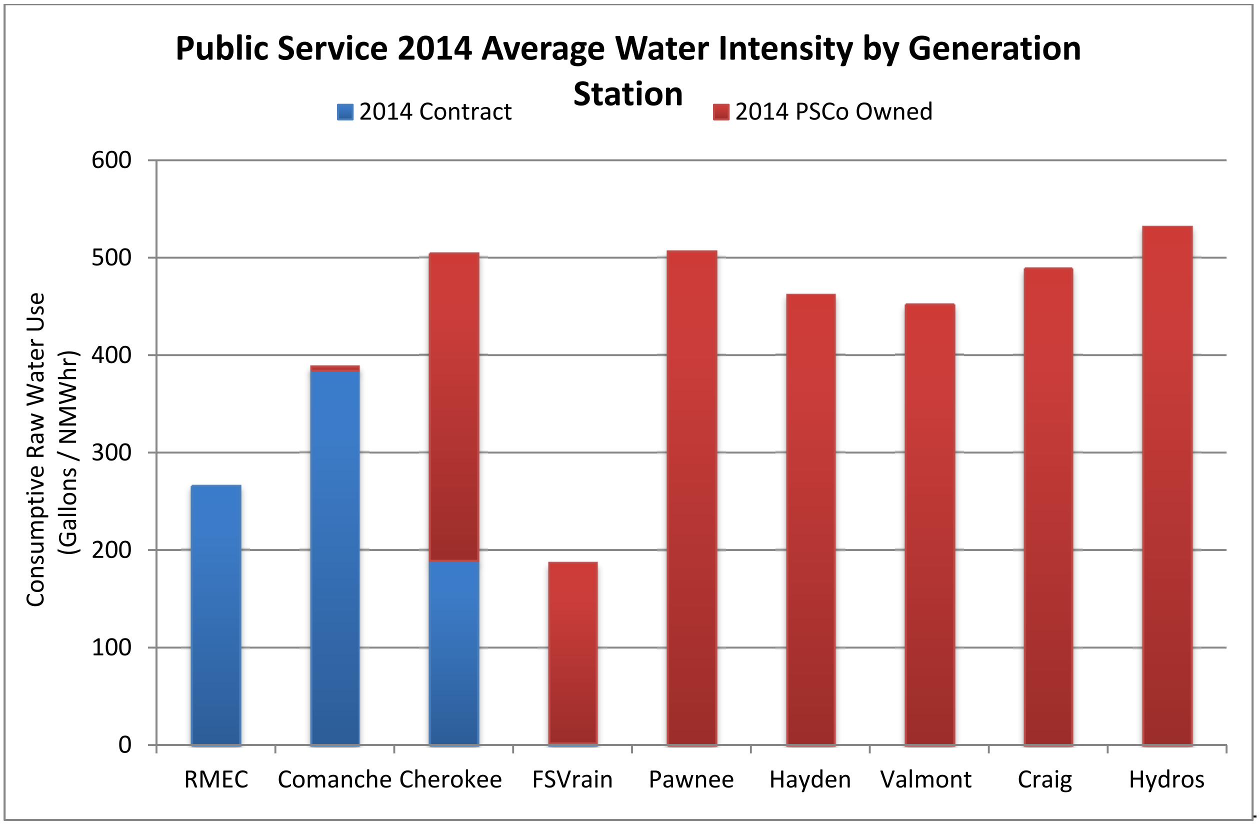
Figure 2.8-1 shows the water intensity for Public Service-owned generation stations and the relative proportion of water supplied through self-owned and contracted water supplies. Generally, self-supplied water is the least expensive and future costs are expected to remain stable, in accordance with operations and maintenance needs. Contracted water supply costs are anticipated to increase in line with regional water costs, but afford plants the reliability and firm yields associated with larger municipal water purveyors. Table 2.8-2 shows annual consumptive water use and intensity by Public Service facility.

Table 2.8-1 2014 Water Use and Generation by Public Service Facility

Public Service Generating Station	2014 Consumptive Water Use	Percent Consumptive Water Use	2014 Net Generation	Water Intensity
	Acre-feet	As a %	NMWHRS	gal/ MWH
Arapahoe(1)	0	N/a	0	N/a
Zuni	0	N/a	-980	N/a
Cherokee	4,763	82%	3,075,364	505
Comanche	9,980	83%	8,294,852	392
Fort Saint Vrain	2,217	64%	3,876,504	186
Hayden (2)	5,731	100%	4,037,492	463
Pawnee	4,210	100%	2,704,998	507
Rocky Mountain Energy Center	2,006	100%	2,452,484	267
Valmont (3)	1,462	100%	1,054,207	452
Hydros(4)	126	100%	76,917	533
Craig (Xcel Portion)(5)	854	100%	568,746	489
Alamosa*	0	N/a	1,544	N/a
Blue Spruce*	0	N/a	300,213	N/a
Ft. Lupton*	0	N/a	2,798	N/a
Fruita*	0	N/a	129	N/a
TOTALS	**30,469**		**25,494,921**	**389**

(1) Arapahoe retired 12/31/2013
(2) Hayden and Pawnee's raw water usage numbers reflect river pumping
(3) Raw water usage at Valmont is the amount of water attributed to diversions under the Valmont water rights
(4) Hydro water consumption from reservoir evaporation. Hydro net generation includes Ames, Georgetown, Salida, Shoshone, and Tacoma, but excludes Cabin Creek.
(5) Xcel Energy owns 9.7% of Craig Units 1&2
* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

Figure 2.8-1 Water Intensity



Notes:

- Arapahoe retired end of 2013. There was zero generation in 2014, and 127AF of raw water use for cleaning and various decommissioning uses.
- Zuni had zero raw water use and -980NMWhr net generation in 2014, so it was not included in the chart.
- Hydros include Cabin Creek, Salida, Shoshone, Tacoma, Ames, and Georgetown. Consumptive water use is from reservoir evaporation.
- Xcel Energy owns 9.7% of Craig Units 1&2

Table 2.8-2 Annual Consumptive Water Use and Intensity by Public Service Facility

Generating Station	*Annual Net Generation (MWh)*	*Annual Consumptive Use (gallons)*	*Water Intensity (gallons/MWh)*
IPP - Gas			
Southwest Generation (Arapahoe)	123,153	58,488,099	475
Brush 1 & 3	14,281	6,036,000	423
Brush 4D	60,167	38,946,000	647
Thermo Cogen	437,912	249,168,000	569
Thermo Power & Electric (UNC Greeley)	123,153	32,685,000	265
Southwest Generation (Valmont)*	12,196	-	0
Fountain Valley Power, LLC*	402,683	-	0
Manchief Power Company LLC*	187,075	-	0
Plains End II, LLC*	137,681	-	0
Plains End LLC*	24,988	-	0
Spindle Hill Energy LLC*	568,883	-	0
WM Renewable Energy*	19,593	-	0
Tri-State G & T Assoc - Brighton*	N/G	-	0
Tri-State G & T Assoc - Limon*	N/G	-	0
Total - IPP Gas	***2,111,765***	***385,323,099***	***182***
IPP - Wind			
Cedar Creek Wind Energy, LLC	851,207	-	0
Cedar Creek II, LLC	N/G	-	0
Cedar Point Wind, LLC	N/G	-	0
Colorado Green Holdings LLC	571,650	-	0
Foote Creek III LLC	71,695	-	0
Limon Wind, LLC	N/G	-	0
Logan Wind Energy LLC	650,000	-	0
NREL's NWTC, ALSTOM Power, Inc	N/G	-	0
NREL/DOE (NWTC)	N/A	-	0
Northern Colorado Wind Energy I	400,000	-	0
Northern Colorado Wind Energy II	5,635	-	0
Peetz Table Wind Energy, LLC	650,000	-	0
Ponnequin I	8,716	-	0
Ridge Crest Wind Partners LLC	92,973	-	0
Siemens Energy, Inc	1,495	-	0
Spring Canyon Energy LLC	202,348	-	0
Twin Buttes Wind	269,814	-	0
Total - IPP Wind	***1,808,819***	-	***0***

* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

N/A - Data not available

N/G - No generation in 2010

N/S - System purchases in 2010

Table 2.8-2 Annual Consumptive Water Use and Intensity by Public Service Facility (cont.)

Generating Station	Annual Net Generation (MWh)	Annual Consumptive Use (gallons)	Water Intensity (gallons/MWh)
IPP - Hydro		-	0
Bridal Veil	1,860	-	0
Boulder - Silverlake	13,447	-	0
Boulder - Betasso	9,946	-	0
Boulder - Kohler	689	-	0
Boulder - Lakewood	9,946	-	0
Boulder - Maxwell	566	-	0
Boulder - Orodell	558	-	0
Boulder - Sunshine	3,561	-	0
Denver Water - Dillon Dam	N/A	-	0
Denver Water - Foothills Water Treatment	N/A	-	0
Denver Water - Hillcrest Hydroelectric	N/A	-	0
Denver Water - Roberts Tunnel	N/A	-	0
Denver Water - Strontia Springs Dam	N/A	-	0
Denver Water - Gross Reservoir	N/A	-	0
Boulder - Boulder Canyon	8,566	-	0
Redlands Water & Power	8,097	-	0
Stagecoach	1,860	-	0
STS Hydro - Mt. Elbert	4,797	-	0
OrchardMesa/GrandValley/Palisade	N/G		0
Total - IPP Hydro	***63,892***	***-***	***0***
IPP - Solar			
SunE Alamosa	17,622	-	0
Boulder - 75th St.	N/A	-	0
Amonix SolarTAC 1, LLC	N/G	-	0
Cogentrix of Alamosa	N/G	-	0
Greater Sandhill 1, LLC	N/G	-	0
San Luis Solar, LLC	N/A	-	0
Total - IPP Solar	***17,622***	***-***	***0***

* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.
N/A - Data not available
N/G - No generation in 2010
N/S - System purchases in 2010

2.9 PHASE II COMPETITIVE ACQUISITION

Company Activities Following the Release of an RFP

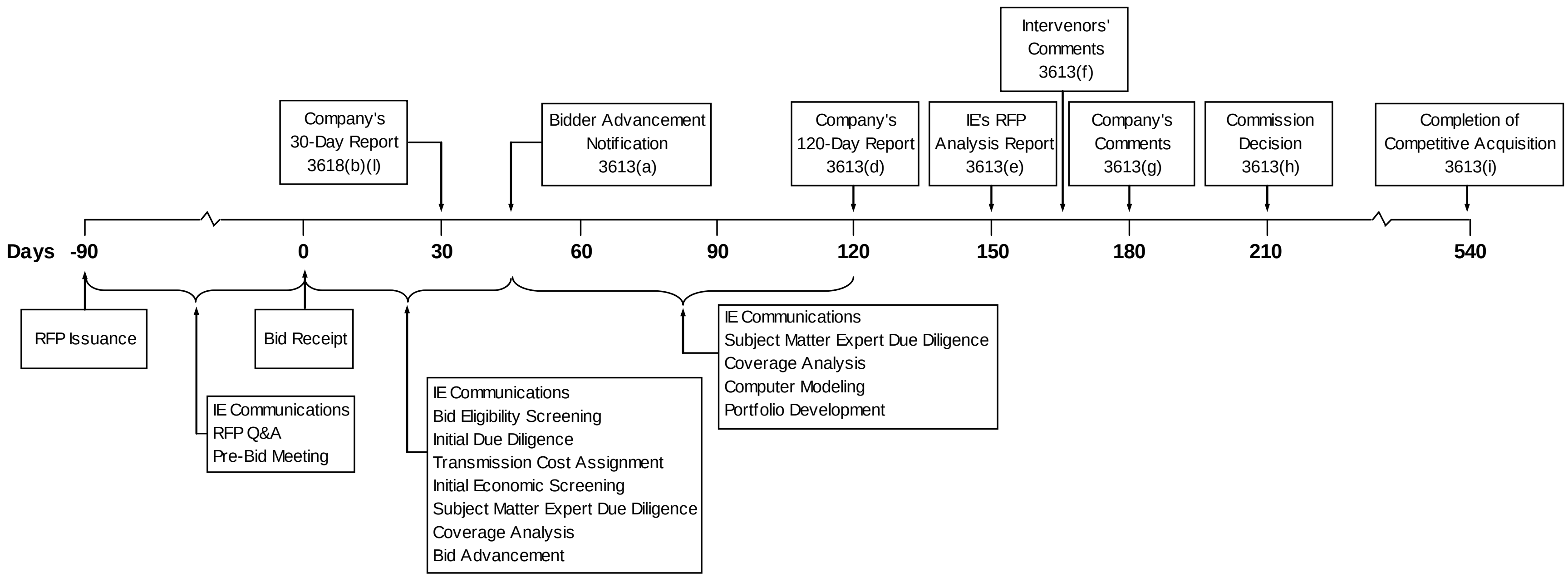
The Company anticipates issuing competitive solicitations approximately 90 days in advance of the bid receipt date. As filed in Volume 3 of this 2016 ERP, the Company is proposing four (4) distinct requests for proposal documents: 1) a Dispatchable Resources RFP, 2) a Renewable Resources RFP, 3) a Semi-Dispatchable Renewable Capacity Resources RFP, and 4) a Company Ownership RFP. Official versions of the RFP documents (the RFP document, a model contracting agreement or model term sheet, and proposal submission forms) will be posted to an RFP webpage on the day of the RFP release. An indicative timeline of Phase II activities is shown in Figure 2.9-1.

ERP Rule 3616(d) requires the Company to provide potential bidders with a copy of the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and non-confidential modeling inputs and assumptions provided by the Company pursuant to ERP Rule 3613(b). The nondisclosure agreement is included in the RFP bid submission forms and are included as part of the Volume 3 filing. ERP Rule 3616(d) also requires the Company to provide potential bidders an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to ERP Rule 3613(b). This explanation can be found in Section 1.1 of the model RFP documents.

ERP Rule 3616(e) directs the Company to require bidders to provide the contact information of a person designated to receive a notice pursuant to ERP Rule 3613(a). Language directing the bidder to provide this information is on Form C of the model bid submission forms. ERP Rule 3616(f) requires the Company to inform bidders that information for all bids submitted in response to the RFP will be made available to the public through posting of the bid information on the Company's website upon the completion of the competitive acquisition process pursuant to ERP Rule 3613(i). This information can be found in Section 1.1 of the model RFP documents.

The Company anticipates that any pre-bid meeting would be held approximately three (3) weeks following the issuance of a competitive solicitation. In addition to a pre-bid meeting, the Company will directly respond to potential bidder questions submitted via email. Non-confidential Q&A versions of issues raised during any pre-bid meeting as well as from questions submitted via email will be posted to the Q&A document on an RFP webpage. The Independent Evaluator will be copied on all emails sent directly to potential bidders.

Figure 2.9-1 Indicative Phase II Timeline



Bid Receipt and Generation Technology Categorization

The Company will request both hard copy and electronic versions of proposals; copies of bid submission materials will be provided to the Independent Evaluator and to Commission Staff. Upon receipt of bids, the Company will conduct an initial review to categorize the bid by its proposed generation source with bids employing similar technologies. Such an initial categorization simplifies downstream due diligence and economic evaluations and is necessary to comply with ERP Rule 3618(b)(I) regarding the 30-day report.

Bid Eligibility Screening and Initial Due Diligence

Once bids have been catalogued, the Company will conduct a review of each bid to ensure that the proposal meets the minimum eligibility requirements. Each of the four RFPs have slightly different minimum eligibility requirements corresponding to the different technologies or ownership structures targeted by the RFPs; specific details on the minimum bid eligibility requirements are laid out in the respective model RFP documents in Volume 3.

The Company intends to notify all RFP respondents within 15 days of bid receipt as to the Company's bid eligibility evaluation.

At the time that the Company conducts its bid eligibility screening, it will also conduct an initial due diligence review of the bids. This initial due diligence review is intended to quickly identify any potential fatal flaws or conceptual misunderstandings as to the proposed project. To the extent the Company requires additional information from the bidder as a result of its initial due diligence, it will contact the bidder promptly and ensure that the Independent Evaluator receives a copy of the request for additional information as well as a copy of the bidder's reply.

Initial Economic Analysis and Screening

Assignment of Transmission Interconnection and Network Upgrade Costs

One of the bid eligibility requirements is that the project function as a network resource, i.e., capacity and energy from the proposed generation project must be delivered to the Company's electric transmission or distribution system at a location such that the capacity and energy can then be delivered to the Company's customers. The Company will assign incremental transmission interconnection costs and/or network delivery costs to each bid, as appropriate. Transmission-associated capital costs will be converted to annual levelized costs utilizing a levelized fixed charge rate ("LFCR") of 0.12 for inclusion in the initial economic screening.

Consistent with prior acquisition evaluations, the Company will not assign network delivery costs to any project that utilizes a transmission upgrade for which the Company has received a CPCN; provided, however, that sufficient transmission transfer capability exists on the transmission project specified in the CPCN after accounting for other generation projects.

Existing generation resources from which the Company currently purchases capacity and energy will not be burdened with any incremental electrical transmission interconnection or network delivery costs provided that the Company currently has sufficient transmission capacity to deliver the entire generation to its load. For existing generation resources with inadequate transmission service, a projection of the purchase of sufficient transmission rights will be added to the bid.

Initial Economic Screening

The initial economic screening consists of calculating an "all-in" levelized energy cost ("LEC"). LECs are calculated as the present value of the sum of the total costs and benefits for each year of the proposed project's term divided by the present value of the estimated annual energy streams. Present values are calculated as of the project's in-service year to avoid confusing the inherent value of delay with true differences in LEC. The Company will employ its after-tax WACC in the present value calculations.

The term "all-in" refers to the inclusion of costs and benefits associated with the project, e.g., wind integration costs for wind bids or fixed and variable costs at a specified annual capacity factor for dispatchable bids. Projects that propose to interconnect at distribution voltages will be credited with avoided line losses in their LEC calculations. The result of this credit is that the LEC for a distribution-interconnected project will be lower than that for an identical, transmission-interconnected project by the avoided line loss assumption.

Initial economic screening (i.e., LEC calculations) will be conducted directly within the bid submission forms supplied by the bidders.[15] The Company will make several adjustments to the LEC calculation inputs as necessary, including, but not limited to:

- the Company's final natural gas forecast,
- the Company's estimates of fuel delivery costs on both an interruptible and a firm basis, where applicable,
- the Company's estimates of any incremental transmission interconnection or network delivery costs,
- adjustments to estimated performance or pricing levels that result from the Company's due diligence efforts and/or updated information received from the bidder.

[15] LEC calculations can be seen on the "LEC" tab of the model RFP Forms in Volume 3. LEC calculations in the model RFP forms are based on the integration costs determined in the studies presented in the 2011 ERP and utilized in the 2013 All-Source Solicitation. Depending upon the Commission's Phase 1 decision, prior to the issuance of a 2016 Phase 2 competitive solicitation, the LEC calculations would be updated to include the Company's most recent integration cost studies presented in the 2016 ERP.

No renewable energy credit ("REC") value benefits will be credited to the LEC calculations for any renewable generation projects.

Outside of these general observations, specific costs and benefits will be assessed to bids employing certain generation technologies as detailed below.

Wind LEC Calculations

Wind bid LECs will be adjusted for:

- Wind integration costs based on the proposed MW above the acquired levels of wind.[16]
- Coal cycling costs based on the proposed MW. Both coal cycling and curtailment cost components will be imposed for purposes of bid screening.[17]

Solar LEC Calculations

Solar bids, e.g., PV and solar thermal with no storage capability, will be adjusted for:

- Solar integration costs.[18]

Base Load Renewable LEC Calculations

Base load renewable generation resources include technologies such as biomass, geothermal, and hydro. In general, these are non-dispatchable renewables in which an expectation of significant generation during off-peak hours is justified. These types of bids will be burdened with:

- Both the cycling and curtailment cost components from the Company's most recent coal plant cycling cost study.

[16] The level of acquired wind at the time of a Phase 2 competitive acquisition will be impacted by the Commission's ultimate decision in Docket No. 16A-0117E in which the Company proposes the ownership of 600 MW of incremental wind from the Rush Creek Project. The Rush Creek Project has a late 2018 proposed in-service date.

[17] The model RFP Bid Forms include the coal cycling costs from the study report utilized in the 2013 All-Source Solicitation. This is the August 29, 2011 study report titled "Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment" as modified for the Commission's 2011 ERP Phase 1 decision. Depending upon the Commission's 2016 ERP Phase 1 decision, the LEC tabs would be updated prior to the issuance of a Phase 2 competitive acquisition with the results from the Company's most recent coal cycling study filed in Proceeding No. 16A-0117E and included for reference in Section 2.13 of Volume 2 of the 2016 ERP.

[18] The model RFP Bid Forms include solar integration costs from the study report utilized in the 2013 All-Source Solicitation. This is the February 9, 2009 study report titled "Solar Integration Study for Public Service Company of Colorado". Depending upon the Commission's 2016 ERP Phase 1 decision, the LEC tabs would be updated prior to the issuance of a Phase 2 competitive acquisition with the results from the Company's most recent coal cycling study filed in in Proceeding No. 16A-0117E and included for reference in Section 2.13 of Volume 2 of the 2016 ERP.

Semi-Dispatchable Renewable Capacity LEC
No incremental costs or benefits will be assessed in the calculation of a semi-dispatchable renewable capacity project's LEC.

Stand-alone Storage LEC
Stand-alone storage bids will be provided with a wind integration cost credit to the portfolios in which they exist as quantified in the Company's 2 GW and 3 GW Wind Integration Cost Study (included for reference in Section 2.13 of Volume 2 0f the 2016 ERP). This credit will be based on the proposed MW above the acquired levels of wind.

Gas-Fired, Dispatchable LEC
LECs for dispatchable generation resources are calculated by converting the fixed costs to variable costs by assuming an annual capacity factor and by assuming an average annual heat rate with which to estimate fuel volumes and costs. Gas-fired, peaking resources will be screened with an assumption of a 5% annual capacity factor. Gas-fired, intermediate resources will be screened with an assumption of a 40% annual capacity factor. The average annual heat rate utilized in the LEC calculations will be the average of the seasonal full load heat rates (without supplemental capacity) supplied in the bid forms.

Start charges are converted to a variable $/MWh cost by assuming a set number of hours that a unit will run at full output once started; full output is defined as the net capability of the unit without supplemental capacity; e.g., duct firing on a combined-cycle power plant. For peaking resources, the Company assumes a four (4) hour run time per unit. For intermediate resources, the Company assumes a twelve (12) hour run time per unit and that all CTs are started, e.g., two (2) turbines started for a 2x1 CC facility.

To the extent a project proposes to wheel capacity and energy across another utility's transmission system prior to delivery to the Company's system, estimated wheeling losses will be imposed against the full load heat rate which will effectively increase the variable cost component of the LEC. Such an adjustment is necessary since the heat rates are calculated at the generation unit (which resides on another utility's system), whereas the other components of the LEC are all based on capacity and energy delivered to the Company's system.

Dispatchable generation units will be credited with $0.20/kW-mo for each kW that can be achieved within 30 minutes and an additional $0.02/kW-mo for each kW that can be achieved within 15 minutes.

Subject Matter Expert Due Diligence
Subject matter experts typically include, but are not limited to, Company personnel from the following organizations:

- Transmission Access

- Generation Resource Planning
- Transmission Planning
- Natural Gas Planning
- Commercial Operations
- Purchased Power
- Credit
- Tax
- Accounting
- Environmental Permitting
- Energy Supply
- Siting and Land Rights

Each department conducts its due diligence reviews in the manner they determine best. In the event that subject matter experts require additional information or clarification on certain aspects of a bid, those requests will be forwarded to the bidders by the RFP Manager. Each bid reviewed by each department will result in a written due diligence report with an indication as to the feasibility of the project's ability to meets its proposed in-service date with the selected technology and proposed performance levels.

The Company reserves the right to employ outside technical experts to review bids to the extent the Company believes such analyses are warranted to sufficiently review any proposal.

<u>30 Day Bid Summary Report (ERP Rule 3617(b)(I))</u>

Pursuant to ERP Rule 3618(b)(I), the Company will report to the Commission within 30 days of bid receipt on the following topics:

- Bidder identity
- # of bids received (total and by resource type)
- MW (total and by resource type)
- Description of prices (by resource type)
- Whether or not the Company believes it needs to implement its contingency plan

<u>Secondary Economic Screening</u>

Any adjustments to bid information that impacts a bid's LEC following the completion of the subject matter experts' due diligence efforts will be incorporated into a final LEC calculation. Based on the final LEC calculations, all bids utilizing similar technologies will be sorted by LEC and by proposed in-service dates.

Selection of Bids for Computer Modeling

All bids from existing thermal generation resources currently under contract with the Company and all Company proposals will be passed through screening to portfolio development. Gas-tolled thermal facilities will be selected for inclusion in computer modeling based on their LEC calculated with an assumption of no incremental firm fuel supply costs. Pursuant to ERP Rule 3616(d) and contingent upon the existence of sufficient bids passing through bid eligibility and due diligence screening, the Company shall pass forward to the portfolio development phase a sufficient quantity of bids across the various generation resource types such that resource plans can be created that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources or Section 123 Resources as specified in the Commission's Phase I decision.

To the extent initial Strategist modeling indicates that <u>all</u> bids of a specific generation resource type (e.g., all wind bids) passed to portfolio development appear in the least-cost portfolio(s), additional bids utilizing that generation resource type will be included in subsequent model runs. This iterative process will be followed until no incremental bids greater than 10 MW employing that generation resource type are selected in the least-cost portfolio. Bidders whose projects are passed forward to portfolio development will be notified of their project's advancement pursuant to ERP Rule 3613(a) and will be provided with the modeling inputs and assumptions for that project pursuant to ERP Rule 3613(b).

<u>Bids for Generation between 100 kW and 10 MW</u>

In prior competitive solicitations the Company had set higher minimum project sizes than the 100 kW level proposed here. The Company's rationale was that a plethora of small-sized bids results in the creation of too many potential portfolios that could adequately meet the targeted need. Under such situations, the Strategist model begins to truncate portfolios (i.e., not examining all relevant portfolios) with the potential outcome of not finding the most cost-effective portfolios. In the 2016 ERP the Company proposes a process to determine the potential cost-effectiveness of proposals for sizes between 100 kW and 10 MW.[19]

In general, the following process will be employed to determine cost-effective bid-eligible proposals <10 MW:

1. Categorize bids by technology,
2. Categorize bids by size: >= 10 MW and < 10 MW,
3. Sort < 10 MW bids by all-in LEC,
4. Review the least-cost portfolio determined by Strategist from the base case run and determine the generation types selected in each portfolio,
5. For each included generation type, determine all bid-eligible proposals < 10 MW that have an all-in LEC less than the highest all-in LEC for that generation type in the portfolio and include those projects in the final portfolios.

[19] Depending upon the pool of proposed projects received in a Phase 2 competitive acquisition, the Company may need to adjust the specific MW cutoff for various technologies instead of the 10 MW proposed here. Such an adjustment would only be done in consultation with the Independent Evaluator.

For example, assume that the most expensive solar bid included in a final portfolio has a $60/MWh LEC and, further, that solar bids <10 MW with the following all-in LEC were proposed:

Bid #	LEC ($/MWh)	Size (MW)
1	$45	2
2	$52	1
3	$59	5
4	$62	5
5	$75	2

In this instance, the Company would include Bids 1-3 (totaling 8 MW) in the portfolio along with those proposals selected by Strategist.

A final check will be made to ensure that the inclusion of all cost-effective proposals < 10 MW does not provide excess capacity credit to the portfolio through the RAP to such an extent that it could replace another source(s) of capacity selected through the Strategist modeling. If it does, two additional Strategist runs will be conducted to determine which is most cost-effective: 1) include all cost-effective generators <10 MW in the final portfolio, or 2) include all cost-effective generators < 10 MW and exclude the other generator(s) that could potentially be displaced. The final portfolio would be the least-cost of these two runs assuming that both runs meet all reliability metrics.

To the extent the least-cost portfolio does not include a certain generation type (e.g. solar) but lower priced bids (based on all-in LEC) exist for similar generators < 10 MW, an ad hoc Strategist run including those generators would be conducted to see if the revenue requirements of the least-cost portfolio increases or decreases. If the revenue requirements decrease with the addition of the < 10 MW generators, they would be included in the final portfolios.

For certain generation types (e.g. hydro or gas-fired micro-turbines), the Company would not typically expect to receive bids in excess of 10 MW. For such situations, the lowest all-in LEC proposals (up to a maximum of three per technology) would be advanced to computer modeling and portfolio development along with those bids > 10 MW already selected. To the extent the Strategist model selected all three of the lowest all-in LEC proposals and other proposals for the same technology were also received, than ad hoc Strategist runs would be conducted to determine the cost-effectiveness of these other proposals.

<u>Report to Advanced Bidders</u>

Pursuant to ERP Rule 3613(a), 45 days after bids are received the Company is to email each bidder and indicate whether its bid has been advanced to computer modeling and portfolio development. For those bids <u>not</u> advanced, the Company is to provide the reason(s) why the project will not be evaluated further. For those bids advanced to computer modeling and portfolio development, the Company is to provide the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the Company.

The Company will meet these reporting procedures for proposals that are 10 MW and greater. However, given that proposals < 10 MW will, in general, not be advanced to computer modeling and portfolio development during the initial phases of portfolio development, these proposals will not receive such notification at the 45 day mark. To the extent that proposals < 10 MW are included in final portfolios after they have been created, bidders will be notified at that time.

Computer Modeling and Portfolio Development

Strategist will be used in developing portfolios of proposals/bids that are advanced to this stage of the competitive acquisition. The modeling framework Public Service will employ in the Phase II portfolio analysis is the same as that used to develop alternative plans that are discussed in ERP Volume 1 with two exceptions: 1) actual bids are used to meet RAP needs instead of generic estimates, and 2) the lowest cost Company self-build combustion turbine proposal will be used to backfill portfolios as needed to meet capacity and reserve margin requirements.[20] An Economic Carrying Charge ("ECC") representation of the Company's lowest-cost, combustion turbine proposal will be used to backfill portfolios to the end of the planning period as needed in order to ensure each portfolio meets the minimum capacity requirements and is not rejected by the model. The ECC representation will reflect all fixed costs (capital, FOM, firm fuel delivery charges).

Company proposals will include the same costs and benefits as those applied in the initial economic screening of bids described earlier in this section. Company proposals will be modeled using traditional capital revenue requirements when reporting annual total system costs. During optimization and ranking of various portfolios of resources, Strategist will use an Economic Carrying Charge ("ECC") representation of the cost for Company proposals. Since the useful lives of Company self-build proposals will extend through the end of the Planning period, no assumptions need be made on how to extend the lives of Company proposals. Surplus capacity will be credited at the short-term capacity purchase price of $2.79/kW-mo for 4 months through 2023 and then at the ECC price of the Company's lowest-cost, combustion turbine proposal for years 2024-2054.

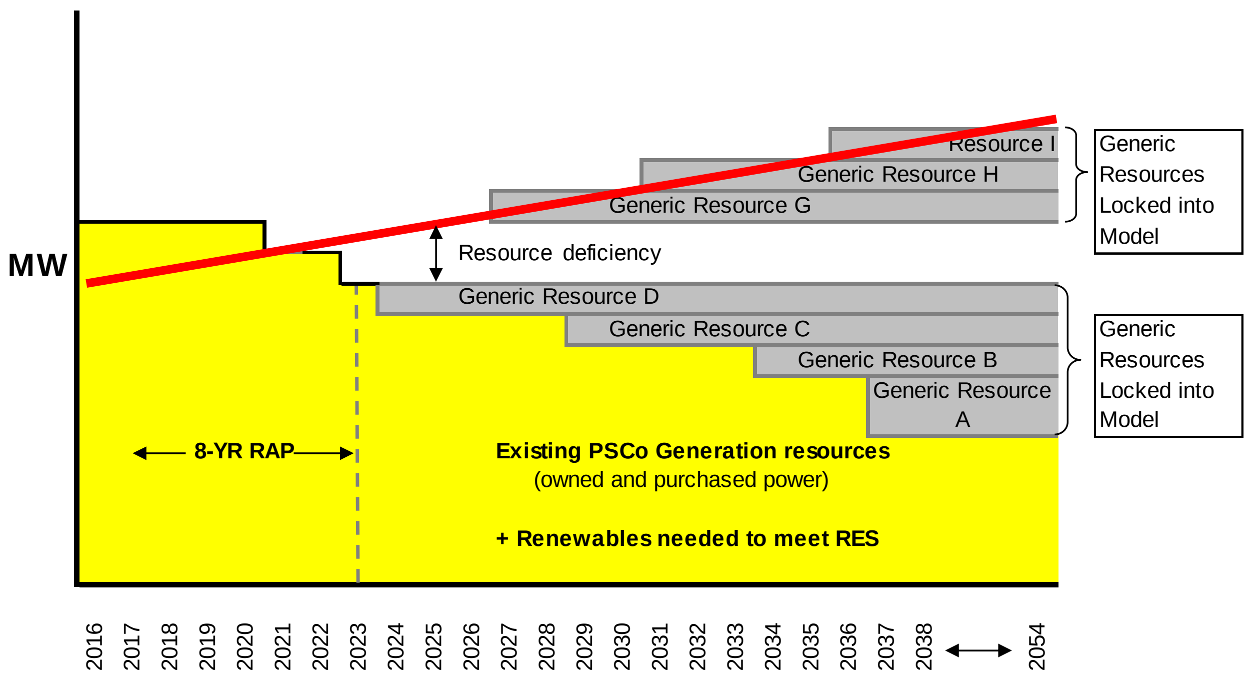
[20] For the purposes of this section, the determination of the lowest-cost Company self-build proposals could potentially include build-own-transfer proposals for new-build assets. These new build assets would need to have sufficient operating lives to extend through the end of the Planning Period.

Development of Bid Portfolios

Portfolios that meet the RAP capacity need utilizing bids that do not extend to the end of the planning period will be "backfilled" with the Company's lowest-cost combustion turbine proposal. The Strategist model will be allowed to determine when this combustion turbine is used in this backfilling role to ensure it is done in a manner that minimizes the PVRR of each portfolio.

As discussed earlier, in the computer modeling of all bid portfolios, Public Service will employ a similar modeling convention as that approved by the Commission in Proceeding No. 07A-447E and 11A-869E. All generic resources added in years beyond the RAP (2024-2054) will be locked down in the Strategist model. Note that the term "locked down" refers to the fact that a generic resource is hardwired into the Strategist model to begin its operating life in a specific year as opposed to being modeled in a fashion where it has a floating in-service date that is ultimately selected by the model based on economics. All generic resources "locked down" in the model will still be capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner with the exception of generation such as wind and solar PV which are not capable of being dispatched. Figure 2.9-2 shows a graphical depiction of the generic resources that are locked down in the modeling.

Figure 2.9-2 Depiction of Strategist Model with Locked-down Resources



Figures 2.9-3(a) and (b) show two examples of how the lowest-cost Company self-build combustion turbine proposal will be used to backfill portfolios of bids that expire before the end of the planning period. Figure 2.9-3(a) shows a portfolio where the least-cost portfolio includes IPP bids in the RAP and the Company combustion turbine proposal

filling in the backend when bids expire. Figure 2.9-3(b) shows a portfolio that includes both a Company proposal and an IPP bid in the least-cost mix. Because IPP bids are limited to a maximum of a 25 year contract term, all portfolios that contain bids will eventually need to be back filled by the end of the Planning period.

Figure 2.9-3(a) Illustration A of a Portfolio of Bids and Company Proposals

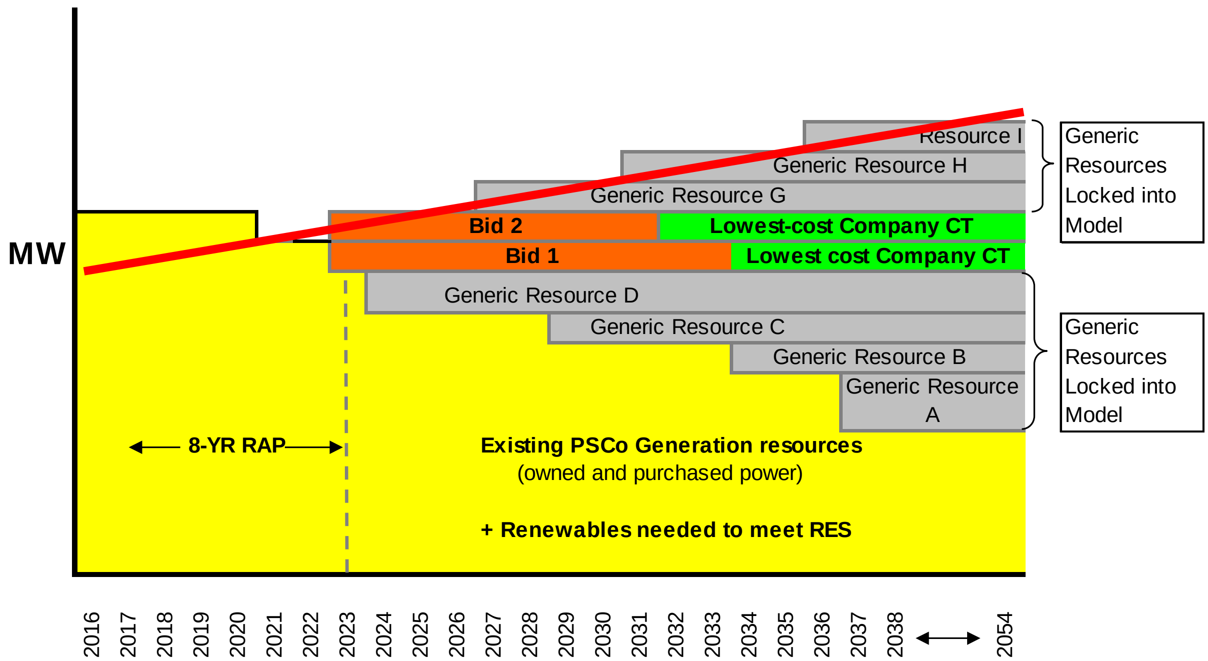
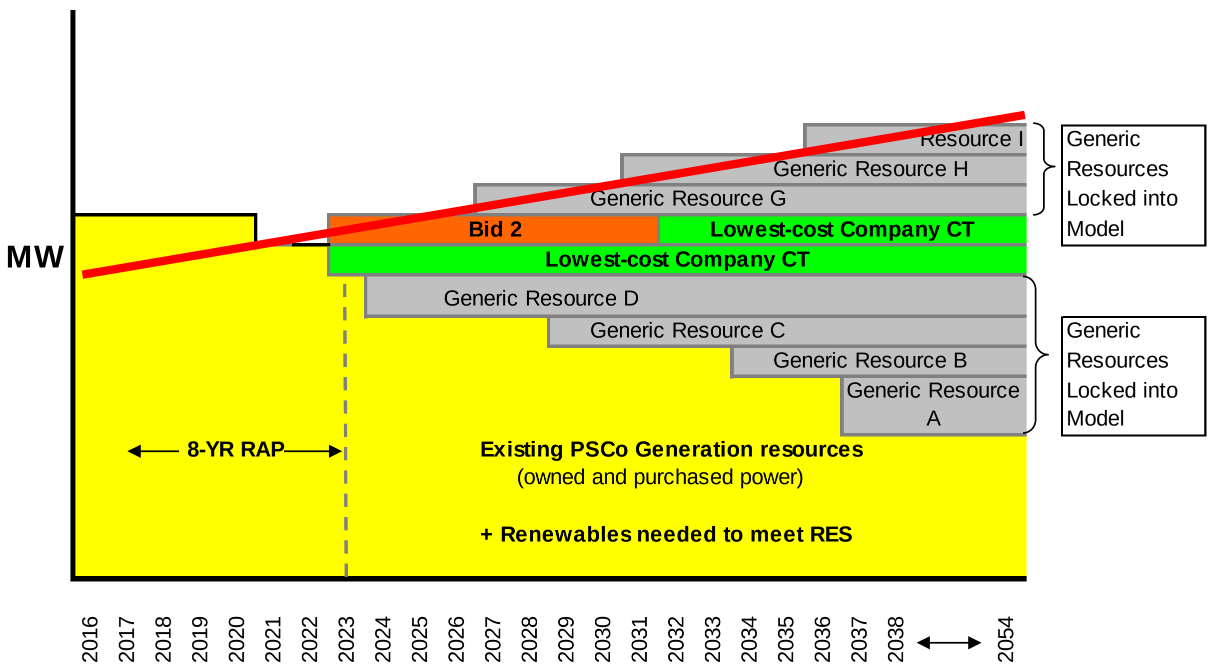
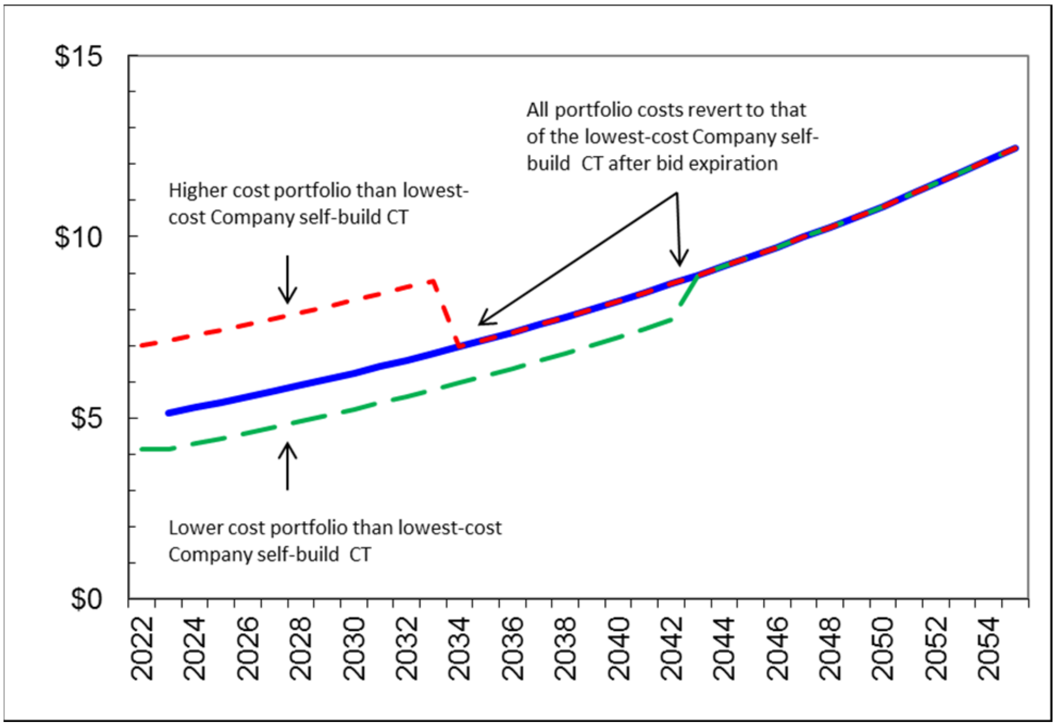


Figure 2.9-3(b) Illustration B of a Portfolio of Bids and Company Proposals



Since each portfolio will revert back to the lowest-cost self-build combustion turbine proposal in the later years of the planning period, this analysis approach will focus the evaluation to the impact of the bids themselves. Figure 2.9-4 illustrates this process. In the figure, the blue line represents the costs of the lowest-cost self-build combustion turbine with the ECC of the proposals fixed costs. The red dashed line represents the costs of a bid portfolio that is higher cost. The green dashed line represents the costs of a bid portfolio that is lower cost. When the bids reach the end of their PPA term, each plan reverts back to the cost of the lowest-cost Company self-build combustion turbine.

Figure 2.9-4 Comparison of Higher and Lower-Cost Bid Portfolios vs. Company-Owned Portfolio



Selection of Bid Portfolios for Sensitivity Analysis

A set of portfolios utilizing a range of technologies to meet the RAP needs will be selected for additional analyses involving an assessment of input assumption sensitivity analyses. A sufficient number of portfolios will be selected for these additional analyses to ensure a diverse set of generation technologies are represented. The Company will use planning period PVRR (calculated using base/starting assumptions) as a key metric in determining the number of portfolios to advance.

Input assumption sensitivities would include:

- High and Low gas price assumptions
- CO_2 proxy price assumptions
- Annuity backfill/tail vs. Company self-build backfill/tail

As was done in the analysis of the baseline case and alternative plans, the mix of proposals used to meet the RAP needs as well as the generic resources included beyond the RAP in each portfolio will be fixed or locked down when the portfolio PVRRs are recalculated under each sensitivity. This will ensure that cost differences between portfolios will be the result of differences in the factors being studied in the sensitivity analyses and not due to changes in the mix of resources beyond the RAP.

RESA Impact Analysis of Portfolios

Portfolios advanced to sensitivity analysis will also be analyzed to estimate their impact on the RESA. An abbreviated analysis will be employed to develop these estimates in which the annual additional costs or benefits will be estimated for each portfolio that result from renewable resources in the RAP. These additional costs or benefits will be added to or subtracted from the RESA impacts for the least-cost portfolio.

Comparing Strategist Model Dispatch of Resources with Actual Resource Dispatch

In previous ERP and ECA proceedings, parties questioned the dispatch modeling of the Strategist software tool, particularly in regard to how often combustion turbines were run in the model compared to the how often they actually operate on the system.

As with most production costing models, Strategist performs an economically optimal dispatch based on the input data provided. Part of the data inputs include the hourly system load profile and hourly generation profile of non-dispatchable resources, such as wind and solar. Thus, the model produces a dispatch projection based on perfect foreknowledge of variables that are, in actuality, uncertain. One of the primary results of this perfect foresight is that peaking resources, such as combustion turbines, are not required to produce as much generation as might actually occur. Peaking resources are one of the primary generation types used to provide real-time balancing of load and generation, and are sometimes ran out of economic merit order to respond to fluctuations in load or intermittent generation or to provide backup “flex reserves” to reduce risk exposure to uncertainty.

The Company’s wind and solar integration studies develop costs that are added to the intermittent renewable generation in Strategist to account for the cost impact of this overly optimistic dispatch. The most influential integration cost for wind generation is the cost of inefficient generation commit and dispatch, which the Strategist model or any other model does not capture in its least-cost dispatch.

A simplified method to address these concerns and align forecasted generation with actual generation was discussed in Appendix E of the Staff's report in Proceeding No. 13I-0215E. In this analysis, the Company's discussed reasonable adjustments to a key variables to reflect forecast vs actual plant availability, load, wholesale-market transactions, and wind integration costs. The results of this analysis showed that the Strategist model does in fact perform a reasonable dispatch of the system resources and is an appropriate planning tool for making resource decisions.

2.10 CONFIDENTIAL AND HIGHLY CONFIDENTIAL INFORMATION

Public Information

The following Public Service information that is relevant to the 2016 ERP is, or will be, public information as the result of Public Service's either filing the information in Phase I or Phase II of the 2016 ERP or as the result of a prior filing with the Commission, the State of Colorado or with federal agencies:[21]

Public Service Company of Colorado Information

- Sales by Customer Class
- Revenue by Customer Class
- Number of Customers by Customer Class
- Sales by Tariff
- Revenue by Tariff
- Sales per Customer by Tariff
- Revenue per kWh by Tariff
- Sales Made to Wholesale Customers
- Revenue from Sales to Wholesale Customers
- Affiliate Transactions
- Reserve Margin
- Contingency Plan
- Resource Need for Resource Acquisition Period
- Renewable Energy Standard
- RES Compliance Position
- Renewable Energy Standard Adjustment
  - Balance
  - Forecast
- Sales and Demand Forecast
  - Total Sales
  - Total Demand
  - Sales by Customer Class
  - Demand by Customer Class
- Aggregate CO_2 Cost Projection
-

Company-Owned Generation Resource Information

- Aggregate Cost of Production
- Energy Production
- Depreciation and Amortization Expense
- Estimated Average Service Life
- Peak Load

[21] Information listed is not all inclusive.

- Plant Hours Connected to Load
- Capacity
- Plant Production Costs
- Average Cost per kWh
- Average Heat Rate
- Total Fuel Consumed
- Fuel Types
- Capacity Factor
- Availability Factor
- Estimated Remaining Useful Lives
- Total Emissions by Type
- Plant Emissions by Type
- Total Fuel Used by Type
- Fuel Cost
  - Historical Coal Cost
  - Historical Gas Cost
  - Coal Cost Projection
  - Gas Cost Projection

<u>Purchased Generation Resource Information</u>

- Capacity
- Energy Purchased
- Cost of Energy Purchased
- Contract Duration
- Contract Modification Terms

<u>Transmission Resource Information</u>

- Operating Costs
- Wheeled Energy
- Wheeled Capacity
- Wheeling Revenue
- Purchase and Sale of Ancillary Services
- Peak Load
- Line Size and Length
- Capacity from Wheeling and Coordination Agreements
- Planned Additions
- Injection Capability

<u>Strategist Model Data</u>

Input Information

- Inflation Rate
- Federal Tax Rate
- State Tax Rate
- Discount Rate

- Weighted Average Cost of Capital
- Variable O&M Escalation Rate
- Fixed O& M Escalation Rate
- Construction Cost Escalation Rate
- SO2 Pricing
- NOx Pricing
- CO2 Pricing
- Wind Integration Costs
- Wind Related Coal Cycling Costs
- Solar Integration Costs
- Natural Gas Price Volatility Mitigation Adder (PVM)
- Annual / Monthly Peak Demand
- Annual / Monthly Total Energy Demand
- Line Loss Assumptions
- DSM Forecast
- Load Management Resources
- Reserve Margin Requirements
- Spinning Reserve Requirement
- Wind Curtailment Pricing
- System Average Colorado Coal Prices
- System Average PRB Coal Prices
- Blended Natural Gas Prices – not proprietary forecasts
- Oil Prices
- Capacity Credit Pricing
- Capacity Credit Limits
- In-Service Dates
- Retirement Dates
- Unit Capacities
- PPA In-service Dates
- PPA Retirement Dates
- PPA Capacities
- Generic Resources
    - Name Plate Capacity
    - Summer Peak Capacity
    - Capital Costs
    - Transmission Interconnection Costs
    - Transmission Grid Upgrade Costs
    - Firm Fuel Supply Costs
    - Book Life
    - Fixed O&M
    - Variable O&M
    - Heat Rate Curves
    - Forced Outage Rates

- Typical Annual Maintenance Requirements
- CO_2 Emission Rate
- NOX Emission Rate
- SO_2 Emission Rate
- PPA Pricing if applicable

Output Information

- Annual System Peak
- Annual System Capacity Obligation
- Total System Capacity
- Capacity Additions (Expansion Plans)
- Capacity Retirements
- System Capacity Mix Aggregated Into the Following Categories
    - Load Management
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle
    - Gas Combustion Turbine
    - Oil
    - Hydro
    - Pumped Storage
    - Wind
    - Solar
    - Geothermal
    - System Purchases / Sales
    - SPS Interchange
- System Emissions
    - CO_2
    - SO_2
    - NOx
    - PM
    - Mercury
- System Fuel Burn
    - Natural Gas
    - Coal
    - Oil
- Revenue Requirements for Capital Projects (not all Public Service capital projects are modeled) Aggregated Into the Following Categories
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle

    - Gas Combustion Turbine
    - Oil
    - Hydro
    - Pumped Storage
    - Wind
    - Solar
    - Geothermal
- Fixed Costs Including Fixed O&M and PPA Capacity Payments Aggregated Into the Following Categories
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle
    - Gas Combustion Turbine
    - Oil
    - Hydro
    - Pumped Storage
    - Wind
    - Solar
    - Geothermal
    - Capacity Credits
- Energy Costs Including Fuel, Variable O&M, and Energy Payments Aggregated Into the Following Categories
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle
    - Gas Combustion Turbine
    - Oil
    - Hydro
    - Pumped Storage
    - Wind
    - Solar
    - Geothermal
    - Short-term Energy Purchases
- Total Emission Costs
    - CO_2
    - NOX
    - SO_2
    - PM
    - Mercury
- Total PVM Costs
- Total Wind Integration Costs
- Total Wind Related Coal Cycling Costs
- Total Wind Curtailment Costs

- Total DSM Costs

Concerning the Strategist model that the Company used to represent the Public Service system,[22] the model has millions of discrete data points that it uses to represent the Public Service system. The model is very much an organic model whose inputs are not in discrete files that can be provided or that would be easily understood or manipulated. Specific questions concerning Strategist inputs will likely receive a specific and useful response. Public Service cautions that the Company cannot answer all non-specific Strategist input questions. An example of a non-specific question would be: "Provide all Strategist input files," or "Provide all Strategist input files and assumptions." There are no such files and the assumptions are too numerous to list in a productive manner.

Confidential Information

Public Service will seek to protect the following proprietary information as confidential information:

Strategist Model Data

Input Information

- Hourly Load Patterns
- DSM Hourly Patterns
- Monthly On/Off Peak Market Prices
- Market Emission Assumptions
- Market Import Constraints
- Unit Seasonal Deration Profiles
- Unit Variable O&M
- Unit Fixed O&M
- System Annual Fixed Gas Delivery Charges
- Unit Average Maintenance Requirements
- Unit Average Forced Outage Rate
- Unit Contribution to Spinning Reserve
- Unit Level Economic Minimum
- Unit Level Emergency Minimum
- Unit Emission Rates
    - SO_2
    - NOX
    - CO_2
    - PM
    - Mercury

[22] The model was used to produce alternative plans for the Phase 1 filing and will be used to evaluate the bids in a solicitation.

- PPA Capacity Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Schedules (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Contribution to Spinning Reserves
- PPA Seasonal Capacity Derate Profiles
- PPA Emission Rates
  - CO_2
  - SO_2
  - NOX
  - PM
  - Mercury
- Hourly Wind Patterns
- Hourly Solar Patterns

Output Information

- Unit Level Maximum Capacity
- Unit Level Summer Accredited Capacity
- Unit Level Generation
- Unit Level Fuel Consumed
- Unit Level Average Heat Rate
- Unit Level Total Variable O&M
- Unit Level Fixed O&M
- DSM Hourly Patterns
- Unit Level Capital Expenditures (note not all Public Service capital expenditures are modeled)
- Unit Level Rate Base (note rate base not modeled for all Public Service units)
- Unit Level Revenue Requirements (note revenue requirements not modeled for all Public Service units)
- Unit Level Emissions
  - NOx
  - SO_2
  - CO_2
  - PM
  - Mercury
- PPA Maximum Capacities
- PPA Summer Accredited Capacities
- PPA Generation
- PPA Capacity Factors

- PPA Total Energy Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Total Capacity Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Emissions
  - NOx
  - SO_2
  - CO_2
  - PM
  - Mercury

Highly Confidential Information

Public Service will seek to protect the following proprietary information as highly confidential information:

- Unit Level Delivered Fuel Costs
- Hourly Market Price Data
- Unit Level Heat Rate Curves
- Unit Detailed Maintenance Schedules
- Bid Information of any Sort (from the Company and from other entities)
- Any information protected by confidentiality clause of a PPA
- Strategist Files[23]

Information that Public Service will Provide Bidders

Public Service will provide the following Public Service developed information to bidders with respect to their own bids after initial bid screening and before Strategist modeling:

- Levelized Cost of Energy
- Transmission Interconnection Costs
- Gas Supply Costs
- Wind Integration Costs
- Benefit of Geographic Diversity of Wind Generation Resource
- Benefit of Energy Storage Resource

[23] Public Service can only provide Strategist Files to Interveners that hold a Strategist License

Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results

Public Service will seek to protect all bid information and bid evaluation results (including Company self-build proposals) that would reveal specific bid pricing or other bid information, as highly confidential information in accordance with the Commission's rules, until completion of the resource acquisition process, i.e. until the last contract for a resource that meets a portion of the 2016 ERP resource need is signed. Upon completion of the resource acquisition process, Public Service will post on its website the following bid information:

- Bidder Name
- Bid Price (Utility Cost for Utility–Owned Proposals)
- Generation Technology Type
- Size of Facility
- Contract Duration (Expected Useful Life of Utility Resource)
- Purchase Option Details as relevant

In accord with Rule 3613(j) within fourteen months after completion of the resource acquisition process, Public Service will make public any confidential information that was redacted from Public Service's testimony and reports by re-filing the testimony or report in an un-redacted form.

If any Public Service highly confidential modeling inputs and assumptions, listed above under highly confidential information are entered into the record in any manner, Public Service will seek to indefinitely continue the protection ordered by the Commission.

2.11 OTHER ISSUES REQUIRED TO BE ADDRESSED BY COMMISSION ORDER

Section 2.11 includes discussion of several miscellaneous issues that the Commission ordered the Company to address in its next ERP. These issues include:

1. Accounting Standards
2. Annuity Tails
3. Filler Capacity Credit
4. Surplus Capacity Credit
5. Gas Price Volatility Mitigation
6. Highly Flexible Resources
7. Carbon Proxy Pricing in Phase II

Commission Decision No. C13-0094 (2011 ERP Phase I) required the Company to file in a new docket the proposed approach for addressing new accounting standards after 2011 ERP Phase II and when it is reasonably certain that the new standards will be implemented.

Commission Decision No. C13-1566 (2011 ERP Phase II), paragraphs 37-41, directed the Company to address "Future ERP Issues" (issues #2-#7 listed above) in its next ERP filing.

Accounting Standards

Certain accounting guidance on leases, variable interest entities and derivatives can present financial complexity and challenges related to purchases of energy and capacity by Public Service through power purchase agreements ("PPAs").

Leases

Under current accounting guidance, leases are classified into two categories: operating leases and capital leases. Historically, significant financial challenges could result if an executed PPA was determined to be a capital lease.

Public Service has historically sought to avoid capital leases due to the potentially negative effect that capital leases can have on items such as:

- Debt-to-Equity Ratios
- Interest Coverage
- Return on Assets
- Operating Margins
- Enterprise Value/EBITDA
- Timing of Recovery – Regulatory (difference between cash flow and return on assets)

However, because any PPAs chosen in this upcoming resource planning process will be evaluated under the new lease accounting standard, the remaining discussion of leases focuses on the new accounting requirements and related financial impacts. In regards to the expected financial impacts of implementing the new lease accounting standard, Public Service believes that the credit reporting agencies and other financial statement users in general will appropriately adapt to the required changes to the financial statements – particularly the requirement that operating leases be recorded to the balance sheet – with an understanding that the economics of Public Service's PPAs have not changed. Nonetheless, the new requirement to recognize all operating leases on the balance sheet will directly impact several of the ratios and financial measures listed above, if not adjusted.

As further discussed in the section that follows, there remains risk under the new standard that the front-loaded expense of a capital lease (called a ***finance lease*** in the new standard) in excess of cash lease payments may not be recovered or deferred in Public Service's GAAP financial statements, and may cause negative financial impacts. For this reason, Public Service will similarly seek to avoid finance leases just as it sought to avoid capital leases under the existing lease standard.

Additionally, it's uncertain at this time whether assets and liabilities associated with finance leases will be viewed differently than those for operating leases by credit rating agencies and other users of the financial statements. If a new PPA selected in the resource planning process results in an increase in the economic debt to total capitalization ratio used by credit rating agencies and other users of the financial statements, Xcel Energy may need to infuse equity into Public Service, increasing Public Service's overall cost of capital.

New Lease Accounting Standard

Accounting Standards Codification (ASC) 842 *Leases* was issued by the Financial Accounting Standards Board (FASB) in February 2016, and introduces several changes to how entities account for leases, including a requirement that all leases be presented on the balance sheet. Overall, based on its current understanding of the new lease guidance, Public Service does not expect the transition to the new lease rules to have a significant impact on its accounting for leases – other than presentation of leases on the balance sheet. The following summarizes the expected impacts of the new lease accounting standard on Public Service's PPAs.

Balance Sheet Recognition

Under ASC 842, all leases (both operating and *finance* leases) will be recognized on Public Service's balance sheet as ***right of use*** assets along with corresponding liabilities for future lease payments. Liabilities initially recognized on the balance sheet will typically be equal to the assets, each measured at the present value of future lease payments.

Income Statement Recognition

Contracts meeting the definition of a lease, but which do not qualify as *finance leases* under ASC 842, will be referred to as ***operating leases***, with lease payments recognized as expense on a straight-line basis.

Recognition of expense for a contract qualifying as a ***finance lease*** under ASC 842 is similar to expense recognition for a capital lease under accounting guidance effective as of the date of this filing, and will consist of (1) straight-line amortization of the right of use asset and (2) recognition of interest on the related lease liability using the effective interest method. This will result in a front-loaded pattern of expense recognition for each finance lease, with reductions in interest expense over time as the liability is amortized. Meeting any of the following criteria would result in the treatment of a lease as a finance lease (in the context of Public Service's PPAs):

1. The PPA transfers ownership of the identified plant assets to Public Service by the end of the lease term
2. The PPA provides an option for Public Service to purchase the identified plant assets that is reasonably certain to be exercised
3. The sum of the present value of future PPA payments and any residual value guaranteed by Public Service equals or exceeds substantially all of the fair value of the identified plant assets
4. The PPA term is for a major part of the remaining economic life of the identified plant assets

5. The identified plant assets are so specialized in nature that they are expected to have no alternative use to the independent power producer at the end of the lease term

In regards to criterion “1”, there are no existing or contemplated PPA terms that directly transfer ownership of plant assets to Public Service. For criterion “2”, it is difficult to foresee a set of circumstances under which Public Service would be considered, at the lease commencement date, reasonably certain of exercising a purchase option. Though Public Service will prudently seek to obtain purchase options in PPAs for the potential future benefit of its ratepayers and shareholders, considerable uncertainties will generally exist related to the future exercise of such options at the commencement date of a PPA, typically including but not limited to required CPUC approval of significant plant acquisitions.

In regards to criteria “3” and “4”, it’s expected the current capital lease guidelines, (a) to determine whether sum of the present value of future lease payments (adjusted capacity payments) and any guaranteed residual value are greater than or equal to 90 percent of the fair value of the asset and (b) to determine whether a lease term is greater than or equal to 75 percent of the remaining economic life of the asset, will be part of the practical framework entities utilize to determine whether a lease meets criteria “3” and “4”, respectively.

For criterion “5”, given the inherent marketability of a generating resource with remaining economic life, plant assets that do not meet criterion “4” would likewise not be expected to meet criterion “5”.

ASC 980 *Regulated Operations* generally provides entities with leases utilized in regulated operations the ability to modify the pattern of expense recognition to be consistent with expense allowed for ratemaking purposes. However, per ASC 980 guidance on *phase-in plans*, regulated entities cannot defer expenses that would otherwise be recognized under general GAAP (including lease expenses) if the costs are associated with *major, newly completed plant*. A significant plant utilized under a PPA can qualify as major, newly completed plant.

Consistent with Public Service’s past practices, in order to prevent the negative impacts associated with any inability to recover or defer excess front-loaded lease expense, Public Service will seek to negotiate and structure terms of any PPA(s) selected in the resource planning process such that executed PPA(s) will not meet the finance lease criteria. Finance leases will also be avoided in order to mitigate the risk that assets and liabilities associated with finance leases will be viewed negatively (relative to operating leases) by credit rating agencies and other users of the financial statements. PPA negotiation and structuring efforts could include shortening the life of a given PPA and/or shifting costs from fixed contractual payments (e.g., for capacity) to variable payments for energy.

Scope and Transition
In regards to whether PPAs will qualify as leases under the new guidance, it's expected that if Public Service controls *when* a *specified* plant operates (i.e., controls dispatch), as in most fossil PPAs, the arrangement will be classified as a lease. When Public Service does not control dispatch, as in most renewable energy arrangements, further qualitative evaluation of other factors, including control over activities such as plant design, will be required to determine whether an arrangement contains a lease.
If a renewable PPA is determined to contain a lease, but all payments under the PPA are contingent on the production of energy (i.e., dependent on wind conditions or solar irradiance), based on Public Service's preliminary understanding of the new lease standard, it's expected that Public Service would conclude that there are no future lease payments (as defined in the accounting guidance), in which case there would be no significant financial statement impacts of classifying the renewable PPA as an operating lease.

The new guidance is effective on Jan. 1, 2019, with required retrospective application to the earliest year presented in the financial statements. The Public Service Form 10-K for the year ending Dec. 31, 2019 will contain consolidated balance sheets for Dec. 31, 2019 and 2018, and consolidated income statements for the years ended Dec. 31, 2019, 2018 and 2017. Therefore, under the method Public Service expects to utilize for the transition, the new accounting guidance will be applied to contracts entered or significantly modified after December 31, 2016. For PPAs that already exist at Dec. 31, 2016 and are not subsequently modified ("pre-2017" PPAs), arrangements that were determined to be leases under prior accounting guidance will continue to be treated as leases under ASC 842.

Additionally, under the practical expedients provided by ASC 842 at transition, pre-2017 PPAs that were determined to be operating leases under prior accounting guidance will be treated as operating leases under ASC 842 for the purposes of income statement recognition; however balance sheet recognition will be required. Likewise, any pre-2017 PPAs previously accounted for as capital leases would be treated as finance leases under the new guidance. However, no existing or contemplated Public Service PPAs have been determined to qualify as capital leases under the current accounting guidance currently effective as of the date of this filing. Public Service expects no significant income statement impacts as a result of applying the transition guidance to pre-2017 PPAs.

Since Public Service's renewable PPAs generally do not qualify as leases under the current accounting guidance, the most significant expected impact of transition to ASC 842 for pre-2017 PPAs is balance sheet recognition of the present value of remaining future lease payments for fossil PPAs that qualify as operating leases under accounting guidance currently effective as of the date of this filing.

Resource Plan Implications

PPA Negotiation and Structuring

Following Jan. 1, 2019, since ASC 842 will apply retrospectively to all leases which commence or are modified after Dec. 31, 2016, it's reasonably assured (given the procedural schedule of the resource plan and RFP) that any PPAs executed as a result of this resource planning process will be accounted for under the new guidance, and the *grandfathering* of prior lease classifications in the transition guidance for pre-2017 PPAs will not apply.

In summary, it remains Public Service's intention to mitigate negative accounting and financial impacts of PPAs to the greatest extent possible in the bid selection and negotiation processes. Public Service intends to negotiate and structure the terms of any selected PPA so that the resulting executed contract(s) do not qualify for finance lease treatment under the new lease accounting standard, similar to how Public Service has historically pursued PPA terms that avoided capital lease treatment under the existing lease standard. As discussed, PPA negotiation and structuring efforts could include shortening the life of a given PPA and/or shifting costs from fixed contractual payments (e.g., for capacity) to variable payments for energy.

Variable Interest Entities

The accounting guidance of ASC 810 *Consolidation* requires Public Service to consider the activities that most significantly impact an entity's[24] financial performance, and Public Service's ability to direct those activities, when determining whether an entity is a Variable Interest Entity (*VIE*) and whether Public Service is the VIE's primary beneficiary. If it is determined that Public Service is the primary beneficiary of the VIE, the standard requires that the VIE's full GAAP financial statements be consolidated into the financial statements of Public Service.

To understand the potential impacts of consolidation, it's important to make a distinction between the consolidation of an independent power producer's financial statements (or those of a subsidiary of the independent power producer) versus the balance sheet recognition that will be required under the new leasing standard for PPAs that qualify as leases and have non-contingent future lease payments.

As explained in the previous section, under the new lease standard, Public Service will be required to present right of use assets and lease payment liabilities consistent with future non-contingent future lease payments on all PPAs that qualify as leases. Consolidation under ASC 810, on the other hand, would involve Public Service

[24] The entity of concern in this discussion is an Independent Power Producer with a PPA with Public Service.

reflecting all operating, investing and financing activities of the variable interest entity that owns the generating resource, including depreciation, O&M and interest expense in Public Service's financial statements. Assets and debt of the variable interest entity would be reflected as assets and debt on Public Service's financial statements. Equity and earnings allocable to the Independent Power Producer and/or other equity owners would be reflected on Public Service's financial statements as equity and earnings attributable to a non-controlling interest(s).

Public Service seeks to avoid the consolidation of independent power producing entities financial statements (and those of their subsidiaries, as applicable) given the potentially negative impacts that consolidation could have on Public Service's financial metrics such as:

- Debt-to-Equity Ratio
- Interest Coverage
- Return on Assets
- Operating Margins
- Enterprise Value/EBITDA
- Timing of Recovery – Regulatory (difference between cash flow and return on assets)

The evaluation of whether an enterprise is an entity's primary beneficiary requires an assessment of the activities that have the greatest impact on the entity's economic performance, and control over those activities. Critical activities impacting the economic performance of a power plant typically include:

- Design and construction
- Directing how the facility is utilized over its economic life
- O&M decisions
- Financing decisions
- Tax decisions (utilization and policy for PTCs, ITCs)

Derivatives and Hedging

ASC 815 *Derivatives and Hedging* provides the primary guidance on accounting for derivative transactions. Because energy purchase contracts often qualify as derivatives, and these purchases are intended to provide for Public Service's normal operating obligations in serving retail and wholesale customers, it is important that these PPA contracts meet the criteria for the Normal Purchase Normal Sale ("NPNS") exception. Derivatives that do not qualify for the NPNS exception must be carried on the financial statements at fair value; absent a regulatory recovery mechanism, changes in the fair value of such derivatives may flow to the P&L and cause earnings volatility. As such, this is an outcome that Public Service will avoid during negotiation of a PPA.

Contracts that have a price based on a formula or index that is not clearly and closely related to the asset being sold or purchased cannot be considered for the NPNS exception. The analysis may include identification of the components of the asset being sold or purchased.

The underlying or price determinate for the price adjustment is not considered clearly and closely related to the asset being sold or purchased in either of the following circumstances:

- The underlying is extraneous (not pertinent) to changes in the cost and fair value of the asset being sold or purchased – or to such changes applicable to ingredients or direct factors in the production of that asset
- The underlying is not extraneous, but the magnitude or direction of the price adjustment is significantly disproportionate or inconsistent with the impact of the underlying on the fair value or cost of the asset being purchased or sold

In order to elect the NPNS exception, in addition to the requirements discussed above, the contract must also provide for the purchase or sale of something other than a financial instrument that is expected to be used by the entity over a reasonable period in the normal course of business.

Filler Capacity Adjustment

In the evaluation of power supply proposals (i.e., bids) in the Phase II acquisition process, the Company begins with the Phase I Strategist model used in the analysis of alternative plans and removes the generic resources that were added in the RAP period, thus creating a "resource deficiency" for the bid resources to fill. The generic expansion plan contained in the Strategist model beyond the RAP is kept the same for all portfolios, which is referred to as a "locked tail" modeling approach. By keeping the long term expansion plan the same, all bids are evaluated against a common future representation of the Public Service power supply system. The Phase II analysis then fairly represents the economics of the various bids based only on the characteristics of the bids themselves, eliminating any cost impacts that could arise by allowing advancement or deferral of the generic CT and CC resources in the expansion plan beyond the RAP.

To facilitate this modeling approach, it is sometimes necessary to slightly adjust the native long or short position of the base model in years following the RAP so the bids can be evaluated correctly. This is a by-product of the process whereby the generic RAP resources are removed from the model, but the post-RAP tail is maintained. In the likely case where the sum of the generic RAP resources' firm capacity does not exactly equal the adjudicated RAP capacity need, there may be some post-RAP years where the existing tail plus a perfectly sized RAP portfolio either fails to create sufficient capacity margin or creates a significant excess capacity margin.

As an example, suppose the generic Phase I model added 3 CT's at 192MW each, for a total of 576MW. At some point in the future, for example 2034, the combination of these 3 CT's plus the future expansion plan and load growth through 2034 results in a net positive capacity surplus of 30MW for that year. Continuing the example, suppose the actual RAP need per the L&R is only 500MW and at least one portfolio of bids can be constructed that meets this need exactly at 500MW. Once the 3 CT's are removed, and the 500MW bid portfolio added, 2034 will now show a capacity deficit of 46MW (30MW - 576MW + 500MW = -46MW). Thus, even though a portfolio is available that fulfills the RAP need requirement, the Strategist model will need to add another resource in 2034 to meet capacity margin requirements, and incorrectly penalize the portfolio by adding the cost of this superfluous resource to its economics.

To avoid this situation, a zero-cost capacity adjustment can be made to 2034 such that a "perfect" 500MW portfolio will clear the model without causing a superfluous resource to be added (in this case adding a +46MW adjustment to 2034 would be the correct value). This adjustment is made in the base model, so all bids benefit from the same adjustment. As all bids are evaluated using the same adjustment, and there is no dollar cost associated with the adjustment, it does not prejudice the modeling for or against any bid or portfolio of bids in any manner. A portfolio smaller than the RAP need will still require additional resources, a portfolio exactly equal to the RAP need will clear successfully with no penalty or credit, and a larger portfolio will receive the surplus capacity credit for any length above the RAP need.

In addition to these adjustment to ensure a perfectly sized portfolio is accepted by the model, an additional adjustment may also be made to ensure that the full amount of adjudicated allowed surplus capacity credit is made available to larger portfolios. After the tail is created and the generic RAP resources are removed, there will most likely be certain years where the model still shows some level of capacity surplus above those of the minimum requirements - this is most often seen in years that large CC units are added. In this situation, some portion of the allowed surplus capacity credit (up to 500MW based on the Company's Phase I proposal) is used up by the tail and is not available for use by a bid portfolio. To avoid this issue, an offsetting zero-cost capacity adjustment is made to ensure the full 500MW of allowed credit is available to a bid portfolio for that year. As with the previous case, all bids are evaluated using the same adjustment and it does not prejudice the modeling for or against any bid or any portfolio of bids.

Note that both of the adjustments are applied in the Phase II bid evaluation process solely for the purposes of creating a fair and consistent modeling framework. Neither adjustment is used in the Phase I modeling.

Surplus Capacity Credit

In previous ERP proceedings, the issue of "how", "if", and "at what level" excess generation capacity should be valued has been a subject of discussion. Clearly, some level of excess capacity above required reserve margins has economic value for several reasons, as discussed below. However, the quantified monetary value and to what amount is subject to debate.

In the simplest case, having a surplus capacity margin in a future year results in excess capacity that could potentially be sold by the utility (predicated on finding a willing counterparty) and readily monetized. The quantity and price at which the parties would transact would depend on the then-current marketplace and the other alternatives available to the counterparty, but the excess capacity would certainly have intrinsic non-zero economic value, whether realized or not.

Having excess capacity in a given year also carries forward and can offset a requirement to procure capacity in a later year. As a numerical example, if a utility has a 100MW surplus in a given year, and then experiences 75MW of load growth the subsequent year, it would have had to procure that 75MW if not for the carried forward surplus from the previous year. This deferral of capacity procurement also has non-zero economic value.

In a market-based approach to capacity valuation, there must always be a non-zero value for capacity for transactions to occur. To estimate what the expected "market value" would be, one must take a long term view of what would result in overall stability of the market whereby all participants are adequately compensated for having sufficient capacity installed (or contracted) to meet their reliability objectives. At the point where the overall market requires new capacity installed (the system grows beyond the level of current installed capacity and load-side management opportunities), the market must provide enough revenue to support construction. In this case, the market price would be the annual carrying costs of lowest-cost new construction. Granted, a market will experience certain years of surplus and carryover where no incremental capacity is needed, but given that a system-wide capacity deficit is not an option due to regulatory and reliability concerns, the overall long term market price must be at or above the cost of new entrants for sustainability.

Lastly, carrying excess capacity above the minimum requirements reduces shortage risk on the system. Assuming there is a real cost associated with failing to ensure reliability, any measure that reduces this risk must have some level of non-zero economic value proportionate to the risk mitigation it provides.

For all of the above scenarios, the expected value of surplus capacity converges to the cost to construct the lowest-cost new capacity resource. In the case of this ERP, the comparable value is the ECC representation of the costs for a new large generic combustion turbine, which is the lowest cost capacity alternative modeled.

The remaining question is how much surplus capacity has economic value. In purely economic terms, essentially all capacity would have value, but for system planning and modeling purposes this must be tempered. In the case of the risk mitigation example, even though all capacity reduces risk somewhat, the first tier of excess provides the most mitigation, with each subsequent tier providing less mitigation. At some point, the amount of risk reduction provided converges asymptotically to zero. In the market-based approach, at some point when the overall market is satisfied, the value of the excess will also converge to zero.

For planning and modeling, one does not want to reward infinite levels of capacity and create portfolios that are much longer than would ever be realistically expected or deemed prudent. However, in addition to the economic reasons for recognizing the intrinsic value of excess capacity, providing credit for surplus to some level also leads to better modeling results by helping offset the “lumpiness” of the expansion plans due to the size differences of the resources offered.

A simple explanation is the comparison between combustion turbine and combined cycle units. Each alternative has a different relationship of construction costs vs. operating costs. The combustion turbine has lower construction costs (on a per-MW basis) but higher operating costs while the combined cycle is the opposite (higher construction costs and lower operating costs). Ideally we would want planning models to accurately determine the value of this tradeoff and select the resource options that match the system’s needs, both for capacity and energy. If the system primarily needs capacity, select the CT; if the system has a significant energy need, select the CC. However, the size difference of the alternatives complicates this analysis. The generic CC is 658MW while the CT is only 192MW. Thus, if the capacity need in a given year is only 150MW, selecting the CC will result in procuring much more capacity than the minimum required, and the model will be prejudiced against selecting it and incurring the carrying costs of the excess for several years. In the Phase I modeling, with the capacity credit proposed as the costs of a CT, the CC will still incur a penalty for the size difference, but the penalty is reduced to only the incremental cost difference (in $/MW) between CC technology and CT technology, i.e. reflective of the technologies themselves, not simply the size difference. This results in a more accurate representation of what the system actually needs.

The Company has proposed allowing up to 500MW of surplus capacity above minimum needs to receive credit. This is close to the size differential between the generic CT and CC, and is also a reasonable tradeoff between allowing zero and an infinite amount of surplus capacity to receive credit. This equates to approximately 6% above the minimum capacity obligation in 2023.

Gas Price Volatility Mitigation Adder (GPVM)

Background

During the course of the 2011 ERP the use of the Gas Price Volatility Mitigation ("GPVM") adder was a contested issue among some parties. Specifically, during Phase I of the 2011 ERP the Colorado Gas Producers ("CGP") argued that the use of GPVM in the modeling of Phase II was unnecessary, and was duplicative to the costs that the Company incurs in its existing gas price risk management program. The Company responded that although the Company has a gas price risk management program, this program only contemplates short term mitigation efforts and is fundamentally different than the GPVM used in an ERP process to evaluate different generation technologies. The Commission ultimately permitted the use of the GPVM in its evaluations during the Phase II all-source solicitation in the 2011 ERP. The following is an excerpt from Commission Decision C14-0094 addressing the use of GPVM for modeling and portfolio evaluation:

> "Because Public Service has a long-standing GPVM program, which incurs actual costs to mitigate volatility, it is appropriate for the Phase II modeling to represent such costs. We therefore approve Public Service's GPVM adder for use of [sic] this ERP."

In its comments to the Company's 120-Day Report, Staff reexamined the use of the GPVM adder and its impact on the Phase II modeling. Specifically Staff stated "Staff questions whether the Company has gone beyond the stated intent of the Commission's decision that modeling should represent actual costs to mitigate volatility."[25] While Staff is correct that the Commission relied on the existence of the Company's gas price mitigation program to justify the use of the GPVM in modeling, the Commission did not order the Company to exclusively reflect the anticipated costs of the gas price mitigation program through the GPVM adder. In fact, although there are contextual similarities between the GPVM adder and the Company's gas price risk mitigation program, the two items are different and are intended to represent or effectuate very different results; Staff's direct comparison of the two is inappropriate and was addressed in the rebuttal testimony of Mr. Carter in the same proceeding.[26]

In the Independent Evaluator's Final Report in Proceeding No. 11A-869E, the IE did not identify any issues with Company's implementation of the GPVM in the Phase II

[25] Staff's Comments on Public Service's 2013 120-Day Report, Docket No. 11A-869E

[26] Corrected Rebuttal Testimony of Timothy J. Carter, Docket No. 11A-869E.

modeling.[27] Notwithstanding, the Commission in its Phase II order directed the Company to address the use of GPVM in greater detail in its next ERP.

Gas Price Volatility Mitigation Adder

The Company believes that the GPVM adder is still an appropriate modeling convention which represents a valid and supportable means to compare different generation technologies over time, and the Company has therefore proposed to continue employing the use of the GPVM adder in this 2016 ERP. As in the 2011 ERP, the Company is proposing to calculate the GPVM adder using an “at the money” Colorado Interstate Gas (“CIG”) call option covering a forward looking ten year period. The GPVM adder will be applied to each MMbtu of gas consumed in the model that is not supplied by a firm price contract.

In order to better understand the GPVM adder and what it is intended to accomplish, it is important to understand the function of an “at the money” call option. Generally speaking, a call option gives the holder of the option the right, but not the obligation, to purchase an asset at a known price (known as a “strike price”) at a known time in the future (the “expiration date”). Call options are primarily available for publicly traded commodities and equities, but are available for a wide array of different financial products. An “at the money” call option is simply an option with its strike price set at the current price of whatever it represents. In the case of a CIG call option, if CIG gas is currently priced at $2.50/MMbtu, a single “at the money” call option would give the holder the right to purchase one MMbtu of CIG gas at $2.50 when the option expires. The cost of an “at the money” call option is known as the option premium, and is primarily determined by two variables; the price volatility of the underlying commodity and the length of time until the option will expire. The option premium is not only dependent upon these two variables, but can also vary over time depending on many different market forces. By adding the GPVM to the forecasted cost of natural gas used for modeling, the model now represents every MMbtu of gas backed by a call option. In its essence, the GPVM represents the cost to lock in the forecasted cost of natural gas such that it is no longer subject to price fluctuation over the entire study period.

The use of the GPVM in the context of the ERP is a modeling convention, and is not designed to represent the cost of the actions taken in the gas price risk mitigation program. The gas price risk mitigation program is short term in nature, seeking to abate fuel cost risk for the upcoming heating season using a mix of financial contracts (such as call options or futures contracts), long term supply contracts, and physical storage. By applying the GPVM to the cost of natural gas, the model is adding the option premium (i.e. GPVM adder) so that natural gas is now represented in the model as a

[27] “Accion does not contest assertion and further recognizes that Public Service modeled the GPVM consideration consistent with the directions in the Phase 1 order.” Independent Evaluator’s Final Report Public Service Company of Colorado 2013 All-Source Solicitation, page 20.

known cost which is no longer subject to price changes. The additional cost of the GPVM accounts for the risk premium associated with energy costs from natural gas fired generation. Presenting natural gas a known quantity permits the fair comparison of costs over long periods of time between those generation technologies which do not incur a fuel price risk such as wind and solar against those generation technologies that do.

Annuity Tails

Background

In the 2011 ERP, there was a significant amount of discussion surrounding the most appropriate technique for approximating the replacement cost of Phase II bids offering a PPA for a time period less than what would be needed for the bid to last through the planning period. The Company originally proposed to use an ECC representation of a utility self-build project to life-extend bids that expire before the end of the resource planning period. During the course of the proceeding, parties advocated for a different approach where the Company would use a representation of a continuation of the originally bid contract referred to by parties as the "annuity method" to backfill the remaining years of the planning period. In Commission Decision No. C13-0094 addressing Phase I of the ERP, the Commission found it appropriate to require the Company to evaluate the results of the Phase II Solicitation using a utility self-build backfill or "tail" as a primary method, as well as a sensitivity using the annuity method. The following is an excerpt from Commission Decision No. C13-0094 discussing the annuity method:

> "We agree with Staff and CCT that the Company's proposal to use utility self-build estimates could result in IPP projects costs being unfairly inflated in comparison to utility proposals under certain circumstances. Consistent with our discussion on the issue in Decision No. C08-1153 in the 2007 ERP, we find that IPPs could re-bid existing capacity at new costs, or if the market is oversupplied the bid prices might be significantly discounted from the cost of new capacity. Therefore, we require Public Service to present in its 120-day report the "bookends" with a range of costs to represent the boundaries of potential future prices for the replacement of expiring bids. We approve Public Service's proposed utility self-build approach as one boundary and set the annuity method used in the 2007 ERP for the other boundary."[28]

Consistent with the Commission Decision No. C13-0094, the Company implemented the use of an annuity tail to backfill utility self-build proposals and PPA bids as a sensitivity analysis in its evaluation of the bids received in the 2013 All-Source Solicitation. In order to calculate an annuity tail, the Company converted the nominal bid prices to real dollars then repeated the bid in real terms throughout the planning period. As all model costs are input as nominal dollars, it was then necessary to adjust the real dollar streams to nominal dollars. This treatment is consistent with how all other cost inputs are modeled.

Following the filing of the Company's 120-Day Report Staff and CIEA filed comments questioning the Company's implementation of the annuity method in the evaluation of

[28] Decision No. C14-0094, Proceeding No. 11A-869E, Paragraph 197.

the solicitation. Specifically, both parties cited the Company's method of repeating the bid prices in real dollars which were then converted to nominal dollars (i.e. inflation adjusted dollars) instead of simply repeating the unadjusted bid prices through the remainder of the planning period as an incorrect application of the annuity method. Both Staff and CIEA cite a whitepaper from Boston Pacific Company Inc.[29] as the basis for how the annuity method is to be applied for purposes of extending bid pricing in order to create bids of equal lives. However, the use of the whitepaper is misplaced, as the Boston Pacific whitepaper does not address application of the annuity method for purposes of extending bid pricing to put proposals on an equal life basis. The whitepaper does enumerate another method of evaluating proposals of unequal lives which it calls "The Filler Method". The Filler Method employs an assumption of what the cost of replacement power supply will be to "fill in" the planning period after the expiration of the original bid, which in the case of the "annuity method" is a representation of the continuation of the original bid. The whitepaper specifically discusses the use of inflation adjustments to the cost replacement power supply as a common assumption when employing the Filler Method.[30]

Furthermore, the results of implementing the annuity tail method under the Company's approach did not demonstrate a significant departure from the results of implementing the utility self-build tail. Staff noted the lack of deviation of the results under the different methods as evidence of a failure of the Company's implementation of the annuity method. The Company disputes these representations that alignment of the results of the utility self-build tail method and the annuity tail method is an indication that the annuity method was improperly implemented. The assertion that these two methods should result in meaningfully divergent results is a flawed assumption. Specifically, this argument assumes that the utility self-build project will always be more expensive than existing IPP generation. In reality the market forces that drive the prices bid by IPPs for existing generation (e.g. market for capacity, cost of labor and O&M, capital recovery) are not completely divorced from the market forces which drive the costs of new utility-self build generation (e.g. the cost of combustions turbines and the existence of viable brown-field expansions sites). All of the factors which underlie the bid prices of an IPP or the cost of utility self-build are interrelated at a fundamental level.

The Independent Evaluator ("IE") reviewed the Company's implementation of annuity tails and found no issues with the methodology employed by the Company.[31] The IE

[29] Boston Pacific Company, Inc. "Bid Evaluation Methods in Competitive Solicitations: A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives" Prepared for Calpine Corporation. ("Boston Pacific Whitepaper")

[30] Ibid.

[31] "However, using the annuity method to provide a reasonable low-cost bookend is not entirely straightforward and thus we do not fault the Public Service approach." P.19, Independent Evaluators Final Report, Proceeding No. 11A-869E.

correctly noted that annuity method may not result in a lower cost bookend because "[the annuity method] effectively replicates the cost structure of the entire bid", which is the fundamental objective of the annuity tail. If the original bid does not compare favorably against other bids with a utility self-build tail, it is reasonable to assume that repricing the tail using an annuity method would result in the same outcome, as was demonstrated by the Company's results in the 120-Day Report.

The Company filed responsive Comments supporting the methodology that was employed by the Company in the annuity method analysis. Specifically, the Company supported the use of nominal dollars (e.g. inflation adjusted) versus unadjusted bid prices in the analysis, and provided industry sources and relevant literature to corroborate the assertions of the Company that the use of nominal dollars is appropriate.

In Decision No. C13-1566, the Commission addressed the Phase II bid evaluation process, as well as the concerns raised by parties in comments. Specifically the Commission ordered the Company to present the annuity method as contemplated by Staff and CIEA, and discuss its potential implementation with regard to modeling in its next ERP:

> "With respect to the annuity tails, we direct Public Service to present in its next ERP, at a minimum, the more traditional annuity method as discussed by CIEA on how the approach should be implemented in modeling."

<u>Annuity Method as Advocated by CIEA</u>

CIEA offered in its Comments to the 120-Day report its preferred methodology for implementing an annuity tail:

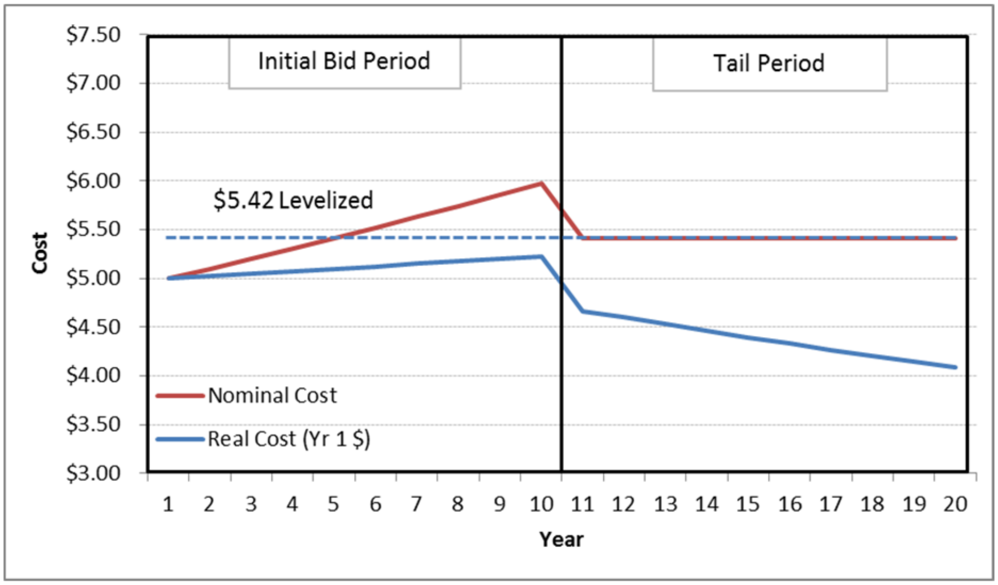
> "To the extent the Commission wishes in its Phase II Order to address how the annuity issues should be handled in future proceedings, CIEA urges the Commission to direct Public Service to utilize a more traditional annuity method that simply extends into the tail period the levelized price annual price of the IPP bid during the entirety of its initial term."

The Company has concerns with the CIEA methodology of applying an annuity tail and its applicability to the evaluation process. Specifically, the method of bid life-extension would fail to effectively replicate the originally bid costs, and would result in a cost stream which would decrease in real terms. Additionally, implementing this approach to only certain costs (e.g. replacement costs of IPP bids) would lead to a nonsensical result when evaluating those bids in the Strategist model in which all future costs (gas prices, VOM, FOM, capacity costs to name a few) escalate at an assumption of future inflation. In order to properly apply the annuity method in the evaluation of bids it is necessary that the life-extension of the original bid be made for each year of the 40-year planning period. When developing these life-extension prices, and comparing them to other modeled costs, it is essential to ensure that the prices are expressed in nominal dollars which incorporate an assumption of inflation. As noted in *Principles of Corporate Finance,*[32] "when you use equivalent annual costs simply for comparison of costs per period…we strongly recommend doing the calculations in real terms." This is precisely the methodology employed by the Company; the bid prices in real terms were not adjusted for the purpose of implementing the annuity tail, they were merely repeated. The authors then add in a footnote, "[d]o not calculate equivalent annual costs as level nominal annuities", which is in direct conflict with the recommendation of CIEA to extend the initial bid with "…the levelized price of the IPP bid during the entirety of its initial term".

If the Commission were to order the Company to present the annuity method consistent with CIEA's comments, the Commission would essentially be instructing the Company to model the annuity tail costs as a decreasing stream in real terms. To help illustrate this Figure 2.11-1provides an illustrative example of the annuity method in nominal and real terms as advocated by CIEA. In this illustrative example, the originally bid PPA is for a ten year term, has a first year price of $5.00 and a price escalation of 2% with an assumption of general inflation at 1.5%.

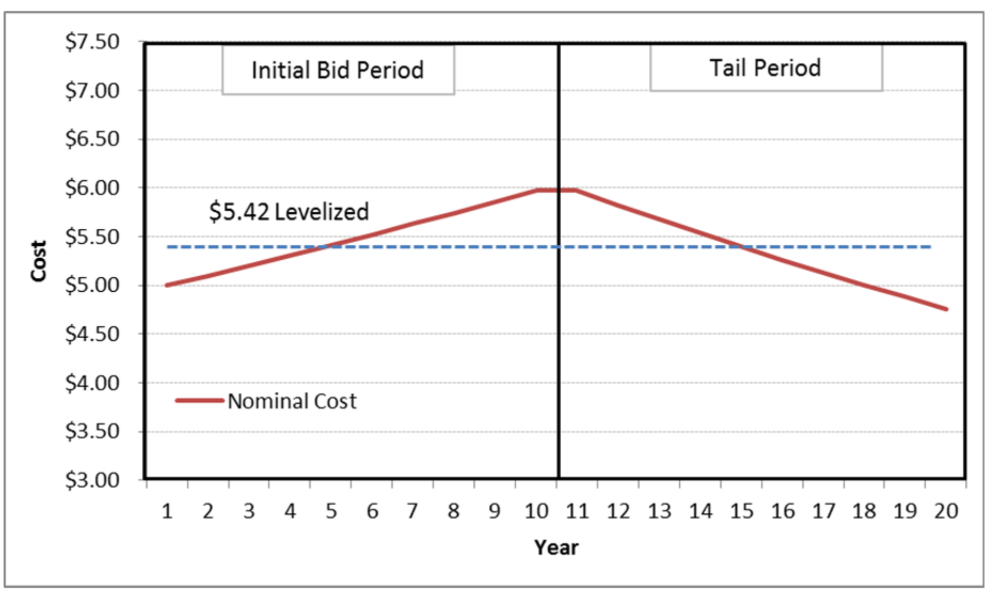
[32] See Brealey, R., Myers, S., Allen, F., Principles of Corporate Finance Ninth Edition McGraw Hill International Edition (2008) p. 158

Figure 2.11-1 Incorrect Annuity Method



As demonstrated in Figure 2.11-1, to effectuate CIEA's method for implementing an annuity tail would result in a tail that costs less in real terms than the originally bid PPA. The impact of this incorrect implementation is even more pronounced when it is demonstrated as a nominal continuation of the initially bid PPA. As demonstrated in Figure 2.11-2, if we were to continue nominal prices forward from the last year of the initial bid PPA, it is necessary to decrease nominal prices to achieve a financially equivalent levelized price from the combination of the initial PPA and the CIEA annuity tail.

Figure 2.11-2 Incorrect Annuity Method Nominal Price Extension



The Company does not believe that a tail period which effectively incorporates a decreasing tail period nominal price is a reasonable outcome to model or present as a basis for resource expansion decisions. This impact of this incorrect tail period is particularly troubling when it is being compared against other costs which are assumed to increase with inflation; it leads to an artificially low tail price which has no bearing on sound economic principles.

Figure 2.11-3 demonstrates the correct application of the annuity method wherein bid prices are repeated in real terms.

Figure 2.11-3 Correct Application of the Annuity Method

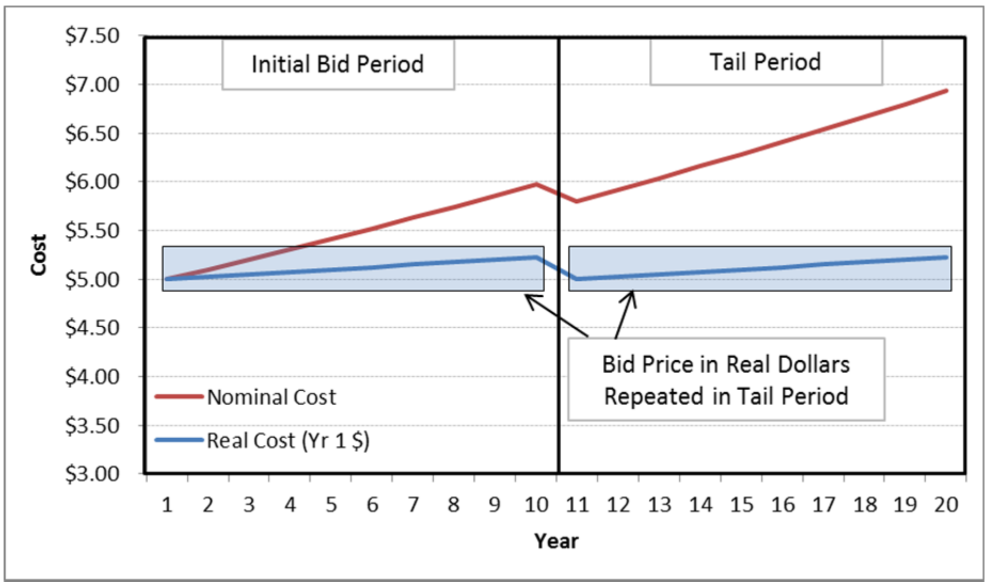


Figure 2.11-3 demonstrates that the Company's methodology results in the same bid being replicated in real terms.

All costs from all sources should be evaluated using consistent cost representations. To do otherwise would result in a meaningless representation of the life-extension cost of bids that is internally inconsistent with the base modeling assumption that other costs increase with inflation.

<u>Correct Implementation of the Annuity Method</u>

Consistent with the discussion above, the Company reasserts that it correctly implemented the annuity method in the evaluation of the 2013 All-Source Solicitation. As demonstrated in Figure 2.11-3 above, after the expiration of the initial PPA term the Company extended the bid with the same prices as originally bid in real terms, and then converted those costs to nominal dollars consistent with all other modeled costs. If the Commission wishes to have an annuity tail sensitivity performed in the evaluation of a future solicitation, the Company recommends that the Commission finds the Company's use of nominal dollars is appropriate.

Flexible Resources

In its comments regarding the Company's 120-Day report, WRA recommended that "in future renewable integration studies, the benefit of highly flexible resources be calculated in a very detailed manner." Although WRA did not provide any examples of how it would define "highly flexible resources", for this response the Company assumes such a definition is targeted at electrical storage devices such as battery storage.

The Company filed with the Commission in Proceeding No. 14M-1160E a study report titled "An Investigation of Potential Electric Storage Options" ("Storage Study") pursuant to the Commission's 2011 ERP Phase II order. As it stated in that study report, "the Company fully anticipates that if the forecasted reductions in bulk energy storage costs are achieved, electricity storage devices may constitute a growing portion of the tools it has available to safely and efficiently operate its electrical system in the future."

The Company would advocate that the potential benefits that storage devices such as batteries can bring to the system would be best studied independently and not as a subsection of a renewable integration cost study. As the Company showed in its Storage Study, the potential benefits of energy storage are varied and are much broader than renewable integration only.

In fact, the Commission recently approved two Innovative Clean Technology projects in which the Company will be testing a broader array of battery technology benefits than just renewable integrations. The Company is partnering with Panasonic Corp., Denver International Airport, and the City and County of Denver on a battery-based micro-grid with solar integration project near the airport. The Company is also adding battery storage devices in the Stapleton neighborhood of Denver in an area with high penetrations of rooftop solar arrays.

Carbon Proxy Pricing in Phase II

In Decision No. C13-1566, the Commission directed the Company to address whether to run a sensitivity case "assuming high carbon costs for all portfolios in future ERP modeling."

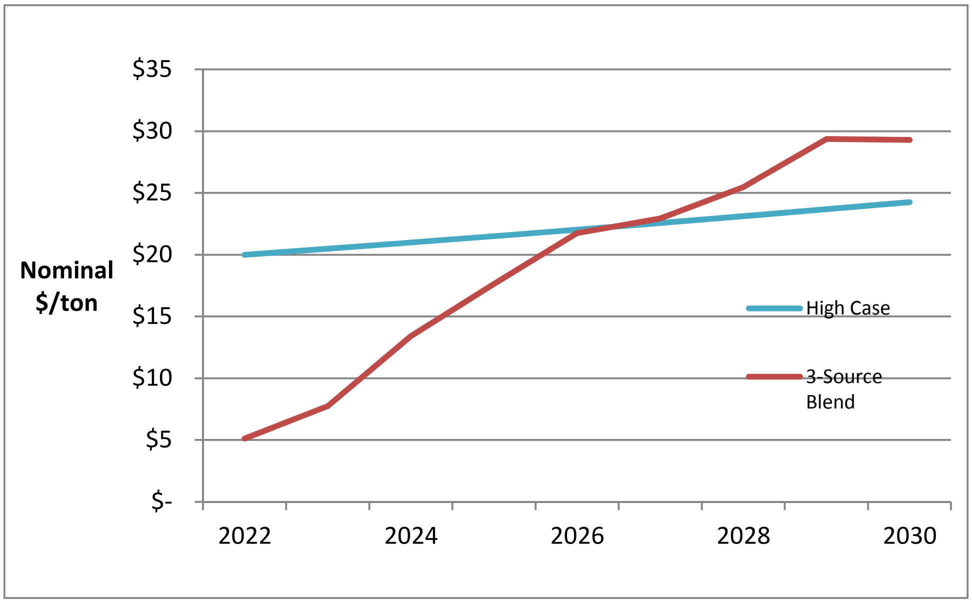
The Company proposes to address this Commission direction by providing two types of information in the Phase II filing. First, we will provide information showing how our preferred case, and also alternative cases with different levels of renewable energy, will address carbon dioxide emissions from our system and comport with potential requirements under EPA's Clean Power Plan (CPP). Second, because the CPP does not define all potential future carbon policy outcomes, we will also provide the Commission with two sensitivity cases reflecting a low and a high carbon proxy price.

The CPP analysis will provide information showing that Public Service's continued efforts to reduce emissions, coupled with our plan to add 600 MW of additional wind, positions the Company well to comply with potential CPP requirements. We believe this type of comparison to state-specific CPP targets provides useful information about likely CPP outcomes. We do note, however, that the CPP faces significant uncertainty. The CPP is currently under review by the D.C. Circuit Court of Appeals, and faces further review by the U.S. Supreme Court. If the rule is upheld, the state will then decide on a variety of implementation questions as discussed elsewhere in this ERP.

Given the uncertainty facing the CPP, and the possibility for other types of future carbon emissions regulation to emerge, we propose to continue the practice of applying carbon proxy pricing in sensitivity analysis cases in Phase II. Specifically, our reference case will be run without a carbon proxy price, and then we will present two alternative cases with high and low carbon proxy prices.

We propose that the High Case be the Commission's recommendation in the last ERP in Decision C13-0094: a $20 per ton carbon proxy price, escalating at inflation (2% per year based on current corporate assumptions). We will begin this value in 2022, rather than 2017, however, as there is no prospect of a price on carbon in Colorado in 2017, and the earliest we expect carbon pricing to begin is 2022, the current start year of the CPP. We have compared this Commission-recommended forecast, revised with the start date moved to 2022, to an average or "blend" of the latest forecasts from the three consultants we surveyed in the last ERP: Wood-MacKenzie, IHS, and PIRA. As shown below in Figure 2.11-4, the Commission forecast is higher than the Three-Source Blend for several years, and then lower until the blended forecast data stops. To extend the forecast out to 2054 for modeling purposes, we then escalate the High case at the rate of inflation, as shown later in Table 2.11-4.

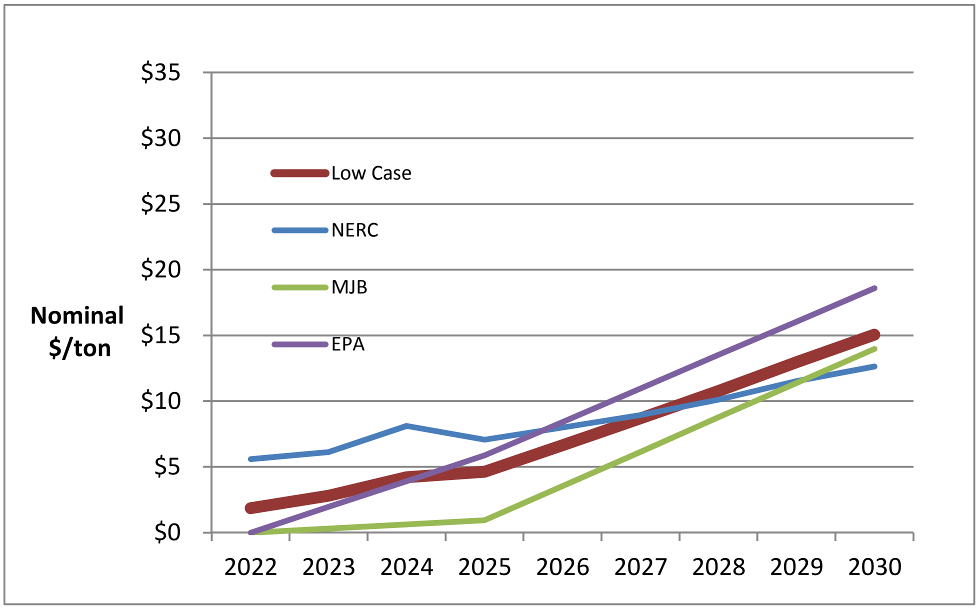
Figure 2.11-4 Modified Commission Carbon Price Recommendation and Three-Source Blend



We also propose to use a Low carbon proxy price case. We think a lower carbon proxy price is merited because recent CPP analysis suggests lower carbon prices than the three-source blend indicates, and because cost reduction trends in natural gas, wind, and solar generation generally suggest lower carbon prices under future carbon policy. We base our Low case on public modeling analysis and data from the U.S. EPA, North American Reliability Corporation, and Michael J. Bradley and Associates:

- U.S. EPA: Regulatory Impact Analysis for the Clean Power Plan Final Rule, August, 2015.
- North American Electric Reliability Corporation (NERC): Potential Reliability Impacts of EPA's Clean Power Plan, May, 2016.
- Michael J. Bradley & Associates: EPA's Clean Power Plan: Summary of IPM Modeling Results, January 2016.

Figure 2.11-5 Proposed Low Carbon Proxy Price and Sources



To develop the Low carbon proxy, we averaged or blended the values from the three sources between 2022 and 2030, interpolating point source values from EPA's and Michael J. Bradley's analysis as needed. Beyond 2030, we again escalated the forecast at the rate of inflation. We provide the values for our proposed Low and High price cases in Table 2.11-4 below. We will run these values in sensitivity cases in Phase II of this ERP.

Table 2.11-4 Proposed High and Low Carbon Proxy Price Values

	Nominal $/Short Ton	
	High Case	Low Case
Year	3-Source Blend	CPP Blend
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
2020	-	-
2021	-	-
2022	$20.00	$1.86
2023	$20.49	$2.79
2024	$20.99	$4.21
2025	$21.50	$4.63
2026	$22.02	$6.65
2027	$22.56	$8.69
2028	$23.11	$10.79
2029	$23.68	$12.97
2030	$24.25	$15.06
2031	$24.85	$15.43
2032	$25.45	$15.81
2033	$26.07	$16.19
2034	$26.71	$16.59
2035	$27.36	$16.99
2036	$28.03	$17.41
2037	$28.71	$17.83
2038	$29.41	$18.27
2039	$30.13	$18.71
2040	$30.87	$19.17
2041	$31.62	$19.64
2042	$32.39	$20.12
2043	$33.18	$20.61
2044	$33.99	$21.11
2045	$34.82	$21.63
2046	$35.67	$22.15
2047	$36.54	$22.69
2048	$37.43	$23.25
2049	$38.34	$23.81
2050	$39.28	$24.40
2051	$40.24	$24.99
2052	$41.22	$25.60
2053	$42.23	$26.23
2054	$43.26	$26.86

Due to the current direction of U.S. carbon policy, we believe the $50/ton proxy price discussed in consolidated Proceeding No. 11A-869E (and referenced generally in Decision No. C13-1566) is too high and unlikely to represent any near-term policy outcome. This is the case for several reasons. First, as shown above in our Low carbon proxy case, recent CPP analysis does not support values this high. Second, stepping away from modeling and looking to actual allowance prices also does not show prices at the $50/ton carbon price level. Rather, actual allowances prices from two North American carbon markets are relatively low. The Western Climate Initiative including California most recently traded at $11.55 per short ton (www.wci-auction.org), and the Regional Greenhouse Gas Initiative recently traded at $5.25 (http://rggi.org/market/co2_auctions/results). Furthermore, federal climate legislation has not been seriously considered by Congress in over five years.

2.12 LOAD AND RESOURCES TABLE

Table 2.12-1 Load and Resources Table (MW)

	2016	2017	2018	2019	2020	2021	2022	2023
Company-Owned Coal Subtotal	2,521	2,521	1,985	1,985	1,985	1,985	1,985	1,985
Purchased Coal Subtotal	248	150	150	150	150	150	150	-
Total Coal-Fired Generation	**2,769**	**2,671**	**2,135**	**2,135**	**2,135**	**2,135**	**2,135**	**1,985**
Company-Owned Gas-Steam Subtotal	0	0	352	352	352	352	352	352
Company-Owned CC Subtotal	1,836	1,836	1,836	1,836	1,836	1,836	1,836	1,836
Purchased CC Subtotal	379	379	379	250	250	250	250	118
Total Gas-Fired CC	2,215	2,215	2,215	2,086	2,086	2,086	2,086	1,954
Company-Owned CT Subtotal	726	726	726	726	726	726	726	726
Purchased CT Subtotal	1,069	1,069	1,069	1,069	1,069	1,069	813	813
Total Gas-Fired CT	1,795	1,795	1,795	1,795	1,795	1,795	1,539	1,539
Total Gas-Fired Generation	**4,010**	**4,010**	**4,362**	**4,233**	**4,233**	**4,233**	**3,977**	**3,845**
Company-Owned Storage Subtotal	**210**	**210**	**162**	**180**	**256**	**256**	**256**	**256**
Purchased Biomass Subtotal	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**-**
Company-Owned Hydro Subtotal	25	25	25	25	25	25	25	25
Purchased Hydro Subtotal	20	20	19	19	18	16	16	15
Total Hydro Generation	**45**	**45**	**44**	**44**	**43**	**42**	**42**	**40**
System Solar	47	130	130	129	128	128	127	127
Customer Choice Solar Total	92	92	91	91	90	90	90	89
Incremental Customer Choice Solar	6	22	68	102	137	170	202	233
Total Solar Generation	**145**	**244**	**289**	**322**	**356**	**388**	**419**	**448**
Company-Owned Wind Subtotal	-	-	-	-	-	-	-	-
Purchased Wind Subtotal	409	404	404	378	378	378	378	378
Rush Creek Wind	-	-	-	49	49	49	49	49
Total Wind Generation	**409**	**404**	**404**	**427**	**427**	**427**	**427**	**427**
SPS Diversity Exchange	**-**	**-**	**101**	**101**	**101**	**101**	**101**	**101**
Net Dependable Capacity	**7,591**	**7,587**	**7,501**	**7,446**	**7,554**	**7,585**	**7,360**	**7,103**
PSCo Load								
Native Load	6620	6712	6768	6884	6970	7102	7161	7225
Interruptible Load	537	555	575	598	623	623	623	623
Firm Obligation Load	**6,083**	**6,157**	**6,193**	**6,286**	**6,347**	**6,479**	**6,538**	**6,602**
Planning Reserve Margin								
Reserve Margin Requirement (MW)	992	1,004	1,009	1,025	1,035	1,056	1,066	1,076
IREA & HCEA Backup Reserves	40	40	40	40	40	40	40	40
Reserve Margin Requirement	**1,032**	**1,044**	**1,049**	**1,065**	**1,075**	**1,096**	**1,106**	**1,116**
Reserve Margin Actual	1,508	1,430	1,308	1,160	1,207	1,107	822	501
Resource Position (MW) (need)	**476**	**387**	**259**	**95**	**133**	**11**	**(284)**	**(615)**

2.13 REFERENCES

Attachment 2.13-1 Wind ELCC Study Report
Attachment 2.13-2 Coal Cycling Study Report
Attachment 2.13-3 Flex Reserve Study Report
Attachment 2.13-4 2GW/3GW Wind Integration Study Report
Attachment 2.13-5 Reserve Margin LOLP Report
Attachment 2.13-6 Appendix E from Proceeding No. 13I-0215E

An Effective Load Carrying Capability Study of Existing and Incremental Wind Generation Resources

on the

Public Service Company of Colorado System

Prepared by:

Xcel Energy Services, Inc.
1800 Larimer St.
Denver, Colorado 80202

May 13, 2016

Executive Summary

This report presents the results of a recent Effective Load Carrying Capability ("ELCC") study conducted on existing and incremental wind generation resources on the Public Service Company of Colorado (the "Company") system. The last wind ELCC study was conducted in 2007. The result of that study estimated a wind ELCC value of 12.5%.

The current study was designed to determine ELCC values for existing and incremental wind generation as a function of geographic location. At the end of 2015, the Company had ~2,580 MW of interconnected wind. The study examined up to 1,000 MW of incremental wind generation at three separate wind resource zones within Colorado. In addition, the study was designed to determine potential beneficial impacts of existing solar generation on the calculation of the wind ELCC values.

Based on the results of this study, the Company currently carries existing wind resources on its loads and resources tables at an average ELCC of 16% vs. the previous study value of 12.5%. Based on an existing wind portfolio of ~2,555 MW of wind, this increase in wind ELCC value results in approximately 90 MW of incremental net dependable capability. Study results also clearly show the degradation in wind ELCC that occurs at higher installation levels and a beneficial impact of including existing solar generation in the base generation portfolio when conducting the existing wind ELCC study.

Table of Contents

Page

Executive Summary....1

Introduction....3

Background....3

Prior Wind ELCC Study....4

Currently-Installed Levels of Wind and Solar....4

Study Methodology....6

Study Goals....7

Data Sources....7

Load Data Sources....8

Study Results....9

Existing Wind....9

Incremental Wind....11

Application of Study Results to Current Loads and Resources Table....12

Conclusions....13

Introduction

Background

In order to reliably serve its customers' electrical demands, Public Service Company of Colorado ("Public Service" or the "Company") forecasts expected, peak annual loads for its system as well as the ability of its existing and planned generation resources to reliably serve those forecast loads. For resource planning purposes, different generation technologies can be relied on to provide different levels of their nameplate generation capacity rating toward serving customer load. In general, the Company affords 100% of a dispatchable, fossil-fuel fired generator's summer net dependable capacity for resource planning purposes, but less than 100% of nameplate capacity for non-dispatchable, intermittent generation technologies such as wind and solar. Underestimating the contribution of intermittent generation resources to help meet forecast system peaks can result in the acquisition of additional generation capacity and higher system costs. Overestimating the ability of intermittent generation resources to help serve forecast system peaks can result in lower levels of system reliability and increased risks of customer load curtailment.

A facility's capacity credit (or capacity value) is frequently confused with the facility's capacity factor. A facility's capacity credit is a probabilistic measure of the fraction of the facility's nameplate rating (measured in MW) [1] that can be relied on to serve customer loads. A facility's capacity factor is the ratio of the total amount of energy (measured in MWh) that the facility is expected to generate over a specific time period to the maximum amount of energy it could generate if it were operated during the time period at full nameplate capacity; capacity factors are typically provided on an annual basis.

Although several methodologies have been proposed through which an intermittent generation resource's capacity credit can be estimated,[2] for its resource planning purposes the Company utilizes an effective load carrying capability ("ELCC") metric. The ELCC of a generator is defined as the amount by which a system's load can increase when the generator is added to the system while maintaining system reliability. Thus, ELCC study results are dependent upon the selection of a specific reliability target. In this study, as in its previous studies, the Company utilized a loss of load expectation ("LOLE") reliability metric of 1 day in 10 years.

[1] Unless otherwise indicated, the terms "MW" and "MWh" in this study report refer specifically to MW_{AC} and MWh_{AC}.

[2] See, for example, "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation", M. Milligan and K. Porter, NREL/CP-500-43433, June 2008 and "Photovoltaic Capacity Valuation Methods", T. Hoff, R. Perez, J.P. Ross, and M. Taylor, SEPA Report #02-08, May 2008.

Prior Wind ELCC Study

The Company last conducted a wind ELCC study in February 2007.[3] At the time of the study the Company had 280 MW of interconnected wind; the maximum total level of wind studied was 1,035 MW. The 2007 wind ELCC study found that a 12.5% ELCC for existing and planned wind was appropriate.

Currently-Installed Levels of Wind and Solar

At the end of 2015, the Company had ~2,580 MW of interconnected wind[4] and ~370 MW of interconnected solar distributed across the state of Colorado as illustrated in Figure 1 below.[5] Additional detail as to the distribution of wind and solar generation is provided in Tables 1 and 2.

Table 1 Wind Generation Portfolio by Geographic Location

Wind Resource Zone	MW
North	1,216
Ponnequin[6]	26
Limon	853
Golden West	249
Lamar	237
Total	2,581

All of the wind resources shown in Table 1 are interconnected at transmission voltage and, except for the Ponnequin facility, are acquired through purchase power agreements.

[3] "An Effective Load Carrying Capability Study for Estimating the Capacity Value of Wind Generation Resources", Public Service Company of Colorado, March 1, 2007.

[4] The total wind as calculated here does not include approximately 11 MW of research and development wind generators located at NREL's Wind Technology Center.

[5] The 120 MW_{AC} Comanche Solar facility shown in Figure 1 as "SFR Solar" is expected to be in-service by the summer of 2016.

[6] The 26 MW Company-owned Ponnequin wind farm was retired on 12/31/2015. Generation meter data from this facility was included in the North wind generation profiles used in this study.

Figure 1 Wind and Solar Geographic Zones

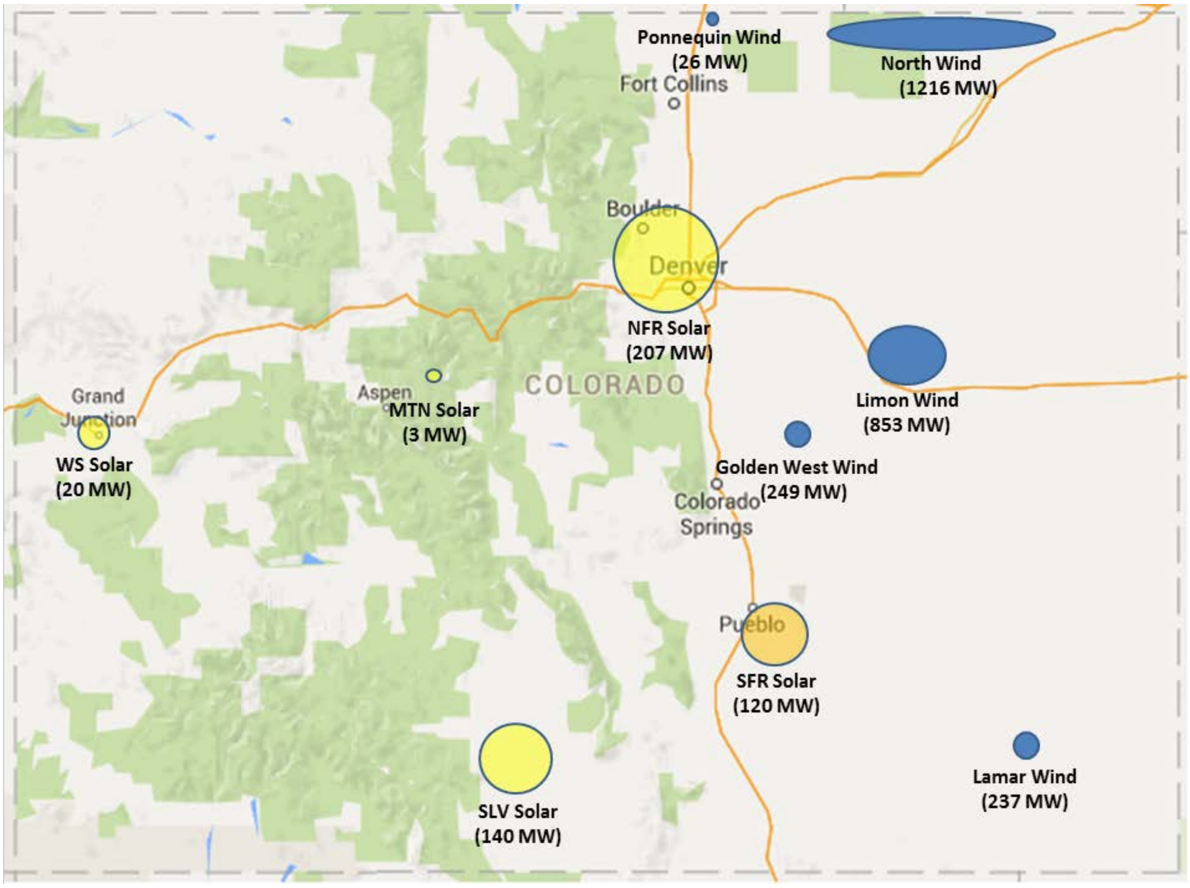


Table 2 Solar Generation Portfolio by Geographic Location and Tracking Capability[7]

	MW		
Solar Resource Zone	**Fixed**	**Tracking**	**Total**
Mountain (MTN)	3		3
Northern Front Range (NFR)	200	6	207
San Luis Valley (SLV)	3	138	140
Western Slope (WS)	19	2	20
	225	145	370
Southern Front Range (SFR)[7]		120	120
Total	225	265	490

[7] Behind-the-meter solar generation resources are typically acquired and denominated in MW_{DC} terms. In this study, those generation resources have been denominated in MW_{AC} terms using a conversion factor of 0.85. Differences between individual values and totals in Table 3 are the result of minor rounding errors.

Of the ~370 MW of installed solar at the end of 2015, ~155 MW are acquired through purchased power agreements including contracts from five, large-scale tracking units in the San Luis Valley and from smaller solar garden-type facilities located across Colorado. The remaining ~215 MW have been installed behind our customers' meters; of these generators ~85% has been installed within the Company's Denver metro area load center (Northern Front Range) in fixed orientations.

Study Methodology

The Company's methodology in this ELCC study follows the "Preferred Methodology" described in a 2011 Institute of Electrical and Electronics Engineers ("IEEE") publication[8] and the Effective Load Carrying Capability methodology described in a 2012 National Renewable Energy Laboratory ("NREL") publication.[9] Following the methodology in those publications, the steps the Company utilized to estimate the ELCC of the target wind generators were:

1. For the generation portfolio that the Company expects to be in-service starting in 2018,[10] the LOLE of the base system without the target generators was calculated for the annual period under study.
2. If the LOLE of the base system was not equal to the reliability target of 1 day in 10 years,[11] equal amounts of load were either added to or subtracted from each hour of the annual study period until the reliability target for the base system was achieved.
3. The target generators were added to the system and the LOLE was recalculated.
4. Keeping the target generators in the system, a constant load was added to each hour.[12] The level of the constant load was adjusted and the resulting LOLE recalculated until the portfolio LOLE once again achieved the target reliability.
5. The amount of load added in Step #4 was the ELCC of the target generators.

[8] "Capacity Value of Wind Power"; Keane, Milligan, Dent, Hasche, D'Annunzio, Dragoon, Holttinen, Samaan, Söder, and O'Malley. IEEE Transactions on Power Systems, Vol. 26, No. 2, May 2011.

[9] "Comparison of Capacity Value Methods for Photovoltaics in the Western United States"; Madaeni, Sioshansi, and Denholm. Technical Report, NREL/TP-6A20-54704, July 2012.

[10] The generation portfolio starting in 2018 reflects the final changes to the Company's coal-fired fleet resulting from the 2007 Colorado Energy Plan and the Clean Air, Clean Jobs Act of 2010; specifically, the retirements of Arapahoe Units 3 and 4, Cherokee Units 1-3, and Valmont Unit 5 and the operation of Cherokee Unit 4 on natural gas. In addition, it also reflects the addition of the gas-fired, combined cycle Cherokee Units 5, 6, 7 and the gas-fired generation acquired as a result of the Company's 2013 All-Source Solicitation.

[11] 1 day in 10 years = 0.1 day per year = 2.4 hours per year.

[12] The resulting LOLE in Step #3 was lower than the LOLE of the base system because an additional generator had been added, thus additional load must be added to increase LOLE.

Study Goals

The Company's goals in this study were to estimate the ELCC of:

1. Wind at existing levels of wind and solar,
2. Incremental levels of wind (as a function of geographic location) above existing levels of wind and solar.

ELCC values for the existing wind fleet are used on the Company's loads and resources tables to determine the need for incremental resources in order to meet planning reserve reliability targets. ELCC values for incremental wind resources are used to evaluate the economic value (e.g., avoided generation capacity costs) of proposed wind projects.

Numerous studies have illustrated the law of diminishing returns for the generation capacity credit attributable to higher penetrations of non-dispatchable generation.[13] That is, all else equal the value of avoided generation capacity attributable to incremental wind is less than the value of the avoided generation capacity of the existing wind. Thus it is important to evaluate how quickly wind ELCC values decrease at increasing levels of incremental generation.

At the start of the study, the Company also believed it important to evaluate the inter-relationship between wind and solar generation on the study results. The Company is a late-afternoon, summer peaking system and it is the level of wind or solar generation during these periods that most impacts the ELCC results. Typically wind generation from the Company's fleet is increasing from noon through this late-afternoon period while, of course, solar generation is decreasing as the sun drops lower in the sky.[14] Given that solar generation levels are higher in earlier portions of the afternoon peak period, it was expected that wind ELCC values would be higher for a generation portfolio that included solar.

The Company selected incremental tranches of wind generation at levels of 250, 500, and 1000 MW for this study.

Data Sources

To conduct the ELCC study, interval wind and solar generation meter data with hourly frequency were obtained. Table 3 below shows, for the seven year period of 2008-2014, the number of

[13] See, for example, "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California"; Mills and Wiser. LBNL-5445E, June 2012 and "Representation of Solar Capacity Value in the ReEDS Capacity Expansion Model"; Sigrin, Sullivan, Ibanez, and Margolis. Technical Report, NREL/TP-6 A20-61182, March 2014.

[14] In addition, the Front Range of Colorado is subject to summer afternoon monsoon conditions which typically results in increasing levels of cloud cover as the afternoon progresses.

wind farms with generation data available for a complete calendar year for each of the three geographic zones in which the Company has wind generation.

Table 3 Number of Wind Farms with Generation Data Available

Wind Resource Zone	2008	2009	2010	2011	2012	2013	2014
North	6	6	8	8	9	9	9
Limon					1	3	3
Lamar	2	2	2	2	2	2	2

As stated in the previous section, one goal of the study was to estimate the ELCC of the existing wind portfolio as shown in Table 1. The Company's most recently-acquired wind generator is the 249 MW Golden West facility located near the existing Limon geographical zone; however, this facility only entered service in October 2015. Given the lack of operational experience with this facility at the time the study was conducted, the Company elected not to assume an hourly generation profile for this facility and include it as an existing generator, but instead to study an existing wind portfolio of 2,332 MW which excluded it.

As Table 3 shows, no generation meter data exists prior to 2012 at the Limon location; however the Limon location currently accounts for between 33% and 40% of the installed wind generation,[15] which is a significant portion of the wind portfolio. Based on the lack of Limon wind generation data prior to 2012, the Company estimated existing wind ELCCs in this study using generation meter data from the period 2012-2014.[16]

Sources of solar generation meter data include interval production meters from the five, large San Luis Valley tracking facilities and from interval production meters that have been set for net-metered customers on a demand-rate tariff who have both interval load and solar generation meters installed.

Load Data Sources

Hourly system obligation load for 2012-2014 was used for the study. As these data are recorded from meters located at substations, the effects of behind-the-meter solar generation and other

[15] The percentage is dependent upon whether the 249 MW Golden West facility is considered to be in the Limon region or not.

[16] 2012 hourly wind generation data at Limon were grossed up to the existing level of Limon wind (i.e., 853 MW) in the Company's portfolio as shown in Table 3.

solar generation interconnected at distribution voltages are embedded in the data. That is, the obligation load data are net of behind-the-meter and solar-garden-type solar generation; absent these generators, the obligation load data would be higher. The solar embedded in the obligation load is included in all analyses completed for this study.

Study Results

Existing Wind

Table 4 shows the ELCC results by year for the existing 2,332 MW wind portfolio modeled both with and without existing solar in the base system model. As behind-the-meter solar generation is embedded in the obligation load, the solar sensitivity cases were performed with and without the 135 MW of San Luis Valley tracking solar.

Table 4 ELCC Results for Existing Wind Generation

	Wind ELCC	
Study Year	**0 MW Solar**	**135 MW Solar**
2012	22.5%	22.8%
2013	16.6%	17.1%
2014	15.6%	15.8%

As expected, the wind ELCC estimates were higher for the cases in which existing solar generation was included in the base system model.

Examining Table 4, it appeared that the 2012 wind result was potentially an outlier and its inclusion might inordinately increase the average ELCC value calculated for the existing wind portfolio. As shown previously in Table 3, the Company only has data for the Limon zone for 2012-2014 and has no additional generation meter data for earlier years. As a test to determine whether the 2012 wind ELCC result was or was not an outlier value, the Company conducted a separate set of ELCC calculations (“2012 Outlier Study”). In this study, 2008 – 2014 historical meter data for the North and Lamar wind regions only were utilized to calculate ELCC values.[17] The results of the 2012 Outlier Study are shown in Table 5.[18]

[17] The hourly load shapes for the two wind zones for each of the years 2008-2014 were grossed up proportionally to represent a wind portfolio consistent with the 2,332 MW of existing wind under study. For example, in 2008 and 2009 the Company’s wind portfolio consisted of 1,242 MW of North wind and 237 MW of Lamar wind (1,479 MW total). In order to create hourly wind generation profiles for 2008 and 2009 consistent with a wind portfolio totaling

Table 5 2012 Outlier Study Results (North and Lamar Wind Only)

Study Year	Wind ELCC
2008	15.4%
2009	**11.1%**
2010	14.0%
2011	12.5%
2012	**19.8%**
2013	16.0%
2014	15.8%
simple average	14.9%
average w/o 2009 and 2012	14.7%

The 2012 ELCC value in Table 5 (19.8%) again is significantly higher than the ELCC values for 2013 and 2014 and all other years. The simple average of the results for 2008-2014 (14.9%) is roughly equivalent to the average of the five estimates (14.7%) when the highest value (19.8% in 2012) and the lowest estimate (11.1% in 2009) are excluded. That is, excluding the highest value (2012) and the lowest value (2009) in the seven years of results shown in Table 5 does not significantly impact the average value calculated. However, including the 2012 ELCC value shown in Table 5 when calculating an average ELCC based on 2012-2014 data does significantly increase the average ELCC based on those three years (17.2% vs. 15.9%). Thus including the 2012 ELCC result shown in Table 4 would also tend to overestimate the actual average ELCC value for the existing wind generation portfolio. For this reason, the Company treated the 2012 study year result shown in Table 4 as an outlier and did not include that result in its final estimate of existing wind ELCC.[19]

Based on the information in Table 6, the Company would ascribe an ELCC value of 16.4% to the 2,332 MW wind portfolio studied.

2,332 MW (58% greater than the 1,479 MW wind portfolio that existed in 2008 and 2009), the North and Lamar wind hourly generation profiles for 2008 and 2009 were grossed up by 58% each.

[18] 135 MW solar ws included in the base portfolio for the 2012 Outlier Study.

[19] For normally-distributed values, outliers are typically identified at ~3 standard deviations. If an assumption is made that the Table 5 results are normally distributed, the 2012 ELCC of 19.8% is ~ 2 standard deviations from the mean which does not indicate a true outlier.

Table 6 Existing Wind ELCC Study Results

Study Year	**Wind ELCC**
2012	
2013	17.1%
2014	15.8%
average	16.4%

Incremental Wind

ELCC estimates for incremental levels of wind were conducted with 2,332 MW of wind and 135 MW of San Luis Valley tracking solar in the base system model; as previously discussed, the effects of behind-the-meter solar generation are embedded in the obligation load data. Incremental wind ELCC values were calculated as the average of the 2013 and 2014 historical periods only. Results for incremental wind generators by location are shown in Table 7 below.

Table 7 Average ELCC to Apply to Incremental Wind

Incremental Wind (MW)	Northern	Limon	Lamar
250	10.0%	9.8%	18.8%
500	9.7%	9.2%	16.9%
1000	9.1%	8.4%	14.0%

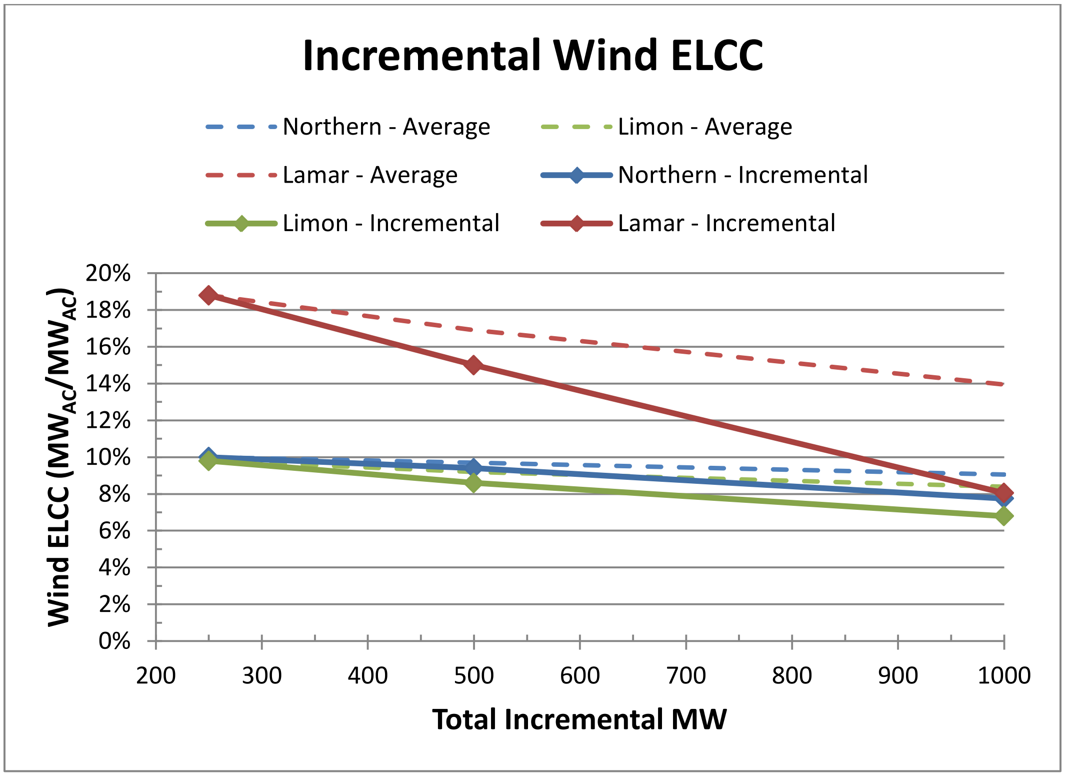
The ELCC values in Table 7 are presented as the average ELCC values that should be attributed to the total level of incremental generation. For example, for an incremental level of 250 MW of Northern wind the entire 250 MW would provide 25 MW of generation capacity credit (250 MW * 10.0%); for an incremental level of 500 MW of Northern wind the entire 500 MW would provide 48 MW of generation capacity credit (500 MW * 9.7%).

Plots of the average wind ELCC values shown in Table 7 along with the incremental ELCC wind values that can be calculated from the average values are shown in Figure 2 below. Note that the ELCC attributable to the first tranches of incremental Lamar wind are nearly twice the ELCC attributable to the first tranches of incremental Northern or Limon wind. However the ELCC attributable to the last tranche of Lamar wind[20] has roughly the same ELCC contribution as does

[20] That is, the incremental 500 MW of wind that goes from the 500 MW tranche to the 1,000 MW tranche.

incremental wind in either the Northern or Limon zones; that is, incremental Lamar wind ELCC falls off much more rapidly than does incremental Northern or Limon zone wind.

Figure 2 Average and Incremental Wind ELCC Values



Recall that the Company's current wind portfolio consists of roughly 1,200 MW in the Northern zone, 853 MW in the Limon zone, but only 240 MW in the Lamar zone. Thus the higher ELCC values for Lamar wind calculated in this study are more an attribute of the relative lack of Lamar wind in the Company's existing portfolio rather than any inherent ability of Lamar wind to better meet the Company's peak load hours.

Application of Study Results to Current Loads and Resources Table

The Company includes the 249 MW Golden West facility on its loads and resources table as part of the Company's existing wind portfolio with an assumption that it is in the Limon zone. As such, it has estimated the ELCC attributed to its entire 2,555 MW wind portfolio by assigning the 16.4% ELCC value from Table 6 to 2,306 MW of wind[21] and the 9.8% incremental Limon wind

[21] 2,306 MW of wind is calculated by subtracting the 26 MW of retired Ponnequin wind from the 2,332 MW of existing wind studied here.

ELCC result from Table 7 to the 249 MW Golden West facility. The resulting ELCC value the Company estimates for its current 2,555 MW wind portfolio is 16%.[22]

Conclusions

Based on the results of this study, the Company currently carries existing wind resources on its loads and resources tables at an average ELCC of 16% vs. the previous study value of 12.5%. Based on an existing wind portfolio of 2,555 MW, this increase in wind ELCC results in approximately 90 MW of incremental net dependable capability.

The study did find a beneficial impact of including existing solar generation in the base generation portfolio when conducting the existing wind ELCC study. As such, existing solar was included in the base generation portfolio for the incremental wind ELCC calculations also.

The average ELCC values attributable to incremental wind generation in the Limon wind resource zone was found to be significantly higher than the average ELCC values attributable to incremental wind generation in the other two wind resource zones studied. However, as this finding is a result of the relatively lower levels of installed wind in the Lamar zone the beneficial ELCC value of Lamar wind collapses relatively quickly as incremental wind is added.

[22] (2,306 MW * 16.4% + 249 MW * 9.8%) / 2,555 MW = 15.8% ≈ 16%.

Wind and Solar-Induced Coal Plant Cycling and Curtailment Costs

on the

Public Service Company of Colorado System

Prepared by

Xcel Energy Services, Inc.
1800 Larimer Street
Denver, Colorado 80202

May 13, 2016

Executive Summary

This report presents the results of a Wind and Solar Induced Coal Cycling study completed on the Public Service Company of Colorado ("Public Service" or the "Company") electrical generation system. A previous Wind Induced Coal Cycling study was completed in August 2011. The purpose of that study was to define and quantify the integration costs directly associated with: 1) cycling baseload coal generator output as a result of wind generation levels, and 2) curtailing wind generation at times to avoid certain excessive system bottoming events.

The current study has the same purpose but also evaluates the potential impacts to coal cycling and curtailment from the effects of wind and solar, both combined and individually. At the time of the original study in 2011, the Company had approximately 130 MW of solar capacity. By the end of 2016, the Company will have about 550 MW of solar and anticipates that several more hundred MW will be installed in the next few years.

The previous study examined wind levels of 2 GW and 3 GW; levelized annual costs from coal cycling and curtailments were estimated at $4.8 million and $8.3 million respectively over a 15-year study period (2011-2025). In this study, over a similar length period (2016-2030), estimated levelized annual coal cycling and curtailment costs are $2.6 million; estimated levelized costs over a 25-year period are $2.0 million. Solar generation was found to contribute to coal cycling and curtailment costs but, at the penetrations studied here, wind continues to be the primary driver. Significant reductions in future estimates of coal cycling costs are attributable to fewer coal units in the fleet, older wind purchased power contracts that can be curtailed without requiring PTC compensation, and ultimate termination of existing wind contracts.

CONTENTS

EXECUTIVE SUMMARY ... 1
CONTENTS ... 2
INTRODUCTION ... 4
COAL PLANT CYCLING COSTS ... 4
CURTAILMENT COSTS ... 4
PRIOR COAL PLANT CYCLING STUDIES ... 4
SOLAR AS A SOURCE OF COAL CYCLING AND CURTAILMENTS ... 5
STUDY METHODOLOGY ... 7
STUDY GOALS ... 7
MODEL UPDATES TO SUPPORT THE STUDY GOALS ... 8
BASELINE STUDY RESULTS ... 8
CURRENT IMPACTS OF SOLAR ... 10
PORTFOLIO ADDITION STUDY RESULTS ... 11
BASELINE SCENARIO RESULTS ... 12
INCREMENTAL WIND SCENARIO RESULTS ... 12
INCREMENTAL SOLAR SCENARIO RESULTS ... 14
INCREMENTAL WIND AND SOLAR SCENARIO RESULTS ... 15
INDIVIDUAL ADDITIONS STUDY RESULTS ... 17
CONCLUSIONS ... 18
APPENDIX A – ASSUMPTIONS AND METHODOLOGY ... 20
PLANT CYCLING COMPONENT CALCULATION ... 20
ESTIMATING THE NUMBER OF CYCLES ... 20
LOAD FORECAST ... 20
GENERATING UNIT CHARACTERISTICS ... 20
WIND GENERATION FORECASTS AND PROFILES ... 20
SOLAR GENERATION PROFILES ... 21
COUNTING THE CYCLES ... 21
CALCULATING THE COST PER CYCLE ... 21
CALCULATING THE CURTAILMENT COST COMPONENT ... 22
FORECASTING VARIABLE ENERGY CURTAILMENT ... 22
PER MWH CURTAILMENT COSTS ... 22
AVOIDED ENERGY COST ... 22
PRODUCTION TAX CREDITS ... 22
CARBON DIOXIDE EMISSIONS COST ... 23
RENEWABLE ENERGY CREDIT OPPORTUNITY COST ... 23
MODEL EXPANSION ... 23
APPENDIX B – ANNUAL RESULTS ... 24
TABLE B.1: SCENARIO 1 BASELINE ANNUAL RESULTS ... 24
TABLE B.2: SCENARIO 2 600 MW ADDED WIND ... 24
TABLE B.3: SCENARIO 3 1,200 MW ADDED WIND ... 25
TABLE B.4: SCENARIO 4 450 MW ADDED SOLAR ... 25
TABLE B.5: SCENARIO 5 900 MW ADDED SOLAR ... 26
TABLE B.6: SCENARIO 6 600 MW ADDED WIND + 450 MW ADDED SOLAR ... 26

TABLE B.7: SCENARIO 7 1,200 MW ADDED WIND + 900 MW ADDED SOLAR 27
TABLE B.8: SCENARIO 8 300 MW WIND (NORTH RESOURCE ZONE) 28
TABLE B.9: SCENARIO 9 600 MW WIND (NORTH RESOURCE ZONE) 28
TABLE B.10: SCENARIO 10 900 MW WIND (NORTH RESOURCE ZONE) 29
TABLE B.11: SCENARIO 11 300 MW WIND (CENTRAL RESOURCE ZONE) 29
TABLE B.12: SCENARIO 12 600 MW WIND (CENTRAL RESOURCE ZONE) 30
TABLE B.13: SCENARIO 13 900 MW WIND (CENTRAL RESOURCE ZONE) 30
TABLE B.14: SCENARIO 14 300 MW WIND (SOUTH RESOURCE ZONE) 31
TABLE B.15: SCENARIO 15 600 MW WIND (SOUTH RESOURCE ZONE) 31
TABLE B.16: SCENARIO 16 900 MW WIND (SOUTH RESOURCE ZONE) 32
TABLE B.17: SCENARIO 17 100 MW SOLAR (NORTHERN FRONT RANGE FIXED) 33
TABLE B.18: SCENARIO 18 200 MW SOLAR (NORTHERN FRONT RANGE FIXED) 33
TABLE B.19: SCENARIO 19 100 MW SOLAR (SOUTHERN FRONT RANGE FIXED) 34
TABLE B.20: SCENARIO 20 200 MW SOLAR (SOUTHERN FRONT RANGE FIXED) 34
TABLE B.21: SCENARIO 21 100 MW SOLAR (SAN LUIS VALLEY FIXED) 35
TABLE B.22: SCENARIO 22 200 MW SOLAR (SAN LUIS VALLEY FIXED) 35
TABLE B.23: SCENARIO 23 100 MW SOLAR (WESTERN SLOPE FIXED) 36
TABLE B.24: SCENARIO 24 200 MW SOLAR (WESTERN SLOPE FIXED) 36
TABLE B.25: SCENARIO 25 100 MW SOLAR (NORTHERN FRONT RANGE TRACKING) 37
TABLE B.26: SCENARIO 26 200 MW SOLAR (NORTHERN FRONT RANGE TRACKING) 37
TABLE B.27: SCENARIO 27 100 MW SOLAR (SOUTHERN FRONT RANGE TRACKING) 38
TABLE B.28: SCENARIO 28 200 MW SOLAR (SOUTHERN FRONT RANGE TRACKING) 38
TABLE B.29: SCENARIO 29 100 MW SOLAR (SAN LUIS VALLEY TRACKING) 39
TABLE B.30: SCENARIO 30 200 MW SOLAR (SAN LUIS VALLEY TRACKING) 39
TABLE B.31: SCENARIO 31 100 MW SOLAR (WESTERN SLOPE TRACKING) 40
TABLE B.32: SCENARIO 32 200 MW SOLAR WESTERN SLOPE TRACKING) 40

Introduction

Wind and solar generation ("variable generation") create additional electrical system costs that are not captured or reflected in traditional resource planning models. These costs are one set of additional costs imposed by variable generation known as integration costs.

The objective of this study is to update the integration costs associated with: 1) cycling baseload coal unit output as a result of wind and solar generation levels, and 2) curtailing variable generation at times to maintain balance between load and generation during system bottoming events.[1] Coal cycling cost from this study are included in the Company's Phase I alternate plans included as part of its Electric Resource Plan ("ERP") filings and also for evaluation of various portfolios of generation resources submitted in a Phase II ERP acquisition process.

Coal Plant Cycling Costs

Cycling is the operation of thermal electric generators at varying load levels, including on/off and low load variations, in response to system load requirements. Some generators (e.g., natural gas-fired combustion turbines and pumped hydro units) are designed for cyclical operation in order to follow, or balance, variations in load. In contrast, coal-fired generating units were principally designed for baseload operation. The inclusion of greater levels of variable generation sources such as wind and solar has forced a movement from the designed non-varying operation of the coal-fired generating units which can result in increased cycling-induced plant wear.

Curtailment Costs

In addition to cycling coal-fired generators in order to balance load and generation, system operators can choose to reduce/curtail the amount of variable generation on the system. While such actions can avoid additional coal cycling and cycling costs, curtailing variable generation results in its own set of costs including replacement fossil fuel costs, potential carbon mitigation costs, Renewable Energy Credit ("REC") opportunity costs, and payments/opportunity costs for the value of lost Production Tax Credits ("PTC").[2]

Prior Coal Plant Cycling Studies

The Company completed a previous coal cycling study in 2011.[3] The previous study evaluated the impacts of wind generation at two levels of installed capacity: 2 GW and 3 GW.[4] That study had two purposes: 1) estimate the costs associated with wind induced coal cycling and with wind curtailments, and 2) evaluate an appropriate coal plant operating protocol with significant amounts of wind generation. Table 1 below shows a summary of results from the prior study.

[1] The term "cycling" in this document refers to variations in the electric output of coal units from their maximum output to their minimum output (while remaining synchronized to the grid).
[2] Wind generators are only eligible for PTCs during the first 10 years of production. After the first 10 year period is over for a wind facility, there are no more "make whole" PTC payments or opportunity costs associated with curtailing wind generation from that facility.
[3] The study report was filed as Attachment 2.12-1 in the 2011 Electric Resource Plan (Docket No. 11A-869E).
[4] In this study report, all references to MW, GW, and MWh refer to MW_{AC}, GW_{AC}, and MWh_{AC} unless otherwise noted.

Table 1: Summary of Scenario Results from 2011 to 2025 (2010 Present Value)

Scenario	Installed Wind	Cycling Protocol	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
1	2GW	Curtail	$3.6	$1.2	$4.82	$0.77
2	2GW	Deep Cycle	$5.1	$0.1	$5.21	$0.83
3	3GW	Curtail	$5.0	$3.3	$8.30	$1.03
4	3GW	Deep Cycle	$8.2	$0.6	$8.75	$1.08

The two operating protocols evaluated were: “Curtail” meaning cycling coal plants down to their economic minimum generation levels (shallow cycle) to accommodate wind and then curtailing wind in excess of the level needed to meet system load, and “Deep Cycle” meaning cycling coal plants down to their lower emergency minimum levels (deep cycle) to accommodate wind and then curtailing in excess of the level needed to meet system load. Because the 2011 study did not find a significant cost difference between the two operating protocols (and because there is a greater risk of reduced system reliability in the Deep Cycle protocol), the Curtail protocol was determined to be—and continues to be—the preferred operational protocol for the Company’s system.[5]

Solar as a Source of Coal Cycling and Curtailments

At the time of the original study in 2011, the Public Service system had approximately 130 MW of solar capacity. Given these low solar levels and the observation that system load is typically higher during daylight hours, the prior study did not include solar generation as a variable generator. By the end of 2016, however, the Company estimates it will have ~ 550 MW of solar and anticipates the acquisition of several hundred MW more in the near future.

At current wind and solar penetration levels, solar generation can impact coal cycling and curtailments. Figure 1 is an illustration of how net load is impacted by projected wind and solar production over a two-day period in 2016.[6] As can be seen in the figure, solar may be affecting coal cycling and curtailments during early morning hours on days with relatively low system load and high wind generation.

[5] The Company will also place some coal units in reserve shutdown during extended periods of time when high levels of wind generation and low levels of customer load are forecast. Such actions serve to lower the system bottom (“Fleet Minimum Output”) and reduce wind curtailments.

[6] Net load is defined here as total customer load less wind and solar generation.

Figure 1: Illustrative Coal Cycling and Curtailments - 2016 Summer

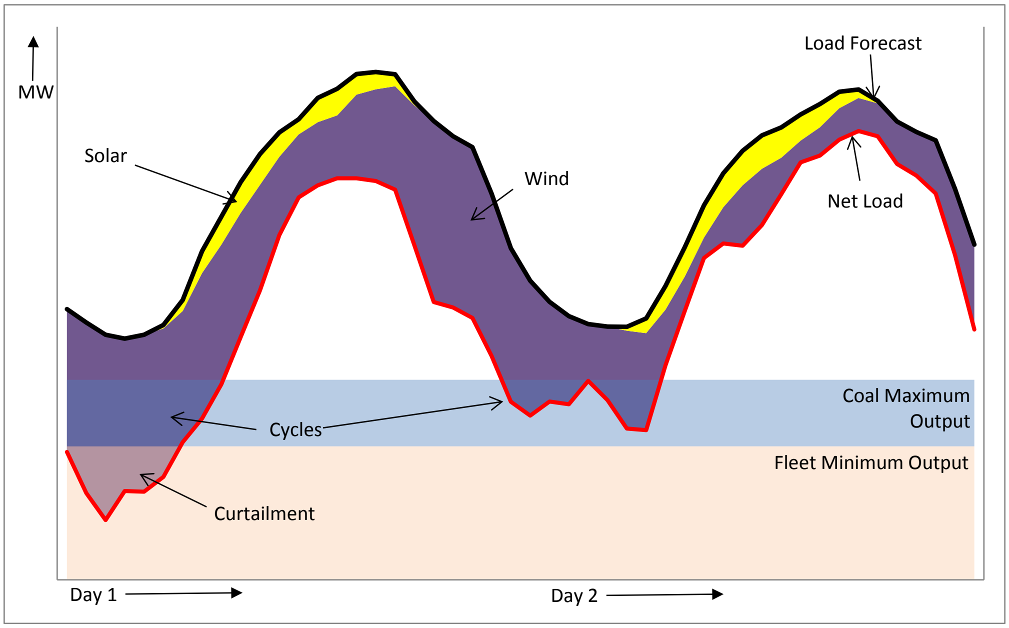
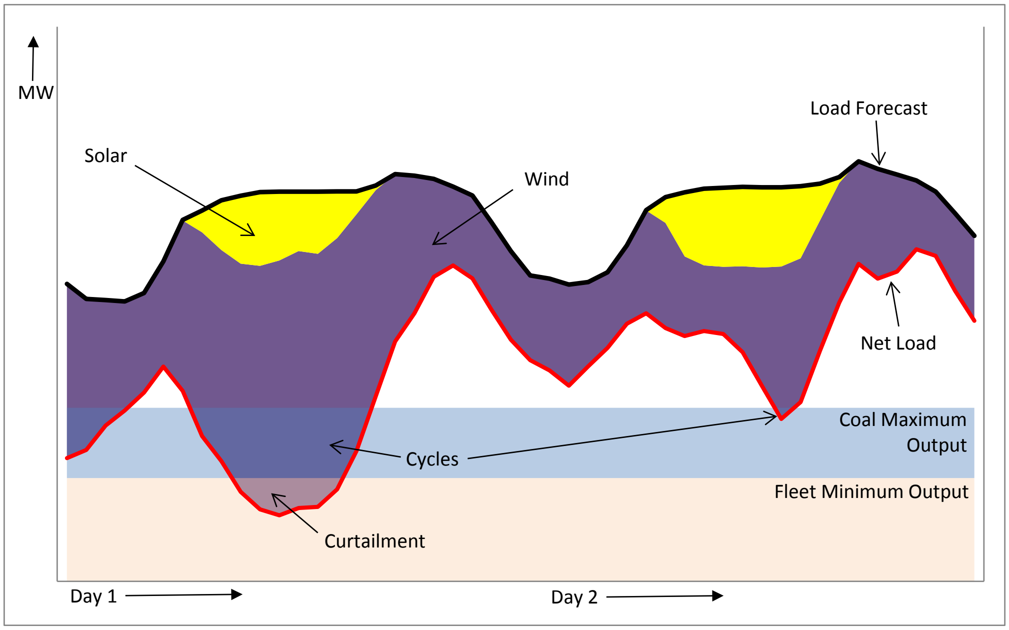


Figure 2 shows that as incremental solar and wind generation are added to the system these affects will be magnified and solar could become a more significant contributor to coal cycling and curtailment costs during daytime hours.[7]

Figure 2: Illustrative Coal Cycling and Curtailments - 2020 Spring



[7] Figure 2 was obtained from hourly data utilized in the analysis of an incremental 600 MW of wind and 450 MW of solar from Scenario 6 described in Table 3.

Study Methodology

In order to determine the plant-cycling cost component attributable to variable generation it is necessary to: 1) estimate the number of coal unit cycles that are directly attributable to a given level of wind and solar generation on the system, and 2) determine the cost per coal-unit cycle.

A spreadsheet model was developed for the prior study in order to estimate the number of coal-unit cycles attributable to variable generation. This model utilized a forecast of load before and net load after the addition of a user-specified level of wind generation to estimate the frequency and intensity of coal-unit cycles. In the spreadsheet model, coal units are stacked by operating cost to meet forecast net load and the number of cycles, by coal unit, are estimated. Plant cycling costs are then calculated as costs per cycle multiplied by the number of cycles estimated in the model.

Within the spreadsheet model, coal-unit generation is reduced until all operating coal units have been reduced to their economic minimum; this point is illustrated in Figures 1 and 2 as "Fleet Minimum Output". In order to balance load and generation, variable generation is curtailed if net load would otherwise fall below Fleet Minimum Output. Curtailment costs are then calculated based on existing coal plant variable and fuel cost forecasts, REC price forecasts, and PTC cost forecasts. These curtailment costs are added to the plant cycling costs to calculate the total costs.

In order to remove cycling and curtailment costs that would have occurred due to reductions in demand alone, cycling and curtailment costs are calculated twice for each scenario; once with variable generation in the generation portfolio and second under a control scenario which excludes variable generation. The cost difference between the variable generation calculation and the control calculation represents the cycling and curtailment cost attributable to the level of variable generation evaluated. Appendix A contains a more detailed description of the modeling assumptions and methodology used.

Study Goals

The Company's goals in this study were to estimate coal cycling and curtailment costs over the 25-year period from 2016-2040 for:

1. The existing system including assumptions for: ongoing customer choice solar programs, coal plant retirements, and expiring wind and solar purchase power agreements.[8] These existing system costs are referred to as "baseline costs" and set the level of costs against which incremental additions of wind and/or solar generation are measured.
2. Incremental portfolios of wind and/or solar generation at multiple locations to support the Company's 2016 Phase I ERP filing which requires various alternative generation plans. These are referred to in this study report as "Portfolio Addition" cases.
3. Incremental wind or solar generation at individual locations to support a 2016 ERP Phase II acquisition process. These location-specific cases could be used to estimate proposal-specific coal cycling costs for individual proposals. These are referred to in this study report as "Individual Addition" cases.

[8] Customer choice solar programs are assumed to add an incremental 110 MW each year over the study period. Customer choice solar is modeled with a 0.5% annual degradation in capacity and energy and with an expected 20-year life expectancy.

Model Updates to Support the Study Goals

As indicated earlier, the coal cycling spreadsheet model developed for the 2011 study was designed to examine the impacts of wind generation only. In order to support the current study goals, the following changes were made to the spreadsheet model:

- The 2011 model only included generic wind generation curves for two locations: "North" (the geographic region along the Colorado-Wyoming border) and "South" (the geographic region near Lamar, CO). For this study, another generic wind generation curve was added for a "Central" region (the geographic region near Limon, CO).
- Generic wind generation curves were utilized in the 2011 model for both existing and incremental generation. For this study, existing wind farms were modeled with plant-specific typical meteorological year ("TMY") profiles.[9] Incremental wind generation was modeled with a generic TMY curve specific to each of the three wind regions.
- Generic solar TMY generation curves were added for both fixed and tracking solar generation profiles at four broad geographic regions: Northern Front Range ("NFR"), Southern Front Range ("SFR"), San Luis Valley ("SLV"), and Western Slope ("WS"). Site-specific solar TMY generation curves were utilized for the Company's existing large-scale solar generators. Incremental solar generation was modeled with the generic solar TMY curves.
- Coal-unit cycle-counting logic was changed to accommodate the possibility that coal units would cycle more than once per day given the impacts of solar generation on system net load.
- The model was expanded from a maximum 15-year study period to a maximum 40-year period.

Other minor changes made to the spreadsheet model are noted in Appendix A.

Baseline Study Results

Table 2 below shows the levels of coal, wind and solar assumed in the baseline model. As mentioned previously, these levels are calculated assuming planned retirement dates for existing coal-fired generators along with terminations in currently existing coal, wind, and solar purchased power contracts. Installed Solar grows over time given the assumptions made for ongoing annual additions of customer choice solar.

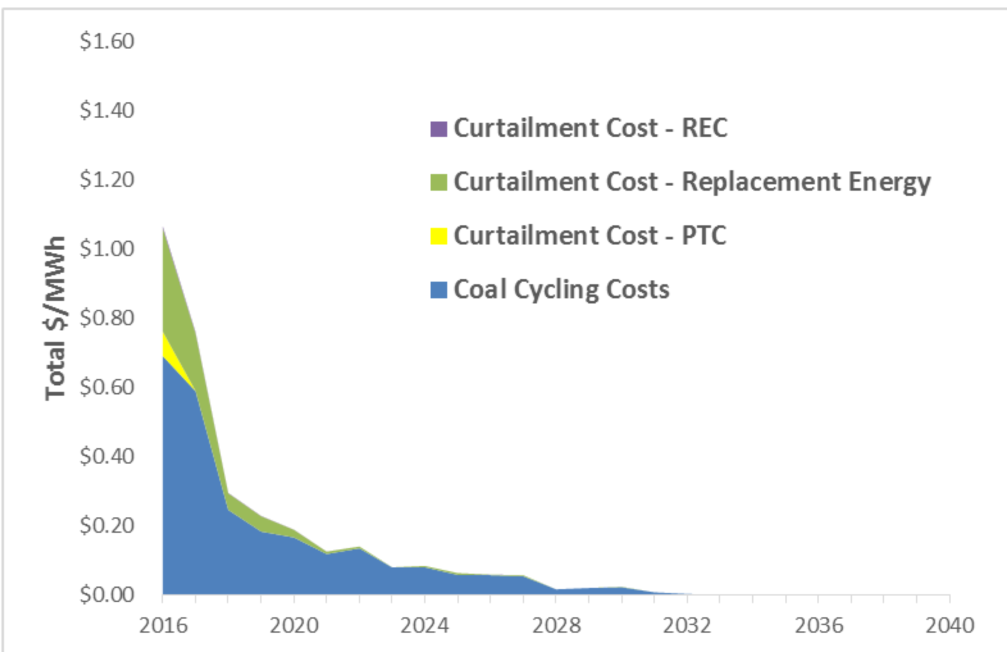
[9] A TMY curve is based on historical generation and is intended to capture typical variations in generation as observed over a multi-year period. Hourly generation for each month of the annual curve comes from the same historical monthly period; however, historical generation for each month can be based on historical generation from different years. The goal is to select hourly generation for each month from historical years in which the data are most typical of all years in the data set for that month. For example, in the TMY curve January data could come from 2012 whereas February data could come from 2014.

Table 2: Coal Economic Minimums and Installed Levels of Wind and Solar in Baseline Model

Year	Coal Economic Minimums (MW)	Installed Wind (MW)	Installed Solar (MW)[10]
2016	1,480	2,560	400
2020	1,150	2,360	870
2025	1,150	2,360	1,330
2030	1,150	1,700	1,720
2035	880	1,100	1,920
2040	620	250	2,050

Figure 3 below shows the costs of coal cycling and curtailments in the Baseline case. Total $/MWh costs are calculated in the figure as total coal cycling and curtailment costs divided by total wind and solar generation. A table of annual results for the Baseline case is included in Appendix B as Table B.1.

Figure 3: Baseline Case Cost of Coal Cycling and Curtailments years 2016-2040



In the Baseline case, the level of curtailments and the number of coal unit cycles decrease over time, eventually dropping to zero due to load growth and changes in the generation supply mix. The large drop

[10] Installed Solar interconnected or assumed to connect at voltages below transmission voltage is grossed up to a transmission-level MW equivalent to compensate for assumed line losses.

in costs that occurs between 2016 and 2018 is driven primarily by the retirement of the 184 MW Valmont 5 coal-fired unit at the end of 2017 and the continued operation of the 352 MW Cherokee 4 coal-fired unit on natural gas past the end of 2017 as part of the Clean Air Clean Jobs Act. In addition, 500 MW of wind generation will lose PTC payments at the end of 2016 and by 2019 over 50% of the existing wind portfolio will not be receiving PTC payments. The result of these changes is that the PTC cost of curtailment, while important in the 2011 Coal Cycling study, is not particularly material in the Baseline case here. REC costs of curtailment are negligible due primarily to the low forecasted price of wind RECs.[11]

Figure 3 shows no Curtailment Costs for incremental carbon dioxide emissions assumed for the replacement energy resources when variable generation is curtailed. The characteristics of pending carbon dioxide regulation for new and existing generation units (i.e., the final version of the EPA's Clean Power Plan released in August 2015) suggest that each state (and the affected generation units within each state) would be required to lower carbon dioxide emissions to a certain level rather than incurring carbon taxes (e.g., the implementation of a $/ton emissions cost). Accordingly, the Company currently assumes a baseline, zero cost of carbon dioxide emissions in its planning efforts; reductions in regulated emissions are modeled separately and assumed emissions costs can be calculated outside of the models. Therefore, the Company assumed no incremental carbon dioxide emission costs resulting from variable generation curtailment in this study.

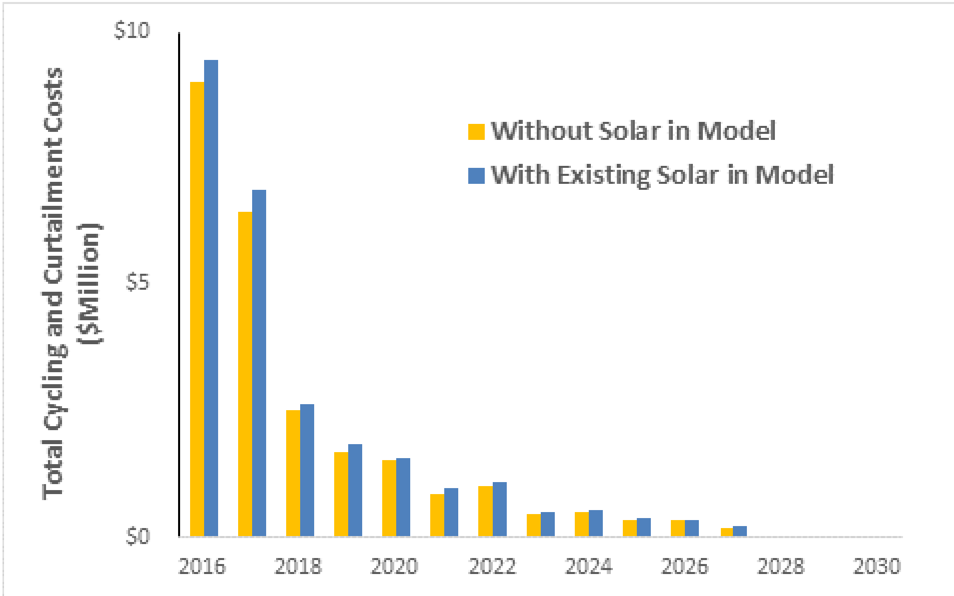
Current Impacts of Solar

As stated earlier, solar generation was examined in this study because it is an increasingly important contributor to the Company's generation mix. To explore whether solar is a factor in coal cycling at current levels, the coal cycling and curtailment spreadsheet model was run with and without solar. Figure 4 shows the total cycling and curtailments costs for these two runs.

Figure 4 indicates that current (2016) levels of installed solar do appear to have an impact on coal cycling and curtailment costs. However the impact is small compared to the costs due to current levels of installed wind generation.

[11] A flat REC price of $0.40/MWh of wind or solar generation was assumed. See Appendix A for further discussion.

Figure 4: Total Coal Cycling and Curtailment Costs with and without Solar



Portfolio Addition Study Results

As indicated previously, the Portfolio Addition study assumptions were designed for use in the development of alternate plan portfolios for Phase I of the Company's ERP. The Company evaluated the incremental additions of a geographic-diverse portfolio of 600 MW and 1,200 MW of wind and 450 MW and 900 MW of solar on top of the Baseline portfolio as shown in Table 3.[12] In order to facilitate the use of the study results in the Company's planning models all incremental generators were assumed to be operational at the start of 2019.

Table 3: Portfolio Wind and Solar Additions by Resource Zones

Scenario	Wind Additions (MW)				Solar Additions (MW)				
#	North	Central	South	Total	NFR	SFR	SLV	WS	Total
1				0					0
2	250	250	100	600					0
3	500	500	200	1,200					0
4				0	100	170	150	30	450
5				0	200	340	300	60	900
6	250	250	100	600	100	170	150	30	450
7	500	500	200	1,200	200	340	300	60	900

[12] The distribution of incremental wind and solar generation assumed in Table 3 is roughly equal to the current distribution of wind and solar generation for these broad geographic areas. All incremental solar generation was assumed to be tracking.

Baseline Scenario Results

Table 4 shows the levelized annual costs of the 25-year coal cycling and curtailment costs from the Baseline run (Scenario 1) as well as those from Scenarios 2-7 with increasing levels of wind and solar. Results are provided in Table 4 on both a levelized annual dollar and $/MWh basis. Tables of annual results for Scenarios 2-7 are included in Appendix B as Tables B.2 through B.7 respectively.

Table 4: Summary of Portfolio Addition Scenario Results for 2016-2040 (2016 present value)

Scenario #	Added Wind (MW)	Added Solar (MW AC)	Cycling Cost Component ($Million)	Curtailment Cost Component ($/Million)	Total Levelized Annual Cost ($Million)	Total Levelized Cost ($/MWh)
1	---	---	$1.55	$0.46	$2.01	$0.23
2	600	---	$2.39	$0.93	$3.32	$0.31
3	1,200	---	$3.43	$2.91	$6.33	$0.52
4	---	450	$1.75	$0.54	$2.29	$0.24
5	---	900	$2.14	$0.77	$2.92	$0.28
6	600	450	$2.68	$1.28	$3.96	$0.35
7	1,200	900	$4.18	$5.23	$9.41	$0.69

Incremental Wind Scenario Results

Figures 5 and 6 below show the Coal Cycling and Curtailment costs (in nominal $/MWh) for Scenarios 2 and 3 which add 600 and 1,200 MW of wind respectively.

**Figure 5: Scenario 2 Total Cycling and Curtailment Costs
600 MW Incremental Wind**

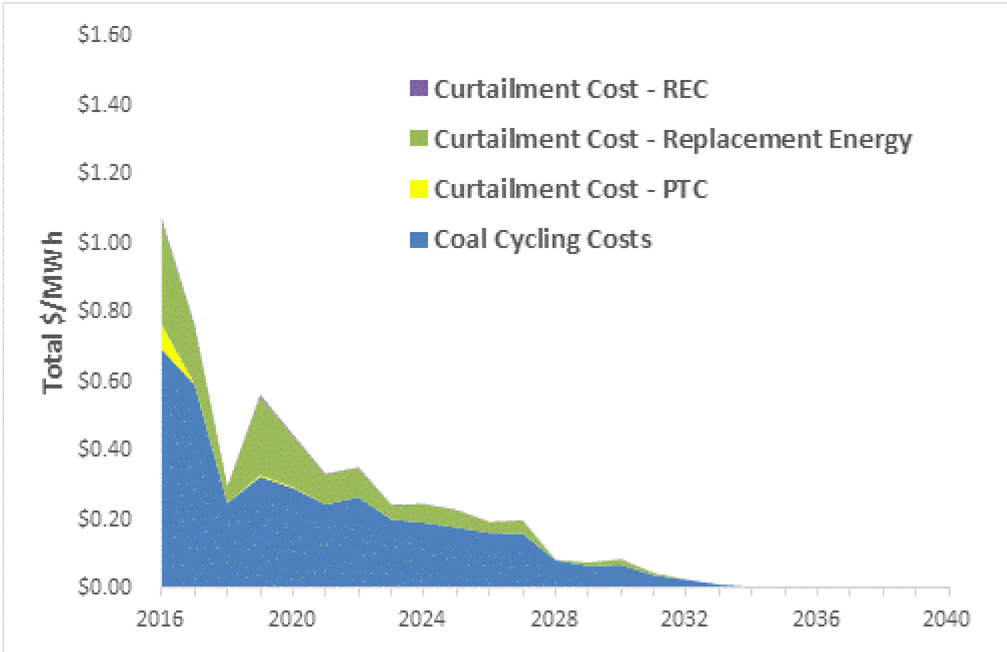
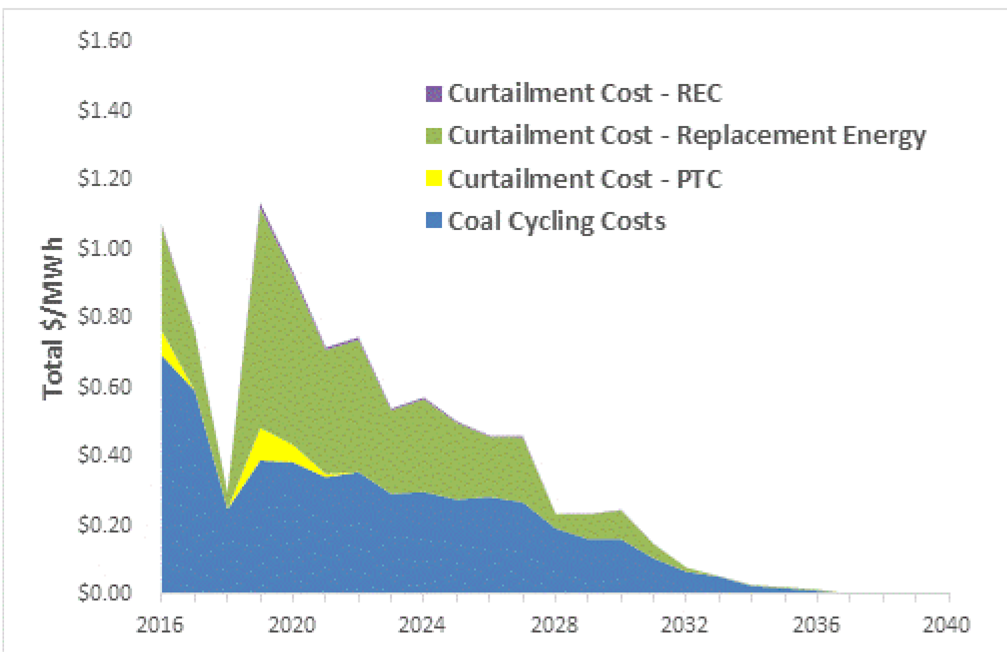


**Figure 6: Scenario 3 Total Cycling and Curtailment Costs
1,200 MW Incremental Wind**

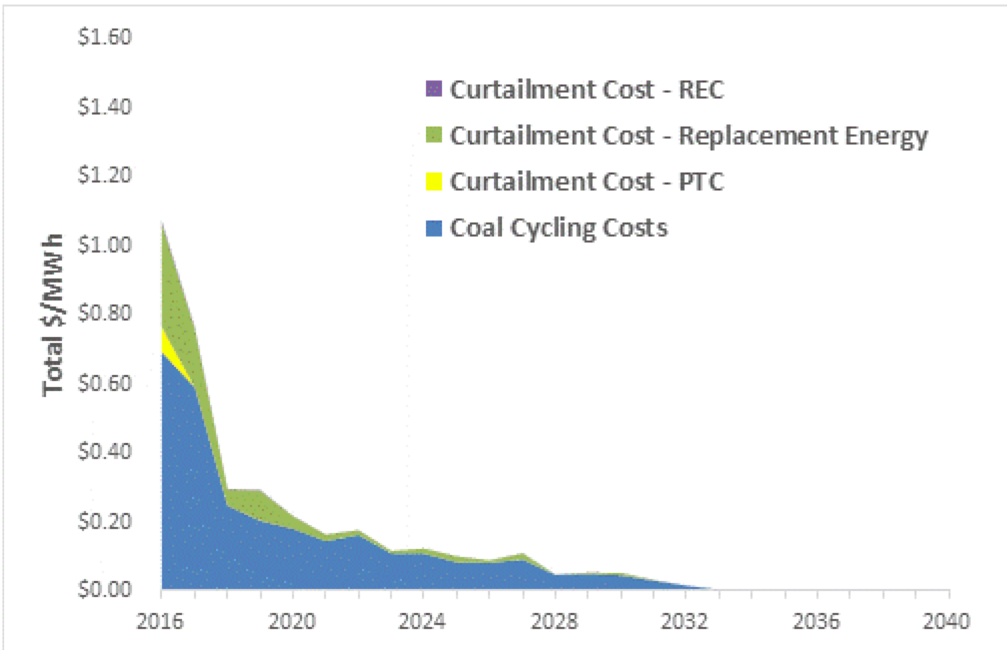


With the addition of 1,200 MW of wind generation, combined coal cycling and curtailment costs increase temporarily, on a $/MWh basis, to current levels; however replacement energy costs represent a larger portion of the costs in 2019 as compared to 2016. PTC curtailment costs become a minor factor again for a few years as a larger portion of wind generation subject to PTC costs would be curtailed.[13]

Incremental Solar Scenario Results

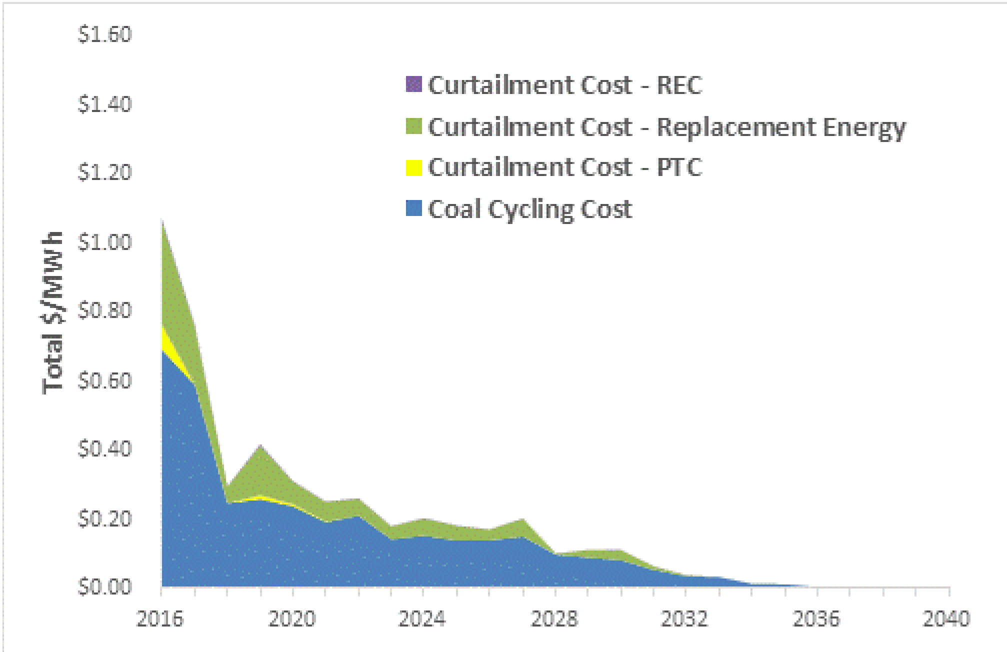
Figures 7 and 8 show the Coal Cycling and Curtailment costs (in nominal $/MWh) for Scenarios 4 and 5 which add 450 and 900 MW of solar respectively. The coal cycling and curtailment impacts for solar are smaller than that of wind but they do impact the total $/MWh costs. Again, the costs eventually drop to zero due to resource and contract retirements over time.

Figure 7: Scenario 4 Total Cycling and Curtailment Costs
450 MW Incremental Solar



[13] The spreadsheet model curtails wind generation before any other variable generation. If solar generation from purchased power contracts is curtailed ahead of PTC-eligible wind, the levelized cost of curtailment shown in Figure 6 for Scenario 3 would be reduced by an insignificant $0.04 million.

Figure 8: Scenario 5 Total Cycling and Curtailment Costs
900 MW Incremental Solar



Incremental Wind and Solar Scenario Results

Figures 9 and 10 show the Coal Cycling and Curtailment costs (in nominal $/MWh) for Scenarios 6 and 7. Scenario 6 adds the 600 MW of wind and 450 MW of solar examined separately in Scenarios 2 and 4. Scenario 7 adds the 1,200 MW of wind and 900 MW of solar examined separately in Scenarios 3 and 5.

**Figure 9: Scenario 6 Total Cycling and Curtailment Costs
Incremental 600 MW Wind and 450 MW Solar**

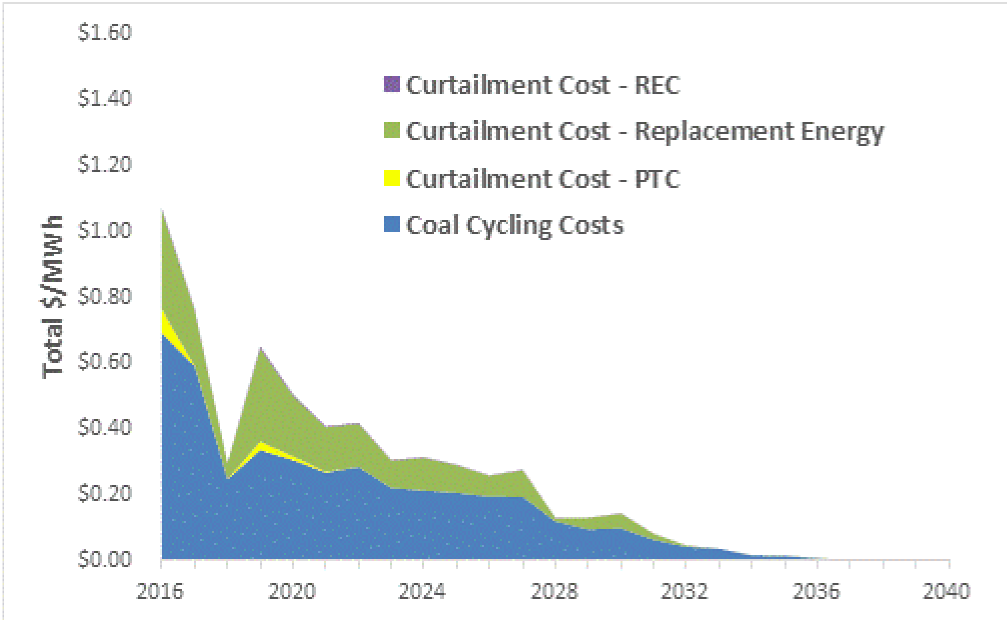
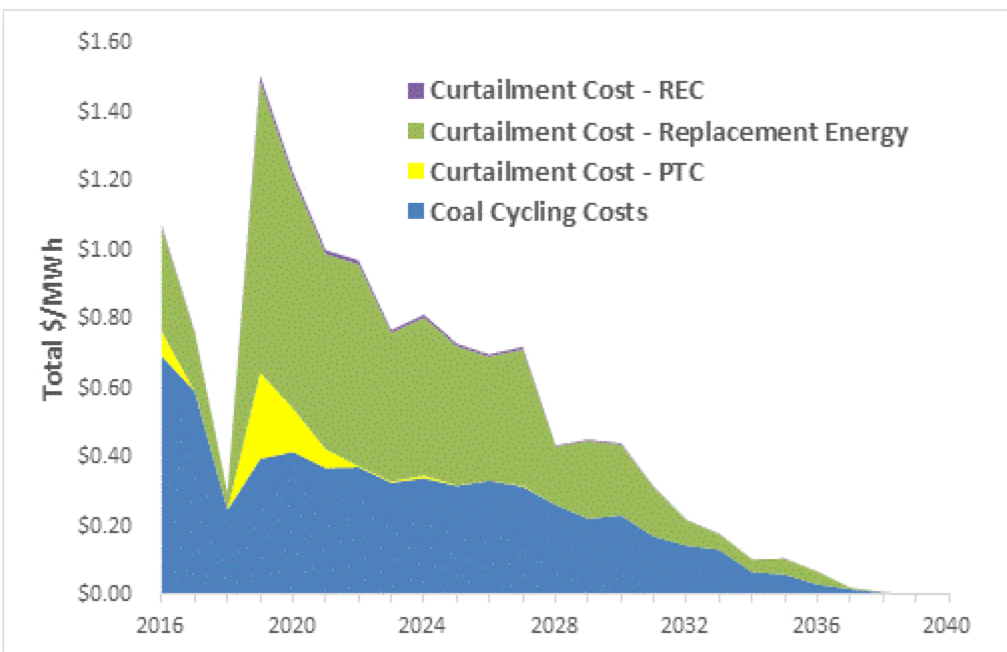


**Figure 10: Scenario 7 Total Cycling and Curtailment Costs
Incremental 1,200 MW Wind and 900 MW Solar**



A comparison of the results for Scenario 2 (600 MW incremental wind only) with the results for Scenario 6 (600 MW incremental wind and 450 MW incremental solar) shows that the incremental solar causes a relatively low level of incremental coal cycling and curtailment costs. However, a similar comparison of

Scenarios 3 and 7 (comparing 1,200 MW of wind only with 1,200 MW of wind and 900 MW of solar) shows that the incremental solar causes a noticeably higher level of incremental costs.

PTC Curtailment Costs shown in Figure 10 for Scenario 7 could likely be reduced through the curtailment of utility-scale solar in lieu of PTC-funded wind curtailment. The model shows that if solar generation from purchased power contracts were curtailed ahead of PTC-eligible wind the levelized cost of curtailment would be reduced $0.34 Million and the levelized Total Cost would decrease by $0.02/MWh.

Individual Additions Study Results

In order to examine the impacts of individual, location-specific additions of wind and solar generation, the Company studied the impacts of 300 MW, 600 MW, and 900 MW of wind at each of the three resource zones (North, Central, South) and the impacts of 100 MW and 200 MW of solar at each of the four resource zones (NFR, SFR, SLV, WS) and for fixed or tracking additions. These results can be used to estimate the impact that individual projects would have on coal cycling and curtailment costs when evaluated as part of a competitive acquisition.

Table 5 shows the incremental levelized costs of adding individual increments of 300 MW, 600 MW, and 900 MW of wind at three resource zones. All of the costs shown are incremental above the Baseline case costs. Annual $/MWh costs for Scenarios 8-16 are shown in Tables B.8 through B.16 in Appendix B.

Table 5: Incremental Levelized Costs over the Baseline Scenario of Individual Additions of Wind by Resource Zone 2019 to 2040

			Incremental over Baseline				
Scenario	**Added Wind**	**Resource Zone**	**Wind Production (GWh/yr)**	**Cycling Cost Component ($Million)**	**Curtailment Cost Component ($/Million)**	**Total Levelized Annual Cost ($Million)**	**Total Levelized Cost ($/MWh)**
8	300 MW	North	1,070	$0.51	$0.18	$0.68	$0.64
9	600 MW	North	2,140	$1.19	$0.65	$1.84	$0.86
10	900 MW	North	3,211	$1.97	$1.69	$3.66	$1.14
11	300 MW	Central	1,022	$0.49	$0.18	$0.67	$0.66
12	600 MW	Central	2,043	$1.12	$0.64	$1.75	$0.86
13	900 MW	Central	3,065	$1.84	$1.66	$3.49	$1.14
14	300 MW	South	1,181	$0.47	$0.16	$0.64	$0.54
15	600 MW	South	2,363	$1.13	$0.62	$1.75	$0.74
16	900 MW	South	3,544	$1.96	$1.66	$3.62	$1.02

Table 6 shows the incremental levelized costs of adding individual increments of 100 MW and 200 MW of fixed orientation solar at four resource zones. Table 7 shows similar incremental costs for tracking solar. The costs for incremental solar are small relative to wind additions both in $/MWh and total dollars; note that wind incremental costs in Table 5 are reported in millions of dollars while solar incremental costs in Tables 6 and 7 are reported in thousands of dollars. Annual $/MWh costs for Scenarios 17-24 are shown in Tables B.17 through B.24 in Appendix B.

Table 6: Incremental Levelized Costs over the Baseline Scenario of Individual Additions of Fixed Solar by Resource Zone 2019 to 2040

			Incremental over Baseline				
Scenario	Added Solar	Resource Zone	1st Year Solar Production (GWh)	Cycling Cost Component ($000)	Curtailment Cost Component ($000)	Total Levelized Annual Cost ($000)	Total Levelized Cost ($/MWh)
17	100 MW	NFR	137	$34	$9	$43	$0.33
18	200 MW	NFR	274	$69	$21	$90	$0.34
19	100 MW	SFR	161	$41	$11	$52	$0.34
20	200 MW	SFR	322	$84	$26	$109	$0.35
21	100 MW	SLV	169	$38	$10	$49	$0.30
22	200 MW	SLV	338	$72	$23	$95	$0.29
23	100 MW	WS	147	$28	$8	$37	$0.26
24	200 MW	WS	293	$62	$19	$81	$0.29

Table 7: Incremental Levelized Costs over the Baseline Scenario of Individual Additions of Tracking Solar by Resource Zone 2019 to 2040

			Incremental over Baseline				
Scenario	Added Solar	Resource Zone	1st Year Solar Production (GWh)	Cycling Cost Component ($000)	Curtailment Cost Component ($000)	Total Levelized Annual Cost ($000)	Total Levelized Cost ($/MWh)
25	100 MW	NFR	167	$41	$13	$53	$0.33
26	200 MW	NFR	334	$85	$29	$115	$0.36
27	100 MW	SFR	197	$49	$16	$65	$0.34
28	200 MW	SFR	393	$99	$36	$135	$0.36
29	100 MW	SLV	224	$46	$14	$60	$0.28
30	200 MW	SLV	448	$92	$32	$124	$0.29
31	100 MW	WS	181	$36	$12	$48	$0.28
32	200 MW	WS	361	$72	$28	$100	$0.29

Conclusions

The Public Service system currently has about 2,550 MW of wind and it expects ~ 550 MW of solar at the end of 2016. These variable generation resources cause incremental integration costs as a result of interactions with the Company's existing coal-fired units. Current integration costs are front loaded; absent incremental variable generation, coal cycling costs are expected to decrease over time with load growth, coal unit retirements, and changes to existing wind generation resources including loss of PTC eligibility and contract termination. Incremental wind and solar generation resources will tend to delay cost reductions or increase coal cycling and curtailment costs depending upon the level of assumed additions.

Coal cycling costs and the replacement energy components of the curtailment costs are the primary drivers of the total costs. Production Tax Credit curtailment costs stop being a significant contributor to curtailment costs by the end of 2017 with the exception of scenarios with large additions of new PTC-funded wind. Even in those cases, however, the impact is minor and only lasts for a few years after assumed installation in 2019. Similarly, Renewable Energy Credit curtailment costs are negligible due to the low assumed price of RECs.

Appendix A – Assumptions and Methodology

This study estimated wind and solar (variable resources) induced cycling costs for a Baseline scenario as well as various levels of added solar and wind resources. The total cycling costs are the sum of the plant cycling component and the curtailment component. The study determined cycling costs and curtailment costs as follows:

Plant Cycling Component Calculation

This study used current resource expansion plans, unit operating characteristics, load forecasts and cost per cycle metrics to estimate variable generation-induced cycling costs using a method that applies a cost per cycle to the forecast number of wind and solar-induced cycles to determine annual cycling costs.

Plant cycling costs are calculated as the number of variable resource-induced cycles multiplied by the cost per cycle. In the original study, three types of cycles were considered: 1) on/off cycling, 2) shallow cycling, and 3) deep cycling. On/off cycling is decommitting the coal unit. In the first study, on/off cycling was not determined to be a viable choice for routine cycling due to its high cost. Deep cycling assumes cycling the coal units down to their emergency minimums while shallow cycling assumes cycling down to economic minimums. Deep cycling increases potential reliability risks and in the first study the cycling costs were estimated to be similar to shallow cycling costs. In that study, shallow cycling was determined to be the recommended operating protocol. Therefore, in this study update, shallow cycling was used for all scenarios.

Estimating the Number of Cycles

To estimate the number of coal unit cycles attributable to wind, the Company developed a spreadsheet tool that forecasts cycles based on hourly obligation load, wind and solar generation forecasts and its baseload unit generation profiles and used this information to estimate the frequency and intensity of cycles. Inputs needed to calculate cycles are as follows:

Load Forecast

The hourly obligation load forecast based upon the typical year hourly load shape used in the Company's planning models. The base year data is scaled to meet forecast energy and peak load.

Generating Unit Characteristics

Unit level detail of baseload and must-take units including: unit minimum and maximum output levels, typical outage schedules, expected forced outage rates and planned capacity changes (additions and retirements). The resource mix used in the analysis includes all coal plant retirements at their scheduled dates, all must-take contract expirations and the planned expansion of the Cabin Creek Pumped Storage Generation Station.

Wind Generation Forecasts and Profiles

Individual plant-specific hourly profiles were used for each of the existing wind contracts. Typical Wind Year ("TWY") hourly profiles for each existing facility plus the three generic profiles (North, Central, and South) are based on historical data or, when unavailable, best available data (wind speeds and generation from geographically proximate sources). The three generic wind profiles were used for incremental wind additions.

In this study, all existing wind contracts are forecasted to expire at the contract termination dates and all generic wind additions are assumed to have 25-year lives.

Solar Generation Profiles

Individual plant-specific hourly profiles were used for each of the existing large-scale solar generating facilities. Typical Solar Year ("TSY") hourly profiles for the existing facilities and customer choice solar facilities were based on historical solar generation data. In addition, eight "generic" TSY profiles were used for future additions. These generic profiles represent four solar resource zones: Northern Front Range, Southern Front Range, San Luis Valley and the Western Slope and either fixed or tracking installations. The generic profiles were also based on historic generation data.

In this study, all existing solar contracts are forecasted to expire at the contract termination dates and all generic solar additions are assumed to have 30-year lives. Incremental customer choice solar is assumed to be added at approximately 110 MW per year in the Baseline scenario. In addition, a single 50 MW facility is also assumed in the Baseline scenario starting in 2018.

Counting the Cycles

The model estimates the number of coal unit load follow cycles directly attributable to wind and solar generation using the following methodology:

- An hourly net load forecast is created for each year. The net load is the difference between the forecast obligation load and the sum of the forecast wind and solar generation.
- For each hour of the year, the net load is compared to the maximum aggregate generation capacity of the baseload plants for that hour. If the net load is lower than the maximum aggregate baseload capacity, then it is assumed that one or more baseload units will have to decrease output, or cycle, to follow load. Unit maintenance schedules, scheduled power purchase contracts and estimated forced outages ("EFOR") are accounted for in the calculation. Therefore the maximum baseload capacity for a given hour is the sum of the expected online units only.
- In the 2011 study, for each day of the year the maximum MW load follow was determined based on the hourly calculations above. This method assumed baseload units cycle a maximum of once per day. Because solar has a different diurnal nature, the potential for multiple coal unit cycles occurring during any given day is higher versus if only wind is modeled. In the current model, for each individual cycle (that is, any time the coal plants are calculated to have reduced generation due to wind and solar generation) the maximum MW reduced generation for that cycle was determined. The model then determines which coal units would reduce their generation in each cycle based on each of their maximum and economic minimum MWs and economic dispatch order.

These calculations are repeated assuming there is no wind or solar generation on the system; i.e., the net load is equal to obligation load so as to count cycles that would have occurred absent any wind or solar. The difference between these two cycle counts (with and without variable energy) is the estimate of the number of cycles attributable to wind and solar.

Calculating the Cost per Cycle

The Company retained APTECH Engineering Inc. in the fall of 2008 to study cycling costs for its baseload units. In March 2009, APTECH completed drafts for the Phase 1 study for Pawnee. These costs were extrapolated to the rest of the coal-fired fleet using data from an earlier study[14] which calculated cycling costs for a number of plants. In the previous study, cycling costs were found to be correlated to plant size. The Phase 1 costs for Pawnee were extrapolated to other coal-fired generating units using the correlation data for the rest of the coal-fired plants. These costs were inflated to 2016 dollars based on the change in the Bureau of Labor Statistic's Producer Price Index-Commodities Finished Goods index.

Calculating the Curtailment Cost Component

In addition to load following by baseload units to accommodate wind and solar generation, curtailment may be required when the cycling capabilities of the baseload fleet have been maximized. Curtailment costs are calculated by multiplying the quantity of variable energy curtailed (MWh) by the cost per MWh of curtailment. The costs are calculated on an annual basis and divided by the total MWh of annual variable energy generation (including curtailed hours) resulting in a dollar per Megawatt-hour metric for ease of discussion and consistency with how wind integration costs have been presented in previous studies.

Forecasting Variable Energy Curtailment

The model estimates the MWhs of curtailed generation by determining, for each hour of the year, the quantity of excess wind and solar remaining on the system after all baseload coal units have cycled down to their minimum loads. This quantity of energy must be curtailed to balance load and generation. In the 2011 study, wind was assumed to be curtailed in 50 MW blocks. Since the 2011 study, the Company now requires wind facilities to have AGC capabilities allowing for more discrete levels of wind curtailment. Therefore, variable energy can now be curtailed by the MW and the 50 MW block requirement was removed from the model.

Per MWh Curtailment Costs

Costs per MWh of curtailed energy are comprised of the following four components:

Avoided Energy Cost

Avoided energy or replacement energy cost is the cost of the coal generation that would have been avoided if not for the curtailment. This cost is based on the annual average coal dispatch costs for the fleet. While this method is a simplification and does not explicitly capture the reduced coal plant efficiencies caused by operating at lower output levels when cycling, it does capture some of these effects of cycling in as much as typical cycles are captured in the dispatch models. Avoided energy costs are multiplied by all curtailed MWhs.

Production Tax Credits

PTC uplift payments may be paid to a wind developer when production is curtailed. PTCs are available for the first 10 years of operations of a wind facility. In the model, it is assumed that the tax credit will be available to wind facilities that begin commercial operations by the end of 2019. The PTC is $23/MWh in 2016 and grows at an assumed inflation rate of 2% annually. To make the developer whole, the PTC is grossed-up for taxes using a composite tax rate of 38%.

[14]APTECH Engineering Services, Inc.; Total Cost of Cycling Fossil Power Plants: Phase 2, January 1997 (PSCo Source Data: 1985-1994).

Energy that is curtailed in the model is identified on an hourly basis as “PTC wind” or “non-PTC wind”: a wind facility is generally PTC wind for 10 years then moves to non-PTC wind. The model subtracts “free curtailment wind” (i.e., certain purchase power contracts allow the Company to curtail specified amounts of wind on an annual basis with no make-whole payments) and non-PTC wind from the curtailed wind; only the remaining curtailed PTC wind is used to calculate the total cost of the annual PTC payments.

Carbon Dioxide Emissions Cost

Carbon dioxide emissions costs are assumed to be zero in this updated study consistent with other recent Company studies and filings.

Renewable Energy Credit Opportunity Cost

The opportunity cost of RECs not generated as a result of curtailment is applied to all curtailed wind. This assumes the REC has value either for compliance or for sale into a market. The forecast REC price of $1.00/MWh is discounted to $0.40/MWh to account for the fact that not every REC is available for sale. This price is held constant for all years.

Model Expansion

The updated model used in this study was expanded from 15-years to 40-years which corresponds to the Company’s maximum resource planning period.

Appendix B – Annual Results

Table B.1: Scenario 1
Baseline Annual Results
(Total Nominal $/MWh)

Year	Total Variable Energy	Curtailed Energy	Cycling Cost	Curtailment Cost: PTC Gross Up	Curtailment Cost: Replacement Energy	Curtailment Cost: REC	Total Cost
	(GWh)	(GWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2016	8,885	134	$0.69	$0.07	$0.30	$0.01	$1.07
2017	9,199	75	$0.59	$0.00	$0.17	$0.00	$0.76
2018	9,337	25	$0.25	$0.00	$0.05	$0.00	$0.30
2019	9,151	21	$0.18	$0.00	$0.04	$0.00	$0.23
2020	9,312	11	$0.17	$0.00	$0.02	$0.00	$0.19
2021	9,473	3	$0.12	$0.00	$0.01	$0.00	$0.13
2022	9,633	3	$0.14	$0.00	$0.01	$0.00	$0.14
2023	9,793	0	$0.08	$0.00	$0.00	$0.00	$0.08
2024	9,953	2	$0.08	$0.00	$0.00	$0.00	$0.08
2025	10,111	2	$0.06	$0.00	$0.01	$0.00	$0.06
2026	10,069	1	$0.06	$0.00	$0.00	$0.00	$0.06
2027	10,224	1	$0.05	$0.00	$0.00	$0.00	$0.06
2028	8,704	0	$0.02	$0.00	$0.00	$0.00	$0.02
2029	8,832	0	$0.02	$0.00	$0.00	$0.00	$0.02
2030	8,868	0	$0.02	$0.00	$0.00	$0.00	$0.02
2031	8,921	0	$0.01	$0.00	$0.00	$0.00	$0.01
2032	8,093	0	$0.00	$0.00	$0.00	$0.00	$0.00
2033	7,554	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	7,647	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	7,304	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	7,414	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	6,734	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	5,401	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	5,407	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	4,579	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.2: Scenario 2
600 MW Added Wind
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy	Curtailed Energy	Cycling Cost	Curtailment Cost: PTC Gross Up	Curtailment Cost: Replacement Energy	Curtailment Cost: REC	Total Cost
	(GWh)	(GWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	2,137	114	$0.92	$0.03	$1.01	$0.02	$1.98
2020	2,137	78	$0.83	$0.01	$0.70	$0.01	$1.56
2021	2,137	48	$0.79	$0.00	$0.44	$0.01	$1.24
2022	2,137	46	$0.85	$0.00	$0.44	$0.01	$1.30
2023	2,137	24	$0.75	$0.00	$0.23	$0.00	$0.99
2024	2,137	29	$0.70	$0.00	$0.28	$0.01	$0.99
2025	2,137	25	$0.74	$0.00	$0.26	$0.00	$1.00
2026	2,137	16	$0.65	$0.00	$0.17	$0.00	$0.82
2027	2,137	19	$0.66	$0.00	$0.20	$0.00	$0.86
2028	2,137	0	$0.35	$0.00	$0.00	$0.00	$0.35
2029	2,137	4	$0.25	$0.00	$0.05	$0.00	$0.30
2030	2,137	7	$0.26	$0.00	$0.08	$0.00	$0.33
2031	2,137	3	$0.16	$0.00	$0.03	$0.00	$0.20
2032	2,137	0	$0.11	$0.00	$0.00	$0.00	$0.11
2033	2,137	0	$0.05	$0.00	$0.00	$0.00	$0.05
2034	2,137	0	$0.02	$0.00	$0.00	$0.00	$0.02
2035	2,137	0	$0.02	$0.00	$0.00	$0.00	$0.02
2036	2,137	0	$0.01	$0.00	$0.00	$0.00	$0.01
2037	2,137	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	2,137	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	2,137	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	2,137	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.3: Scenario 3
1,200 MW Added Wind
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	4,274	432	$0.82	$0.30	$1.90	$0.04	$3.06
2020	4,274	336	$0.85	$0.16	$1.50	$0.03	$2.55
2021	4,274	246	$0.83	$0.03	$1.14	$0.02	$2.02
2022	4,274	258	$0.85	$0.00	$1.23	$0.02	$2.11
2023	4,274	163	$0.78	$0.00	$0.80	$0.02	$1.59
2024	4,274	179	$0.80	$0.00	$0.89	$0.02	$1.70
2025	4,274	143	$0.79	$0.00	$0.74	$0.01	$1.54
2026	4,274	112	$0.81	$0.00	$0.58	$0.01	$1.40
2027	4,274	120	$0.78	$0.00	$0.63	$0.01	$1.42
2028	4,274	23	$0.55	$0.00	$0.13	$0.00	$0.68
2029	4,274	39	$0.45	$0.00	$0.22	$0.00	$0.67
2030	4,274	46	$0.44	$0.00	$0.25	$0.00	$0.70
2031	4,274	22	$0.31	$0.00	$0.12	$0.00	$0.43
2032	4,274	6	$0.18	$0.00	$0.03	$0.00	$0.22
2033	4,274	0	$0.14	$0.00	$0.00	$0.00	$0.14
2034	4,274	1	$0.07	$0.00	$0.01	$0.00	$0.07
2035	4,274	1	$0.05	$0.00	$0.01	$0.00	$0.06
2036	4,274	1	$0.03	$0.00	$0.01	$0.00	$0.04
2037	4,274	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	4,274	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	4,274	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	4,274	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.4: Scenario 4
450 MW Added Solar
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	891	24	$0.40	$0.01	$0.51	$0.01	$0.93
2020	887	8	$0.32	$0.00	$0.18	$0.00	$0.50
2021	882	7	$0.41	$0.00	$0.15	$0.00	$0.56
2022	878	4	$0.46	$0.00	$0.10	$0.00	$0.56
2023	874	3	$0.44	$0.00	$0.07	$0.00	$0.51
2024	869	6	$0.42	$0.00	$0.14	$0.00	$0.56
2025	865	6	$0.37	$0.00	$0.15	$0.00	$0.53
2026	861	3	$0.36	$0.00	$0.07	$0.00	$0.43
2027	856	7	$0.53	$0.00	$0.19	$0.00	$0.72
2028	852	0	$0.35	$0.00	$0.00	$0.00	$0.35
2029	848	1	$0.35	$0.00	$0.04	$0.00	$0.39
2030	844	2	$0.28	$0.00	$0.06	$0.00	$0.35
2031	839	1	$0.26	$0.00	$0.02	$0.00	$0.28
2032	835	0	$0.13	$0.00	$0.00	$0.00	$0.13
2033	831	0	$0.04	$0.00	$0.00	$0.00	$0.04
2034	827	0	$0.01	$0.00	$0.00	$0.00	$0.01
2035	823	0	$0.03	$0.00	$0.00	$0.00	$0.03
2036	819	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	814	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	810	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	806	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	802	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.5: Scenario 5
900 MW Added Solar
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	1,783	62	$0.64	$0.07	$0.66	$0.01	$1.38
2020	1,774	27	$0.61	$0.03	$0.29	$0.01	$0.95
2021	1,765	29	$0.59	$0.01	$0.32	$0.01	$0.92
2022	1,756	25	$0.62	$0.00	$0.29	$0.01	$0.92
2023	1,747	20	$0.49	$0.00	$0.24	$0.00	$0.74
2024	1,739	26	$0.57	$0.00	$0.31	$0.01	$0.88
2025	1,730	21	$0.61	$0.00	$0.26	$0.00	$0.87
2026	1,721	16	$0.62	$0.00	$0.20	$0.00	$0.82
2027	1,713	26	$0.72	$0.00	$0.34	$0.01	$1.07
2028	1,704	1	$0.51	$0.00	$0.02	$0.00	$0.53
2029	1,696	10	$0.45	$0.00	$0.14	$0.00	$0.59
2030	1,687	12	$0.39	$0.00	$0.17	$0.00	$0.57
2031	1,679	5	$0.29	$0.00	$0.06	$0.00	$0.36
2032	1,670	1	$0.19	$0.00	$0.01	$0.00	$0.20
2033	1,662	0	$0.18	$0.00	$0.00	$0.00	$0.18
2034	1,654	0	$0.07	$0.00	$0.00	$0.00	$0.07
2035	1,645	0	$0.06	$0.00	$0.00	$0.00	$0.06
2036	1,637	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	1,629	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	1,621	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	1,613	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	1,605	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.6: Scenario 6
600 MW Added Wind + 450 MW Added Solar
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	3,028	162	$0.80	$0.10	$1.01	$0.02	$1.93
2020	3,024	108	$0.73	$0.05	$0.69	$0.01	$1.48
2021	3,019	82	$0.73	$0.01	$0.54	$0.01	$1.29
2022	3,015	79	$0.76	$0.00	$0.54	$0.01	$1.31
2023	3,011	51	$0.68	$0.00	$0.35	$0.01	$1.04
2024	3,006	59	$0.65	$0.00	$0.42	$0.01	$1.07
2025	3,002	48	$0.70	$0.00	$0.35	$0.01	$1.06
2026	2,998	37	$0.65	$0.00	$0.27	$0.00	$0.93
2027	2,993	46	$0.67	$0.00	$0.35	$0.01	$1.02
2028	2,989	5	$0.41	$0.00	$0.04	$0.00	$0.45
2029	2,985	18	$0.31	$0.00	$0.14	$0.00	$0.45
2030	2,980	22	$0.32	$0.00	$0.18	$0.00	$0.50
2031	2,976	9	$0.23	$0.00	$0.07	$0.00	$0.30
2032	2,972	2	$0.14	$0.00	$0.01	$0.00	$0.16
2033	2,968	0	$0.12	$0.00	$0.00	$0.00	$0.12
2034	2,964	0	$0.05	$0.00	$0.00	$0.00	$0.05
2035	2,960	0	$0.05	$0.00	$0.00	$0.00	$0.05
2036	2,955	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	2,951	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	2,947	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	2,943	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	2,939	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.7: Scenario 7
1,200 MW Added Wind + 900 MW Added Solar
(Incremental over Baseline Nominal $/MWh)

Year	Total Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	6,057	657	$0.71	$0.63	$2.05	$0.04	$3.43
2020	6,048	526	$0.80	$0.32	$1.66	$0.03	$2.81
2021	6,039	440	$0.76	$0.14	$1.44	$0.03	$2.37
2022	6,030	446	$0.75	$0.01	$1.51	$0.03	$2.29
2023	6,021	325	$0.72	$0.01	$1.13	$0.02	$1.88
2024	6,012	343	$0.77	$0.02	$1.20	$0.02	$2.01
2025	6,004	293	$0.75	$0.01	$1.07	$0.02	$1.85
2026	5,995	259	$0.79	$0.00	$0.96	$0.02	$1.77
2027	5,986	283	$0.76	$0.01	$1.07	$0.02	$1.85
2028	5,978	108	$0.62	$0.00	$0.42	$0.01	$1.04
2029	5,969	141	$0.52	$0.00	$0.56	$0.01	$1.09
2030	5,961	128	$0.54	$0.00	$0.51	$0.01	$1.06
2031	5,953	89	$0.41	$0.00	$0.35	$0.01	$0.77
2032	5,944	43	$0.33	$0.00	$0.17	$0.00	$0.51
2033	5,936	25	$0.30	$0.00	$0.10	$0.00	$0.40
2034	5,927	19	$0.15	$0.00	$0.08	$0.00	$0.24
2035	5,919	23	$0.13	$0.00	$0.10	$0.00	$0.23
2036	5,911	18	$0.07	$0.00	$0.08	$0.00	$0.15
2037	5,903	2	$0.04	$0.00	$0.01	$0.00	$0.04
2038	5,895	0	$0.01	$0.00	$0.00	$0.00	$0.01
2039	5,887	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	5,878	0	$0.01	$0.00	$0.00	$0.00	$0.01

Table B.8: Scenario 8
300 MW Wind (North Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	1,070	40	$0.95	$0.00	$0.71	$0.02	$1.68
2020	1,070	27	$0.87	$0.00	$0.48	$0.01	$1.37
2021	1,070	11	$0.78	$0.00	$0.20	$0.00	$0.98
2022	1,070	11	$0.88	$0.00	$0.21	$0.00	$1.09
2023	1,070	5	$0.64	$0.00	$0.09	$0.00	$0.73
2024	1,070	8	$0.67	$0.00	$0.15	$0.00	$0.83
2025	1,070	7	$0.67	$0.00	$0.15	$0.00	$0.82
2026	1,070	4	$0.52	$0.00	$0.08	$0.00	$0.60
2027	1,070	5	$0.61	$0.00	$0.10	$0.00	$0.71
2028	1,070	0	$0.23	$0.00	$0.00	$0.00	$0.23
2029	1,070	1	$0.18	$0.00	$0.02	$0.00	$0.20
2030	1,070	1	$0.22	$0.00	$0.03	$0.00	$0.25
2031	1,070	0	$0.13	$0.00	$0.00	$0.00	$0.13
2032	1,070	0	$0.06	$0.00	$0.00	$0.00	$0.06
2033	1,070	0	$0.01	$0.00	$0.00	$0.00	$0.01
2034	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	1,070	0	$0.01	$0.00	$0.00	$0.00	$0.01
2036	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	1,070	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.9: Scenario 9
600 MW Wind (North Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	2,140	122	$0.99	$0.02	$1.08	$0.02	$2.11
2020	2,140	88	$0.95	$0.01	$0.78	$0.02	$1.75
2021	2,140	51	$0.90	$0.00	$0.47	$0.01	$1.38
2022	2,140	52	$0.95	$0.00	$0.50	$0.01	$1.45
2023	2,140	27	$0.82	$0.00	$0.26	$0.01	$1.09
2024	2,140	33	$0.75	$0.00	$0.32	$0.01	$1.07
2025	2,140	27	$0.78	$0.00	$0.28	$0.01	$1.06
2026	2,140	19	$0.74	$0.00	$0.19	$0.00	$0.93
2027	2,140	19	$0.73	$0.00	$0.20	$0.00	$0.94
2028	2,140	0	$0.38	$0.00	$0.00	$0.00	$0.39
2029	2,140	4	$0.27	$0.00	$0.05	$0.00	$0.32
2030	2,140	8	$0.25	$0.00	$0.08	$0.00	$0.34
2031	2,140	3	$0.15	$0.00	$0.03	$0.00	$0.18
2032	2,140	0	$0.11	$0.00	$0.00	$0.00	$0.11
2033	2,140	0	$0.06	$0.00	$0.00	$0.00	$0.06
2034	2,140	0	$0.02	$0.00	$0.00	$0.00	$0.02
2035	2,140	0	$0.02	$0.00	$0.00	$0.00	$0.02
2036	2,140	0	$0.01	$0.00	$0.00	$0.00	$0.01
2037	2,140	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	2,140	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	2,140	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	2,140	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.10: Scenario 10
900 MW Wind (<u>North</u> Resource Zone)
(<u>Incremental</u> over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	3,211	264	$0.97	$0.09	$1.55	$0.03	$2.64
2020	3,211	203	$1.00	$0.04	$1.21	$0.03	$2.27
2021	3,211	137	$0.99	$0.00	$0.84	$0.02	$1.85
2022	3,211	148	$0.98	$0.00	$0.94	$0.02	$1.94
2023	3,211	83	$0.89	$0.00	$0.54	$0.01	$1.44
2024	3,211	93	$0.88	$0.00	$0.61	$0.01	$1.51
2025	3,211	75	$0.86	$0.00	$0.51	$0.01	$1.38
2026	3,211	55	$0.84	$0.00	$0.38	$0.01	$1.23
2027	3,211	59	$0.79	$0.00	$0.41	$0.01	$1.21
2028	3,211	7	$0.48	$0.00	$0.05	$0.00	$0.53
2029	3,211	17	$0.35	$0.00	$0.12	$0.00	$0.48
2030	3,211	22	$0.36	$0.00	$0.17	$0.00	$0.53
2031	3,211	9	$0.25	$0.00	$0.07	$0.00	$0.32
2032	3,211	2	$0.16	$0.00	$0.02	$0.00	$0.18
2033	3,211	0	$0.12	$0.00	$0.00	$0.00	$0.12
2034	3,211	0	$0.05	$0.00	$0.00	$0.00	$0.05
2035	3,211	0	$0.04	$0.00	$0.00	$0.00	$0.04
2036	3,211	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	3,211	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	3,211	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	3,211	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	3,211	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.11: Scenario 11
300 MW Wind (<u>Central</u> Resource Zone)
(<u>Incremental</u> over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	1,022	40	$0.95	$0.00	$0.74	$0.02	$1.71
2020	1,022	25	$0.88	$0.00	$0.47	$0.01	$1.35
2021	1,022	13	$0.78	$0.00	$0.25	$0.01	$1.03
2022	1,022	11	$0.90	$0.00	$0.21	$0.00	$1.12
2023	1,022	5	$0.72	$0.00	$0.10	$0.00	$0.83
2024	1,022	8	$0.70	$0.00	$0.17	$0.00	$0.87
2025	1,022	7	$0.64	$0.00	$0.16	$0.00	$0.80
2026	1,022	3	$0.57	$0.00	$0.07	$0.00	$0.64
2027	1,022	6	$0.56	$0.00	$0.13	$0.00	$0.69
2028	1,022	0	$0.22	$0.00	$0.00	$0.00	$0.22
2029	1,022	1	$0.21	$0.00	$0.02	$0.00	$0.23
2030	1,022	1	$0.21	$0.00	$0.03	$0.00	$0.25
2031	1,022	0	$0.16	$0.00	$0.01	$0.00	$0.16
2032	1,022	0	$0.05	$0.00	$0.00	$0.00	$0.05
2033	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	1,022	0	$0.01	$0.00	$0.00	$0.00	$0.01
2036	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	1,022	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.12: Scenario 12
600 MW Wind (Central Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	2,043	119	$0.97	$0.06	$1.10	$0.02	$2.15
2020	2,043	80	$0.89	$0.04	$0.75	$0.02	$1.69
2021	2,043	50	$0.88	$0.00	$0.49	$0.01	$1.38
2022	2,043	47	$0.90	$0.00	$0.47	$0.01	$1.37
2023	2,043	24	$0.81	$0.00	$0.25	$0.00	$1.06
2024	2,043	30	$0.82	$0.00	$0.31	$0.01	$1.13
2025	2,043	27	$0.81	$0.00	$0.29	$0.01	$1.10
2026	2,043	17	$0.70	$0.00	$0.18	$0.00	$0.88
2027	2,043	22	$0.69	$0.00	$0.25	$0.00	$0.94
2028	2,043	1	$0.36	$0.00	$0.01	$0.00	$0.37
2029	2,043	5	$0.28	$0.00	$0.06	$0.00	$0.34
2030	2,043	8	$0.28	$0.00	$0.09	$0.00	$0.38
2031	2,043	3	$0.19	$0.00	$0.04	$0.00	$0.23
2032	2,043	0	$0.10	$0.00	$0.00	$0.00	$0.10
2033	2,043	0	$0.06	$0.00	$0.00	$0.00	$0.06
2034	2,043	0	$0.02	$0.00	$0.00	$0.00	$0.02
2035	2,043	0	$0.03	$0.00	$0.00	$0.00	$0.03
2036	2,043	0	$0.01	$0.00	$0.00	$0.00	$0.01
2037	2,043	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	2,043	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	2,043	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	2,043	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.13: Scenario 13
900 MW Wind (Central Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	3,065	257	$0.93	$0.26	$1.58	$0.03	$2.80
2020	3,065	189	$0.91	$0.15	$1.18	$0.02	$2.25
2021	3,065	128	$0.91	$0.03	$0.83	$0.02	$1.79
2022	3,065	127	$0.93	$0.00	$0.85	$0.02	$1.79
2023	3,065	73	$0.88	$0.00	$0.50	$0.01	$1.39
2024	3,065	85	$0.86	$0.00	$0.58	$0.01	$1.46
2025	3,065	68	$0.85	$0.00	$0.49	$0.01	$1.35
2026	3,065	51	$0.85	$0.00	$0.37	$0.01	$1.22
2027	3,065	60	$0.82	$0.00	$0.44	$0.01	$1.26
2028	3,065	7	$0.54	$0.00	$0.05	$0.00	$0.59
2029	3,065	20	$0.43	$0.00	$0.15	$0.00	$0.58
2030	3,065	24	$0.39	$0.00	$0.18	$0.00	$0.58
2031	3,065	10	$0.26	$0.00	$0.07	$0.00	$0.33
2032	3,065	1	$0.15	$0.00	$0.01	$0.00	$0.15
2033	3,065	0	$0.12	$0.00	$0.00	$0.00	$0.12
2034	3,065	0	$0.04	$0.00	$0.00	$0.00	$0.05
2035	3,065	0	$0.04	$0.00	$0.00	$0.00	$0.04
2036	3,065	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	3,065	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	3,065	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	3,065	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	3,065	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.14: Scenario 14
300 MW Wind (South Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	1,181	38	$0.78	$0.00	$0.61	$0.01	$1.41
2020	1,181	24	$0.76	$0.00	$0.39	$0.01	$1.15
2021	1,181	12	$0.69	$0.00	$0.20	$0.00	$0.89
2022	1,181	10	$0.76	$0.00	$0.18	$0.00	$0.94
2023	1,181	5	$0.58	$0.00	$0.09	$0.00	$0.67
2024	1,181	7	$0.58	$0.00	$0.12	$0.00	$0.70
2025	1,181	6	$0.55	$0.00	$0.11	$0.00	$0.66
2026	1,181	3	$0.46	$0.00	$0.06	$0.00	$0.52
2027	1,181	4	$0.48	$0.00	$0.08	$0.00	$0.57
2028	1,181	0	$0.14	$0.00	$0.00	$0.00	$0.14
2029	1,181	1	$0.13	$0.00	$0.02	$0.00	$0.15
2030	1,181	1	$0.17	$0.00	$0.03	$0.00	$0.19
2031	1,181	0	$0.12	$0.00	$0.00	$0.00	$0.12
2032	1,181	0	$0.05	$0.00	$0.00	$0.00	$0.05
2033	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	1,181	0	$0.01	$0.00	$0.00	$0.00	$0.01
2036	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	1,181	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.15: Scenario 15
600 MW Wind (South Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	2,363	117	$0.90	$0.04	$0.93	$0.02	$1.89
2020	2,363	80	$0.82	$0.02	$0.64	$0.01	$1.50
2021	2,363	49	$0.78	$0.00	$0.41	$0.01	$1.19
2022	2,363	49	$0.80	$0.00	$0.42	$0.01	$1.23
2023	2,363	25	$0.65	$0.00	$0.22	$0.00	$0.88
2024	2,363	28	$0.69	$0.00	$0.25	$0.00	$0.95
2025	2,363	25	$0.68	$0.00	$0.23	$0.00	$0.91
2026	2,363	17	$0.63	$0.00	$0.16	$0.00	$0.80
2027	2,363	18	$0.62	$0.00	$0.17	$0.00	$0.80
2028	2,363	1	$0.30	$0.00	$0.00	$0.00	$0.30
2029	2,363	6	$0.22	$0.00	$0.06	$0.00	$0.27
2030	2,363	7	$0.22	$0.00	$0.07	$0.00	$0.29
2031	2,363	2	$0.15	$0.00	$0.02	$0.00	$0.17
2032	2,363	0	$0.09	$0.00	$0.00	$0.00	$0.09
2033	2,363	0	$0.03	$0.00	$0.00	$0.00	$0.03
2034	2,363	0	$0.01	$0.00	$0.00	$0.00	$0.01
2035	2,363	0	$0.03	$0.00	$0.00	$0.00	$0.03
2036	2,363	0	$0.01	$0.00	$0.00	$0.00	$0.01
2037	2,363	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	2,363	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	2,363	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	2,363	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.16: Scenario 16
900 MW Wind (South Resource Zone)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replace ment Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	3,544	256	$0.93	$0.19	$1.36	$0.03	$2.52
2020	3,544	190	$0.87	$0.11	$1.03	$0.02	$2.02
2021	3,544	129	$0.84	$0.02	$0.72	$0.01	$1.59
2022	3,544	137	$0.87	$0.00	$0.79	$0.02	$1.67
2023	3,544	79	$0.79	$0.00	$0.47	$0.01	$1.26
2024	3,544	84	$0.79	$0.00	$0.50	$0.01	$1.31
2025	3,544	70	$0.79	$0.00	$0.43	$0.01	$1.23
2026	3,544	56	$0.76	$0.00	$0.35	$0.01	$1.12
2027	3,544	55	$0.73	$0.00	$0.35	$0.01	$1.08
2028	3,544	7	$0.46	$0.00	$0.04	$0.00	$0.50
2029	3,544	19	$0.37	$0.00	$0.13	$0.00	$0.50
2030	3,544	21	$0.35	$0.00	$0.14	$0.00	$0.50
2031	3,544	7	$0.23	$0.00	$0.05	$0.00	$0.28
2032	3,544	1	$0.16	$0.00	$0.01	$0.00	$0.17
2033	3,544	0	$0.08	$0.00	$0.00	$0.00	$0.08
2034	3,544	0	$0.03	$0.00	$0.00	$0.00	$0.03
2035	3,544	0	$0.03	$0.00	$0.00	$0.00	$0.03
2036	3,544	0	$0.02	$0.00	$0.00	$0.00	$0.02
2037	3,544	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	3,544	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	3,544	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	3,544	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.17: Scenario 17
100 MW Solar (Northern Front Range Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	137	3	$0.38	$0.00	$0.38	$0.01	$0.77
2020	136	1	$0.22	$0.00	$0.15	$0.00	$0.37
2021	135	0	$0.43	$0.00	$0.05	$0.00	$0.49
2022	135	0	$0.39	$0.00	$0.01	$0.00	$0.40
2023	134	0	$0.53	$0.00	$0.01	$0.00	$0.54
2024	133	0	$0.32	$0.00	$0.07	$0.00	$0.39
2025	133	1	$0.33	$0.00	$0.13	$0.00	$0.46
2026	132	0	$0.39	$0.00	$0.03	$0.00	$0.43
2027	131	1	$0.41	$0.00	$0.09	$0.00	$0.50
2028	131	0	$0.05	$0.00	$0.00	$0.00	$0.05
2029	130	0	$0.28	$0.00	$0.01	$0.00	$0.28
2030	129	0	$0.20	$0.00	$0.03	$0.00	$0.24
2031	129	0	$0.23	$0.00	$0.00	$0.00	$0.23
2032	128	0	$0.04	$0.00	$0.00	$0.00	$0.04
2033	128	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	127	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	126	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	126	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	125	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	124	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	124	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	123	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.18: Scenario 18
200 MW Solar (Northern Front Range Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	274	6	$0.38	$0.00	$0.41	$0.01	$0.80
2020	272	2	$0.29	$0.00	$0.15	$0.00	$0.45
2021	271	1	$0.39	$0.00	$0.07	$0.00	$0.47
2022	270	0	$0.42	$0.00	$0.02	$0.00	$0.44
2023	268	0	$0.45	$0.00	$0.02	$0.00	$0.47
2024	267	1	$0.37	$0.00	$0.08	$0.00	$0.45
2025	265	2	$0.29	$0.00	$0.14	$0.00	$0.43
2026	264	1	$0.30	$0.00	$0.04	$0.00	$0.35
2027	263	1	$0.44	$0.00	$0.13	$0.00	$0.57
2028	262	0	$0.15	$0.00	$0.00	$0.00	$0.15
2029	260	0	$0.27	$0.00	$0.01	$0.00	$0.28
2030	259	0	$0.23	$0.00	$0.04	$0.00	$0.27
2031	258	0	$0.23	$0.00	$0.00	$0.00	$0.23
2032	256	0	$0.07	$0.00	$0.00	$0.00	$0.07
2033	255	0	$0.01	$0.00	$0.00	$0.00	$0.01
2034	254	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	253	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	251	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	250	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	249	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	248	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	246	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.19: Scenario 19
100 MW Solar (Southern Front Range Fixed)
(<u>Incremental</u> over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	161	3	$0.39	$0.00	$0.39	$0.01	$0.79
2020	160	1	$0.23	$0.00	$0.15	$0.00	$0.38
2021	159	0	$0.39	$0.00	$0.05	$0.00	$0.45
2022	159	0	$0.46	$0.00	$0.01	$0.00	$0.48
2023	158	0	$0.51	$0.00	$0.01	$0.00	$0.52
2024	157	1	$0.32	$0.00	$0.07	$0.00	$0.39
2025	156	1	$0.35	$0.00	$0.13	$0.00	$0.48
2026	155	0	$0.38	$0.00	$0.04	$0.00	$0.41
2027	155	1	$0.46	$0.00	$0.10	$0.00	$0.55
2028	154	0	$0.10	$0.00	$0.00	$0.00	$0.10
2029	153	0	$0.30	$0.00	$0.01	$0.00	$0.31
2030	152	0	$0.24	$0.00	$0.03	$0.00	$0.27
2031	152	0	$0.27	$0.00	$0.00	$0.00	$0.27
2032	151	0	$0.03	$0.00	$0.00	$0.00	$0.03
2033	150	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	149	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	149	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	148	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	147	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	146	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	146	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	145	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.20: Scenario 20
200 MW Solar (Southern Front Range Fixed)
(<u>Incremental</u> over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	322	7	$0.37	$0.00	$0.42	$0.01	$0.80
2020	320	3	$0.29	$0.00	$0.15	$0.00	$0.45
2021	319	1	$0.36	$0.00	$0.08	$0.00	$0.44
2022	317	0	$0.48	$0.00	$0.02	$0.00	$0.50
2023	315	0	$0.45	$0.00	$0.02	$0.00	$0.47
2024	314	1	$0.37	$0.00	$0.09	$0.00	$0.46
2025	312	2	$0.32	$0.00	$0.14	$0.00	$0.47
2026	311	1	$0.32	$0.00	$0.05	$0.00	$0.37
2027	309	2	$0.44	$0.00	$0.14	$0.00	$0.58
2028	308	0	$0.23	$0.00	$0.00	$0.00	$0.23
2029	306	0	$0.28	$0.00	$0.02	$0.00	$0.29
2030	305	1	$0.26	$0.00	$0.04	$0.00	$0.31
2031	303	0	$0.25	$0.00	$0.00	$0.00	$0.25
2032	302	0	$0.08	$0.00	$0.00	$0.00	$0.08
2033	300	0	$0.01	$0.00	$0.00	$0.00	$0.01
2034	299	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	297	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	296	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	294	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	293	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	291	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	290	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.21: Scenario 21
100 MW Solar (San Luis Valley Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	169	3	$0.40	$0.00	$0.35	$0.01	$0.76
2020	168	1	$0.20	$0.00	$0.14	$0.00	$0.34
2021	167	0	$0.34	$0.00	$0.03	$0.00	$0.38
2022	166	0	$0.44	$0.00	$0.01	$0.00	$0.45
2023	166	0	$0.46	$0.00	$0.01	$0.00	$0.48
2024	165	0	$0.23	$0.00	$0.06	$0.00	$0.29
2025	164	1	$0.28	$0.00	$0.12	$0.00	$0.40
2026	163	0	$0.33	$0.00	$0.03	$0.00	$0.36
2027	162	0	$0.36	$0.00	$0.07	$0.00	$0.43
2028	161	0	$0.10	$0.00	$0.00	$0.00	$0.10
2029	161	0	$0.25	$0.00	$0.00	$0.00	$0.26
2030	160	0	$0.24	$0.00	$0.03	$0.00	$0.27
2031	159	0	$0.21	$0.00	$0.00	$0.00	$0.21
2032	158	0	$0.03	$0.00	$0.00	$0.00	$0.03
2033	157	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	157	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	156	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	155	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	154	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	154	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	153	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	152	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.22: Scenario 22
200 MW Solar (San Luis Valley Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	338	7	$0.34	$0.00	$0.38	$0.01	$0.73
2020	336	2	$0.21	$0.00	$0.14	$0.00	$0.35
2021	334	1	$0.36	$0.00	$0.05	$0.00	$0.42
2022	333	0	$0.38	$0.00	$0.01	$0.00	$0.39
2023	331	0	$0.34	$0.00	$0.02	$0.00	$0.36
2024	329	1	$0.30	$0.00	$0.07	$0.00	$0.38
2025	328	2	$0.26	$0.00	$0.12	$0.00	$0.38
2026	326	1	$0.24	$0.00	$0.04	$0.00	$0.28
2027	324	1	$0.38	$0.00	$0.10	$0.00	$0.48
2028	323	0	$0.11	$0.00	$0.00	$0.00	$0.11
2029	321	0	$0.22	$0.00	$0.01	$0.00	$0.23
2030	320	0	$0.24	$0.00	$0.03	$0.00	$0.28
2031	318	0	$0.21	$0.00	$0.00	$0.00	$0.21
2032	316	0	$0.06	$0.00	$0.00	$0.00	$0.06
2033	315	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	313	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	312	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	310	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	309	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	307	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	306	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	304	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.23: Scenario 23
100 MW Solar (Western Slope Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	147	3	$0.31	$0.00	$0.33	$0.01	$0.64
2020	146	1	$0.24	$0.00	$0.13	$0.00	$0.37
2021	145	0	$0.30	$0.00	$0.03	$0.00	$0.33
2022	144	0	$0.32	$0.00	$0.01	$0.00	$0.32
2023	144	0	$0.51	$0.00	$0.01	$0.00	$0.52
2024	143	0	$0.20	$0.00	$0.05	$0.00	$0.25
2025	142	1	$0.19	$0.00	$0.11	$0.00	$0.30
2026	142	0	$0.26	$0.00	$0.03	$0.00	$0.29
2027	141	0	$0.27	$0.00	$0.06	$0.00	$0.33
2028	140	0	$0.09	$0.00	$0.00	$0.00	$0.09
2029	139	0	$0.24	$0.00	$0.00	$0.00	$0.25
2030	139	0	$0.13	$0.00	$0.02	$0.00	$0.16
2031	138	0	$0.17	$0.00	$0.00	$0.00	$0.17
2032	137	0	$0.04	$0.00	$0.00	$0.00	$0.04
2033	137	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	136	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	135	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	135	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	134	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	133	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	133	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	132	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.24: Scenario 24
200 MW Solar (Western Slope Fixed)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	293	5	$0.36	$0.00	$0.35	$0.01	$0.72
2020	292	2	$0.23	$0.00	$0.14	$0.00	$0.37
2021	290	1	$0.35	$0.00	$0.05	$0.00	$0.40
2022	289	0	$0.35	$0.00	$0.01	$0.00	$0.36
2023	287	0	$0.35	$0.00	$0.01	$0.00	$0.36
2024	286	1	$0.30	$0.00	$0.06	$0.00	$0.36
2025	285	1	$0.25	$0.00	$0.12	$0.00	$0.37
2026	283	0	$0.27	$0.00	$0.03	$0.00	$0.30
2027	282	1	$0.33	$0.00	$0.09	$0.00	$0.42
2028	280	0	$0.12	$0.00	$0.00	$0.00	$0.12
2029	279	0	$0.24	$0.00	$0.01	$0.00	$0.25
2030	278	0	$0.20	$0.00	$0.03	$0.00	$0.23
2031	276	0	$0.22	$0.00	$0.00	$0.00	$0.22
2032	275	0	$0.05	$0.00	$0.00	$0.00	$0.05
2033	273	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	272	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	271	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	269	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	268	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	267	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	265	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	264	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.25: Scenario 25
100 MW Solar (Northern Front Range Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	167	4	$0.41	$0.00	$0.42	$0.01	$0.85
2020	166	1	$0.18	$0.00	$0.16	$0.00	$0.35
2021	165	0	$0.46	$0.00	$0.06	$0.00	$0.52
2022	165	0	$0.43	$0.00	$0.03	$0.00	$0.46
2023	164	0	$0.42	$0.00	$0.02	$0.00	$0.45
2024	163	1	$0.36	$0.00	$0.08	$0.00	$0.45
2025	162	1	$0.36	$0.00	$0.13	$0.00	$0.50
2026	161	0	$0.18	$0.00	$0.04	$0.00	$0.22
2027	160	1	$0.44	$0.00	$0.09	$0.00	$0.54
2028	160	0	$0.13	$0.00	$0.00	$0.00	$0.13
2029	159	0	$0.24	$0.00	$0.01	$0.00	$0.26
2030	158	0	$0.24	$0.00	$0.04	$0.00	$0.28
2031	157	0	$0.23	$0.00	$0.00	$0.00	$0.23
2032	156	0	$0.05	$0.00	$0.00	$0.00	$0.05
2033	156	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	155	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	154	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	153	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	153	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	152	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	151	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	150	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.26: Scenario 26
200 MW Solar (Northern Front Range Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	334	8	$0.33	$0.00	$0.46	$0.01	$0.80
2020	332	3	$0.25	$0.00	$0.17	$0.00	$0.42
2021	331	1	$0.43	$0.00	$0.08	$0.00	$0.51
2022	329	1	$0.47	$0.00	$0.04	$0.00	$0.52
2023	327	1	$0.49	$0.00	$0.03	$0.00	$0.52
2024	326	2	$0.36	$0.00	$0.10	$0.00	$0.46
2025	324	2	$0.28	$0.00	$0.14	$0.00	$0.43
2026	323	1	$0.32	$0.00	$0.05	$0.00	$0.37
2027	321	2	$0.45	$0.00	$0.12	$0.00	$0.58
2028	319	0	$0.23	$0.00	$0.00	$0.00	$0.23
2029	318	0	$0.27	$0.00	$0.03	$0.00	$0.30
2030	316	1	$0.25	$0.00	$0.04	$0.00	$0.30
2031	315	0	$0.20	$0.00	$0.00	$0.00	$0.20
2032	313	0	$0.09	$0.00	$0.00	$0.00	$0.09
2033	311	0	$0.01	$0.00	$0.00	$0.00	$0.01
2034	310	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	308	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	307	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	305	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	304	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	302	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	301	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.27: Scenario 27
100 MW Solar (Southern Front Range Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	197	4	$0.37	$0.00	$0.43	$0.01	$0.81
2020	196	2	$0.19	$0.00	$0.16	$0.00	$0.36
2021	195	1	$0.43	$0.00	$0.06	$0.00	$0.49
2022	194	0	$0.48	$0.00	$0.03	$0.00	$0.51
2023	193	0	$0.47	$0.00	$0.03	$0.00	$0.49
2024	192	1	$0.40	$0.00	$0.09	$0.00	$0.49
2025	191	1	$0.35	$0.00	$0.13	$0.00	$0.48
2026	190	0	$0.23	$0.00	$0.04	$0.00	$0.27
2027	189	1	$0.42	$0.00	$0.09	$0.00	$0.52
2028	188	0	$0.17	$0.00	$0.00	$0.00	$0.17
2029	187	0	$0.28	$0.00	$0.01	$0.00	$0.29
2030	186	0	$0.26	$0.00	$0.04	$0.00	$0.30
2031	185	0	$0.21	$0.00	$0.00	$0.00	$0.21
2032	184	0	$0.07	$0.00	$0.00	$0.00	$0.07
2033	183	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	182	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	181	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	180	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	180	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	179	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	178	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	177	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.28: Scenario 28
200 MW Solar (Southern Front Range Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	393	10	$0.30	$0.00	$0.47	$0.01	$0.78
2020	391	3	$0.27	$0.00	$0.17	$0.00	$0.45
2021	389	2	$0.33	$0.00	$0.09	$0.00	$0.42
2022	387	1	$0.47	$0.00	$0.05	$0.00	$0.52
2023	385	1	$0.52	$0.00	$0.04	$0.00	$0.55
2024	383	2	$0.39	$0.00	$0.10	$0.00	$0.49
2025	381	2	$0.29	$0.00	$0.14	$0.00	$0.43
2026	379	1	$0.30	$0.00	$0.05	$0.00	$0.36
2027	378	2	$0.48	$0.00	$0.13	$0.00	$0.61
2028	376	0	$0.23	$0.00	$0.00	$0.00	$0.23
2029	374	0	$0.31	$0.00	$0.03	$0.00	$0.33
2030	372	1	$0.25	$0.00	$0.05	$0.00	$0.29
2031	370	0	$0.20	$0.00	$0.00	$0.00	$0.20
2032	368	0	$0.08	$0.00	$0.00	$0.00	$0.08
2033	366	0	$0.01	$0.00	$0.00	$0.00	$0.01
2034	365	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	363	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	361	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	359	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	357	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	356	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	354	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.29: Scenario 29
100 MW Solar (San Luis Valley Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	224	4	$0.35	$0.00	$0.34	$0.01	$0.70
2020	223	2	$0.24	$0.00	$0.13	$0.00	$0.38
2021	222	1	$0.36	$0.00	$0.05	$0.00	$0.41
2022	221	0	$0.37	$0.00	$0.02	$0.00	$0.38
2023	220	0	$0.41	$0.00	$0.02	$0.00	$0.43
2024	218	1	$0.27	$0.00	$0.06	$0.00	$0.33
2025	217	1	$0.25	$0.00	$0.11	$0.00	$0.36
2026	216	0	$0.12	$0.00	$0.03	$0.00	$0.16
2027	215	1	$0.35	$0.00	$0.08	$0.00	$0.42
2028	214	0	$0.11	$0.00	$0.00	$0.00	$0.11
2029	213	0	$0.24	$0.00	$0.01	$0.00	$0.25
2030	212	0	$0.21	$0.00	$0.03	$0.00	$0.24
2031	211	0	$0.19	$0.00	$0.00	$0.00	$0.19
2032	210	0	$0.02	$0.00	$0.00	$0.00	$0.02
2033	209	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	208	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	207	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	206	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	205	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	204	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	203	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	202	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.30: Scenario 30
200 MW Solar (San Luis Valley Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	448	9	$0.27	$0.00	$0.37	$0.01	$0.65
2020	446	3	$0.20	$0.00	$0.14	$0.00	$0.34
2021	444	2	$0.32	$0.00	$0.07	$0.00	$0.40
2022	441	1	$0.38	$0.00	$0.03	$0.00	$0.41
2023	439	1	$0.40	$0.00	$0.03	$0.00	$0.42
2024	437	2	$0.32	$0.00	$0.08	$0.00	$0.40
2025	435	2	$0.24	$0.00	$0.11	$0.00	$0.36
2026	433	1	$0.23	$0.00	$0.04	$0.00	$0.27
2027	430	2	$0.35	$0.00	$0.10	$0.00	$0.45
2028	428	0	$0.17	$0.00	$0.00	$0.00	$0.17
2029	426	0	$0.23	$0.00	$0.02	$0.00	$0.25
2030	424	1	$0.22	$0.00	$0.03	$0.00	$0.26
2031	422	0	$0.17	$0.00	$0.00	$0.00	$0.17
2032	420	0	$0.06	$0.00	$0.00	$0.00	$0.06
2033	418	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	416	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	414	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	411	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	409	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	407	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	405	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	403	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.31: Scenario 31
100 MW Solar (Western Slope Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	181	3	$0.32	$0.00	$0.37	$0.01	$0.70
2020	180	1	$0.19	$0.00	$0.16	$0.00	$0.35
2021	179	0	$0.33	$0.00	$0.05	$0.00	$0.38
2022	178	0	$0.33	$0.00	$0.02	$0.00	$0.35
2023	177	0	$0.42	$0.00	$0.02	$0.00	$0.43
2024	176	1	$0.29	$0.00	$0.07	$0.00	$0.36
2025	175	1	$0.24	$0.00	$0.13	$0.00	$0.38
2026	175	0	$0.23	$0.00	$0.04	$0.00	$0.27
2027	174	1	$0.32	$0.00	$0.07	$0.00	$0.39
2028	173	0	$0.12	$0.00	$0.00	$0.00	$0.12
2029	172	0	$0.23	$0.00	$0.01	$0.00	$0.24
2030	171	0	$0.15	$0.00	$0.04	$0.00	$0.18
2031	170	0	$0.22	$0.00	$0.00	$0.00	$0.22
2032	169	0	$0.04	$0.00	$0.00	$0.00	$0.04
2033	168	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	168	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	167	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	166	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	165	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	164	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	163	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	163	0	$0.00	$0.00	$0.00	$0.00	$0.00

Table B.32: Scenario 32
200 MW Solar Western Slope Tracking)
(Incremental over Baseline Nominal $/MWh)

Year	Variable Energy (GWh)	Curtailed Energy (GWh)	Cycling Cost ($/MWh)	Curtailment Cost: PTC Gross Up ($/MWh)	Curtailment Cost: Replacement Energy ($/MWh)	Curtailment Cost: REC ($/MWh)	Total Cost ($/MWh)
2016	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2017	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2018	0	0	$0.00	$0.00	$0.00	$0.00	$0.00
2019	361	8	$0.31	$0.00	$0.39	$0.01	$0.71
2020	360	3	$0.20	$0.00	$0.16	$0.00	$0.37
2021	358	1	$0.30	$0.00	$0.07	$0.00	$0.37
2022	356	1	$0.38	$0.00	$0.03	$0.00	$0.41
2023	354	0	$0.37	$0.00	$0.02	$0.00	$0.39
2024	353	1	$0.24	$0.00	$0.08	$0.00	$0.32
2025	351	2	$0.20	$0.00	$0.14	$0.00	$0.35
2026	349	1	$0.24	$0.00	$0.04	$0.00	$0.28
2027	347	2	$0.35	$0.00	$0.10	$0.00	$0.45
2028	346	0	$0.23	$0.00	$0.00	$0.00	$0.23
2029	344	0	$0.23	$0.00	$0.02	$0.00	$0.25
2030	342	1	$0.20	$0.00	$0.04	$0.00	$0.24
2031	340	0	$0.17	$0.00	$0.00	$0.00	$0.17
2032	339	0	$0.05	$0.00	$0.00	$0.00	$0.05
2033	337	0	$0.00	$0.00	$0.00	$0.00	$0.00
2034	335	0	$0.00	$0.00	$0.00	$0.00	$0.00
2035	334	0	$0.00	$0.00	$0.00	$0.00	$0.00
2036	332	0	$0.00	$0.00	$0.00	$0.00	$0.00
2037	330	0	$0.00	$0.00	$0.00	$0.00	$0.00
2038	329	0	$0.00	$0.00	$0.00	$0.00	$0.00
2039	327	0	$0.00	$0.00	$0.00	$0.00	$0.00
2040	325	0	$0.00	$0.00	$0.00	$0.00	$0.00

30-Minute Flex Reserve

on the

Public Service Company of Colorado System

Prepared by:

Xcel Energy Services, Inc.
1800 Larimer St.
Denver, Colorado 80202

May 13, 2016

Introduction

In Public Service Company of Colorado's (the "Company") "2011 Wind Limits Study"[1] it detailed the creation and application of its 30-Minute Wind Reserve Guideline. The Company provided further details on the 30-Minute Wind Reserve Guidelines in a study report titled "An Investigation of Potential Electric Storage Options" dated December 8, 2014 and filed in Docket No. 14M-1160E (the "2014 Storage Study"). The guideline was adopted in order to help System Operators maintain enough standby resources that could be brought online within 30 minutes in response to large, sustained down ramps in wind generation.

On May 15, 2014 the Company filed with the Federal Energy Regulatory Commission ("FERC") for a new transmission tariff, Schedule 16: Flex Reserve Service. This new Schedule is a supplemental reserve category designed to address large reductions of online wind generation due to losses in wind speed. On December 5, 2014, FERC conditionally accepted the Company's filing with an effective date of January 1, 2015 subject to Hearing and Settlement Judge Procedures. On March 3, 2016, FERC issued a letter order accepting the settlement agreement between the settlement parties. As a result of the FERC's decision, the Flex Reserve Service included in the Company's transmission tariff has replaced the former 30-Minute Wind Reserve Guideline.

Flex Reserve is comprised of excess Contingency Reserve[2] as well as online and offline generation available within 30-minutes that is not already included in the Contingency Reserve calculation. This definition of Flex Reserve includes three of the four categories of flexible resources listed on page 15 of the 2014 Storage Study: (1) offline Flex Reserve capacity; (2) excess Contingency Reserve capacity; and (3) greater than 10-minute ramp capability from online/unloaded generation. The fourth category, curtailed wind generation, is not currently included as a Flex Reserve resource.[3] Of the three categories of flexible resources which the Company uses to meet its Flex Reserve requirement, only maximum potential offline Flex Reserve capacity is easily quantifiable without a detailed analysis of current system conditions which are constantly in flux.

Since the last Wind Reserve Guideline study was performed, the Company has added 850 MW of wind generation capacity.[4] This incremental wind generation has increased the size and frequency of large, loss-of-wind-generation events. This study report provides updates to the 30-minute Flex Reserve calculation for the existing wind generation portfolio and for incremental

[1] The 2011 Wind Limits Study was filed as Attachment 2.14-1 in Docket 11A-869E as part of the Company's 2011 Electric Resource Plan.

[2] Contingency Reserve (Operating Reserve) is generation capacity adequate to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. At least 50% of Contingency Reserve must be Spinning Reserve with the balance comprised of one or more of several types of resources including Supplemental Reserve (Non-Spinning Reserve).

[3] Wind curtailments do limit the potential for loss of wind generation but, as an inherently variable resource the volume of curtailed energy is not a dependably dispatchable resource for a future time (i.e., a 30-minute Flex Reserve product).

[4] The last Wind Reserve Guideline study anticipated the 400 MW wind generation contribution from the Limon 1 and Limon 2 wind farms. In addition to those facilities, the Company subsequently acquired generation from Limon 3 (200MW) and Golden West (250 MW) as a result of the 2013 All-Source Solicitation.

wind generation additions. It also examines whether existing offline Flex Reserve capacity[5] is sufficient to meet the wind generation down ramps that could occur with wind generation portfolios with incremental wind generation.

Flex Reserve Methodology

The previous 30-minute Wind Reserve Guideline calculation was a two-part formula. For wind generation levels up to 290 MW, the guideline generally required 1 MW of 30-minute Wind Reserve for each 1 MW of wind generation. For wind generation levels greater than 290 MW, when the largest wind ramps are possible, the guideline was based on a best-fit curve through a scatter plot of the largest 30-minute wind generation down ramps when plotted as a function of wind generation at the start of a ramp. This calculation resulted in a monotonically increasing Wind Reserve with increasing levels of wind generation. With increasing wind generation experience, this result did not match the Company's anecdotal experience in which it was observed that the largest wind generation down ramps occurred when total wind generation levels were closer to a 50% capacity factor rather than a 100% capacity factor.

In order to address this discrepancy, the Company changed the definition of "largest wind ramps" used to set the Flex Reserve levels. This was done by binning all wind generation down ramps into 100 MW bins based on the wind generation at the start of the 30-minute ramp and then selecting the largest wind ramp for each 100 MW bin.[6] 5-minute instantaneous wind generation data from November 1, 2014 through October 31, 2015 were used for this analysis.[7]

In Figure 1, a plot of these "largest wind ramps" from the current 2,566 MW wind generation portfolio is compared to the previous 30-minute Wind Reserve Guideline. As can be seen in Figure 1, the best fit trend line through the new definition of "largest wind ramps" for the current wind portfolio of 2,566 MW peaks at a wind generation level of 1,310 MW with a negative wind ramp/Flex Reserve requirement of 708 MW. Comparatively, the previous Wind Reserve Guideline would calculate 454 MW of reserves when instantaneous wind generation was at 2,566 MW.[8]

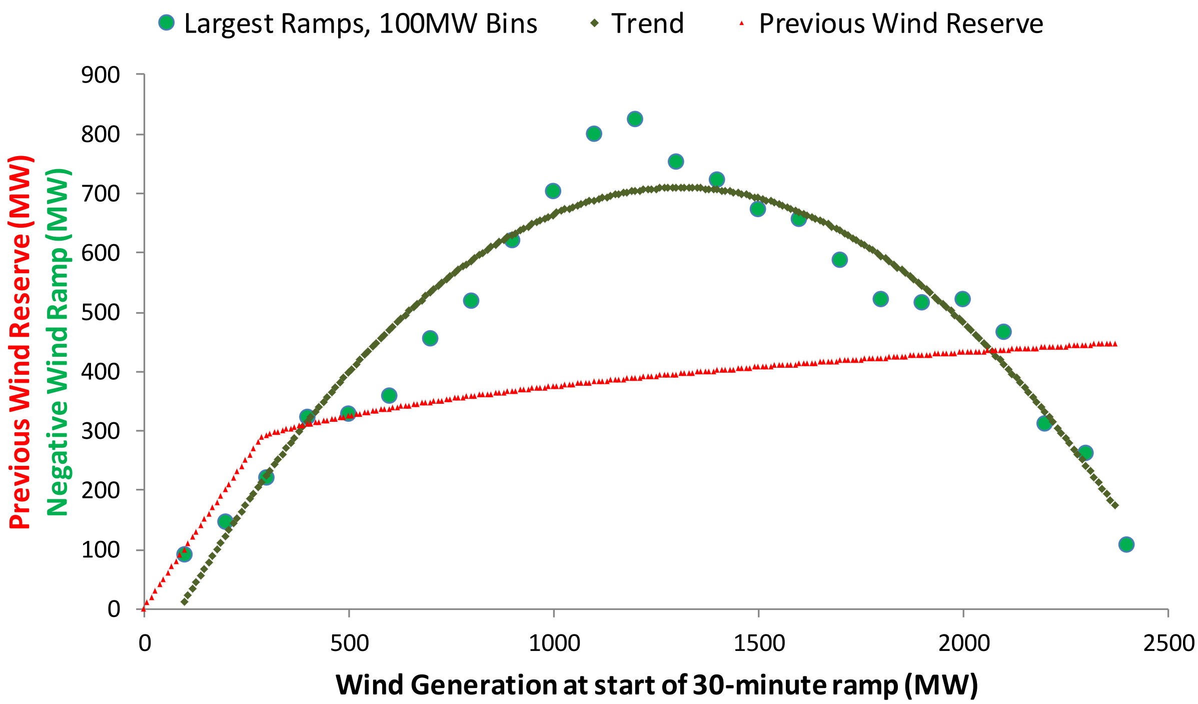
[5] Offline Flex Reserve capacity is the available capacity of those units which are offline, but can be online in less than 30 minutes, less the Rocky Mountain Reserve Group's Supplemental Reserve (Non-Spinning Reserve) requirement for the Company.

[6] This new methodology of binning wind ramps based on wind generation output is a technique borrowed from the National Center for Atmospheric Research's ("NCAR") power conversion process used in Xcel Energy's Wind Forecasting System. NCAR uses multiple weather models to predict the hub-height wind speeds at Xcel Energy's various wind farms, then converts those wind speeds into wind generation forecasts. The power conversion from wind speeds to wind generation is based on empirical power curves developed through extensive data mining in which the expected wind turbine generation output is based on observed wind generation data binned by wind speeds of one tenth (0.1) of a meter per second.

[7] Estimates of wind curtailment levels were added back to the generation meter data so that these curtailments did not appear in the data sets as sudden losses in wind generation caused by decreasing wind speeds.

[8] The 30-minute Wind Reserve formula was monotonically increasing, so Wind Reserve was always higher for increasing levels of wind generation. The current wind portfolio has 2,566 MW of wind generation capacity, so the 30-minute Wind Reserve formula was highest at 2,566 MW of generation, that is, at a 100% capacity factor.

Figure 1: Largest Ramps vs. Previous Wind Reserve

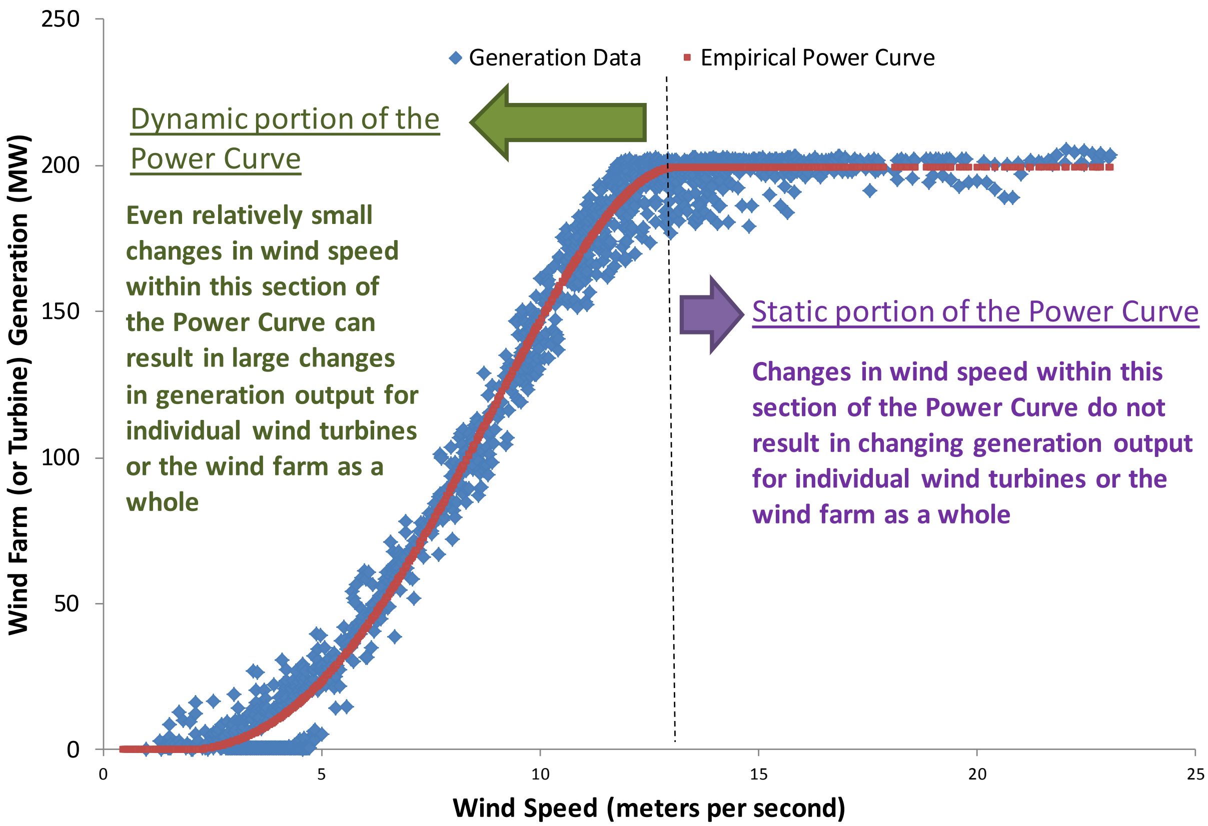


Why do the largest ramps occur near 50% capacity factor?

For Flex Reserve purposes, the metric of interest is how much wind generation can be lost ***in the next 30 minutes*** due to declining wind speed. A wind turbine or wind farm power curve is helpful to illustrate that similar changes in wind speed can have very different effects on generation output. Figure 2 depicts the generation output (y-axis) at a 200 MW wind farm as a function of wind speed (x-axis). A wind turbine power curve has the same shape as this wind farm power curve;[9] the only difference is the scale of the y-axis.

[9] The generation output for a wind farm is the sum of all the individual turbines at that wind farm.

Figure 2: Empirical Power Curve for 200 MW PSCo wind farm



As can be seen in Figure 2, a five meter-per-second (mps) loss of wind speed from 20 mps to 15 mps would result in no expected change in wind farm generation output. A similar 5 mps loss of wind speed from 15 mps to 10 mps would result in a loss of ~50 MW, from 200 MW to 150 MW of wind farm generation. A loss of 5 mps of wind speed from 10 mps to 5 mps would result in a loss of ~130 MW, from 150 MW to 20 MW of wind farm generation. So the change in total wind farm generation output can vary widely depending on where the 5 mps loss of wind speed occurs on the power curve.

Similarly, when wind generation for the Company's total wind portfolio approaches a 100% capacity factor almost all of the individual wind turbine generators are somewhere in the static portion of the power curve where small changes in wind speed result in virtually no change in generation output. When wind generation for the total wind portfolio approaches 50% capacity factor, a much larger percentage of individual wind turbine generators are somewhere in the dynamic portion of the power curve where small changes in wind speed can result in significant changes in generation output. That is, the largest wind generation down ramps occur when many individual turbines are in the dynamic portion of their power curves and simultaneously experience a loss of wind speed.

20-Minute vs. 30-Minute Offline Flex Reserve Capacity

The change in Flex Reserve was discussed earlier and as shown in Figure 1 results in a larger reserve requirement compared to the prior Wind Reserve Guideline which more accurately reflects the size of the largest 30-minute wind generation down ramps that Flex Reserve is intended to address. The Company has also changed the definition of offline Flex Reserve capacity from those used in the 2011 Wind Limits Study and the 2014 Storage Study.

In the 2011 Wind Limits Study, the Company only counted offline Flex Reserve capacity which could be online within 20 minutes. The logic was that the System Operator might take up to 10 minutes of the 30-minute wind generation down ramp to recognize the ramp event, which would only leave 20 minutes to dispatch the offline Flex Reserve capacity. In the current study, offline Flex Reserve capacity includes all offline resources that can be online within 30 minutes. This change of including all offline generation capacity available within 30 minutes rather than just 20 minutes results in a higher offline Flex Reserve capacity because large frame combustion turbines (e.g., Blue Spruce 1&2, and Fort St. Vrain 5&6) typically take ~22 minutes to come online.

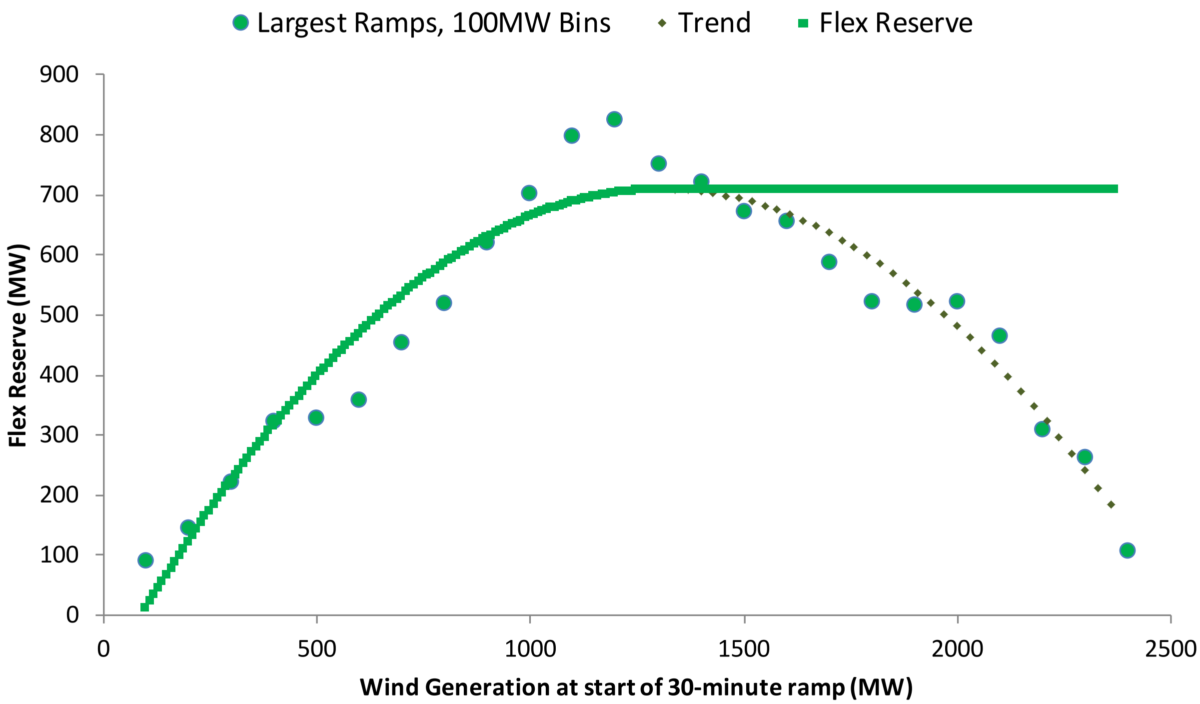
The largest 30-minute wind generation down ramps represent the steepest 30-minute loss of wind generation that is almost always embedded within a longer and larger wind generation down ramp. The System Operator typically has plenty of warning that a wind generation down ramp is in progress before the start of the steepest 30-minute portion of that ramp, so it appeared overly conservative to only credit offline capacity which can be available within 20 minutes. The Company believes this change from 20 minutes to 30 minutes is a more accurate metric of system flexibility.

Flex Reserve Requirement

Flex Reserve is intended to cover large 30-minute wind down ramps. The Company has had great success reducing average day-ahead forecast error, but less success at accurately predicting the onset of very large wind generation down ramps. Further, data show that very large wind ramps occur during all seasons and at any time of the day.

The data also show that the size of the largest wind generation down ramps decreases after instantaneous wind generation exceeds an ~50% capacity factor; however, reducing the Flex Reserve at higher levels of wind generation to match this reduction in ramp amplitude poses an operational risk. The concern is that a reduction in wind generation output, say from 2,000 MW to 1,500 MW, would be accompanied by an increase in the Flex Reserve obligation from 447 MW to 681 MW. In other words, at the same time that wind generation has decreased by 500 MW and must be replaced by non-Variable Energy Resource (non-VER) generation (which of itself decreases the available Flex Reserve resources), the Flex Reserve requirement would be increasing by 234 MW. To mitigate this coincident depletion of Flex Reserve capacity and increase in Flex Reserve requirement, the final Flex Reserve calculation is based on the best-fit parabolic curve up to the vertex and then this maximum Flex Reserve value is applied to all higher levels of instantaneous wind generation (see Figure 3).

Figure 3: 30-minute Flex Reserve



Flex Reserve Requirements for Incremental Wind

In order to evaluate Flex Reserve requirements for portfolios with incremental wind generation, the Company studied two scenarios: 1) a portfolio with 2,974 MW of total wind generation and 2) a portfolio with 3,174 MW of total wind generation. The portfolio with 2,974 MW was created by adding an incremental 600 MW of Energy Resource Zone 2 ("ERZ 2")[10] wind generation and removing currently-existing wind generation totaling 192 MW that is subject to purchase power agreements scheduled to expire within the next three years. The 3,174 MW portfolio added an additional 200 MW of ERZ 2 wind to the 2,974 MW portfolio. A single ERZ 2 wind generation profile was developed for both the incremental 600 MW and 800 MW scenarios.[11]

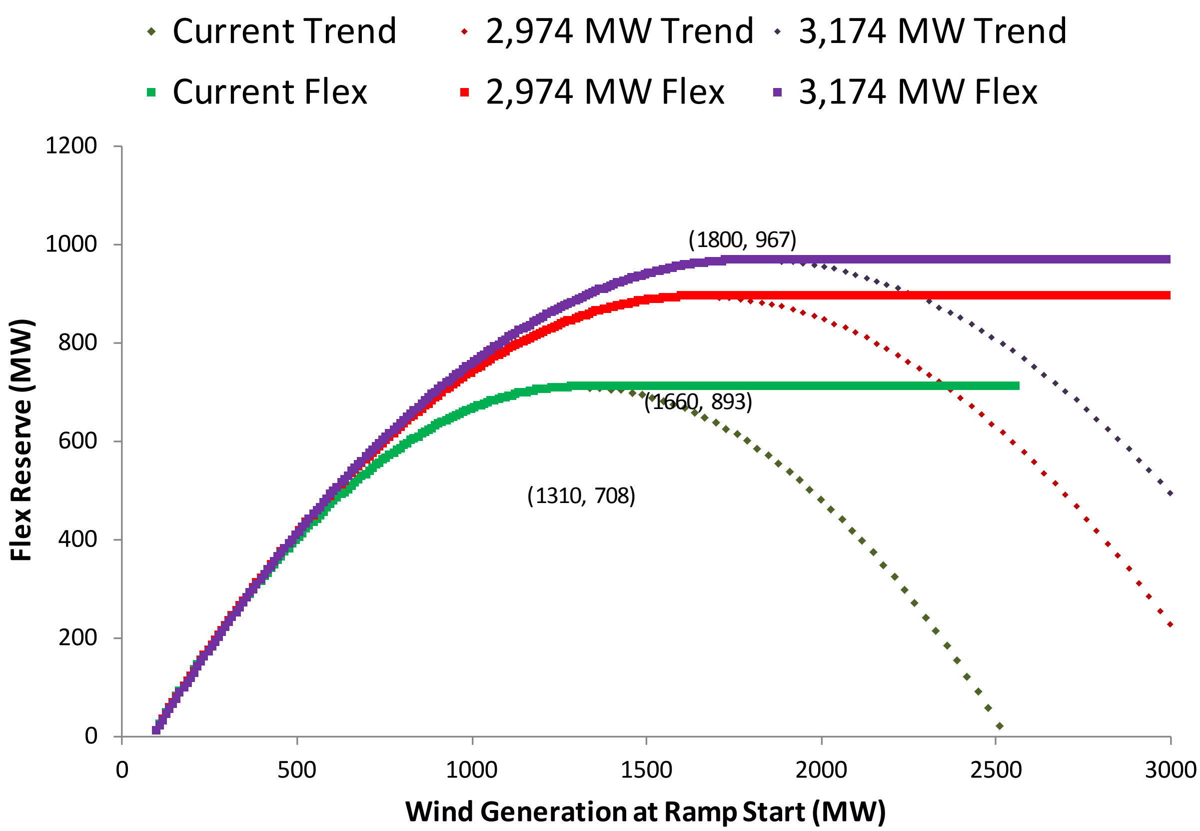
As can be seen in Figure 4, the 2,974 MW and 3,174 MW portfolios increase the size of the potential 30-minute loss of wind generation events which, in turn, increase the 30-minute Flex Reserve requirements. The coordinates shown on the Figure indicate the vertex of each curve with the first value representing the volume of wind generation at the start of the ramp and the second value representing the volume of Flex Reserve required for that volume of wind

[10] ERZ 2 is a geographical area east and southeast of the Denver metro area. It encompasses all or parts of the following counties: Adams, Arapahoe, Cheyenne, El Paso, Elbert, Kiowa, Kit Carson, Lincoln, Washington, and Yuma.

[11] In order to represent geographic diversity, 5-minute wind speed data for five ERZ 2 wind farms (Cedar Point, Limon 1, Limon 2, Limon 3 and Golden West) was gathered for the study period. Two separate wind farm empirical power curves (Limon 3 and Golden West) were used to convert the wind speeds to generation volumes. These ten wind generation profiles were combined into a single generation profile that is representative of the geographic diversity that currently exists within ERZ 2. This single generation profile was then scaled to represent either 600 MW or 800 MW of new ERZ 2 wind capacity.

generation. For example, for the 3,174 MW wind scenario 967 MW of Flex Reserve would be required given the apex in the curve fit that occurs at 1,800 MW of Wind Generation at Ramp Start.

Figure 4: 30-minute Flex Reserve Requirement



Offline Flex Reserve capacity as a measure of portfolio flexibility

As discussed earlier, for the purposes of this study, maximum potential offline Flex Reserve capacity is the only component of Flex Reserve that is easily quantifiable. The Company believes that maximum offline Flex Reserve capacity is the best available—though not perfect—measure of system flexibility necessary to meet the Flex Reserve requirement. Figure 5 lists the maximum dependable capacity for all the existing generation resources in the Company's portfolio which, if offline and available, are capable of providing 30-minute Flex Reserve. Assuming all these generators are both offline and available, there is 1,501 MW of available Flex Reserve capacity after accounting for the Company's 211 MW Supplemental (Non-Spinning) Reserve requirement which is met with this same pool of resources.

The Company is not suggesting that all of the generating resources listed in Figure 5 are always, or even usually, both offline and available. For example, one or more of these resources may be unavailable due to planned or unplanned maintenance outages, some units may not be staffed during overnight hours and therefore may not be immediately available, several plants may be unavailable at times due to the lack of firm gas supply, and many of these resources are often online providing economic energy to meet load. When offline Flex Reserve capacity is solely insufficient to meet the Flex Reserve requirement, System Operators are responsible for ensuring that sufficient additional flexible resources are available from the other two categories of Flex Reserve: 1) excess Contingency Reserve capacity, and 2) greater than 10-minute ramp capability from online/unloaded generation.

Figure 5: 30-Minute, Flex Reserve Capable Generation Resources (when offline and available)[12]

Generator(s)	Flex Reserve (MW)
Cabin Creek	320
Ft. Lupton	89
Fort St. Vrain 5 or 6	145
Blue Spruce 1 or 2	130
Valmont 6	43
Alamosa	26
Fruita	14
Spindle Hill 1 or 2	158
Manchief	267
Arapahoe 5,6,7	39
Plains End	215
Fountain Valley 1-6	236
Brush 3	30
Total Generation	1,712
RMRG Reserve Req.	211
Max. Offline Flex Reserve	1,501

Figure 6 shows the Flex Reserve required for the current wind generation portfolio and for the 2,974 MW and 3,174 MW wind portfolios. The maximum, excess offline Flex Reserve capacity is calculated by subtracting the Flex Reserve requirements for each scenario from the 1,501 MW of maximum offline Flex Reserve. Figure 6 demonstrates the Company currently has sufficient offline Flex Reserves to accommodate a wind portfolio with the 3,174 MW of wind assumed in this study.

12 Blue Spruce and Spindle Hill are listed as "1 or 2" and Fort St. Vrain is listed as "5 or 6" to indicate that, as currently configured, these facilities only have a single unit at any one time that qualifies as a 30-minute Flex Reserve even though these facilities have two identical generators. The installation of load cummutated inverters ("LCIs") at any of these sites would allow both units to start simultaneously and double the amount of offline Flex Reserve capability shown in the Figure for those facilities.

Figure 6: Excess Offline Flex Reserve Capacity

Wind Portfolio	Flex Reserve Requirement (MW)	Excess Flex Reserve (MW)
2,566 MW	708	793
2,974 MW	893	608
3,174 MW	967	534

Conclusions

The Company has recently altered the methodology through which it maintains sufficient flexible generation resources to reliably accommodate its wind generation portfolio. The new methodology quantifies in real time: 1) offline Flex Reserve capcity, 2) excess Contingency Reserve capacity, and 3) greater than 10 minute ramp capacity from online/unloaded generation. These available resources are compared to a 30-minute Flex Reserve requirement that has been created based on a historical examination of large wind down ramps on the Company's system.

In the current study, the Company has also examined the change in 30-minute Flex Reserve requirements that would be expected with wind portfolios of 2,974 MW and 3,174 MW of total wind. The Company believes its current portfolio of maximum potential offline Flex Reserve capacity is sufficient to reliably integrate these levels of incremental wind generation. Should incremental Flex Reserve capacity be needed, the Company has multiple low-cost opportunities at its existing generators to obtain those resources.

Final Report:

Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study

Prepared by

Xcel Energy Inc
1800 Larimer Street
Suite 1400
Denver, Colorado 80202

Jeff Butler
Regulatory Consultant
jeffry.a.butler@xcelenergy.com

and

EnerNex Corporation
620 Mabry Hood Rd. Suite 300
Knoxville, Tennessee 37932

R.M. Zavadil
Vice President & Principal Consultant
bobz@enernex.com

Tom Mousseau
Principal Consultant
tmousseau@enernex.com

August 19, 2011

CONTENTS

Contents 1

Figures 2

Tables 3

Technical Review Committee 4

Project Team 5

Executive Summary 6

Background 6
Wind Integration Costs Quantified in this 2GW/3GW Study 7
Summary and Conclusions 7

Introduction 9

2GW/3GW Study Objectives 10
Wind Integration Costs Quantified in this Study 11
Calculating the Average Regulation Wind Integration Cost 11
Calculating the Average System Operations Wind Integration Cost 12
Calculating the Average Gas Storage Wind Integration Costs 13
Study Data and Assumptions 14
Couger Model Input and Operation Review 17
Scope of Work 17

Study Results 20

Base Case Results 20
Geographic Diversity Influence on Average System Operations Integration Cost 20
Average Regulation Wind Integration Costs 20
Average Gas Storage Wind Integration Costs 21
Total Average Wind Integration Costs 22

Gas Price Sensitivity 23

Storage Sensitivity 24

Wind Energy Proxy Sensitivity 27

Wind Forecast Methods Sensitivity 31

Quick Start Resources Sensitivity 32

Carbon Sensitivity 33

Demand Response Sensitivity 34

Application of the Study Results 35

Appendix A – Location of Wind Facilities 36

Appendix B – Wind Integration Costs: Flat Block and On/Off Peak Proxy vs Back Cast Study 38

FIGURES

Figure 1: 24 Hour Gas Nomination for 2014 using 2004 Wind and Load Profile 21
Figure 2: Example "Flat Block Proxy" with Four Hour Ramp Between Blocks 27
Figure 3: Example On/Off Peak Proxy with Two Hour Ramp Between Blocks 28

TABLES

Table 1: Nameplate Wind Capacity Levels for the Public Service Wind Integration Cost Studies 6

Table 2: Average Regulation Wind Integration Cost 7

Table 3: Average System Operations Wind Integration Cost ($5.06/MMBtu gas price) 7

Table 4: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price) 8

Table 5: Prior Integration Cost Study Results ($5.06/MMBtu gas) 9

Table 6: Nameplate Wind Capacity Levels - Public Service Wind Integration Cost Studies 10

Table 7: Number of Couger Base Case and Sensitivity Model Runs 18

Table 8: Average System Operations Wind Integration Costs ($5.06/MMBtu gas price) 20

Table 9: Modeled Annual Actual Wind Energy Production 20

Table 10: Average Regulation Wind Integration Cost 21

Table 11: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price) 22

Table 12: Total Average Wind Integration Cost ($5.06/MMBtu gas price) 22

Table 13: Gas Prices for Base Cases and for Sensitivities ($/MMBtu) 23

Table 14: Average System Operations Wind Integration Cost/Gas Price Matrix 23

Table 15: Average System Operations Wind Integration Cost - Storage Sensitivities ($5.06/MMBtu gas price) 24

Table 16: Pumped Storage Generation Comparison 25

Table 17: Pumped Storage Pumping Comparison 26

Table 18: Average System Operations Wind Integration Cost – Proxy Shape Sensitivity ($5.06/MMBtu gas price) 28

Table 19: Average System Operations Wind Integration Cost – Forecast Methods Sensitivities ($5.06/MMBtu gas price) 31

Table 20: Average System Operations Wind Integration Cost – Quick Start Resources Sensitivities ($5.06/MMBtu gas price) 32

Table 21: Average System Operations Wind Integration Cost – CO_2 Sensitivity ($5.06/MMBtu gas price)33

Table 22: Average System Operations Wind Integration Cost – No Demand Response Sensitivity ($5.06/MMBtu gas price) 34

Table 23: Example Total Incremental Wind Integration Cost Calculation 35

TECHNICAL REVIEW COMMITTEE

The following individuals comprised a technical review committee (TRC) for this project. The TRC was kept apprised of the approach, methodology, and assumptions for the analysis described in this report, and provided valuable comments, suggestions, and guidance at several junctures from project commencement to conclusion.

Xcel Energy Services Inc. Staff

Jeff Butler

Sean Connelly

Curt Dallinger

Jim Hill

Keith Parks

Jim Schetter

CPUC Staff

Rich Mignogna

External

Mark Ahlstrom	WindLogics
Ed DeMeo	Renewable Energy Consulting Services, Inc.
Erik Ela	National Renewable Energy Laboratory
Tom Ferguson	Independent Consultant
Brendan Kirby	Kirby Consulting
Debra Lew	National Renewable Energy Laboratory
Michael Milligan	National Renewable Energy Laboratory
Tom Mouseau	EnerNex Corporation
John Nielsen	Western Resource Advocates
Charlie Smith	Utility Wind Integration Group
Bob Zavadil	EnerNex Corporation

PROJECT TEAM

Xcel Energy Services Inc. on behalf of Public Service Company of Colorado (Public Service or the Company) retained EnerNex Corporation of Knoxville, Tennessee for this project to assist the Company in determining the wind integration costs for the Public Service system.

EnerNex Corporation is an electric power engineering and consulting firm specializing in the development and application of new electric power technologies. EnerNex provides engineering services, consulting, and software development and customization for energy producers, distributors, users, and research organizations. EnerNex has substantial expertise with a broad range of technical issues related to wind generation, from turbine electrical design to control area operations and generation scheduling.

EXECUTIVE SUMMARY

Background

This wind integration cost study, the 2GW/3GW Study, is the third such analysis of wind integration costs performed by Public Service Company of Colorado. This particular study addresses the 2 GW and 3 GW levels of nameplate wind capacity on the Company's electric system. The prior studies examined wind penetration levels of 10%, 15%, and 20% (nameplate wind capacity divided by peak load). The focus of this 2GW/3GW study is to determine the costs of integrating 2,000 MW and 3,000 MW (nominal values) of wind energy into the Public Service electric system. The wind integration costs quantified in this study are associated with the uncertain and variable nature of wind generation. These costs are often referred to as "hidden costs." When Public Service evaluates new power supply options for its system, the total incremental integration cost determined using this study will be added to the bid or build price of wind resources to ensure that all costs associated with wind generation are represented and that wind is compared on an equivalent basis with other generation technologies.

The wind integration costs for the 2,000 MW nominal wind penetration level were determined in this study using an installed nameplate wind capacity of 1,939 MW. The wind integration costs for the 3,000 MW nominal wind penetration level were determined in this study using an installed nameplate wind capacity of 2,999 MW.

At the outset of the modeling phase of this 2GW/3GW Study, Public Service chose to reanalyze the 20% wind penetration level on its system that was previously studied in 2008. The reason for this "recasting" of the 20% study results was that sufficient changes and updates (different study year, thermal resource additions, retirements and performance characteristics) were made to the modeling inputs for this 2GW/3GW study compared to those used in the prior 20% study. By recasting the 20% study results with these updated assumptions, the resulting total incremental wind integration cost associated with moving from the 20% level (~1,400 MW) of wind up to the 2 GW level of wind will be based on a consistent set of assumptions and analyses. Table 1 contains the wind capacity levels used for the "original" 20% Study and the 2GW/3GW Study.

Table 1: Nameplate Wind Capacity Levels for the Public Service Wind Integration Cost Studies[1]

Wind Integration Cost Study	Nameplate Wind Capacity (MW)
Original 20%	1,440
20% with the 2GW/3GW Study inputs	1,414
2GW	1,939
3GW	2,999

[1] The nameplate wind capacity values chosen as capacity levels for modeling were determined by aggregating nameplate levels of installed wind (installed by year end 2012) to achieve aggregate levels that approximate the nominal levels of 20% (1,440 historically) and 2,000 MW and aggregating nameplate levels of installed wind and potential wind to achieve a level that approximated the nominal 3,000 MW level.

Wind Integration Costs Quantified in this 2GW/3GW Study

This study analyzed and quantified the average wind integration costs associated with three aspects of power supply system operations:

1. Regulation,
2. System operations,
3. Gas storage.

The study did not quantify wind integration costs associated with curtailment of wind generation,[2] electricity trading inefficiencies introduced by wind uncertainty, or increased operating and maintenance costs at existing thermal units that may be called upon to ramp output levels over a broader range more often and with shorter notice. The costs of curtailment of wind generation and increased operating and maintenance costs at existing coal plants were evaluated by Public Service in a separate study, the *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study, which was completed in parallel with the 2GW/3GW Study. Like total incremental wind integration costs, incremental wind curtailment and cycling costs will be added to the bid or build price of wind resources when evaluating wind against other power supply options.

Summary and Conclusions

The 2GW/3GW Study results for the regulation component of wind integration costs are shown in Table 2. This cost arises from the intra-hour variability of wind resources that requires additional fast-responding regulation capacity be available.

Table 2: Average Regulation Wind Integration Cost

Wind Penetration Level	20%	2 GW	3 GW
Average Regulation Wind Integration Costs ($/MWh)	0.10	0.14	0.21

The 2GW/3GW Study results for the system operations component of wind integration costs are shown in Table 3. This cost arises from less than optimal operation of the electric system as the result of the uncertain nature of wind energy production. The results were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy.

Table 3: Average System Operations Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	20%	2 GW	3 GW Scenario 2[3]
Average System Operations Wind Integration Cost ($/MWh)	2.39	3.40	3.71

[2] As explained below, the calculation of average gas storage wind integration cost included the price of a limited amount of wind energy curtailment that was used to preclude the purchase of additional natural gas storage injection demand.

[3] The "Scenario 2" designation refers to geographic diversity sensitivities performed in the 2GW/3GW Study.

The 2GW/3GW Study results for the gas storage component of wind integration costs are shown in Table 4. The gas storage component of wind integration costs stems from inaccuracies in the amount of gas nominated each day for electric energy production caused by the uncertain nature of forecasting the wind. The average gas storage wind integration cost was determined by Public Service's gas planning business units based on estimates of how gas nomination inaccuracies due to wind generation result in the need to either inject or withdraw gas from storage.

Table 4: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Average Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17

The costs in Tables 2, 3 and 4 were calculated by estimating the total annual integration costs for a given level of wind on the Public Service system and dividing by the total system annual wind energy. The resulting $/MWh value, therefore, represents the *average* wind integration cost for the entire amount of wind energy on the system. When Public Service uses wind integration costs for purposes of evaluating future power supply options, the Company will use the total *incremental* wind integration cost (the sum of the incremental wind integration cost for the three components divided by the incremental wind energy production).[4]

[4] As determined by calculations using the On/Off Peak Proxy approach discussed later in this report.

INTRODUCTION

Public Service is an electric operating company with a large and growing wind energy resource. The Company first integrated wind energy into its resource mix in 1997 and has since continued in the development of wind resource operating protocols and performance of studies to estimate the cost impacts of increasing levels of wind generation. This wind integration cost study is the third performed by Public Service and addresses the 2 gigawatt (GW) and 3 GW levels of nameplate wind capacity operating on the Company's electric system. Public Service uses the total incremental wind integration cost when assessing the overall cost of wind resources during resource planning/selection processes. In addition to determining wind integration costs, this study continues the Company's approach of investigating the value of other aspects of wind resource integration, e.g., geographic diversity, that can help reduce integration costs and inform future resource selection and investment decisions as discussed at greater depth in this study.

Public Service previously analyzed wind integration costs in 2008 when it completed its study of the wind integration costs for the 20% penetration level of wind resources (the "20% Study" - and in 2006 when it analyzed the wind integration costs for the 10 and 15% levels of wind penetration. Table 5 provides the results of Public Service's prior wind integration cost studies at a natural gas cost of \$5.06/MMBtu.[5]

Table 5: Prior Integration Cost Study Results (\$5.06/MMBtu gas)[6]

Wind Penetration	Average Regulation and System Operations Wind Integration Cost (\$/MWh)	Average Gas Storage Wind Integration Cost (\$/MWh)
10%	\$2.25	\$1.26
15%	\$3.32	\$1.45
20%	\$3.95	\$1.18

For this study the Company chose to deviate from the past approach of analyzing wind integration costs at different wind penetration percentages and to instead perform this study for two discrete levels of nominal nameplate wind capacity, 2GW and 3 GW. The reason for this

[5] The average system operations wind integration cost is dependent of the cost of energy for the fossil-fueled resources in an electric operating company's generating resource portfolio as those resources constitute the majority of the resource portfolio and the less-than-optimal operation of fossil-fueled resources (as the consequence of wind generation uncertainty) produces average system operations wind integration cost. Please note that while the prior studies were done for a 2007 test year and this study uses a 2018 test year, the results of the studies are comparable as it concerns dollar value as gas costs, a major driver for the average system operations wind integration cost, are normalized. The operations and maintenance expense component of average system operations cost, which would be modeled for a different study year and expressed in a different nominal dollar, is a smaller component of the determined average system operations wind integration cost and Public Service does not believe that discounting the costs to an equivalent year's dollars is necessary as it would not be material.

[6] Zavadil, Bob, King, Jack, "Wind Integration Study for Public Service of Colorado Addendum detailed Analysis of 20% Wind Penetration," December 1, 2008, Page 7.

change is that growth in the Company's peak load, the denominator in a wind penetration percentage calculation, means that reported percentage levels, which were ostensibly comparable, were in fact not comparable from study to study. Therefore, Public Service chose to begin performing, and naming these studies, using installed nameplate wind capacity.

For this study a nominal level of 2 GW and 3 GW was selected and the study is referred to as the "2GW/3GW Study." The wind integration cost for the nominal 2,000 megawatt (MW) level was determined in this study using an installed nameplate wind capacity of 1,939 MW which closely represents the amount of wind Public Service expects to be operating on its system by the end of 2012. The wind integration cost for the nominal 3,000 MW level was determined in this study using an installed nameplate wind capacity of 2,999 MW. Differences between the nominal 2 GW and 3 GW levels and the 1,939 MW and 2,999 MW levels reflected in the study are rooted in the sizes of the existing and under construction wind facilities on the Public Service system.

In addition to analyzing 2GW and 3GW of wind, Public Service chose to recalculate the wind integration costs for the 20% penetration level of wind that was previously studied in 2008. The reason for this recalculation was that sufficient changes and updates (different study year, thermal resource additions, retirements and performance characteristics) were made to the modeling inputs for this 2GW/3GW Study compared to those used in the prior 20% Study. By recasting the 20% results with these updated assumptions, the Company believes the resulting total incremental wind integration costs associated with moving from the 20% level (~1,400 MW) of wind up to the 2 GW level of wind will be more accurate because the 20% and the 2 GW wind integration costs will have been derived from a common set of assumptions and the same computer model representation of the Public Service System. Table 6 contains the wind capacity levels used for the "original" 20% Study and the 2GW/3GW Study.

Table 6: Nameplate Wind Capacity Levels - Public Service Wind Integration Cost Studies

Wind Integration Cost Study	Nameplate Wind Capacity (MW)
Original 20%	1,440
20% with the 2GW/3GW Study inputs	1,414
2 GW	1,939
3 GW	2,999

2GW/3GW Study Objectives

The focus of this study is to determine the costs of integrating wind energy into the Public Service system. The integration costs quantified in this study are associated with the uncertain and variable nature of wind generation. When Public Service performs resource planning and selection processes, total incremental wind integration costs are added to the bid price of wind resources to ensure that all costs associated with wind generation proposals are represented such that wind can be equitably compared with other generating technologies.

The Couger unit commitment and dispatch model was used in this study to determine wind integration costs at three levels, 1,414 MW, 1,939 MW and 2,999 MW, of nameplate wind generation capacity on the Public Service system. The wind facilities that comprise the 1,414 MW and 1,939 MW levels of nameplate wind capacity are currently constructed or are under construction at known locations and have known points of interconnection to the Public Service electric transmission system and are referred to as the Base Case.

Four alternative scenarios were analyzed for the 1,060 MW of wind facility additions that would grow the total Public Service wind resource from approximately 2 GW to approximately 3 GW. The four scenarios grew the nameplate wind on the system by 1,060 MW through differing patterns of addition. The first scenario (No Diversity Scenario) added 1,060 MW of nameplate wind capacity in the northeast corner of Colorado, an area of Colorado that contains the majority of the Company's existing wind resources. The second scenario (Diversity in Addition Scenario) added 1,060 MW of nameplate wind capacity in equal amounts to four likely areas for wind resource development in the state, Energy Resource Zones (ERZ) 1,2,3 and 5. The third scenario (Diversity in Result Scenario) added 265 MW of nameplate wind capacity in ERZs 2 and 5 and 530 MW of nameplate wind capacity in ERZ 3. The fourth scenario (Wyoming Scenario) added 1,060 MW of nameplate wind capacity in southeast Wyoming. See Appendix A.

A number of sensitivity cases were also constructed and run through the Couger model to understand the effects of different assumptions on the costs of integrating wind resources.

Wind Integration Costs Quantified in this Study

The 2GW/3GW Study analyzed and quantified the wind integration costs associated with three aspects of the electric power supply operations:

1. Regulation,
2. System operations,
3. Gas storage.

The study did not quantify integration costs associated with curtailment of wind generation,[7] electricity trading inefficiencies introduced by wind uncertainty, or increased O&M costs at existing thermal units that may be called upon to ramp output levels over a broader range more often and with shorter notice. The costs of curtailment of wind generation and increased O&M costs at existing coal plants were evaluated by Public Service in a separate study, the *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study, which was completed in parallel with the 2GW/3GW Study. Like total incremental wind integration costs, incremental wind curtailment and cycling costs will be added to the bid or build price of wind resources when evaluating wind against other power supply options.

Calculating the Average Regulation Wind Integration Cost

Regulation wind integration cost arises from the intra-hour variability of intermittent generating resources that require additional fast-responding regulation capacity be available. This component of wind integration costs was calculated by Public Service's Commercial Operations business unit which examined historical time-series load data to quantify the range of regulation capability that would be required to compensate for the fast variations in net system load. The evaluation process involved performing a statistical analysis of a system Net Load profile (Obligation Load less wind generation) and an Obligation Load profile and then using that

[7] As explained below, the calculation of average gas storage wind integration cost included the price of a limited amount of wind energy curtailment that was used to preclude the purchase of additional natural gas storage injection demand.

analysis to determine the amount of required regulation capacity for the specific levels of wind. This regulation capacity was then assigned a cost using Public Service's Open Access Transmission Tariff (OATT) Schedule 3 – Regulation and Frequency Response Service filed on May 13, 2011. This tariff specifies a cost of Network Integration Delivery of $6.740/kW-month, or $80.88/kw-year. Once the cost is determined, the average regulation wind integration cost was determined for the 20%, 2 GW and 3 GW levels by dividing by the calculated annual system wind energy production for each scenario.

Calculating the Average System Operations Wind Integration Cost

System operations wind integration cost arises from less than optimal operation of the electric system as the result of the uncertain nature of wind energy production. Specifically, day-ahead commitment of generation resources using load and wind forecasts and the subsequent dispatch of those committed units is often less than optimal given the uncertainty of the wind resource. Public Service engaged EnerNex Corporation for the 2GW/3GW Study to perform computer modeling to determine average system operations wind integration costs using Ventyx's Couger model.

Couger is a unit commitment and dispatch model that can both produce an optimal day-ahead generating unit commitment plan, and also dispatch the committed generating units of that plan in a least-cost manner to serve load for the electric system being represented.[8] The 2GW/3GW Study methodology involved developing individual commitment and economic dispatch plans within the Couger model for every hour of the study year, which was the year 2018.

Similar to the Company's previous wind integration studies, the modeling protocol used in this study to quantify system operations wind integration costs consisted of a five step process. The first four steps involve performing four separate Couger modeling runs of the Public Service electric supply system under specific configurations in order to establish four separate operating costs for serving system load. The fifth step takes the arithmetic difference in total system costs between the fourth and the second modeling runs and uses this difference to represent the system operations wind integration cost. The specifics of this process are as follows. The Couger model is first run in "optimization mode" using a forecast of the next day's load to create a day-ahead generating unit commitment plan. A separate commitment plan is developed for each hour of the 2018 study year. This generating unit commitment plan is then used in "simulation" mode to serve the actual day's load and produce a system operating cost for each hour of the study year. These first two steps of the modeling process are performed with the system wind generation represented by an hourly wind energy shape termed a "proxy" (two proxy types were used – the Flat Block Proxy which distributes the wind energy such that for each day of the study year the daily wind generation is distributed evenly over each hour of that 24 hour period and the On/Off Peak Proxy which distributes the daily wind energy over two flat blocks, an on-peak block and an off-peak block).

Two additional model runs are then performed, Steps 3 and 4, to produce a system operating cost with the wind energy proxy replaced by, first, the day-ahead hourly forecast of wind energy (Step 3, which like Step 1 uses the day-ahead load forecast) and second by a representation of the actual hourly wind energy (Step 4, which like Step 2 uses the actual load). The average system

---

[8] The Couger model was at one time used by Xcel Energy Services. Inc's Commercial Operations group for the purpose of establishing day-ahead commitment plans to be used in the operation of the Public Service electric supply system.

operations wind integration cost is determined in Step 5 by subtracting the system production cost produced by Step 2 from the system production cost produced in Step 4 and dividing the result by the total MWh of modeled actual annual wind energy production. Since the system production costs for Step 2 and Step 4 were both produced with the actual load, subtracting Step 2 results from Step 4 removes any costs associated with load forecasting error leaving only the estimated cost associated with integrating wind onto the system. The five steps or modeling runs are described again below.

Step 1 - Reference case optimization: Unit commitment of Public Service system generation to meet Public Service's *day-ahead forecast of system load* using a *proxy* shape for the wind energy production.

Step 2 - Reference case simulation: Economic dispatch of unit commitment from Step 1 to meet Public Service's *actual load* and the same *proxy* shape for wind energy production.

Step 3 - Actual case optimization: Develop a new unit commitment of Public Service system generation fleet to meet Public Service's *day-ahead forecast of system load* and using a *day-ahead forecast for the wind energy production*.

Step 4 - Actual case simulation: Economic dispatch of the unit commitment from Step 3 to meet Public Service's *actual load* and *actual wind energy production*.

Step 5 – System operations wind integration cost is difference between Steps 4 and 2. The average system operations wind integration cost is the system operations wind integration cost divided by the modeled actual annual wind energy production.

The 2GW/3GW Study using the Couger model and with the above described protocol simulated the economic commitment and dispatch of the Public Service electric supply system at nominal 20% (1.4 GW), 2 GW and 3 GW levels of installed wind generation. As will be explained in greater detail, the 2GW/3GW Study also simulated commitment and dispatch of the Company's electric supply system under different assumptions for key system parameters, i.e., sensitivities.

Calculating the Average Gas Storage Wind Integration Costs

The gas storage component of wind integration cost stems from inaccuracies in the amount of natural gas nominated each day for electric energy production as a result of the uncertainty of wind energy production. This component of wind integration costs was calculated by Public Service's Gas Planning business unit based on gas consumption projections from the Couger-modeling of Steps 3 and 4 discussed above.

To determine the average gas storage wind integration cost, Public Service had EnerNex extract from the base case model runs both the largest over and under nominations of natural gas volumes for a gas day[9] and the total *annual* amounts of over and under-nomination of natural gas for a gas day. Over-nomination results when electric system generation resources require less gas (Step 4 in modeling process) than predicted the day before (Step 3 in modeling process).[10] Under-nomination results when electric system generation resources require more gas (Step 4) than was estimated the prior day (Step 3). The over and under nominations for the largest gas day

---

[9] A gas day is defined as the 24 hour period beginning at 8:00 AM MST.

[10] The Run 4 minus Run 3 gas burn figure was adjusted to remove load related gas nomination error. The load related gas error was determined by subtracting the Run 1 gas burn from the Run 2 gas burn.

represent the largest required levels of gas extraction and injection flexibility on Public Service's gas storage fields in order to accommodate wind energy on the system. The largest gas day over and under nominations set the demand charge for injection and withdrawal from storage facilities. The total yearly amounts of over and under-nomination determine the commodity charge for the injected or withdrawn gas volumes into/from gas storage facilities. These demand and commodity charges were totaled (with a less consequential "losses" charge set by total annual amounts) for both over and under nomination costs and the most controlling of those cost totals, i.e., the value that requires the greatest storage system demand, and which is most costly, was used to determine the average gas storage wind integration cost.

Study Data and Assumptions

Clean Air-Clean Jobs

Contemporaneous with the initiation of the 2GW/3GW Study in 2010 the Colorado Legislature enacted the Colorado Clean Air-Clean Jobs Act (CACJA or the Act). The CACJA required Public Service to evaluate various options for reducing NOx emissions from electric generating facilities prior to the end of 2017. While the level of emissions reductions in the CACJA were specified, the Act allowed Public Service flexibility to determine how best to achieve those reductions. The Company could retrofit coal-fired power plants with new emission controls, replace coal-fired power plants with natural gas generation (by retirement and new build or by fuel-switching) or consider other clean energy resources.

Ultimately, the Company proposed and the Colorado Public Utilities Commission (CPUC) approved (with modifications) a course of action that included installation of emission controls on some coal units, coal plant retirements and replacement with natural gas generation and coal plant fuel switching to natural gas. The CPUC final order was issued on February 3, 2011. While development and verification of Couger model input files for this 2GW/3GW study were completed in advance of this February 3 final order, the Couger model's representation of the Public Service generation fleet was consistent with that approved by the CPUC in CACJA with the exception of the representation of Cherokee 4. In this study, Cherokee 4 was modeled to burn coal during the study year of 2018 but will likely burn gas in 2018 per the CPUC final CACJA order. The Company does not believe this discrepancy in the representation of Cherokee 4 effects the validity of the study approach or results.

The Calendar year 2018 was chosen as the "study year" for modeling the Public Service electric system because that was the year by which CACJA related actions to the Company generation fleet would be completed.

Modeling and Calculation Specifics

The chronological simulation algorithm employed by the Couger model to determine production costs requires extended sets of hourly load data including day-ahead forecasts of hourly load, which were used for forward scheduling and unit commitment in addition to nomination of natural gas for both owned and tolled gas-fired generation. The load data used was from recent historical years so that the daily patterns represent future Public Service system loads as closely as possible.

It is also important for the wind resource generation data to be comparable to the load data, i.e., drawn from same historical year so that correlations between hourly wind and hourly load due to meteorology are properly retained within the analysis. Public Service chose to use historical system load data from three years, 2004, 2005, and 2006, since these match the years for which wind energy generation data was developed for the Western Wind Resources Dataset (WWRD) that was selected as the source for the day-ahead forecasted wind energy generation patterns as well as the actual wind energy generation patterns involved with the five step process described earlier. The 2004, 2005, and 2006 WWRD data sets, and the hourly load patterns, were scaled so that the wind generation level matched the level of wind integration and the peak hour loads matched that projected for the year 2018.

The *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment* study results were not incorporated into the dispatch costs of coal units within the Couger production cost modeling.

The study year, Calendar year 2018, was represented in the Couger model input files with:

- Projected peak load of 7,035 MW;
- Projected energy requirements of 37,655 GWh;
- Nameplate wind capacity levels of 1,414 MW, 1,939 MW, and 2,999 MW. Note that the price or cost of wind energy is not a factor in this study methodology. It is assumed that the wind energy generated is a "must take" resource, and that the Public Service will manage its other dispatchable generating units in a manner to accommodate wind energy production when balancing overall system load and generation. The added costs associated with using these other generating units in a sub-optimal manner to accommodate wind energy production (higher production costs due to less-than optimal commitment and dispatch operations, etc.) are what constitute the system operations component of wind integration cost;
- A generation supply portfolio that reflected the planned coal unit retirements and gas-fired replacement generation associated with the CACJA with the exception that Cherokee Unit 4 ran on coal in the Couger model; whereas, Cherokee 4 is expected to be operating on gas in 2018;
- Projected solar capacity of 395 MW AC of solar electric power, including customer-sited solar facilities. Solar insolation data was used to construct an hourly energy production pattern for the solar electric generation resources on the Public Service system. The data was used to adjust (reduce) total system load;[11]
- Updates to various existing power purchase and sale contracts as appropriate to reflect 2018;
- Planned maintenance and forced outage history for generating units;
- Gas Prices for base case runs and for sensitivity runs were chosen to be consistent with those used in the Company's prior wind integration cost studies. The average base case

[11] While it was not addressed in the 2GW/3GW Study, it is possible that the variability of the energy produced by the solar resources may have had the result of slightly increasing the wind integration costs produced by this study compared to an analysis where solar generation was not reflected in the study. Future wind integration cost studies should investigate whether this is in fact the case.

gas price was $5.06/MMBtu and the sensitivities were performed at average gas prices of $7.83/MMBtu and $9.83/MMBtu;[12]

- Hourly wind energy production profiles, both day-ahead forecasts and actual day wind energy generation, were derived from the WWRD. Wind sites from the WWRD for the 20%, 2GW and 3GW study cases were selected based on the proximity of the WWRD sites to 1) existing wind facilities on the Public Service system; 2) planned wind facilities on the system; and 3) potential future sites for wind facility additions. The National Renewable Energy Laboratory (NREL) members of the study's Technical Review Committee counseled that the WWRD day-ahead forecasts for the CO East area had a 15-20% positive forecast error bias (over-forecasting)[13] and recommended that as part of this study, EnerNex take the average of this bias and subtract it out of each of the hourly day-ahead wind forecasts. In accordance with this NREL recommendation, EnerNex created an adjusted WWRD wind production forecast for the selected wind sites used in the study. The resulting adjusted WWRD forecasted wind energy production profiles trend to the original forecast profile while maintaining the annual forecast energy production in appropriate proximity to the actual energy production. EnerNex performed the following steps to produce the adjusted WWRD wind data:

  1) Calculated the monthly forecast and actual wind energy production;
  2) Determined the ratio of monthly forecast and actual wind energy production;
  3) Calculated the hourly mean absolute error (MAE) for the forecasted wind energy production;
  4) Created a histogram of hourly MAE in increments of 10% ;
  5) For each hour of forecast wind
     a. applied the respective monthly ratio
     b. trimmed the result with the error adjustment based on the MAE of the forecast.

  The capacity factors of the selected WWRD sites were low compared to the historical wind production Public Service has observed at the sites. The Technical Review Committee believes that an improved source for wind generation data, if available, would be beneficial for use in future wind integration cost studies.

- In situations when the committed generation capacity (Steps 1 and 3) was insufficient in dispatch (Steps 2 and 4) to serve customer loads (a.k.a., unserved energy), it was necessary to post-process each computer model run and manually add the costs associated with starting gas turbines into the previously calculated production costs as well as increasing the gas consumption and unit hourly loading for gas units. Unit starts were determined by analyzing how many 190 MW gas turbines were required to meet the unserved energy need. The parameters for calculating the added costs to eliminate unserved energy are as follows:

---

[12] As explained below, gas price sensitivities in addition to those listed here were performed to further explore proxy performance and to produce additional gas price curves.

[13] GE Energy, "Western Wind And Solar Integration Study," May 2010, Section 5.6, Page 88.

1) Number of gas turbine starts;
2) Hours of operation;
3) MWh generated;
4) Cost parameters as described below for CT.

- For purposes of this study, when building the Couger model representation of the year 2018 Public Service electric system, approximately 2,000 MW of additional generic gas-fired generating capacity (summer rating) was added to meet the Company's planning reserves. This 2,000 MW of generation capacity was comprised of the following thermal generating resources;

1) Combustion Turbines - Six (6) Generic Combustion Turbines before 2018
   a. Ratings - Summer = 169.9 MW (each); Winter = 189.4 MW (each)
   b. Full Load Heat Rate = 9,723 MMBtu /MWh
   c. Variable O&M = $8.36/MWh
   d. Min Run Time = 0 hours
   e. Ramp Rate = 15 MW/Minute
   f. Start-Up Costs = $7,414/turbine start

2) Combined Cycle – Two (2) Generic Combined Cycle plants before 2018
   a. Ratings - Summer = 501 MW (each); Winter = 547.8 MW (each)
   b. Heat Rate = 6,849 MMBtu /MWh
   c. Variable O&M = $2.90/MWh
   d. Min Run Time = 1 hour
   e. Ramp Rate = 11 MW/minute
   f. Start-Up Costs = $13,668/facility start

Couger Model Input and Operation Review

After configuring the Couger model to properly represent the Public Service electric system for year 2018, EnerNex ran the model and produced a variety of output information pertaining to how the model simulated economic dispatch of the generation fleet to meet system load. These output results were compared to the output results produced by the Company's PROSYM production cost model that is used for our internal business planning and budget projections. This comparison showed the Couger model results to be in good agreement with PROSYM thereby providing confidence that the Couger model was properly configured for use in performing the 2GW/3GW Study.

Scope of Work

A total of 12 base case Couger model runs and 65 Couger model sensitivity case runs were performed for this study. Base case runs were done with Public Service year 2018 hourly system load represented in a manner consistent with three historical years, 2004, 2005 and 2006 (to allow maintaining correlation to the WWRD study years of 2004, 2005 and 2006). Several additional sensitivity runs were performed to validate or further explore aspects of the 2G/3G Study.

Additionally, four alternative base case scenarios were produced with geographically diverse locations for the 1,000 MW of wind facilities needed to grow the Public Service system wind resource from 2 GW to 3 GW. All four of these scenarios added wind facilities in strong wind regions on the eastern plains of either Colorado or Wyoming. These regions are reasonably close to the Colorado Front Range load center. The four alternative scenarios were developed to achieve 1) no geographic diversity by siting the expansion facilities in close proximity to the largest existing base of wind generation in Colorado's northeast corner; 2) geographic diversity in addition by siting the expansion facilities in equal capacity increments over several strong wind regions in Colorado's eastern plains where wind facilities currently exist; 3) geographic diversity in result by siting the expansion facilities in underrepresented strong wind regions in Colorado's eastern plains; and 4) a Wyoming scenario by siting the expansion facilities solely in Wyoming. See Appendix A for maps of the 2 GW wind resource locations and the locations of the facilities added to achieve 3 GW of wind resource penetration.

Please see Table 7 for a complete listing of the base case and planned sensitivity runs.

Table 7: Number of Couger Base Case and Sensitivity Model Runs

	Wind Scenario Name	Base Case			Gas Price			Storage	Proxy Shape	CO_2	Forecast Methods	Quick Start	Demand Response
Load Year		2004	2005	2006	2004	2005	2006	2004	2004	2004	2004	2004	2004
Wind Level													
New 20%	Installed MW	1	1	1	8				1				
2 GW	Installed Plus Planned MW	1	1	1	8			2	1	1	2	2	1
3 GW													
Scenario 1	No Diversity	1			1				1				
Scenario 2	Diversity in Addition	1	1	1	8	2	2	2	1	1	2	2	1
Scenario 3	Diversity in Result	1			1				1				
Scenario 4	Wyoming	1			1				1				
Total Model Runs = 65		6	3	3	27	2	2	4	6	2	4	4	2

A description of the sensitivities that were performed follows:

- **Gas Price**
  In addition to the base case runs made at a base gas price of $5.06/MMbtu, four gas price sensitivity cases were performed, $3.24, $7.83, $9.83 and $12.00/MMBtu. A complete set of gas price sensitivities was performed for both the Flat Block and On/Off Peak Proxy approaches to modeling for the 20%, 2GW and 3GW (Scenarios 2) levels of wind integration. The gas price sensitivities were not performed for all of the six base case runs. The 3GW Scenarios 1, 3 and 4 had runs at only the base case gas price of $5.06.

- **Storage**
  Two storage sensitivity cases were performed for the 2 GW and the 3 GW (Scenario 2) levels of wind. 1) the "Upgrade Cabin Creek" sensitivity modeled a 36 MW/115 MWh upgrade of the Company's existing Cabin Creek pumped storage facility and 2) the "Additional Storage Resource" sensitivity which considered the addition of a second pumped storage facility similar in size to the existing 324 MW Cabin Creek facility.
- **Wind Energy Proxy**
  An "On/Off Peak Proxy" sensitivity examined the impacts of substituting an On/Off Peak Proxy (with a two hour ramp between on and off peak) for the Flat Block Proxy that used a four hour ramp between days.
- **Day Ahead Wind Forecast Methods**
  Two sensitivity cases were performed on the day-ahead forecast of both the 2 GW and the 3 GW (Scenario 2) levels of wind. The objective of these sensitivities was to establish the outer bounds of integration costs as a function of the day-ahead wind forecast. The first set of sensitivity cases, the "No Forecast" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by replacing the "day-ahead forecast" of wind production data in the Actual Case Optimization run (Step 3) with a wind production level of zero MWh for the day i.e., likely the most you could ever miss on your wind generation forecast. The second set of sensitivity cases, the "Perfect Forecast" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by replacing the "day-ahead forecast" of wind production data in the Actual Case Optimization run (Step 3) with the "actual" wind production data i.e., the least you could ever miss your wind generation forecast.
- **Quick Start Resources**
  Two Quick Start Resource sensitivity cases were performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind. The first set of sensitivity cases, the "No Additional Quick Start Resources" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by removing six Quick Start CT resources. The second set of sensitivity cases, the "Two Additional Quick Start Resources" sensitivity, (one 2 GW and one 3 GW (Scenario 2)) were performed by adding two Quick Start CT resources.
- **Carbon**
  One sensitivity case, the "CO_2" sensitivity, was performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind using a CO_2 cost of $20/ton. The CO_2 cost was accounted for by adding a cost to the wind integration cost in a post-processing calculation.
- **Demand Response**
  One sensitivity case, the "No Demand Response" sensitivity, was performed for both the 2 GW and the 3 GW (Scenario 2) levels of wind. In the base case runs the level of unserved energy from the Couger model run results was reduced by 6,000 MWh at no cost to reflect use of the Company's demand response resources. In the "No Demand Response" sensitivity this 6,000 MWh adjustment was not performed. In both the base case runs and the sensitivity, the remaining unserved energy was then addressed through the start of a requisite number of CTs as discussed earlier.

STUDY RESULTS

Base Case Results

The base case 2GW/3GW Study results are shown in Table 8. The results were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy.[14]

Table 8: Average System Operations Wind Integration Costs ($5.06/MMBtu gas price)

Wind Penetration Level	20%	2 GW	3 GW Scenario 1	3 GW Scenario 2	3 GW Scenario 3	3 GW Scenario 4
Average System Operations Wind Integration Cost ($/MWh)	2.39	3.40	4.02	3.71	3.37	3.82

The "actual" annual wind energy production modeled in the base case is shown in Table 9.

Table 9: Modeled Annual Actual Wind Energy Production

Wind Penetration Level	Wind Energy Production (MWh)
20%	3,305,791
2 GW	4,378,115
3 GW	6,925,855

Geographic Diversity Influence on Average System Operations Integration Cost

At the base gas price of $5.06/MMBtu, the degree of geographic diversity in the wind facilities added to grow the wind penetration level from 2 GW to 3 GW produced changes in average system operations integration cost in the range of 4-16%. The Company believes that reductions in average system operations integration cost with increased geographic diversity makes intuitive sense. 3 GW (Scenario 2) was chosen as the "base case" for 3 GW sensitivity runs because the Company believes this 3 GW scenario represents a plausible outcome for future wind resource additions – future resources being added in more than one ERZ.

Average Regulation Wind Integration Costs

The 2GW/3GW Study results for the regulation component of wind integration costs are shown in Table 10. The results are not gas price dependent.

---

[14] All 2GW/3GW Study results, other than those for gas price sensitivities, were created with the Couger model using an average annual gas cost of $5.06/MMBtu.

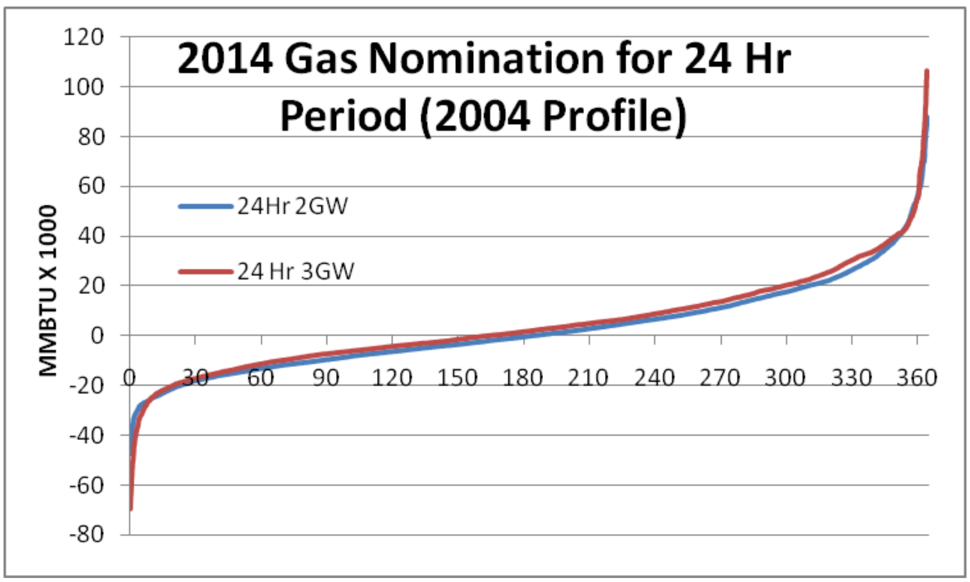
Table 10: Average Regulation Wind Integration Cost

Wind Penetration Level	20%	2 GW	3 GW
Average Regulation Wind Integration Costs ($/MWh)	0.10	0.14	0.21

Average Gas Storage Wind Integration Costs

In reviewing the Couger model runs, Public Service observed that the gas day over nomination demand charge was being set or determined by only a few "outlier" days over the entire 2018 study year that exceeded the 60,000 Decatherm/day gas injection capability used to represent the remaining capacity of the Company's existing storage facilities. Figure 1 shows over and under nomination for 365 days of 24 hour gas days ordered from lowest under nomination to greatest over nomination and illustrates the occurrence of outliers.

Figure 1: 24 Hour Gas Nomination for 2014 using 2004 Wind and Load Profile



Public Service determined that curtailment of wind resources to allow the excess gas to be burned rather than purchasing additional injection demand would be the most cost-effective approach to managing these outlier days. Therefore, Public Service chose a curtailment approach to handle the "outlier" gas day over nominations to minimize the average gas storage wind integration cost. The cost to curtail wind on these outlier days is included in the average gas storage wind integration costs which were determined with a base gas price of $5.06/MMBtu and with the On/Off Peak Proxy and which are shown in Table 11 below.

Table 11: Average Gas Storage Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17

Total Average Wind Integration Costs

The total average wind integration costs is the sum of the three components of wind integration cost and the values for the 2GW and 3GW levels of wind are summarized in Table 12

Table 12: Total Average Wind Integration Cost ($5.06/MMBtu gas price)

Wind Penetration Level	2 GW	3 GW Scenario 2
Average Regulation Wind Integration Cost ($/MWh)	0.14	0.21
Average System Operations Wind Integration Cost ($/MWH)	3.40	3.71
Average Gas Storage Wind Integration Cost ($/MWH)	0.14	0.17
Total Average Wind Integration Cost ($/MWH)	**3.68**	**4.09**

As explained in the "Application of Results" section below, Public Service will use the total *incremental* not *average* wind integration costs in its resource planning and selection processes. Therefore, **Table 12 is provided for illustrative purposes only**.

GAS PRICE SENSITIVITY

The price of natural gas is a key factor in the calculation of average system operations wind integration cost estimates since much of the wind uncertainty is accommodated by starting, operating, and stopping gas-fired generating units. Table 13 below shows the range of gas prices analyzed in this 2GW/3GW Study. A total of 31 gas price sensitivities were run, eight for the 2004/20% base case run, eight for the 2004/2 GW base case run, and one for each scenario of the 2004/3 GW base case runs with the exception of 3 GW Scenario 2 which had eight (as well as 2 each for 2005 and 2006). Each of the four sensitivities was run for the Flat Block Proxy and for the On/Off Peak Proxy.

Table 13: Gas Prices for Base Cases and for Sensitivities ($/MMBtu)

	AVG	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base	**5.06**	6.02	5.82	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80	5.11	5.40
Sensitivity 1	**7.83**	8.18	8.26	8.16	7.45	7.48	7.56	7.68	7.72	7.48	7.52	8.09	8.32
Sensitivity 2	**9.83**	10.27	10.37	10.25	9.35	9.39	9.49	9.65	9.69	9.39	9.44	10.16	10.45
Sensitivity 3	**3.24**	3.85	3.73	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.27	3.46
Sensitivity 4	**12.00**	14.28	13.80	11.38	11.38	11.38	11.38	11.38	11.38	11.38	11.38	12.12	12.81

The average system operations wind integration costs determined for the base case and gas price sensitivities using the On/Off Peak Proxy are presented in Table 14 below. Average system operations wind integration costs are given in $/MWh and gas costs are given in $/MMBtu.

Table 14: Average System Operations Wind Integration Cost/Gas Price Matrix

Gas Price Sensitivity Cases	Average Gas Price ($/MMBtu)	Average System Operations Wind Integration Costs ($/MWh)					
		20%	2 GW	3 GW Scenario 1	3 GW Scenario 2	3 GW Scenario 3	3 GW Scenario 4
Sensitivity 3	3.24	2.19	2.70	N/A	2.87	N/A	N/A
Base	5.06	2.39	3.40	N/A	3.71	N/A	N/A
Sensitivity 1	7.83	3.35	4.68	N/A	5.87	N/A	N/A
Sensitivity 2	9.83	5.11	5.57	N/A	7.50	N/A	N/A
Sensitivity 4	12.00	5.85	6.54	N/A	9.60	N/A	N/A

STORAGE SENSITIVITY

The base case runs were performed with Public Service's 324 MW Cabin Creek pumped storage facility as the sole "energy storage" resource on the system. The "Upgrade Cabin Creek" sensitivity involved increasing the efficiency and generation capacity of the existing Cabin Creek facility and the "Additional Storage Resource" sensitivity included the addition of a second 324 MW pumped storage plant.

For the "Upgrade Cabin Creek" sensitivity, the following improvements were made to the model representation of the Cabin Creek facility 1) the upper storage pond holding capacity and its spill capacity was increased by 115 MWh per cycle (1,400 to 1,515 MWh); 2) the nameplate capacity rating of the unit was increased 36.6 MW (324 MW to 360 MW).; and 3) the pumping efficiency of the facility was increased 7% (from 0.62 to 0.66).

The "Additional Storage Resource" sensitivity added a second, two unit pumped storage resource with the same 324 MW capability and efficiency as the exiting Cabin Creek facility.

The purpose of these sensitivities is to examine the effect additional storage capability might have on reducing average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 15 below.

Table 15: Average System Operations Wind Integration Cost - Storage Sensitivities ($5.06/MMBtu gas price)

Storage Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
Upgrade Cabin Creek Sensitivity	3.87	5.11
Additional Storage Resource Sensitivity	3.63	4.32

The storage sensitivity results indicate that average system operations wind integration cost can be reduced by making improvements to the Cabin Creek facility or by the addition of a second pumped storage facility. The reduction in average system operations wind integration cost for the upgrade sensitivity is $0.24/MWh for the 2 GW scenario and $0.33/MWh for the 3 GW (Scenario 2) scenario. The reduction in average system operations wind integration cost for the storage facility addition sensitivity is $0.48/MWh for the 2 GW scenario and $1.12/MWh for the 3 GW (Scenario 2) scenario. Both the upgrade and additional storage resource sensitivity cases were built upon the base case.

The average system operations wind integration cost reductions achieved by the addition of a second 324 MW storage facility appeared disproportionately low when compared to the reduction achieved by increasing the efficiency and MW capability of the existing pumped storage facility. This result prompted further review of the results of the storage sensitivities.

In addition to verifying that the Couger model was functioning properly, including the dispatch of the storage resources, when it produced the sensitivity results provided above, Public Service and EnerNex investigated the effects of storage resources on reserve capacity, unserved energy, start up costs etc. and also performed an additional sensitivity. The additional sensitivity was identical to the "Additional Storage Resource" sensitivity except that the additional storage resource was also modeled with improved pumping efficiency (7% improvement). This sensitivity produced average system operations wind integration costs of $3.47 for 2 GW and $4.13 for 3 GW Scenario 2.

In deciding when to generate with the pumped storage resource, Couger first examines the hours within the week when the pumped storage resource can displace a high cost resource. Couger then considers whether the water used to provide this generation can be pumped to the upper reservoir with an available thermal generating resource that is sufficiently low in cost to make the combined pumping and generation cycle economic. As background assumption, wind energy was modeled in Couger as a must take energy resource thereby acting to reduce the load on the system that is eventually served by dispatchable resources. As a result, all of the energy used to pump water back to the upper reservoir is from dispatchable resources.

Tables 16 and 17 show the generation and pumping parameters for the storage sensitivity cases. For the 2 GW level of wind penetration, the "Upgrade Cabin Creek" sensitivity shows a 9.2% increase in pumped storage generation and the "Additional Storage Resource" sensitivity shows a 75.5% increase in pumped storage generation over the Base Case. For the 3 GW (Scenario 2) level of wind penetration, pumped storage generation also increased when compared to the Base Case – 16.1% and 68.6% for the two sensitivities. Corresponding increases in pumped storage pumping were also seen in the sensitivities. The additional pumped storage efficiency or capability (upgrade or second unit) provided an increase in pumped storage utilization that is generally proportional to the modifications made to the storage resource.

Table 16: Pumped Storage Generation Comparison

	2 GW				3 GW (Scenario 2)			
Storage Sensitivity Cases	Pumped Storage Generation (MWh)	Delta to Base (MWh)	% Delta to Base (MWh)	Average System Lambda	Pumped Storage Generation (MWh)	Delta to Base (MWh) (1)	% Delta to Base (MWh)	Average System Lambda
Base Case	256,513			54.38	281,379	24,866		60.57
Upgrade Cabin Creek Sensitivity	280,178	23,665	9.2%	53.72	326,770	45,391	16.1%	58.74
Additional Storage Resource Sensitivity	450,149	193,636	75.5%	53.70	474,328	192,949	68.6%	60.20

Table 17: Pumped Storage Pumping Comparison

	2 GW				3 GW (Scenario 2)			
Storage Sensitivity Cases	Pumped Storage Pumping (MWh)	Delta to Base (MWh)	% Delta to Base (MWh)	Average System Lambda	Pumped Storage Pumping (MWh)	Delta to Base (MWh) (1)	Delta to Base (MWh) (1)	Average System Lambda
Base Case	(413,833)			29.00	(454,012)			32.03
Upgrade Cabin Creek Sensitivity	(434,768)	(20,935)	5.1%	29.10	(492,641)	(38,629)	8.5%	32.66
Additional Storage Resource Sensitivity	(726,202)	(312,370)	75.5%	32.28	(765,383)	(311,371)	68.6%	34.65

Notes:

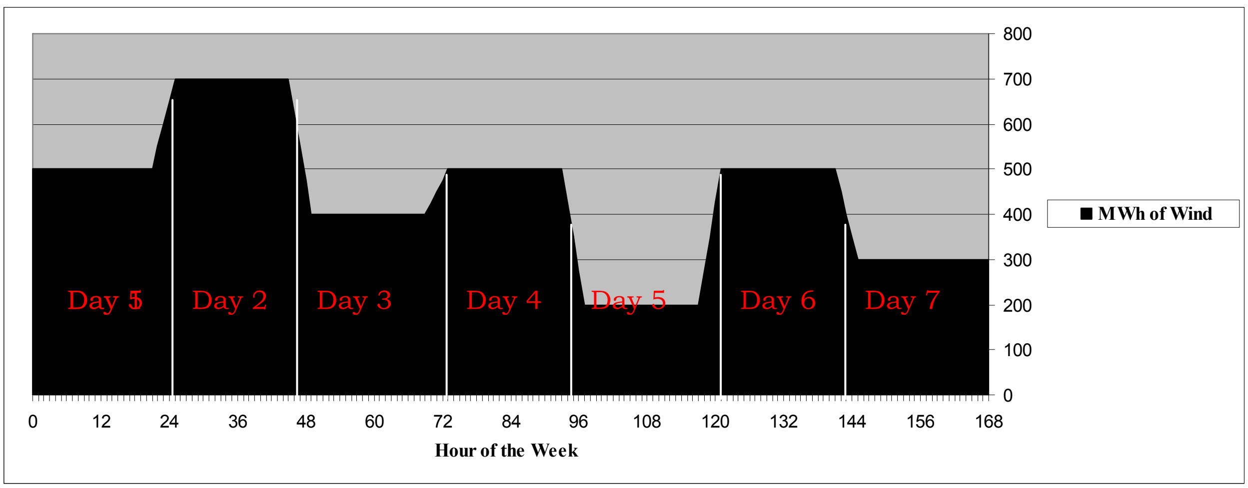
1) The "Delta to Base" figures for 3 GW (Scenario 2) Base Case are a comparison to the 2 GW Base Case figures.

The average system lambdas (the average cost of the marginal unit of energy) for each of the case results show the pumping costs for the "Additional Storage Resource" sensitivities were notably higher. This higher cost to pump the water appears to diminish the cost effectiveness of the additional storage resource with regards to reducing the average system operations integration cost of wind on the Public Service system.

WIND ENERGY PROXY SENSITIVITY

Both the Reference Case Optimization run (Step 1) and the Reference Case Simulation run (Step 2) employed an hourly wind energy pattern or proxy as a substitute for actual hourly wind energy production patterns. Public Service employed a "flat block proxy" that, for each day of the study year, distributed the actual wind energy production from WWRD for a 24 hour period evenly over each hour of that 24 hour period. In addition, the block energy proxy step change from one day's block to the next day's block was smoothed by calculating a four-hour ramp between blocks (a day's last two hours and the following day's first two hours had wind energy production values that incremented up or down between block proxy values). See Figure 2 for an illustration of a Flat Block Proxy with a four hour ramp between daily proxy energy blocks.

Figure 2: Example "Flat Block Proxy" with Four Hour Ramp Between Blocks

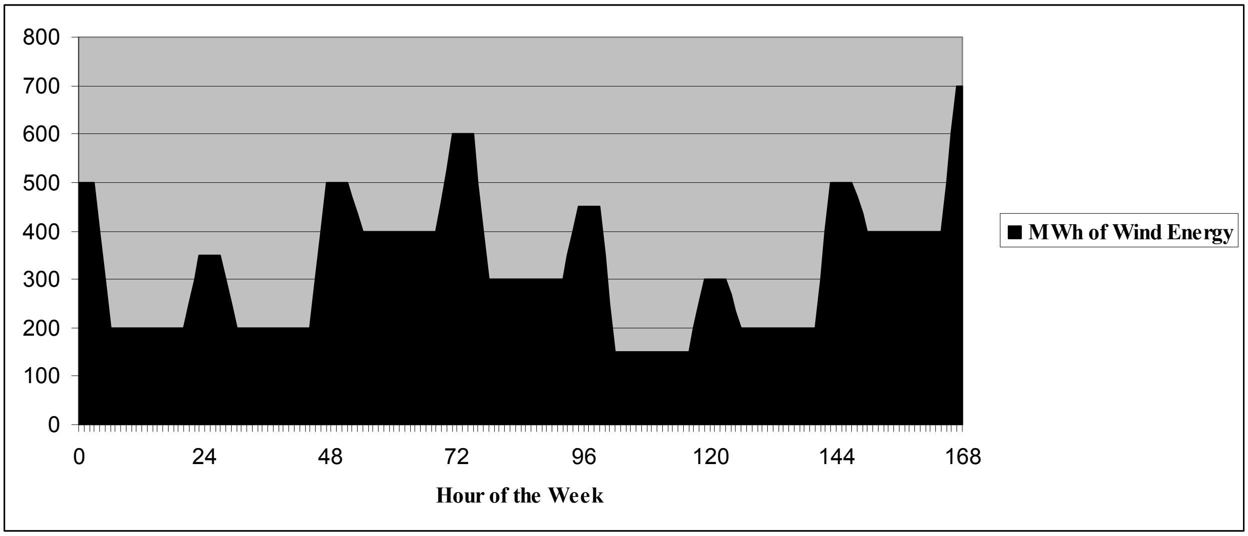


For the "On/Off Peak Proxy" proxy shape sensitivity an On/Off Peak wind energy proxy with a two hour ramp between on-peak and off-peak energy proxy blocks was used for both the 2 GW and the 3 GW (Scenario 2) levels of wind penetration. The On/Off Peak Proxy distributes the wind energy production from WWRD into two blocks within each 24 hour day to more closely match the diurnal on-peak and off-peak periods of the day. See Figure 3 for an illustration of an On/Off peak Proxy with a two hour ramp between the on-peak and the off-peak proxy energy blocks.[15]

---

[15] The illustration uses a large or exaggerated difference between peak and off-peak energy levels.

Figure 3: Example On/Off Peak Proxy with Two Hour Ramp Between Blocks



The purpose of the proxy sensitivity is to determine the effect that wind proxy shapes/approaches utilized in the Steps 1 and 2 model runs have on the average system operations wind integration costs that result from the methodology applied in this study. Proxy shape does not affect the average regulation wind integration cost and would have a de minimus affect on the average gas storage wind integration cost. The result of the sensitivity is provided in Table 18 below.

Table 18: Average System Operations Wind Integration Cost – Proxy Shape Sensitivity ($5.06/MMBtu gas price)

Proxy Shape Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case – Flat Block Proxy	4.11	5.44
On\Off Peak Proxy Sensitivity	3.40	3.71

The proxy shape sensitivity results indicate that average system operations wind integration costs produced in this study are lowered when the Step 1 and 2 model runs are performed using an On/Off Peak Proxy. The Company believes that the results of this sensitivity create a decision point as to the appropriate average system operations wind integration cost to select for purposes of calculating the incremental wind integration costs to be used in comparing the cost of wind resources with other power supply alternatives. The decision, "Is it most appropriate to use the "Flat Block Proxy" or "On/Off Peak Proxy" results?"

Recall that the wind energy proxy is used in Steps 1 and 2 of the modeling protocol in order that Step 4 total system costs minus Step 2 total system costs removes the load uncertainty factor from the determination of average system operations wind integration cost. It is, therefore, integral and important to the modeling protocol to employ a wind energy proxy. At issue is the nature or shape of the proxy and the effect the proxy has on Step 2 costs.

To put the issue succinctly, when a flat block proxy is used, some wind energy is moved to the daytime period where wind is generally displacing more costly resources. The result is that Step 2 system costs determined with the proxy are "artificially" lowered. In the modeling protocol Step 2 costs are subtracted from Step 4 costs; therefore, any reduction in Step 2 costs results in a higher wind integration cost. This issue was explored in the paper, "Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Costs Impacts."[16] Block proxies of any sort also have the attendant issue of ramping events between the blocks which can cause cost increases as changing generation levels up or down causes operating inefficiencies.

Alternatives to the Flat Block and the On/Off Peak proxies include block proxies that use shorter time periods, e.g., six hours, and moving or rolling average proxies. The smaller time period block proxies more closely match the proxy energy levels to those actually encountered during wind generator operation mitigating the problem caused by larger time period block proxies. The rolling average proxies mitigate both the adverse effects of ramping and the time shifting of wind production produced by block proxies.

The historical context is that many wind integration cost studies and Public Service's past wind integration cost studies used a Flat Block Proxy. Public Service recognizes the validity of arguments for using a different proxy than the Flat Block Proxy but was concerned that sufficient research with empirical data has not been conducted that demonstrates the superiority of the On/Off Peak Proxy, other time period block proxies, or the rolling average proxies as it concerns more valid results for average system operations wind integration cost.

Public Service believes that the question of what proxy wind shape produces the most accurate prediction of actual average system operations wind integration cost can be informed by assessing how well each proxy approach aligns with average system operations wind integration cost estimates developed from actual historical operation data for the Public Service system. The process for developing average system operations wind integration cost estimates from actual historical operational data is referred to herein as "back casting."

Pubic Service's back casts of historical average system operations wind integration costs are developed in a manner similar to that used to estimate future average system operations wind integration cost within the Couger model, i.e., the back cast compares 1) the system operating costs of a unit commitment developed from a wind energy forecast to 2) the system operating costs of a commitment developed using actual wind energy production. Specifically, a day-ahead wind forecast is used to commit resources and then those resources are dispatched against the wind generation that actually occurred on the system. Finally, a third step is performed using the actual wind generation for both the commit and dispatch decisions. The total amount of wind energy is the same between the second and third runs. The system operating cost difference between the second and third steps is representative of the actual average system operations wind integration cost of wind for the historical period analyzed.

The key distinction between the Couger modeling and the back cast modeling is that the back cast uses *actual* hourly forecasts of load and wind energy production, an *actual* day-ahead commitment and *actual* loads and wind energy production to estimate the average system operations wind integration cost. The back cast determines only the integration costs associated

---

[16] Milligan, Michael, Kirby, Brendan, "Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Costs Impacts," National Renewable Energy Laboratory, July 2009.

with the electric system operations component of wind integration costs that the Couger model determines and is, therefore, comparable to the values contained in Table 8 of this report.

Public Service's back cast analysis of the average system operations wind integration cost for 2010 (a period that reflects the results of Public Service's most recent efforts to improve wind forecasting) determined that the average system operations wind integration cost averaged \$3.22/MWh at an average gas price of \$4.01/MMBtu. The level of wind generation installed on the Public Service system throughout the time period of the back cast was 1,233 MW name plate; therefore, the 20% penetration level results from this study are most comparable to those of the 2010 back cast. With a comparable level of mean absolute forecast error, and at the \$4.01/MMBtu gas price, the average system operations wind integration cost for the 20% wind penetration Flat Block Proxy is \$2.89/MWh and the "like" figure for the On/Off Peak Proxy is \$2.27/MWh. Please see Appendix B.

The Company believes that the 2010 back casting results validate the wind integration cost results produced in this 2GW/3GW study using either the adjusted Flat Block Proxy and the On/Off Peak Proxy approaches. The Flat Block Proxy result (with the appropriate adjustments) more closely approximates the average system operations wind integration cost developed through the 2010 historical back casting but not in a way that indicates that the Flat Block Proxy produces a more valid result or that the On/Off Peak Proxy produces a less valid result. Because the On/Off Peak Proxy more accurately distributes the wind energy to the appropriate time period and energy cost category, Public Service intends to use the On/Off Peak Proxy results when assessing the overall cost of wind resources during future resource planning/selection processes.

WIND FORECAST METHODS SENSITIVITY

The base case studies were performed using WWRD wind production data for both the day-ahead "forecast" of wind generation in the Actual Case Optimization run (Step 3) and the "actual" production figure used for wind generation in the Actual Case Simulation run (Step 4).

The "No Forecast" sensitivity was performed by replacing the day-ahead "forecast" wind generation in the Actual Case Optimization run (Step 3) with a wind generation level of zero MWh for the day. The "Perfect Forecast" sensitivity was performed by replacing the day-ahead "forecast" wind generation in the Actual Case Optimization run (Step 3) with the "actual" wind generation for the day. The purpose of these sensitivities is to establish the bounds of the day-ahead wind forecast's effect on the average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 19 below.

Table 19: Average System Operations Wind Integration Cost – Forecast Methods Sensitivities ($5.06/MMBtu gas price)

Forecast Methods Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Forecast Sensitivity	10.24	14.69
Perfect Forecast Sensitivity	1.48	3.33

The 2G/3G Study results provide a level of validation to the modeling approach employed in this study in that the value of an accurate day-ahead wind forecast is shown by the large increase in the average system operations wind integration cost when no forecast of wind generation is available or used, the "No Forecast" sensitivity. In addition, the "Perfect Forecast" sensitivity demonstrates a marked decrease in the average system operations wind integration cost when the same value of wind production is used to perform both the commitment and dispatch of the system. As noted above, the results of the No Forecast and Perfect Forecast sensitivities "bound" the 2G/3G Study results between $1.48/MWh and $10.24/MWh for the 2 GW level of wind integration.

QUICK START RESOURCES SENSITIVITY

The base case studies were performed with each thermal resource receiving a designation as to whether it is a Quick Start resource or not. For purposes of this study quick start units are those capable of being off-line and counting towards the 10-minute spinning reserve requirement because of their ability to start, synchronize, and come to full load in 10 minutes. The Public Service power supply system is expected to have approximately 194 MW of quick start resources in 2018 (not counting any of the six generic CT resources included in the Couger model for purposes of meeting future load requirements).

The "No Additional Quick Start Resources" sensitivity was performed by changing the designation of the six quick start CT resources added to the model to non-quick start such that they would need to be on line to count against the 10-minute reserve requirement. The "Two Additional Quick Start Resources" sensitivity was performed by changing the designation of four of the six quick start CT resources to non-quick start. The purpose of these sensitivities is to examine the value provided by quick start facilities in lowering average system operations wind integration cost. The results of the sensitivities using the Flat Block Proxy are provided in Table 20 below.

Table 20: Average System Operations Wind Integration Cost – Quick Start Resources Sensitivities ($5.06/MMBtu gas price)

Quick Start Resources Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Additional Quick Start Resources Sensitivity	4.13	5.44
Two Additional Quick Start Resources Sensitivity	4.13	5.46

The quick start resources sensitivities results indicate that for purposes of minimizing average system operations wind integration cost, sufficient quick start resource are expected to exist on the Public Service system by 2018 (not counting any of the six generic CT's added to the system) and that adding more quick start resources will have little incremental impact on reducing these costs. Note that the Couger model, being an *hourly* unit commitment and dispatch model, is not capable of fully quantifying the total value that quick start and flexible resources can bring to the system. The Couger model allows an offline quick start unit to meet a portion of the system operating reserve requirement. The results of these sensitivity runs indicate that the amount of quick start units that will exist on the Public Service system in 2018 (not counting any of the generic CTs added) will be sufficient to minimize wind integration costs at both the 2GW and 3GW levels and that additional quick start capability is expected to provide little if any value in reducing integration costs.

CARBON SENSITIVITY

The base case studies were performed with no cost included for CO_2 emissions from fossil fuel plants. One sensitivity case, the "CO_2" sensitivity, was performed by adding a CO_2 cost of \$20/ton to the prior-determined average system operations wind integration cost.

The purpose of the "CO_2" sensitivity was to produce a wind integration cost value for application in situations where wind generation is being compared with other generation technologies and a cost is being assigned to CO_2 emissions. Since the majority of total incremental wind integration cost results from sub-optimal thermal unit commitment and dispatch, the expectation going into this sensitivity was that these sub-optimal outcomes would result in increased CO_2 emissions and subsequently a higher integration cost. The result of the sensitivity using the Flat Block Proxy is provided in Table 21 below.

Table 21: Average System Operations Wind Integration Cost – CO_2 Sensitivity (\$5.06/MMBtu gas price)

CO_2 Sensitivity Cases	Average System Operations Wind Integration Cost (\$/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
CO_2 Sensitivity	3.81	4.85

Unexpectedly, the assignment of costs to CO_2 emissions produced lower integration costs. This result is misleading. In reviewing this outcome, EnerNex and Public Service concluded that the methodology employed to examine the impacts of CO_2 does not produce a reliable result. The reason for this stems from the use of the wind energy proxy resource in Steps 1 and 2. The wind energy proxy 1) averages or "smooths" the forecasted daily wind energy production either over a single period, the Flat Block proxy, or over two periods, the On/Off Peak Proxy; and 2) allows Public Service to isolate the cost of load forecast error and ensure these load forecast related costs don't get included in the wind integration cost. Recall that wind energy acts to reduce system load in the model and that the average system operations wind integration cost is the result of the total production cost of Run 4 minus the total production cost of Run 2 (divided by the modeled actual annual wind energy produced).

Use of the flat block proxy shifts wind generation to daytime hours when lower CO_2 emitting gas units are on the margin. This effect reduces the level of CO_2 emissions that wind avoids in Runs 1 and 2 relative to the level of CO_2 wind avoids in Runs 3 and 4. Run 2 ends up with more CO_2 per level of wind than does Run 4. When a cost is applied to CO_2, more cost is applied to Run 2 versus Run 4, thus reducing the overall cost delta between the runs subsequently reducing the wind integration cost result.

DEMAND RESPONSE SENSITIVITY

In the base case studies it was assumed that 6,000 MWh of Public Service's demand response program, Interruptible Service Option Credit, would be used for purposes of helping reduce the average system operations wind integration cost.[17] In these base case studies the level of unserved energy within the Couger model was reduced by 6,000 MWh. The remaining unserved energy was then assigned a $/MWh cost representative of the operating costs of a CT. In the "No Demand Response" sensitivity, no downward adjustments were made to the unserved energy within the Couger model runs.

The purpose of "No Demand Response" sensitivity is to examine the effect of demand response resources on the average system operations wind integration cost. The result of the sensitivity using the Flat Block Proxy is provided in Table 22 below.

Table 22: Average System Operations Wind Integration Cost – No Demand Response Sensitivity ($5.06/MMBtu gas price)

Demand Response Sensitivity Cases	Average System Operations Wind Integration Cost ($/MWh)	
	2 GW	3 GW Scenario 2
Base Case	4.11	5.44
No Demand Response Sensitivity	4.21	5.51

The procedure for performing this sensitivity predetermines the result of an increase in the average system operations wind integration cost. The sensitivity serves to define the amount of change in the average system operations wind integration cost for a given amount of demand response resource. Within the 2GW/3GW study model, a 6,000 MWh resource can change the average system operations wind integration cost by $0.10 for a 2 GW wind penetration level and $0.07 for a 3 GW wind penetration level.

[17] There is approximately 17,200 MWh of possible demand response energy provided by the Interruptible Service Option Credit tariff in 2018 (215 MW multiplied by 80 hours average availability). Commercial Operations estimated that approximately 6,000 MWh of this amount would be used for purposes of reducing wind integration costs in 2018.

APPLICATION OF THE STUDY RESULTS

At the base case gas price of $5.06/MMBtu and with the On/Off Peak Proxy, the 2GW/3GW Study determined that the average system operations wind integration cost was $3.40 at the 2 GW level of penetration and $3.71 at the 3 GW level of wind. The integration cost to be included for any additional or incremental wind generation above 2 GW is not, however, equivalent to either the $3.40 or $3.71 values stated above. A total *incremental* wind integration cost must be determined for additional wind by taking the difference between the total average integration costs (electric and gas) determined for the 2 GW wind penetration level and any new level of wind penetration and dividing that figure by the incremental actual annual wind energy produced. Below is an illustration of the calculation for adding a 200 MW wind facility to a 2,000 MW level of installed wind generation.

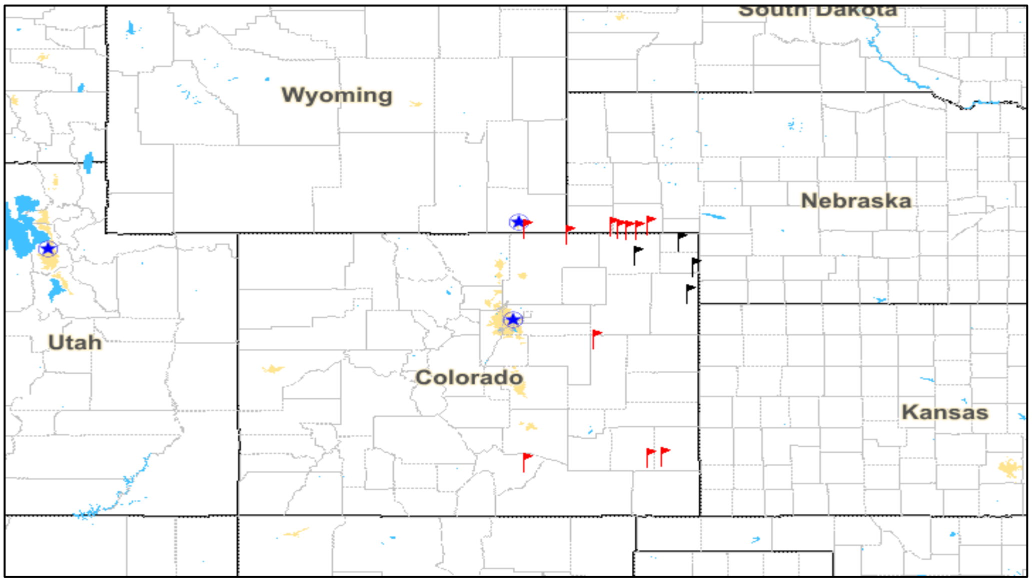
Table 23: Example Total Incremental Wind Integration Cost Calculation

Step	Value and (Calculation)	Result
	2,000 MW Calculation	
a	Total Actual Annual Wind Energy Assumption (MWh)	6,000,000
b	Average Regulation Wind Integration Cost ($/MWh)	0.14
c	Regulation Wind Integration Cost ($) **(a*b)**	840,000
d	Average System Operations Wind Integration Cost ($/MWh)	3.40
e	System Operations Wind Integration Cost ($) **(a*d)**	20,400,000
f	Average Gas Storage Wind Integration Cost ($/MWh)	0.14
g	Gas Storage Wind Integration Cost ($) **(a*f)**	840,000
h	Total Wind Integration Cost ($) **(c+e+g)**	22,080,000
	2,200 MW Calculation	
i	Capacity addition between 2,000 and 3,000 MW	1000
j	Capacity Factor of Added Wind Assumption	0.5
k	Amount of Added Wind Capacity Assumption (MW)	200
l	Hours in a Year	8,760
m	Total Actual Annual Wind Energy (MWh) **(a+(j*k*l))**	6,876,000
n	Average Regulation Wind Integration Cost at 3,000 MW ($/MWh)	0.21
o	Average Regulation Wind Integration Cost ($/MWh) **(b+((k/i)*(n-b)))**	0.15
p	Regulation Wind Integration Cost ($/MWh) **(m*o)**	1,058,904
q	Average System Operations Wind Integration Cost at 3,000 MW ($/MWh)	3.71
r	Average System Operations Wind Integration Cost ($/MWh) **(d+((k/i)*(q-d)))**	3.46
s	System Operations Wind Integration Cost ($) **(m*r)**	23,804,712
t	Average Gas Storage Wind Integration Cost at 3,000 MW ($/MWh)	0.17
u	Average Gas Storage Wind Integration Cost ($/MWh) **(f+((k/i)*(t-f)))**	0.15
v	Gas Storage Wind Integration Cost MW ($) **(m*u)**	1,003,896
w	Total Wind Integration Cost ($) **(p+s+v)**	25,867,512
	Total Incremental Wind Integration Cost Calculation	
x	Total Incremental Wind Integration Cost ($/MWh) **((w-h)/(m-a))**	4.32

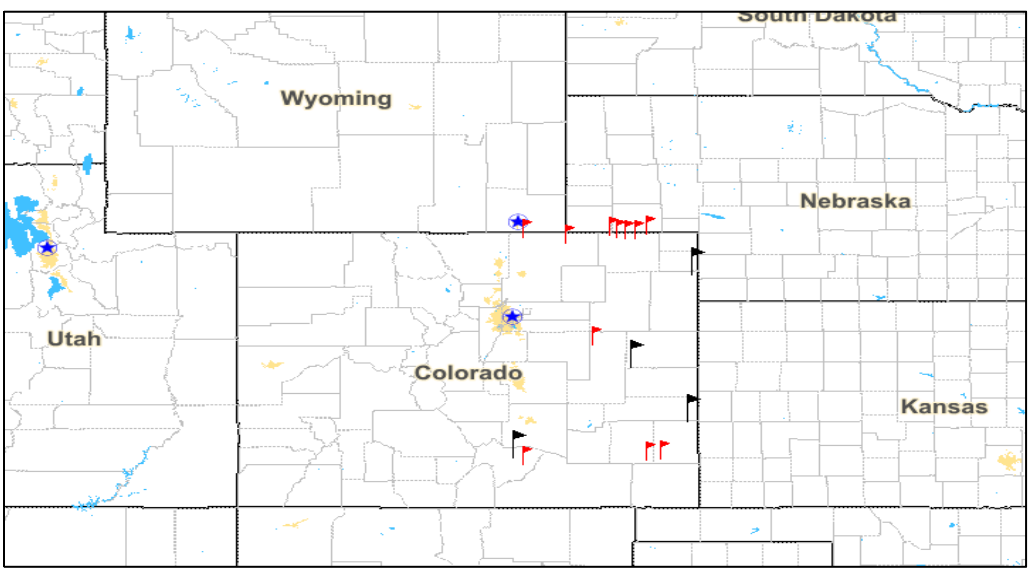
APPENDIX A – LOCATION OF WIND FACILITIES

Red flags indicate location of 2 GW wind facilities. Black flags indicate location of the wind facilities added (1,060 MW) to reach 3 GW of wind generation resources.

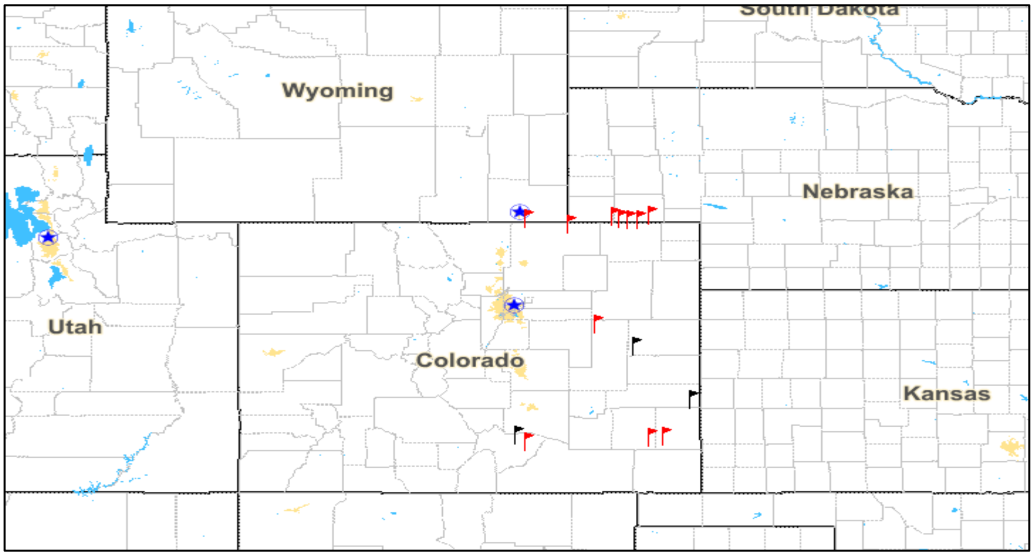
3 GW Scenario 1 Wind Site Locations



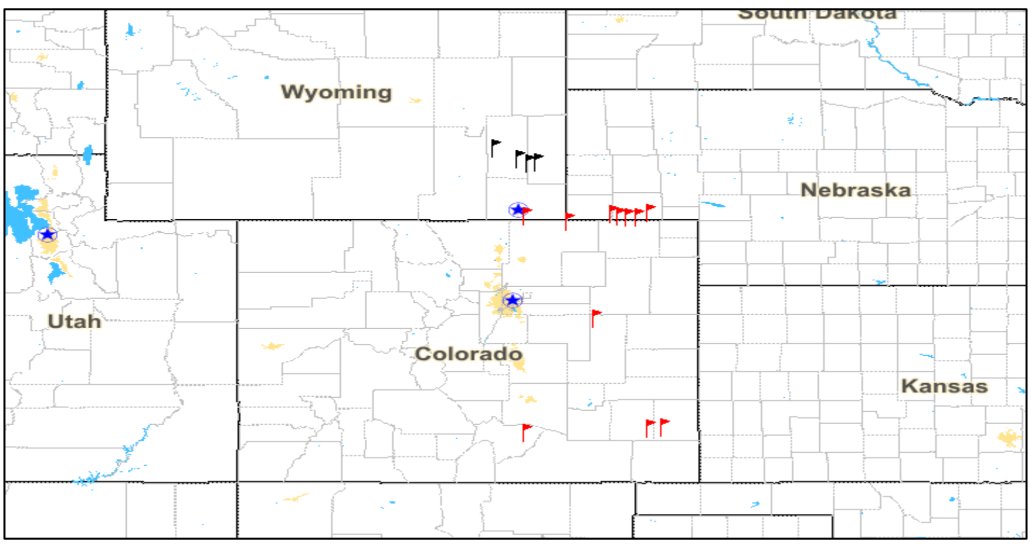
3 GW Scenario 2 Wind Site Locations



3 GW Scenario 3 Wind Site Locations [18]



3 GW Scenario 4 Wind Site Locations



[18] 3 GW Scenario 3 has 530 MW added at one site in Southeast Colorado and, therefore, has only three black flags to identify facility location.

APPENDIX B – WIND INTEGRATION COSTS: FLAT BLOCK AND ON/OFF PEAK PROXY VS BACK CAST STUDY

Comparison of Average System Operations Wind Integration Costs Determined with a Flat Block Proxy and an On/Off Peak Proxy to Average System Operations Wind Integration Costs Determined by a Back Cast Study

Public Service monthly performs a back cast study of average system operations wind integration costs The study is done for installed wind capacity that ranged from 1,130 MW in 2009 to 1,234 MW in 2010 and, therefore, is closest in installed capacity to the 20% Study Results

		Average System Operations Wind Integration Costs			**Slope of Gas Cost Curve 1**	**Slope of Gas Cost Curve 2**
		2009	**2010**			
Backcast Average Gas Price ($/MMBtu)		3 33	4 01			
Backcast GW		1 13	1 23			
Backcast Average System Operations Wind Integration Cost ($/MWh)		3 00	3 22			
Backcast Mean Absolute Error of Forecast to Actual Wind (%)		19 55%	14 18%			
Backcast Mean Absolute Error of Forecast to Actual Wind of 1 4 GW study (%)		13 80%	13 80%			
MAE of Forecast to Actual Wind Generation Adjustment		41 65%	2 78%			
		2 12	3 13			
Avg Annual Gas Price ($/mmBtu)	**3.24**	**5.06**	**7 83**	**9.83**		
20% (~1 4 GW) Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	2 70	3 15	4 50	5 24	0 25	0 48
2 GW Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	3 29	4 11	5 96	7 37	0 45	0 67
3 GW Flat Block Proxy Average System Operations Wind Integration Cost ($/MWh)	3 77	5 44	7 84	10 02	0 92	0 87
20% (~1 4 GW) On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 19	2 39	3 35	4 51	0 11	0 35
2 GW On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 70	3 40	4 68	6 54	0 38	0 46
3 GW On/Off Peak Proxy Average System Operations Wind Integration Cost ($/MWh)	2 87	3 71	5 87	6 86	0 46	0 78
Adjustment to Back Cast Gas Price		**Flat Block**				
		$3 33	**$4.01**			
MAE and Gas Price Adjusted 20% Average System Operations Wind Integration Costs ($/MWh)	1 4 GW	2 72	2 89			
MAE and Gas Price Adjusted 2 GW Average System Operations Wind Integration Costs ($/MWh)	2 GW	3 33	3 64			
MAE and Gas Price Adjusted 3 GW Average System Operations Wind Integration Costs ($/MWh)	3 GW	3 85	4 48			
		On/Off Peak				
MAE and Gas Price Adjusted 20% Average System Operations Wind Integration Costs ($/MWh)	1 4 GW	2 20	2 27			
MAE and Gas Price Adjusted 2 GW Average System Operations Wind Integration Costs ($/MWh)	2 GW	2 73	3 00			
MAE and Gas Price Adjusted 3 GW Average System Operations Wind Integration Costs ($/MWh)	3 GW	2 91	3 22			

Analysis of "Loss of Load Probability" (LOLP) at various Planning Reserve Margins

Prepared for:
Public Service Company of Colorado

Date Submitted:
December 1, 2008

Prepared by:
Ventyx
2379 Gateway Oaks Drive, Suite 200
Sacramento, CA 95833
(916) 569-0985
www.ventyx.com

Contact:
Richard Lauckhart, Senior Vice President
Chintamani Kulkarni, Consultant
916-609-7769

Liability Note

Ventyx provides this document "as is" without warranty of any kind, either expressed or implied, including, but not limited to, the implied warranty of merchantability or fitness for a particular purpose. Ventyx may make changes or improvements in the equipment, software, or specifications described in this document at any time and without notice.

Ventyx has made every reasonable effort to ensure the accuracy of this document; however, it may contain technical inaccuracies or typographical errors. Ventyx disclaims all responsibility for any labor, materials, or costs incurred by any person or party as a result of their use or reliance upon the content of this document. Ventyx and its affiliated companies shall in no event be liable for any damages (including, but not limited to, consequential, indirect or incidental, special damages or loss of profits, use or data) arising out of or in connection with this document or its use, even if such damages were foreseeable or Ventyx has been informed of their potential occurrence.

Table of Contents

Section **Page**

EXECUTIVE SUMMARY 1
1 RECENTLY ACCEPTED APPROACHES........ 1-1
1.1 Previous Lolp Studies 1-1
2 PSCO FOCUSED ANALYSIS USING PORTFOLIO STATISTICAL ANALYSIS AND EXPECTED ENERGY NOT SERVED (ENS)........ 2-1
2.1 Overview Of Analysis Performed 2-1
2.2 Test Year For Analysis........ 2-1
2.3 Resources in the base year 2-1
2.4 Year 2013 loads........ 2-2
2.4.1 Load Stochastic Process And Volatility Parameters 2-3
2.5 Modeling Of Wind Volatility........ 2-4
2.6 Forced outage rates on supply resources 2-5
2.7 Rocky Mountain Reserve Group Support 2-6
2.7.1 Modeling the RMRG Support 2-8
2.8 Transmission LIFELINE - Non Psco Imports 2-9
2.9 Using A Generic Gas Turbine As A Proxy For Increasing Planning Reserves At The Margin........ 2-9
2.10 Determination Of Lolp 2-10
2.10.1 Calculating The Planning Reserve Margin........ 2-10
2.11 Analysis Starting Point Operating Reserve Margin........ 2-11
3 ANALYSIS RESULTS 1

List of Figures

Figure 1 PSCo Load Distribution - Confidence Intervals 2-4
Figure 2 PSCo Stochastic Wind Data for a Location 2-5
Figure 3 Expected Hours of Energy Not Served........ 1

List of Tables

Table 1 Public Service of Colorado expected 2013 Summer Resource Capacity 2-2
Table 2 PSCo Load Stochastic Parameters 2-3
Table 3 Public Service of Colorado Station Outage Rate........ 2-5
Table 4 Rocky Mountain Reserve Group Response Matrix 2-7
Table 5 RMRG Contingency Assistance for PSCo Units Greater than 200 MW........ 2-8
Table 6 2013 PSCo Expected Reserve Margin........ 2-11
Table 7 LOLP Results Summary 1

EXECUTIVE SUMMARY

At the request of Public Service Company of Colorado (PSCo), Ventyx performed a stochastic analysis of the relationship between electric generating capacity reserve margin (aka, planning reserves) and the ability of the PSCo system to reliably maintain service to load. The analysis focused on the year 2013 and accounts for PSCo existing and expected generation resources and the anticipated availability characteristics of those resources. The analysis takes into consideration PSCo's hourly customer electric demands and the volatility of those demands due to weather. The analysis incorporates a representation of the reliability support that PSCo can expect to receive from the Rocky Mountain Reserve Group (RMRG) under single contingency events of 200 MW or greater. The reserve margin study also incorporates PSCo's obligation to carry approximately 419 MW of operating reserves for year 2013 as part of its membership in the RMRG. Additionally, the analysis considers the reliability contribution of transmission lifeline capacity generally reserved for system emergencies.

Ventyx performed the analysis using the Market Analytic's Planning & Risk Module (PaR). The load, wind generation, and unit availability were treated stochastically. The level of energy not served from the PaR modeling work was used to determine the expected level of reliability for the system for different levels of capacity reserve margin. The analysis indicates that a Planning Reserve Margin of 16.3% would provide an expected probability that the PSCo system would be unable to serve firm load customers approximately 1-day-in-10-years. This level of reliability is considered acceptable and often used as a standard for reliable systems within the electric utility industry.

1 RECENTLY ACCEPTED APPROACHES

1.1 PREVIOUS LOLP STUDIES

In 2003 Resource Plan Filings with the California Public Utility Commission, three different Investor Owned Utilities (PG&E, SCE, and SDG&E) all performed portfolio stochastic analysis to assess appropriate levels of planning reserves. In these analyses, the utilities selected an upcoming applicable year and tested the ability of their power supply systems to meet customer loads in that year under different utility supply portfolios that gave different levels of planning reserve. The methodology involved performing hourly economic dispatch of resources against loads for each hour of the year. Because of the uncertainties of unit forced outage and load level variations caused by weather, multiple iterations of the year were performed. Under each iteration, Monte Carlo draws were made daily that adjusted load levels either upward or downward. Further, Monte Carlo draws were made to reflect possibilities of unit forced outage. The California PUC accepted the methodology at that time, but more recently some utilities have indicated that higher reserve margins should be required because of the possibility of non-performance of PPAs, etc. The California PUC has therefore opened another proceeding to discuss possible changes to reflect these matters.

It is typical to use a 1-day-in-10-year Loss of Load Probability (LOLP) when determining the needed Planning Reserve Margin. This level of LOLP is equivalent to failing to serve the energy requirements of the system for 2.4 hours each year or 24 hours during a 10-year period.

2 PSCO FOCUSED ANALYSIS USING PORTFOLIO STATISTICAL ANALYSIS AND EXPECTED ENERGY NOT SERVED (ENS)

2.1 OVERVIEW OF ANALYSIS PERFORMED

Ventyx has performed a stochastic analysis of Loss of Load Probability on the PSCo system in a manner similar to the analysis performed by California investor owned utilities in the year 2003 and accepted by the California PUC as well as by PSCo in 2004 (filed with PSCo's 2003 LCP). In particular, Ventyx focused on PSCo existing and expected generation resources and loads in year 2013. The analysis also reflects a PSCo operating reserve of 419 MW, which represents PSCo's expected operating reserve obligation under the RMRG after the Comanche 3 unit becomes operational.

Ventyx utilized its regional Market Analytics software module, Planning & Risk, to perform this stochastic reserve margin analysis of the PSCo system. The key factors represented stochastically in this analysis are:

- Unit forced outages and maintenance,
- Weather related load volatility,
- Wind generation, and
- Transmission lifeline capacity.

Ventyx stochastically simulated the hourly dispatch of the PSCo system for year 2013, where Monte Carlo draws were performed for 100 iterations in order to capture the impact of uncertainties in these key factors.

2.2 TEST YEAR FOR ANALYSIS

Consistent with PSCo's 2007 CRP, PSCo provided the portfolio of resources, wind pattern, unit maintenance and forced outages and the hourly load forecast for the year 2013 for the purpose of this study.

2.3 RESOURCES IN THE BASE YEAR

PSCo generation resources in the year 2013 reflected in the analyses are listed in Table 1 below. The Comanche 3 facility was modeled at it full expected capacity of 784 MW and the full load requirements of IREA and Holy Cross were included in the modeling of customer demand (i.e., as opposed to modeling only PSCo's share of Comanche 3 and removing the portion of IREA and Holy Cross's load that will be served by their ownership share of Comanche 3).

Table 1
Public Service of Colorado expected 2013 Summer Resource Capacity

Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW
Alamosa 1	12.82	Comanche 1	325	Hayden 1	139	Sunshine Hydro	0.7
Alamosa 2	13.5	Comanche 2	335	Hayden 2	99	Tacoma Hydro	8.5
AMES HYDRO	3.75	Comanche 3	784	HillCrest Hydro	2.3	Thermo RS1 31CC	152
Arapahoe CC	479	Craig 1	41.6	Kohler Hydro	0.15	Tower04WT	42.12
Basin1 LRS2	50	Craig 2	41.6	LakeGeorge Hydro	0.23	Tower41WT	98.75
Basin1 LRS3	50	CT_129_A	258.6	Manchief CT	260.7	Tower49WT	41.37
Basin2 LRS2	37.5	Dillon Hydro	1.9	Maxwell Hydro	0.15	Tri2 Craig1	9.93
Basin2 LRS3	37.5	Foothills Hydro	2.3	On_Site Solar	11.89	Tri2 Craig2	9.93
Betasso Hydro	8.57	Fruita	15	Orodell Hydro	0.22	Tri2 Craig3	38.29
BioGas 75th ST	0.5	FSV CC 1x1	226	Ouray Hydro	0.5	Tri2 LRS2	19.18
BioMass	4	FSV CC 2x1	252	Palisade Hydro	1.7	Tri2 LRS3	19.18
Brush 13	75	FSV CC 3x1	230	Pawnee 1	505	Tri3 Craig1	2.49
Brush 4D CC2	133	FSV CT	270	PlainsEnd2 CC	224	Tri3 Craig2	2.49
Cabin Crk Gen1	105	Ft Lupton 1	44.7	Redlands Hydro	1.4	Tri3 Craig3	9.84
Cabin Crk Gen2	105	Ft Lupton 2	44.7	Roberts T Hydro	6.1	Tri3 LRS2	4.8
Central Solar	11.12	Georgetown Hydro	1.2	Rocky Mtn CC21	601	Tri3 LRS3	4.8
Cherokee 1	107	Gross Res Hydro	8.1	Salida Hydro	1.4	TST Brighton	132
Cherokee 2	106	Spindle_CT	269	Shoshone Hydro	15	TST Limon	66
Cherokee 3	152	SPS TieLine	101	Stagecoach Hydro	0.8	UNC Greeley EXT	68.86
Cherokee 4	352	Valmont 6	43	Strontia Hydro	1.2	Valmont 5	186
Cherokee Diesel	5.5	WM Landfill Gas	3.2	SunEdison Solar	2.87		

(Wind contributed 12.5% of nameplate, Solar at 58% and Cabin Creek 210 MW)

In the analysis, the PSCo wind generation resources were lumped together into three distinct geographic zones: Colorado/Wyoming border zone near the existing Ponnequin facility, northeast zone near Peetz Table, and the southern zone near the Colorado Green facility. The three wind zones provide geographic diversity for wind generation based on the modeling techniques applied for stochastic wind generation discussed later in this report. For the calculation of planning reserves, the wind capacity is counted at 12.5% of their nameplate capacity.

2.4 YEAR 2013 LOADS

The analysis applied Monte Carlo draws on load to reflect the likelihood that loads will be higher or lower as a result of weather, than what is being forecast for year 2013. To perform this type of Monte Carlo analysis, an hourly profile of PSCo loads for the year 2013 was developed. The forecasted peak demand for year 2013 is 7,310 MW, which is comprised of the September 2007 peak demand of 7,094 MW and an additional 216 MW of coincident peak demand from IREA and Holy Cross. As seen above Comanche 3 was modeled at its full capacity to accommodate serving the full load requirements of IREA and Holy Cross. While IREA and Holy Cross will have a 250 MW share of the Comanche 3 unit, it is expected that only 216 MW of load would be coincidental with the PSCo peak demand and only that coincident amount was considered for the total 2013 PSCo peak demand. As described above, PSCo's portion of Comanche 3 and IREA's and Holy Cross's portion of Comanche 3, totaling to 784 MW of capacity for Comanche 3, was also included since IREA and Holy Cross wholesale load requirements were included as part of the PSCo load.

2.4.1 Load Stochastic Process and Volatility Parameters

The stochastic model used to perform the stochastic draws on load is a two-factor model in which one factor represents short-term or temporary deviations and the other factor represents long-term or cumulative deviations. Long-term effects include trends such as change in annual peak demand growth and other forces whose effects are of long duration, which follow a random walk. In the short term, shocks may drive variables away from their long-term equilibrium level, but adjustment processes tend to pull them back to their equilibrium or expected level in the short term. In other words, short-term shocks such as changes to load due to weather are mean reverting. The rate at which the random variable tends to revert to the expected value is an input to the process. This is referred to as the mean reversion rate. The two-factor model combines the short-term mean reverting process with the long-term random walk process.

The volatility estimates for PSCo load in this study were developed from historical hourly load data from 1996-2007. The estimated short-term stochastic parameters for PSCo load, used as inputs into the Planning & Risk models stochastic analysis, are presented in Table 2 below. Long-term stochastic parameters were not necessary since the study period is a single year. As a result of these stochastic parameter inputs, a distribution of load volatility is created.

Table 2
PSCo Load Stochastic Parameters

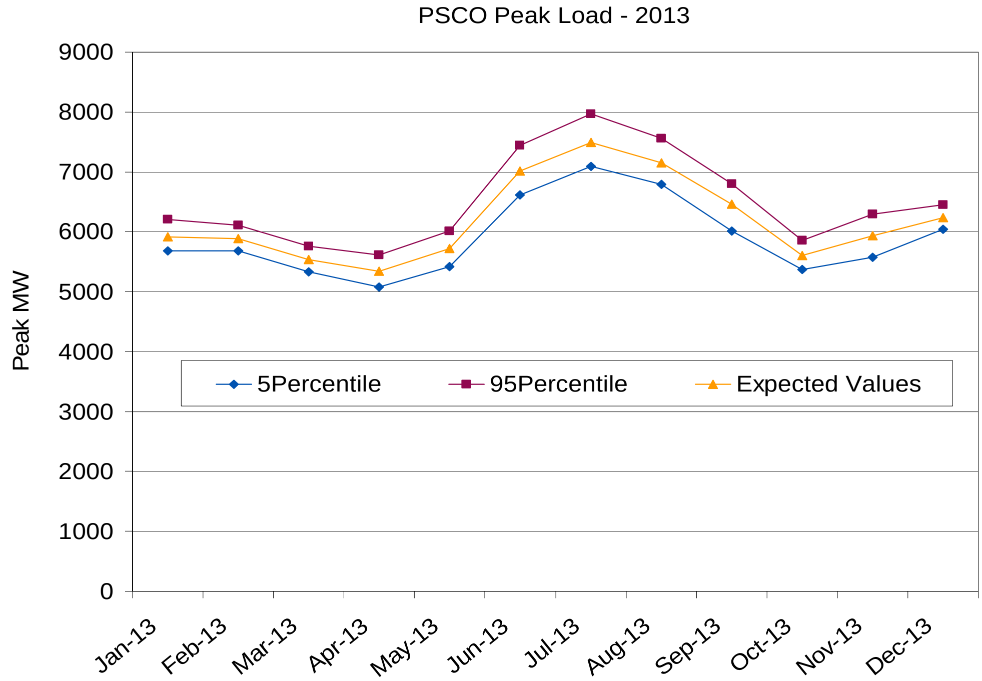
Season[1]	Load PSCo	
2013	**Alpha**	**Sigma**
Winter	0.275	0.014
Spring	0.266	0.015
Summer	0.195	0.016
Fall	0.276	0.019

Source: Ventyx.

Figure 1 illustrates the 5th, Average, and 95th confidence intervals of load distribution for the year 2013.

[1] Season definition: Winter = December-February; Spring = March-May; Summer = June-August; Fall = September-November. Sigma is the volatility parameter and alpha is the mean reversion parameter.

Figure 1
PSCo Load Distribution - Confidence Intervals



2.5 Modeling Of Wind Volatility

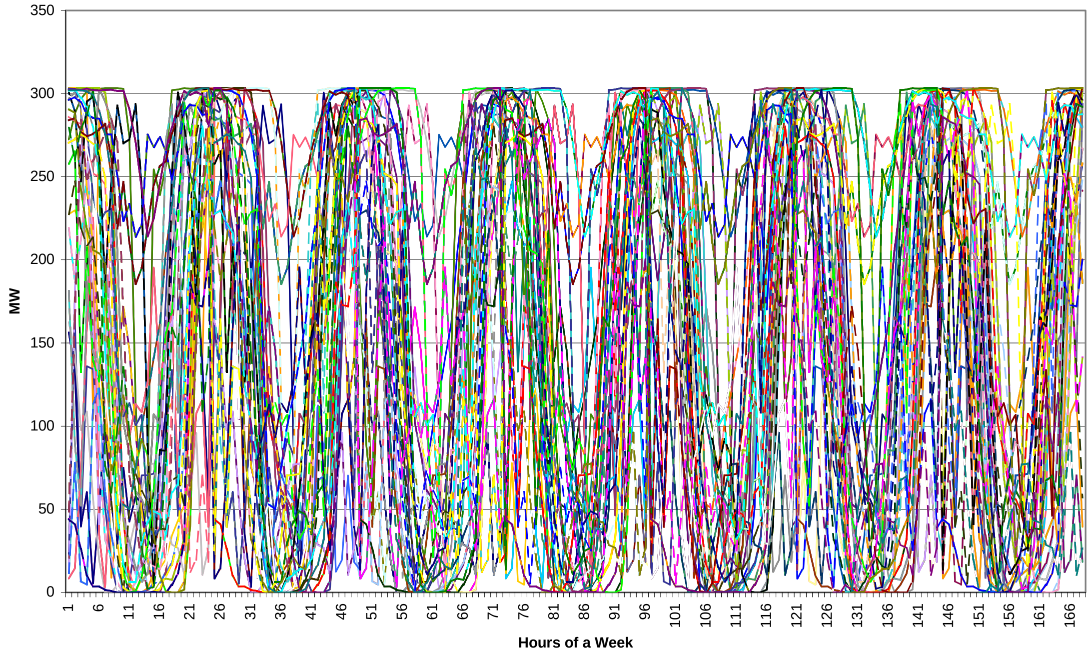
Using historical hourly wind generation from existing PSCo wind facilities, Ventyx created 100 different hourly wind patterns that reflect the unpredictable nature of the PSCo wind resource. PSCo provided wind shapes for three wind zones: Colorado/Wyoming border, northeast Colorado, and southeast Colorado. These three wind shapes were utilized to model wind variability within the analysis.

The stochastic wind data was developed external to the Planning & Risk model, and introduced during model simulation. The following method was used in creating the stochastic wind data:

1. Hourly historical wind shapes for the three locations were developed and each fluctuates differently due to their location and associated wind pattern.
2. To capture the randomness of wind generation, Ventyx used its Hourly Historical Simulation Tool, which randomizes daily-hourly profiles within a month. This process was repeated for each aggregated wind location. For example, in creating the 24-hour by 100 iterations of data for January 1 for a location, the random number generator picked which hourly day profile in January to choose. Since January has 31 days, the random number generator chose any one of the 31 days of January for each of the 100 iterations for January 1. So for January 1, iteration 1 may use the hourly profile of day 30 of January, iteration 2 may use the hourly profile of day 2 of January and so on. This process was continued until all days of the year for each of the 100 iterations was developed. Figure 2 shows the stochastic wind data for a representative week in July.

3. The randomized wind data was then fed into Planning & Risk through XML integration and included in the model simulation.

Figure 2
PSCo Stochastic Wind Data for a Location



2.6 FORCED OUTAGE RATES ON SUPPLY RESOURCES

The expected level of forced outages for PSCo units (both owned and purchased) was estimated from actual historical availability data. The model assumed the following expected levels of forced outage rates on the following supplies.

Table 3
Public Service of Colorado Station Outage Rate

Station	EFOR	Station	EFOR	Station	EFOR
Alamosa 1	0.10%	Dillon Hydro	5.00%	Rocky Mtn CC21	5.00%
Alamosa 2	0.10%	Foothills Hydro	5.00%	Salida Hydro	3.00%
AMES HYDRO	6.00%	Fruita	7.30%	Shoshone Hydro	1.00%
ArapCC	1.60%	FSV CC 1x1	2.50%	Spindle_CT	3.00%
Basin1 LRS2	3.00%	FSV CC 2x1	2.50%	SPS TieLine	0.50%
Basin1 LRS3	3.00%	FSV CC 3x1	2.50%	Stagecoach Hydro	5.00%
Basin2 LRS2	3.00%	FSV CT	3.00%	Strontia Hydro	5.00%
Basin2 LRS3	3.00%	Ft Lupton 1	9.50%	Sunshine Hydro	5.00%
Betasso Hydro	5.00%	Ft Lupton 2	17.20%	Tacoma Hydro	5.00%
BioGas 75th ST	3.00%	Gen GT	3.60%	Thermo RS1 31CC	3.00%
BioMass	10.00%	Georgetown Hydro	2.00%	Tri2 Craig1	4.80%
Brush 13	2.00%	Gross Res Hydro	5.00%	Tri2 Craig2	4.80%
Brush 4D CC2	2.00%	Hayden 1	6.60%	Tri2 Craig3	3.00%
Cabin Crk Gen1	6.00%	Hayden 2	3.50%	Tri2 LRS2	3.00%
Cabin Crk Gen2	6.00%	HillCrest Hydro	5.00%	Tri2 LRS3	3.00%

Station	EFOR	Station	EFOR	Station	EFOR
Cherokee 1	9.50%	Kohler Hydro	5.00%	Tri3 Craig1	4.80%
Cherokee 2	12.40%	LakeGeorge Hydro	5.00%	Tri3 Craig2	4.80%
Cherokee 3	10.10%	Manchief CT	5.00%	Tri3 Craig3	3.00%
Cherokee 4	8.90%	Maxwell Hydro	5.00%	Tri3 LRS2	3.00%
Cherokee Diesel	9.40%	Orodell Hydro	5.00%	Tri3 LRS3	3.00%
Comanche 1	13.30%	Ouray Hydro	5.00%	TST Brighton	5.00%
Comanche 2	4.40%	Palisade Hydro	3.00%	TST Limon	5.00%
Comanche 3	6.30%	Pawnee 1	8.40%	UNC Greeley EXT	5.00%
Craig 1	4.80%	PlainsEnd2 CC	1.50%	Valmont 5	4.20%
Craig 2	4.80%	Redlands Hydro	5.00%	Valmont 6	9.90%
CT_129_A	1.00%	Roberts T Hydro	5.00%	WM Landfill Gas	5.00%

Table continued on next page.

100 iterations of the model were run for year 2013. Monte Carlo draws determined if a resource was on forced outage or not. In this case, the model was set up so that if a unit was forced out in a week as a result of a Monte Carlo draw, the unit is assumed out for the entire week. If a unit has an expected forced outage rate of, for example, 5%, then the average outage hours for that unit over the 100 iterations is 5% of the time. However, any individual iteration could have an outage rate for that iteration for the year of greater or less than 5%. The Monte Carlo draws are designed such that over a large number of random draws of unit outage, statistically one would expect the average hours of unit being forced out during a year to be 5%. However, statistically it is possible that over 100 iterations the average outage rate is slightly above or below the 5% number.

2.7 ROCKY MOUNTAIN RESERVE GROUP SUPPORT

One key aspect of the analysis was to reflect the reliability support that PSCo receives from neighboring electric systems. PSCo is a member of the Rocky Mountain Reserve Group (RMRG) and thus has the right to call for support from the group under certain qualifying contingency events. In accordance with the RMRG rules, PSCo must notify the RMRG group and may request group support for outages of PSCo plants of 200 MW and larger. For outage events of less than 200 MW, PSCo is not required to notify the RMRG group and generally covers the event using its own reserves. For this analysis Ventyx reflected RMRG support to PSCo for outages of plants of 200 MW or larger. Table 4 shows the RMRG Response Matrix and the contingency assistance provided to PSCo by the RMRG Members. The RMRG support contained in Table 4 is based on the individual members’ forecasts of load for year 2013.

The RMRG Response Matrix details the amount of contingency assistance provided to PSCo at different megawatt levels of outages. The contingency assistance by RMRG rules is available only for the hour of the event and the following hour for a total of 2 hours per outage event per month. If multiple units are out at the same time, the contingency assistance is provided to the unit with largest capacity.

Based on the RMRG response matrix, Ventyx calculated the RMRG contingency assistance provided by the participating surrounding utilities to PSCo for the PSCo units above 200 MW. Table 5 summarizes the RMRG assistance available for each unit.

Table 4
Rocky Mountain Reserve Group Response Matrix

		B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14
RMRG responsibilty					**784**	**759**	**734**	**709**	**684**	**659**	**634**	**609**	**584**	**559**	**534**
EMERGENCY ASST * -> FOR PSCO					391	378	367	354	341	329	317	305	294	283	269
	RRR	**Member response requirement**													
MEAN	0.011756				10	9	9	9	8	8	8	7	7	7	7
WMPA	0.002232				2	2	2	2	2	2	1	1	1	1	1
TRIS	0.108974				88	85	83	80	77	75	72	69	66	64	61
BHPL	0.035493				29	28	27	26	25	24	23	23	22	21	20
CSU	0.074984				61	59	57	55	53	51	49	48	46	44	42
FRPC	0.007988				6	6	6	6	6	5	5	5	5	5	4
WACM	0.062762				51	49	48	46	44	43	41	40	38	37	35
					0	0	0	0	0	0	0	0	0	0	0
WALC	0.034187				28	27	26	25	24	23	23	22	21	20	19
					0	0	0	0	0	0	0	0	0	0	0
PRPA	0.060373				49	47	46	44	43	41	40	38	37	35	34
WPEC	0.014808				12	12	11	11	10	10	10	9	9	9	8
PSCO	0.517850				419	406	393	380	367	354	341	328	315	302	289
BEPC	0.068591				55	54	52	50	49	47	45	43	42	40	38
GROUP	1.0000				810	784	760	734	708	683	658	633	609	585	558
WACM AGC offsets					-297	-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
After 15 minutes, change to:					-247	-238	-232	-224	-215	-208	-199	-193	-185	-179	-170
PSCO AGC offsets					-225	-215	-208	-199	-189	-181	-172	-165	-156	-149	-139
After 15 minutes, change to:					-275	-265	-258	-249	-239	-231	-222	-215	-206	-199	-189
WACM AGC offsets						-318	-312	-304	-295	-288	-279	-273	-265	-259	-250
After 10 minutes, change to:						-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
PSCO AGC offsets						-245	-238	-229	-219	-211	-202	-195	-186	-179	-169
After 10 minutes, change to:						-315	-308	-299	-289	-281	-272	-265	-256	-249	-239
WALC AGC offsets					-28	-27	-26	-25	-24	-23	-23	-22	-21	-20	-19

		B18	B19	B20	B21	B22	B23	B24	B25	B26	B27	B28	B29	B30	B31
RMRG responsibilty		**434**	**409**	**384**	**359**	**334**	**309**	**284**	**259**	**234**	**209**	**184**	**159**	**134**	**109**
EMERGENCY ASST * -> FOR		218	206	194	182	171	161	147	135	123	111	89	76	65	53
	RRR	**Member response requirement**													
MEAN	0.011756	5	5	5	4	4	4	4	3	3	3	2	2	2	1
WMPA	0.002232	1	1	1	1	1	1	1	1	1	1	0	0	0	0
TRIS	0.108974	49	47	44	41	39	36	33	30	28	25	20	17	15	12
BHPL	0.035493	16	15	14	13	13	12	11	10	9	8	7	6	5	4
CSU	0.074984	34	32	30	28	27	25	23	21	19	17	14	12	10	8
FRPC	0.007988	4	3	3	3	3	3	2	2	2	2	1	1	1	1
WACM	0.062762	28	27	25	24	22	21	19	18	16	14	12	10	8	7
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WALC	0.034187	16	15	14	13	12	11	10	10	9	8	6	5	5	4
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRPA	0.060373	27	26	24	23	21	20	18	17	15	14	11	10	8	7
WPEC	0.014808	7	6	6	6	5	5	5	4	4	3	3	2	2	2
PSCO	0.517850	235	222	209	196	195	178	157	144	132	119	95	82	69	56
BEPC	0.068591	31	29	28	26	24	23	21	19	17	16	13	11	9	7
GROUP	1.0000	453	428	403	378	366	339	304	279	255	230	184	158	134	109
WACM AGC offsets		-137	-130	-122	-114	-109	-102	-93	-85	-78	-70	-56	-48	-41	-33
PSCO AGC offsets		-153	-145	-136	-127	-121	-113	-103	-95	-87	-78	-62	-53	-46	-37
WALC AGC offsets		-16	-15	-14	-13	-12	-11	-10	-10	-9	-8	-6	-5	-5	-4

Table 5
RMRG Contingency Assistance for PSCo Units Greater than 200 MW

PSCo Units > 200 MW	Capacity MW	RMRG Contingency Assistance MW (shadow station)
Comanche3	784	391
RockyMontCC2	601	301
Pawnee1	505	253
Cherokee4	352	179
Comanche2	335	171
Comanche1	325	167
RockyMontCC1	259	135
FSV2	252	132
FSV3	230	121
FSV1	226	119
Plainsend2	224	118

2.7.1 Modeling the RMRG Support

For each PSCo units ≥ 200 MW, Table 5, Ventyx modeled a corresponding RMRG support unit called a shadow station. The size of each RMRG shadow station was determined by the actual plant size and the corresponding assistance available as reported in Table 5.

To reflect the fact that each RMRG shadow station may only be called upon during its parent station's outage event, PaR Rules of Existence (Rule Groups) modeling was utilized. Rule Group modeling included assigning each of the RMRG Shadow Units to a Rule that tells PaR the RMRG unit can exist to help serve load only if the parent station is on outage.

Since only the largest station during overlapping outages receives the RMRG contingency assistance, a Rule Group hierarchy of RMRG shadow stations was implemented to ensure only the largest contingency was called upon.

Under the terms of the RMRG, pool members are required to provide contingency assistance to PSCo, if requested, for up to two hours for each qualifying contingency event. To reflect this real-life constraint, Ventyx modeled the RMRG Shadow Units as "limited energy" stations. For each of the RMRG shadow stations Ventyx input a weekly energy limit equal to 2 times the MW rating of the shadow unit (i.e., 2-hours of full load operation). Once the RMRG unit is been called upon in the modeling, it will not be available again for contingency assistance until the next outage. As a limited energy station, PaR will attempt to choose the best hours to run limited energy RMRG shadow station based on dispatch economics. For instance, if a 300 MW PSCo plant is tripped off-line at 12 am and is forced out for the week, PaR will not immediately activate the RMRG shadow station but rather will attempt to save the limited energy from the shadow unit for peak hours or for hours where energy not served exists. In other words, because the RMRG shadow stations are modeled with such a high cost of operating (i.e. just below the cost of ENS), the units will only be run when there would otherwise by ENS, and the units will only run for two hours following each outage. This methodology allowed the RMRG unit to be available to contribute generation assistance to PSCo after the station goes on forced outage and only during an ENS event. This limited energy methodology meets the two hour limitation of the RMRG but has a shortcoming in that it provides the two hours of generation support during the highest marginal energy cost hours. Given that high marginal energy costs typically occur during hours when system load is at it's highest, this means that the reliability contribution provided by the two hours of RMRG support is likely somewhat overstated in the PaR modeling To understand the potential magnitude by which the RMRG support might be overstated, a sensitivity was performed in which the RMRG units were excluded from the analysis. The results of this sensitivity showed the generation support provided by the RMRG acts to reduce the Planning Reserve Margin from approximately 17.8% to 16.3% or 1.5%. From this we can see that the limited energy methodology used to represent the RMRG support is likely to be a small factor in the overall reserve margin level required for the system (i.e., it is probably a small part of the 1.5% total impact of the RMRG support).

2.8 TRANSMISSION LIFELINE - NON PSCO IMPORTS

PSCo is interconnected with the Western Interconnect (WECC reliability council area) and expects that in an emergency situation it can utilize these interconnections to import additional power supplies into its system. The exact quantity of additional power supply is dependent on the availability of unused transmission capacity. PSCo estimates that it will have access to roughly 200 MW plus or minus 50 MW of unused transmission capacity during peak load periods. The reliability benefit of this transmission import capability was included in this analysis through the representation of an additional 200 MW of imports with Monte Carlo draws around plus or minus 50 MW.

Model runs were also performed without this 200 MW of import capability. These runs allowed PSCo to isolate the contribution that this 200 MW of import capability provides to the system through a reduction in the required planning reserve. As reported in Section 3 below, from this sensitivity run it was found that the existence the 200 MW Transmission LIFELINE allows reducing the Planning Reserve Margin from approximately 19.2% to 16.3% while maintaining the LOLP at 1-day-in-10-years.

2.9 USING A GENERIC GAS TURBINE AS A PROXY FOR INCREASING PLANNING RESERVES AT THE MARGIN

In order to perform this study, it was necessary to run the stochastic analysis at several different levels of planning reserve. For example if additional resources need to be added to the model in order to move the Planning Reserve Margin level from 10 percent to 12 percent and so on. The resource used to incrementally increase Planning Reserve Margin needs to be (a) highly reliable as a supply source and (b) relatively low cost to acquire since it will likely used at a very low capacity factor. While there are numerous supply technologies available for increasing supply, the reasonable supply unit to use for this purpose is a simple cycle GT.

2.10 Determination Of LOLP

The LOLP analysis methodology Ventyx applied in this study is a marked improvement over traditional methods for determining LOLP. Where, in the past, company's often computed an annual LOLP index as the summation of daily probabilities (often termed the "daily risks") over the entire year being studied, Ventyx computes LOLP based on a stochastic production cost model simulation where all relevant factors and uncertainties are included in the simulation. The analysis predicts both the probability of not serving a specific amount of load, and in addition provides insights into the dimension and amount of energy that would not be served—referred to as unserved energy or expected un-served energy (EUE). The Ventyx LOLP methodology calculates LOLP for each hour where the LOLP is the probability that available generation capacity in a given hour is less than the system load. The primary measurement used in accessing resource adequacy in this analysis is Loss of Load Hours (LOLH), which is typically used in the energy industry. Generally, if a utility's loss of load hours is not greater than or equals 1-day-in-10-years (or 2.4 hours in 1 year), it is seen as a reliable system. Unserved Energy (aka Energy Not Served…ENS) results in the model if on a particular hour the model is unable to find sufficient supply to meet the load plus the required operating reserve margin. If that happens on an hour, then this is counted as one LOLH. For LOLH counting purposes, there is a single LOLH if on an hour the load is not met. The counting is the same if the unserved load is 1 MW or if it is, for example, 200 MW. Given multiple iterations of the study year (with different Monte Carlo draws on loads and unit forced outages, etc), the metric used for this LOLP study is the average number of hours of LOLH over the 100 iterations. So if there are 99 iterations with zero LOLH and one iteration with 100 LOLH, then the expected (average) LOLH for the 100 iterations for this year is 1 LOLH. As indicated above, and average LOLH of 2.4 hours in the 1 year analysis is considered to be 24 LOLH hours in 10 years or 1 day in ten years.

For purposes of this study, Ventyx analysis looks for that Planning Reserve Margin level that will provide a 1-day-in-10-year LOLP.

2.10.1 Calculating The Planning Reserve Margin

A number of questions arise when the objective is calculating an accurate Planning Reserve Margin for a system. The common method of calculating Planning Reserve Margin is represented by the following equation:

$$\frac{[(\text{Resources} - \text{Peak Load}]}{(\text{Peak Load})}$$

Peak Load: Peak load is generally the needle peak load of the control area. In this study, where PSCo is modeled as a single zone, the peak hour for the entire system occurs in July.

Resources: The peak capacities of thermal and hydro stations that are in PSCo are included in the calculation except for Cabin Creek Pumped Storage which is counted at 210 MW. Wind capacity is counted at 12.5% of nameplate rating. Interruptible loads and demand side management programs are included as resources but for load and resource balance purposes, they are subtracted from the peak load.

Table 6
2013 PSCo Expected Reserve Margin

2013 L&R	MW	LOLH
Peak Load 50th percentile	7310	
interruptible loads	-401	
Firm Peak Obligation	**6909**	
Net Dependable Capacity from Table I above not including CT 129A and not including FSV CT	7410	
NET Planning Reserve Margin in 2013 without CT 129A	7.3%	
Needed Operating Reserves	5.7%	
Effective Starting Point Planning Reserve Margin	13.0%	69.8
Recommended Reserve Margin -- 1 day in 10 years	16.3%	24.0

The conclusion of this LOLH is that a 16.3% PRM is needed to provide a 1 day in 10 year LOLP. This level is determined by performing analysis that does not interrupt load until the operating reserve drops below zero.

Table 7 in section 2.11 below reflects the loads and resources in the year 2013 for PSCo currently planned, but without the assumed generic CT 129A and without the new FSV CT units. This was the starting point for the LOLP analysis in this report. The generic CT 129A and FSV CT units were removed to assure that the starting analysis results in a LOLP that was greater than one-day-in-10 years. That staring point as indicated above resulted in a LOLH of 69.8 hours. A one-day-in-10 years would have an LOLH of 24.0 hours. To achieve that, Ventyx then started adding gas turbines until it found the level of Planning Reserve Margin that resulted in a LOLP of one-day-in-10 years.

2.11 Analysis Starting Point Operating Reserve Margin

For year 2013, PSCo estimates it will be required to maintain approximately 419 MW of operating reserves as its portion of the RMRG reserve obligation. If operating reserves fall below 419 MW, PSCo would likely curtail load if it cannot arrange for additional power supplies. The PaR model used to perform this LOLP analysis, however, is not capable of curtailing load (i.e., registering unserved energy) and enforcing an operating reserve requirement. The model will only register unserved energy events in hours where the sum of all generation resources operating at their full capability is less than the load on the system and there is energy not served.

To account for this PaR model limitation, it is necessary to add “operating reserves” to the “planning reserve” level included in the model run that produces a 1-day-in-10-year level of reliability. Based on the 2013 peak load forecast of 7,310 MW, the 419 MW operating reserve requirement represents 5.73% (419 MW/7,310 MW = 0.0573) that must be added to the model results. As summarized in Section 3 below, the starting point for the PSCo Planning Reserve Margin analysis is a 13.0% starting reserve level that resulted in an LOLH of 69.8, which is 2.9-days-in-10-years (69.8 / 24 hours = 2.9 days) as shown in the table above. To determine an expected LOLP of 1-day-in-10-year LOLP, Ventyx added 210 MW of generic CT generation and found a LOLP of slightly higher than 1-day-in-10-years, or 26.9 hours. This level equates to a Planning Reserve Margin of 16%. Ventyx then added another 60 MW of CT capacity which is a Planning Reserve Margin of 17% and found a LOLP of less than 1-day-in-10-years, or 17.7 hours.

Interpolating between these two LOLP values determines a Planning Reserve Margin of 16.3% equates to a target 1-day-in-10-years LOLH of 24.0 hours. This interpolation to a one-day-in-10-years indicates PSCo’s Planning Reserve Margin should be 16.3%.

3 ANALYSIS RESULTS

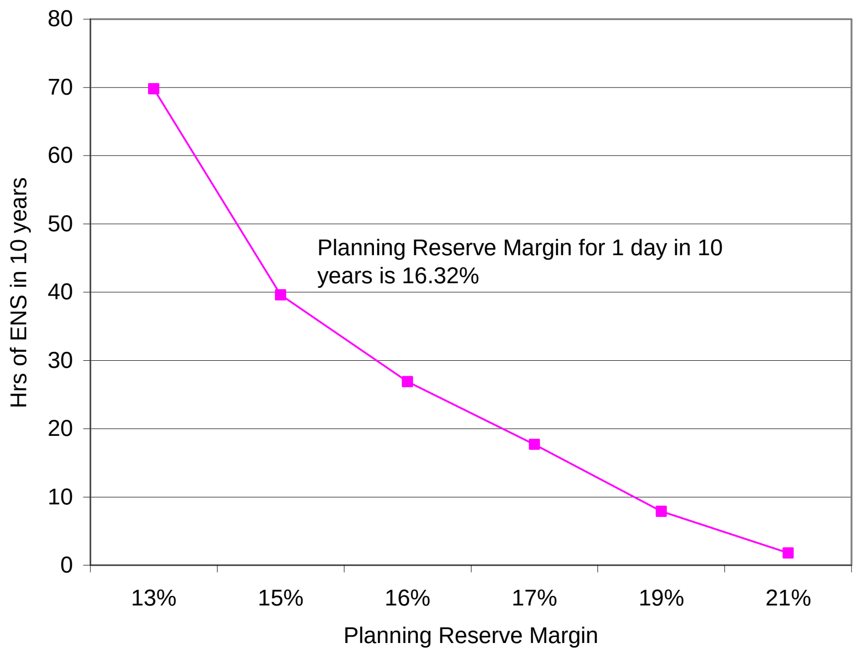
The goal of this LOLP analysis was to determine the Planning Reserve Margin for the PSCo system that would achieve an LOLP of 1 day in 10 years or, an Energy Not Served (LOLH) of 24 hours in 10 years (or 2.4 hours in one year). Table 7 contains a summary of the relationship between reserve margin and LOLH, both with and without 200 MW of transmission lifelines (i.e., transmission capacity held for use in accessing additional power supplies on short notice). All reserve margin values in Table 7 include the effects of operating reserve requirements.

Table 7
LOLP Results Summary

Reserve Margin (no transmission lifelines)	Reserve Margin (with 200 MW transmission lifeline)	LOLH (hrs in 10 Years)
16%	13%	69.8
18%	15%	39.6
19%	16%	26.9
20%	17%	17.7
22%	19%	7.9
24%	21%	1.8

Figure 3 below is an illustration of the LOLH / Energy Not Served values provided in Table 7 as a function of reserve margin level. By interpolation a reserve margin of 16.3% (with 200 MW transmission lifeline) yields 1-day in 10 years level of LOLH

Figure 3
Expected Hours of Energy Not Served



Appendix E

A COMPARISON OF ACTUAL HISTORICAL OPERATING RESULTS WITH ADJUSTED STRATEGIST MODELING

In reviewing a draft of Staff's report, Public Service Company of Colorado ("Public Service" and "Company") believed additional explanation would be beneficial to the Commission. When investigating how well a model such as Strategist predicts the dispatch of the Company's generation fleet, there are two primary areas of focus, namely 1) the impact of various key variables on the dispatch of the system, and 2) how well the model utilizes these inputs to reflect actual operations. While the input factors for the Strategist model are of great debate in the resource planning process, the ultimate values that are agreed upon and utilized as the forecast variables in the model form the basis for comparing modeled results to actual results. Key variables that have the potential to impact the comparison of the modeled results to the actual results include weather, load, gas prices, market energy prices, plant availability, integration of wind and solar resources, and the cycling of coal plants in an effort to minimize wind curtailment. All of these key variables have the potential to significantly impact the actual dispatch of the Company's generation fleet. Since the assumptions for these key variables are agreed upon in the resource planning process for use over a long-term basis and we have only a very limited amount of actual data for these variables relative to the forecast, this portion of the review will focus on the second major issue -- i.e., how accurately does the model incorporate these key variables in predicting the dispatch of the Company's generation portfolio.

The most likely step to take to perform this analysis is to compare the predicted level of generation at each plant or groups of plants to the actual level of generation at those same plants for a given period of time using the actual value for these key variables. While this type of post period analysis would seem straight forward, a truly meaningful comparison would require the Company to rebuild the entire model using actual data for key variables. This assignment would take a great deal of time and effort. In lieu of such a detailed post analysis, the Company performed an analysis that began with comparing the unadjusted model results to actual generation data. Then, in an effort to focus the analysis on the effectiveness of the Strategist model as opposed to the accuracy of the long-term forecast of key variables relative to near-term actual conditions, the Company trued up the modeled results to reflect the impacts of the utilizing actual values for the key assumptions/variables. This true-up effort allowed the Company to make a more meaningful comparison of the modeled data, adjusted to reflect actual conditions, to the actual level of generation.

In performing this analysis, the Company focused its review on three primary areas: 1) a grouping of key variables associated with actual load (incorporating actual weather and actual demand), economy purchases, and economy sales; 2) coal plant operations; and 3) the impact of wind integration and coal cycling. The Company's abbreviated review of the Strategist modeling included data for 2011 and 2012.

Comparison of Unadjusted 2011 Strategist to 2011 Actual Generation

This section of the report compares Staff's analysis of the unadjusted 2011 Strategist output that was derived using Public Service's 2011 ERP data compared to 2011 actual operating data. Staff selected the 2011 ERP data because it was the most recent model run. During the discovery phase of this docket, Public Service notified the Staff that the 2011 ERP Strategist model was designed for use beginning in 2012 and that the data in 2011 was not fully developed and is questionable. Since the 2011 ERP was filed in late 2011, a full year of operation of 2011 was not fully developed and was never used for the ERP. To compensate for the lack of complete data for 2011, Public Service adjusted the 2011 Strategist modeling data to reflect some of the most significant updates that would need to be included to make the 2011 modeling data more meaningful. These 2011 model modifications included making the 600 MW Rocky Mountain Energy Center combined cycle available for operation in the first four months of the 2011 (the current existing model did not have RMEC available during these four months) and correcting the market prices associated with economy energy purchases (the existing model included a market price for economy energy that was much lower than it should have been for 2011, while the model had correct market energy price for the years of 2012 and beyond). The adjustments necessary to make the 2011 model data more accurate and complete are included in the Adjusted 2011 Strategist Comparison Section and include a reduction in short-term energy purchases and an increased operation of Public Service's natural gas fired generation.

Staff's report shows a graph that depicts the actual 2011 aggregated hourly generation in comparison to the unadjusted 2011 Strategist model results from the various technologies on the Public Service system. Staff then discusses the performance of coal when compared to the unadjusted Strategist results, and the relationship to the operations of combined cycle ("CC") and combustion turbine ("CT") generation. Staff's report suggests coal generation was 2,302,473 MWh less than projected in unadjusted Strategist data. When the reviewing the same data, the Company made the necessary adjustments to Strategist and analyzed the comparison of the Strategist model results for 2011 adjusted for actual operating conditions. Once the data was adjusted to make a more apples-to-apples comparison, the difference in predicted coal to actual coal generation dropped to 456,000 MWh. In the unadjusted case coal production is 12 percent lower than expected, while in the adjusted case the actual coal production is only 2.6% less than what would have been predicted by Strategist.

Adjusted 2011 Strategist Data in Comparison to Actual Generation

In an effort to provide a more apples-to-apples comparison of the effectiveness of Strategist to accurately reflect the dispatch of the Public Service system, the Company performed a simplified analysis of its 2011 Strategist data adjusted for actual data on the key variables that drive the modeling. In addition, Public Service corrected as many of the deficiencies in the 2011 Strategist model that it could in the limited time that was available. Since this specific model year was not fully developed in Strategist for the 2011 ERP filing, the unadjusted model results are not necessarily very meaningful. The results of the Company's adjustments to the Strategist modeling data, to reflect actual conditions and to more fully complete the development of the 2011 model, falls into three main categories:

1) Actual load, turning on RMEC for a full year, modifying market prices for 2011 economy energy purchases, and including economy market sales;

2) Actual coal unit operations and availability; and

3) The impact of wind integration and coal cycling on the operations of the coal, combined cycle and combustion turbine unit operations.

Taking into account the model revisions and the updating of key variables significantly changes the expected operations of these units as predicted by Strategist. The following is a chart that identifies the impact of the adjustments to these key variable and the corrections necessary to be able to make a more appropriate apples-to-apples comparison.

Chart 1. 2011 Strategist Adjustment Waterfall

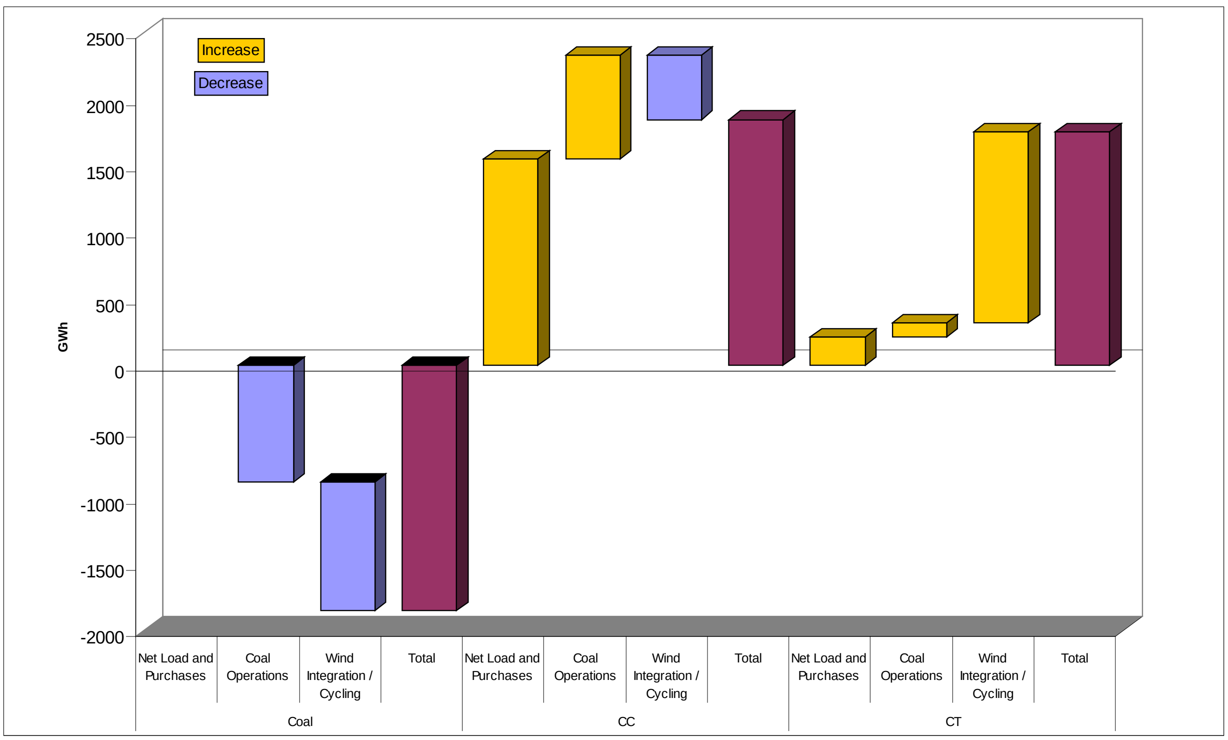


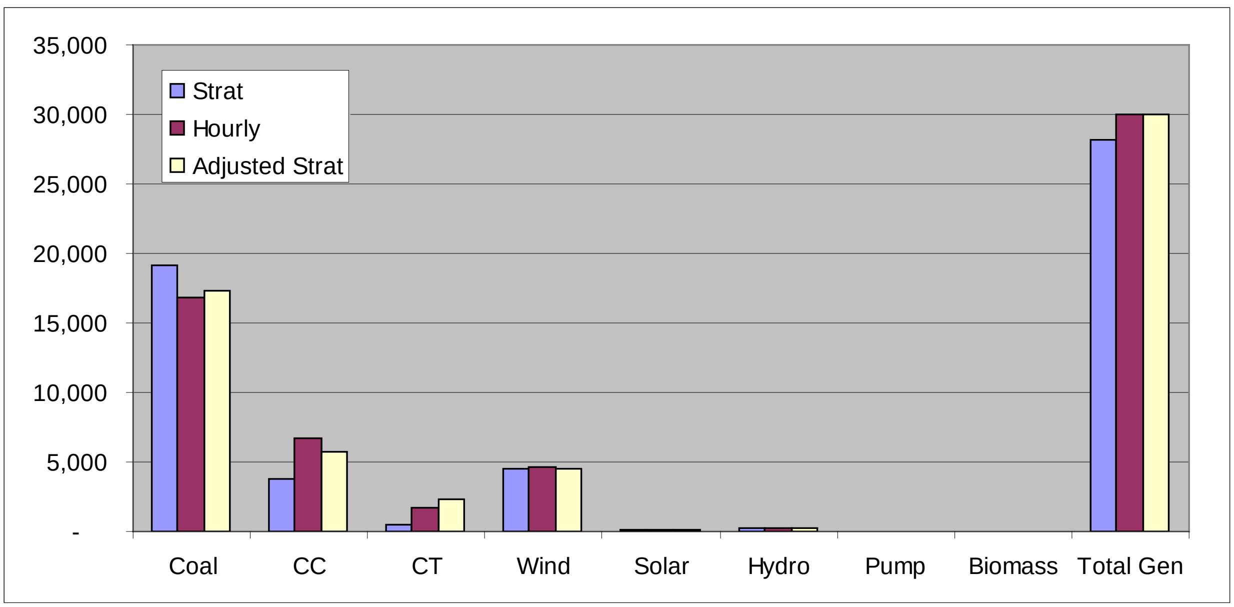
Table 1 below, incorporates the model adjustments identified in Chart 1. Table 1 provides a more accurate reflection of the ability of Strategist to accurately model the operations of and costs of Public Service's generation fleet. The comparison in Table 1 shows that the adjusted Strategist model overestimated coal generation by about 456 GWh or 2.6% of coal generation (1.5% of overall generation), underestimated combined cycles operations by (999 GWh) or (3%)

of overall generation, and overestimated combustion turbine operations by 607 GWh or 2% of overall generation.

Table 1. Strategist Results after Adjustments

GWh	Staff Report Strat	Staff Report Hourly	Adjusted Strat
Coal	19,174	16,871	**17,327**
CC	3,832	6,678	**5,679**
CT	515	1,666	**2,273**
Wind	4,494	4,601	4,494
Solar	67	70	67
Hydro	249	219	249
Pump	(135)	(158)	(135)
Biomass	15	22	15
Total Gen	28,213	29,967	29,969

Chart 2. Adjusted Strategist Comparison to 2011 Actual Generation



<u>**Comparison of Unadjusted and Adjusted 2012 Strategist to 2012 Actual Generation**</u>

Unlike the 2011 Strategist data, the 2012 Strategist data was thoroughly reviewed by the Company prior to using for the ERP and was included in all our analysis in the ERP. When we compare the Company's 2012 actual generation data to the unadjusted 2012 Strategist the modeling output shows a better correlation to the actual generation for 2012 than it did for the 2011 unadjusted data. If we perform the same adjustments as performed for the 2011 data -- such as adjusting for actual load, market sales and purchases and actual plant outages -- Strategist output compares very well to actual generation.

The adjustments made to Strategist 2012 data was broken out into three sections to analyze the impact of various operating condition on the production from coal, CC, and CTs. The first adjustment is for net load and purchases which include short term system sales. This total adjustment was 905 GWh. Strategist does not project short term sales of which the Company had 1,105 GWh of short term sales in 2012 so majority of the adjustment to net load and purchase was due to short term sales. The second adjustment was for actual coal unit outages as compared to Strategist inputs. This resulted in 34 GWh more coal production than modeled. The final adjustment was to look at the impact of wind integration on the production of coal, CC and CT. The impact was a decrease to coal and CC production and increase in CT production.

To summarize the comparison of 2012 Strategist output to actual 2012 generation data similar tables to the 2011 data are included below.

Chart 3. 2012 Strategist Adjustment Waterfall

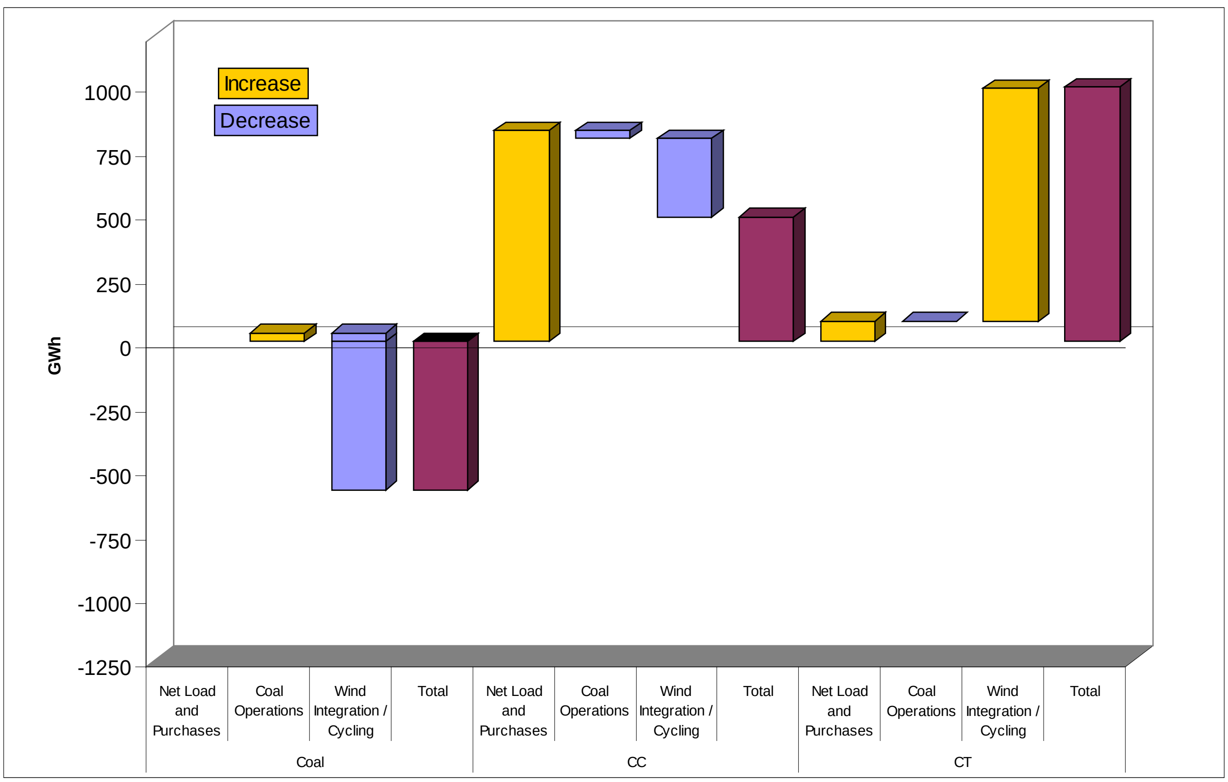
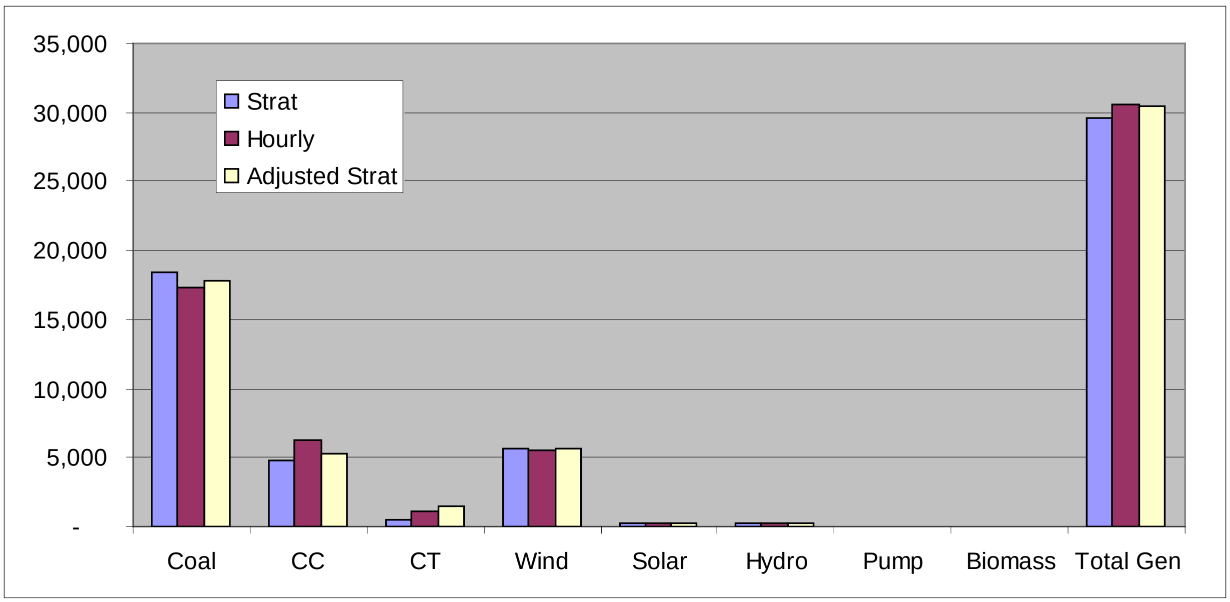


Chart 3 incorporates the model adjustments identified in Table 2. Chart 3 provides a more accurate reflection of the ability of Strategist to accurately model the operations of and costs of Public Service's generation fleet. The comparison in Table 2 shows that the adjusted Strategist model overestimated coal generation by about 503 GWh or 2.9% of coal generation (1.6% of overall generation), underestimated combined cycles operations by (974 GWh) or (3.1% of overall generation, and overestimated combustion turbine operations by 393 GWh or 1.3% of overall generation.

Table 2. Strategist Results After Adjustment

GWh	Staff Report Strat	Staff Report Hourly	Adjusted Strat
Coal	18,363	17,281	**17,784**
CC	4,820	6,282	**5,308**
CT	467	1,069	**1,462**
Wind	5,617	5,586	5,617
Solar	208	206	208
Hydro	235	219	235
Pump	-118	-149	-118
Biomass	18	21	18
Total Gen	29,610	30,519	30,515

Chart 4. Adjusted Strategist Comparison to 2012 Actual Generation



In conclusion, the Company firmly believes that to perform an accurate after the fact review of the ERP modeling function and the use of Strategist would take considerable time to true-up the Strategist model to reflect actual conditions. Without truing up the Strategist model, the comparison is mixing the impacts of the accuracy of the long-term forecast variables to short-term actual conditions with the ability of Strategist to use these variables to predict the dispatch of the Company's generation fleet. In an effort to provide as much clarity on this issue as possible in such a short time period, the Company has developed some of the adjustments that are necessary to make this post review comparison more meaningful. From this limited review the Company believes the PUC can conclude the Strategist model reasonable predicts the operation of the Company' generation and is a solid planning tool for making resource decisions.