**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

*** * * * ***

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF A NUMBER OF STRATEGIC ISSUES RELATING TO ITS ELECTRIC AND GAS DEMAND SIDE MANAGEMENT PLAN	**)))))))**	**PROCEEDING NO. 17A-____EG**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN G. DOYLE</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 3, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

*** * * * ***

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF A NUMBER OF STRATEGIC ISSUES RELATING TO ITS ELECTRIC AND GAS DEMAND SIDE MANAGEMENT PLAN	**) PROCEEDING NO. 17A-___EG**

<u>SUMMARY OF THE DIRECT TESTIMONY OF BRIAN G. DOYLE</u>

Mr. Brian G. Doyle is Team Lead, Strategic Segment of Xcel Energy Services Inc. (“XES”). In this position, he is responsible for Demand Response programs and portfolios in all eight of Xcel Energy Service Inc.’s state jurisdictions with active demand response programs. He provides strategic direction and oversees the team responsible for managing the Interruptible Service Option Credit (“ISOC”), Peak Partner Rewards (“PPR”), Critical Peak Pricing Pilot (“CPP”), Saver’s Switch® and Smart Thermostats programs for Public Service Company of Colorado (“Public Service” or the “Company”), one of four utility operating company subsidiaries of Xcel Energy Inc. (“Xcel Energy”). His duties include the daily management, tracking, and reporting of these programs as well as implementing the long-term strategy for Demand Response across all state jurisdictions.

In his testimony, Mr. Doyle explains the Company’s existing Demand Response portfolio. The Company’s current programs include the Residential Demand Response program, the ISOC program, the Critical Peak Pricing Pilot, and Peak Partner Rewards program.

Mr. Doyle details Public Service's ISOC program, which allows customers to earn bill credits for helping the Company manage the electric demand on its system. In return, participating customers receive monthly credits for committing capacity for interruptions. Per the Commission's order in Public Service's 2015/2016 DSM Plan, the Company has reviewed its ISOC program, and Mr. Doyle presents the modifications the Company is proposing to its ISOC program as a result of that analysis. Specifically, Mr. Doyle recommends the Commission: (1) approve modifications to the Company's ISOC program, which include eliminating the Company's "One-Hour Notice Program"; (2) approve the grandfathering of existing Within Ten Minute Notice customers; and (3) approve implementation of a new Within Ten Minute program based on a modified foundational credit.

As Mr. Doyle explains, the Company's proposed ISOC modifications are largely driven by changes to what generation asset costs are avoided. These changes are driven largely by advancements in peaking generation technology.

Finally, as required by the settlement agreement approved in the Company's last DSM plan, Mr. Doyle explains the Company's current demand response dispatch procedures, and concludes that no changes to those procedures are necessary.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF A NUMBER OF STRATEGIC ISSUES RELATING TO ITS ELECTRIC AND GAS DEMAND SIDE MANAGEMENT PLAN	**)))))))**	**PROCEEDING NO. 17A-____EG**

DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN G. DOYLE

TABLE OF CONTENTS

SECTION **PAGE**

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS 7

II. BACKGROUND 10

III. DEMAND RESPONSE GOALS 20

IV. PROPOSED REVISIONS TO THE ISOC PROGRAM 29

V. ELIMINATION OF ONE-HOUR NOTICE OPTION 42

VI. GRANDFATHERING OF EXISTING WITHIN TEN-MINUTE NOTICE CUSTOMERS 43

VII. NEW WITHIN TEN-MINUTE NOTICE ISOC PROGRAM 45

VIII. DSM DISPATCH PROCEDURES 46

IX. CONCLUSION 49

LIST OF ATTACHMENTS

Attachment BGD-1	ISOC Fact Sheet
Attachment BGD-2	ISOC Tariff

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
AGC	Automatic Generation Control
AGIS	Advanced Grid and Intelligence Security
Ca	Capacity Availability Factor
CPP	Critical Peak Pricing Pilot
CT	Combustion Turbine
DCS	Disturbance Control Standard
DLC	Direct Load Control
DSM	Demand Side Management
ERP	Electric Resource Plan
Ha	Interruptible Hours
ISOC	Interruptible Service Option Credit
O&M	Operations and Maintenance
PPR	Peak Partner Rewards
Public Service or the Company	Public Service Company of Colorado
Slf	System Loss Factors
VER	Variable Energy Resources
WA	Weighted Average
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

*** * * * ***

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF A NUMBER OF STRATEGIC ISSUES RELATING TO ITS ELECTRIC AND GAS DEMAND SIDE MANAGEMENT PLAN	**)))))))**	**PROCEEDING NO. 17A-____EG**

DIRECT TESTIMONY AND ATTACHMENTS OF BRIAN G. DOYLE

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian G. Doyle. My business address is 1800 Larimer, Suite 1500, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. (“XES”) as Team Lead, Strategic Segment. XES is a wholly owned subsidiary of Xcel Energy Inc. (“Xcel Energy”), and provides an array of support services to Public Service Company of Colorado (“Public Service” or the “Company”) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Team Lead, Strategic Segment, I am responsible for demand response programs and portfolios in all eight of Xcel Energy Service Inc.'s state jurisdictions with active Demand Response programs. I provide strategic direction and oversee the team responsible for managing the Interruptible Service Option Credit ("ISOC"), Peak Partner Rewards ("PPR"), Critical Peak Pricing Pilot ("CPP"), and Residential Demand Response[1] programs for Public Service. My duties include the daily management, tracking, and reporting of these programs as well as implementing the long-term strategy for demand response across all state jurisdictions. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to explain the Company's existing demand response portfolio, including available programs, targeted dispatch and the ISOC program; including the history, purpose, and benefits of the program. I explain that the Company has reevaluated its ISOC program, and I explain the modifications the Company is proposing to its ISOC program as a result of its analysis. Finally, as required by the settlement agreement approved in the Company's last DSM plan, I explain Public Service's current Demand Response

[1] The Residential Demand Response program consists of the Saver's Switch® and AC Rewards℠ programs. These are the marketing names for customer facing communications.

dispatch procedures and conclude that no changes to those procedures are necessary.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring Attachments BGD-1 and BGD-2, which were prepared by me or under my direct supervision. Attachment BGD-1 is an ISOC Fact Sheet that provides a general description of the program. Attachment BGD-2 is an illustrative ISOC tariff that captures the various changes that are described in testimony.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR TESTIMONY?

A. I recommend the Commission approve three modifications to the Company's ISOC program, as follows:

- Approval of modifications to the Company's ISOC program, which include eliminating the One-Hour Notice program;
- Authorizing the grandfathering of existing Within Ten Minute Notice customers; and
- Approval to implement a new Within Ten Minute program based on a modified foundational credit.

II. BACKGROUND

Q. PLEASE DEFINE DEMAND RESPONSE AND HOW IT FITS INTO THE COMPANY'S DEMAND-SIDE MANAGEMENT PORTFOLIO.

A. As discussed further in Section III of the Direct Testimony of Company witness Mr. Scott B. Brockett, demand response programs fall into two main categories: dispatchable and non-dispatchable resources. I address the Company's dispatchable resources that involve direct or physical control of electric demand reductions from retail customers that are often used during specified periods.

The Company maintains a number of demand response programs in part to comply with the statutory requirements of House Bill 07-1037, which was recently extended by House Bill 17-1227. Together, these statutes require the Company to achieve a reduction of five percent of 2018 peak demand by 2028 beginning in 2019. House Bill 07-1037, codified at §§ 40-1-102(5), (6) and (7) C.R.S., and 40.3.2-101, *et seq*. define demand side management ("DSM") as follows: "Demand-Side Management Programs or DSM programs mean energy efficiency, conservation, load management, and demand response programs or any combination of these programs."

Q. OPERATIONALLY, HOW DOES THE COMPANY DEPLOY THE DISPATCHABLE DEMAND RESPONSE PROGRAMS DISCUSSED BY MR. WHITE?

A. The Company maintains three types of demand response programs:

(1) **Direct Load Control ("DLC")**: The utility directly controls a customer's load remotely during periods of high demand. For example, the Company's Saver's Switch® measure is an example of DLC. A switch is installed on a central air conditioner, which is remotely cycled during periods of peak demand during summer.

(2) **Interruptible Tariffs:** A customer on an interruptible tariff agrees to reduce consumption to a pre-specified level in return for an incentive, credit, or discount. The Company's ISOC (Sheet No. 110) offering falls within the Company's interruptible tariff.

(3) **Other Demand Response offerings:** Examples include CPP and PPR.

Q. WHAT ARE THE DEMAND RESPONSE PROGRAMS THE COMPANY CURRENTLY OFFERS?

A. The Company currently offers four demand response programs – one residential, and three commercial and industrial programs. The residential program is the Residential Demand Response program. The commercial and industrial programs are the ISOC, CPP, and PPR.

Q. PLEASE DESCRIBE THE RESIDENTIAL DEMAND RESPONSE PROGRAM.

A. The Residential Demand Response program offers residential customers with central air conditioning incentives for allowing the Company to directly control operation of their central air conditioners through a direct load control switch or a smart thermostat on days when the system is approaching its peak.

Q. HOW DOES A CUSTOMER PARTICIPATE IN THE RESIDENTIAL DEMAND RESPONSE PROGRAM?

A. Customers enroll in the program through various direct marketing efforts by the Company or by accessing the Company's customer web portals. These programs are "opt in," meaning customers have the initial choice to participate.

Q. PLEASE DESCRIBE THE COMPANY'S ISOC PROGRAM.

A. The ISOC program allows customers to earn bill credits for helping the Company manage the electric demand (i.e., load) on its system. A participating customer receives monthly credits for committing capacity for interruptions.

The Company typically calls on program participants to reduce their load during periods when the peak electric demand of the system is at its highest, such as hot summer days. Customers who participate in the ISOC program agree to reduce their electricity demand at the Company's request. The program benefits the electric system as a whole because of the economies of scale provided by being able to quickly ramp down large amounts of load within a relatively short time period.

Q. WHO QUALIFIES TO PARTICIPATE IN THE ISOC PROGRAM?

A. To qualify for ISOC, a customer must:

- Be a Public Service electric business customer within our Colorado service area;
- Agree to the rates, terms, and conditions set forth in the ISOC tariff and Public Service's ISOC agreement;

- Be able to maintain at least 300 kW of interruptible electric demand; and,
- Install and maintain a phone line to allow the Company to communicate directly with the meter.

Customers without previous energy usage history at a given location can join ISOC if they demonstrate they are likely to achieve an interruptible electricity demand of at least 300 kW.

Q. HOW DOES A CUSTOMER PARTICIPATE IN THE COMPANY'S ISOC PROGRAM?

A. Under the current program, a customer executes a contract, which among other things, identifies the customer's selected Contract Firm Demand, the hours of interruption per year (40, 80 or 160 hours), and the customer's desired advance-notice requirement (either Within-Ten Minutes or One Hour Notice).

Q. WHO DETERMINES THE AMOUNT OF LOAD EACH PARTICIPATING CUSTOMER WILL PROVIDE TO THE ISOC PROGRAM?

A. The customer decides how much of its total interruptible electric load it is willing to offer into the program. This is referred to as Contract Interruptible Load. The customer also decides how much firm load – i.e. Contract Firm Demand - the customer desires. As shown in the equation below, a customer's Contract Firm Demand and Contract Interruptible Load combined equal the customer's total load.

Total Customer Load = Contract Firm Demand + Contract Interruptible Load

Q. HOW IS THE CONTRACT INTERRUPTIBLE LOAD FOR PARTICIPATING CUSTOMERS DETERMINED?

A. The Contract Interruptible Load is the median of the customer's maximum daily 1-hour integrated Kilowatt Demand that occurs between 12 p.m. and 8 p.m. on Monday through Friday (excluding federal holidays) from June 1 through September 30 of the previous year, less any Contract Firm Demand.

Q. HOW ARE CUSTOMERS CREDITED FOR PARTICIPATING IN THE ISOC PROGRAM?

A. The participating customer's bill credit is the product of their Contract Interruptible Load (KW) and the ISOC monthly rate ($/KW). As reflected in Attachment BGD-1 the monthly $/KW rate varies depending on the annual hours of interruption, the notice period each customer selects (i.e., One Hour Notice or Within 10-Minute Notice), and the month in which the interruptions occur (the credit is seasonally differentiated to reflect the greater value of summer interruptions).

Q. PLEASE DESCRIBE THE PPR PROGRAM.

A. The PPR Program is a demand response program designed to provide Public Service's business customers an incentive for agreeing to reduce their electrical loads when the electric grid experiences peak demand periods. The program is similar in concept to the ISOC program, but designed to be more flexible and target customers who are not eligible for ISOC.

Q. WHO QUALIFIES TO PARTICIPATE IN THE PPR PROGRAM?

A. PPR is available to all commercial customers who can commit to reducing their electric load by at least 25 kW. This program covers a diverse spectrum of commercial and industrial customers, ranging in size from greater than one MW to less than 100 kW.

Q. HOW DOES A CUSTOMER PARTICIPATE IN THE COMPANY'S PPR PROGRAM?

A. Participating customers sign a contract agreeing to reduce a minimum load of at least 25 kW at their facility during peak demand periods. This minimum load is determined by the customer based on their ability to manage operations at their facility. Customers receive a monthly credit (i.e., reservation incentive) based on their committed load reduction. During peak periods, customers receive an additional incentive based on their total load reduction, measured in kWh, during the event (i.e., a customer performance incentive). Customers who participate in the program receive an added benefit of having access to their electric load profile data in near real time. Access to this data not only allows participants to insure they are complying with their contractual obligations, but also provides insight into their energy use throughout the year.

Q. PLEASE DESCRIBE THE CPP PILOT PROGRAM.

A. The CPP pilot program is a tariff rate that provides price signals as an incentive to reduce system costs, including reducing system peak, ultimately reducing costs for all customers. Tariffs focused on the reduction of system peak act much like demand response programs, and as such should count towards the Company's demand response goals.

CPP is designed to encourage – rather than require – customers to reduce their usage during periods when forecasts indicate the electric grid is about to experience high system loads as a percentage of available generation capacity. The nomenclature "critical peak" refers to such periods. The term "pricing" indicates that, rather than requiring load reductions, the Company will charge a high price for usage during these hours that will encourage customers to reduce their usage. During all other hours customers are assessed lower charges than the standard applicable energy rate.

Q. HOW DO CUSTOMERS PARTICIPATE IN THE CPP PILOT PROGRAM?

A. The CPP pilot program is available to commercial and industrial customers who have existing interval metering. This program provides an alternative for customers who cannot or choose not to participate in the Company's other demand response programs.

Participating customers receive day-ahead notice when "critical peak" days occur. Critical peak events are no more than four hours in duration. These events will always occur on non-holiday weekdays between the hours of noon and 8 p.m. A maximum of 15 events can be called in any calendar year.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE RESIDENTIAL DEMAND RESPONSE, PPR, OR CPP PILOT PROGRAMS IN THIS PROCEEDING?

A. No.

Q. WHAT ARE THE BENEFITS OF THE COMPANY'S DEMAND RESPONSE PROGRAMS?

A. Demand response programs provide a dispatchable demand response resource that functions similarly to a traditional peaking generation resource such as a combustion turbine ("CT"). By investing in in demand response programs such as ISOC, the Company avoids the need to build and avoids the long-term capacity costs and fuel costs incurred when using this generation. In particular, demand response programs are beneficial because they delay or eliminate the need to invest in peaking generation resources.

Thus, because demand response programs and a CT are reasonable substitutes under the conditions of system peaking events, it is appropriate to use the cost of developing a CT (with appropriate adjustments) to determine the credit offered to interruptible customers who participate in the program.

Q. UNDER WHAT CIRCUMSTANCES ARE INTERRUPTIONS INITIATED?

A. Interruption events are initiated as a result of capacity, contingency, or economic events. When the Company calls a capacity or contingency interruption, ISOC customers must reduce their Total Load down to their Contract Firm Demand or face a fine. If the interruption is initiated for economic reasons, the customer may choose to buy-through the interruption to avoid reducing its load. Economic interruptions are the only interruptions that offer a buy-through option. Generally, interruptions are initiated on hot days during the months of June, July, August, and September. Most interruptions last a minimum of four hours, unless the customer elects a shorter interruption option. I explain the types of events and process for dispatching resources in Section VIII of my Direct Testimony.

Q. WHAT ARE THE FUTURE PROSPECTS OF DEMAND RESPONSE FOR PUBLIC SERVICE?

A. The future opportunities to grow demand response on Public Service's system are likely to be different than the historic opportunities and performance of demand response programs. Dispatchable DR is a methodology the Company has traditionally used and will continue to use as a demand-side resource to maintain system reliability. However, with the anticipated approval of the Company's Advanced Grid Intelligence and Security ("AGIS") application[2] and the evolution of the Residential Demand – Time Differentiated Rates and Residential Time of Use rates,[3] the Company sees future demand reduction opportunities through concepts such as alternative rate structures and associated pricing mechanisms. The Company is not seeking approval to implement any

[2] Proceeding No. 16A-0588E, In the Matter of the Application of Public Service Company of Colorado for an Order Granting a Certificate of Public Convenience and necessity for Distribution Grid Enhancements, Including Advanced Metering and Integrated Volt-VAR Optimization Infrastructure (deliberated June 21, 2017).

[3] Proceeding No. 16AL-0048E, In Re In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No. 7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

specific rate designs or pricing mechanisms through this proceeding, but may consider making such proposals in future Phase II rate proceedings.

III. DEMAND RESPONSE GOALS

Q. PUBLIC SERVICE WITNESS MR. SHAWN WHITE PRESENTS THE COMPANY'S PROPOSED DEMAND RESPONSE GOALS IN HIS DIRECT TESTIMONY. CAN YOU ELABORATE ON HOW THOSE GOALS WERE DEVELOPED?

A. Yes. The proposed goals represent the Company's forecast of the potential dispatchable demand response given current market conditions and available technologies. First, the Company evaluated the current trajectory of participation in its demand response programs, including ISOC, PPR, CPP pilot program, and the Residential Demand Response program, which includes AC Rewards℠ (smart thermostats) and Saver's Switch® measures, to determine the level of realignment necessary with the current goals. Second, the Company evaluated the potential for future growth across all programs.

Q. WHAT ARE THE COMPANY'S GROWTH EXPECTATIONS FOR EACH OF THE PROGRAMS?

A. We expect the primary area of growth within the Residential Demand Response program to be in the area of smart thermostats. As these measures become more familiar to customers and the tools and resources to enable them become more widely adopted, the Company expects steady growth in the potential curtailable load from these measures. For the PPR program, the expected incremental growth is likely to come from recruiting smaller commercial customers that have historically not qualified for the ISOC program. As discussed in the Direct and Supplemental Direct testimonies of Shawn M. White in Proceeding No. 16A-0152EG[4], this is an area that has been historically underserved. The Company also expects additional participation from medium to large commercial and industrial customers in the PPR program; however, a significant portion of this growth is unlikely to be incremental. Instead, this growth is likely from the anticipated transfer of capacity from the ISOC program to the PPR program due to termination of the One-Hour Notice option, as discussed later in my testimony.

Finally, we expect growth in the CPP pilot program to come from, and better serve, the medium commercial and industrial sectors. The program will provide these customers with another, more flexible demand response option, with 24-hour advanced notice and a tool for monitoring their electric loads in "near real time." The Commission approved this service schedule in the Company's most recent Phase II electric rate proceeding (Proceeding No. 16AL-0048E).

[4] Proceeding No. 16A-0152EG, In the Matter of the Application of Public Service Company of Colorado for Approval of (1) Its Electric and Natural Gas Demand-Side Management (DSM) Plan for Calendar Years 2017 and 2018, (2) Revisions to its Electric and Gas DSM Cost Adjustment (DSMCA) Tariffs, including Rates Effective January 1, 2017, and (3) Approval of the Pear Partner Rewards Tariff.

Q. IS THE COMPANY INCLUDING ANY SAVINGS FROM ITS INTEGRATED VOLT VAR OPTIMIZATION PROJECT PROPOSED IN THE AGIS PROCEEDING?[5]

A. No. Per the terms of the settlement agreement reached in the AGIS proceeding, the Company cannot claim credit for Integrated Volt-VAR ("IVVO") in its DSM goals, nor incorporate the potential form IVVO in its DSM goals.[6]

Q. WHAT AREAS OF RISK DOES THE COMPANY SEE CONCERNING MEETING THE GOALS OF THE DEMAND RESPONSE PORTFOLIO OF PROGRAMS?

A. There are two areas of risk that should be considered regarding the Company's demand response goals. The first area of risk is the possible decline in participation in the ISOC program and limited future growth opportunity due to the revised ISOC program design. The second risk is the reduction in potential savings associated with Saver's Switch®.

Q. IS PUBLIC SERVICE PROPOSING CHANGES TO ISOC THAT COULD IMPACT THE COMPANY'S ABILITY TO ACHIEVE ITS DEMAND RESPONSE GOALS?

A. It is possible. Though I discuss our proposed modifications in more detail in Section IV below, eliminating the One-Hour Notice option within the ISOC

[5] Proceeding No. 16A-0588E, In the Matter of the Application of Public Service Company of Colorado for an Order Granting a Certificate of Public Convenience and Necessity for Distribution Grid Enhancements, Including Advanced Metering and Integrated Volt-VAR Optimization Infrastructure.
[6] Proceeding No. 16A-0588E. Unopposed Comprehensive Settlement Agreement, Exhibit A. at page 13.

program will require customers interested in participating in demand response to migrate to the Within Ten-Minute option, PPR, or the CPP pilot program. While the Company has confidence most customers will migrate to a new demand response program, there is risk that some customers will drop out of the Demand Response program altogether.

Q. YOU STATED THAT THE COMPANY HAS FALLEN SHORT OF ITS DEMAND RESPONSE GOALS IN PART DUE TO THE "GENERAL LIMITS TO DEMAND RESPONSE." WHAT ARE YOU REFERRING TO?

A. This statement refers to the fact that the amount of customers (both eligible and able to participate) in demand response programs are limited by technology, operations, and willingness.

As discussed earlier in my testimony, the Company's base of large industrial customers – the types most likely to have significant demand reduction capacity available – is significant but limited. Many of these customers are already engaged in the Company's existing offerings, specifically the ISOC and PPR programs. Commercial customers also offer opportunity because, while they offer smaller curtailable loads, they are a larger segment of the Company's customer base than the large industrial customers. Commercial customers are engaged primarily in the PPR program, which the Company has forecasted in its goals, will grow.

Conversely, residential customers offer the most limited opportunity for participation given current technologies. Residential customer demand response is primarily limited to direct load control offerings like the Saver's Switch® program or voluntary demand response offerings like AC Rewards℠. Residential participation is widespread, with approximately 47 percent of customers enrolled in one of the two offerings. However, the incremental demand reductions from both offers are small compared to commercial and industrial demand reductions. Furthermore, demand response is also constrained by customers' willingness to interrupt their business practices (i.e., shutting down production) or willingness to disrupt their comfort level (i.e., curtailing air conditioning use in homes and offices on hot summer days).

Q. WHY MIGHT CURRENT ISOC CUSTOMERS DROP OUT OF DEMAND RESPONSE PROGRAMS?

A. Customers may be unable to participate due to the participation requirements. For example, the Within Ten-Minute Notice ISOC program requires that customers allow Public Service to directly control their load reduction within ten-minutes' notice. This requires that customers either have flexible systems capable of shutting down quickly or have backup generation able to quickly ramp up and remain running for a sustained period of time. Over the last few years, new standards have come into effect that have made backup generation more costly to implement, thereby reducing some customers' abilities to participate in demand response programs.

In addition, some customers may not participate because the value of continuing production may outweigh the credit value for participation. Also, some customers may not agree to certain program requirements, such as the requirement to nominate and deliver a specific amount of curtailable load.

While the Company designs its programs to provide valuable incentives to encourage customers to participate, it must also be cognizant of ensuring cost-effectiveness to all ratepayers. It would not be cost effective for the Company to acquire demand response at a cost that exceeds avoided capacity cost.

Q. HAVE THERE BEEN ANY RECENT CHANGES TO STANDARDS FOR BACKUP GENERATION THAT HAVE IMPACTED CUSTOMERS' ABILITIES TO PARTICIPATE IN DEMAND RESPONSE PROGRAMS?

A. The most recent change was the EPA's 2012 Reciprocating Internal Combustion Energy amendments to the National Emissions Standards for Hazardous Air Pollutants, commonly referred to as "RICE NESHAP."[7] These amendments affected stationary engines, which some participants in the ISOC program use as backup generation during demand response events. The RICE NESHAP amendments reduced the run time of reciprocating engines to 50 hours without incurring emissions limits if the engine was participating in a demand response program.

However, under the Company's ISOC program, the Company has the ability to interrupt service to a customer for more than 50 hours in a given year. In turn, the participant needs to be prepared to address emissions limits through either limited operation – possibly resulting in the curtailment of business

[7] 40 C.F.R. § 63 Subpart ZZZZ (2012).

practices – or the installation of emissions limiting technologies that may require significant capital expense.

Q. DOES THE COMPANY HAVE ANY CONCERNS ABOUT ITS SAVER'S SWITCH® PROGRAM?

A. Yes. The Company is concerned that the savings per switch estimate (currently estimated around one kW per switch) attributable to the Saver's Switch® program will drop in future years. We attribute this phenomenon to lower temperatures and humidity, increased air conditioner efficiencies, and increased conservation efforts. More efficient air conditioners provide fewer savings per unit than older, inefficient models. We expect some of these factors to impact the savings achieved per switch over the next several years as well.

Q. DOES THE COMPANY'S PROPOSED DEMAND RESPONSE GOAL INCLUDE DEMAND REDUCTIONS FROM EMERGING TECHNOLOGIES AND SERVICES?

A. Yes. The goal assumes that cost-effective, new technologies and services will become available during the 2019 through 2023 period. As cost-effective technologies and services become available, the Company may propose to include them in future DSM plans.

Q. ARE THERE OTHER FACTORS THAT MAY IMPACT CUSTOMERS' DECISIONS TO PARTICIPATE IN DEMAND RESPONSE PROGRAMS?

A. Yes, one factor is the value of the credit the Company offers participants. In order for the programs to be cost-effective, this value must be less than the avoided capacity cost, and the avoided capacity cost has been decreasing over time. This decline can affect all of the demand response programs. As the avoided capacity cost decreases, this can affect the incentive customers have to participate in demand response programs. Their return on investment in capital measures or tools to enable the curtailment of peak load grows longer, and the tradeoff between maintaining production and the credit grows larger.

Q. HAS THE COMPANY CONSIDERED OTHER BENEFITS THAT DEMAND RESPONSE DELIVERS?

A. Yes, the Company has considered using demand response in different ways to drive additional benefits to customers and participants; however, these additional benefits are limited.

One benefit would be DSM geo-targeting to defer or avoid distribution infrastructure investments, as discussed further in the Direct Testimony of Public Service witness Ms. Donna Beaman. As she explains, strategically targeted demand response can be used to defer investments in the distribution system. The current potential for demand response as part of DSM geo-targeting is contingent on the types of customers in a targeted area. For example, if the Company is pursuing the deferral of a transformer and feeder that provides service to a residential area, there would most likely be an emphasis on the dominant loads in that area (i.e., residential, in this example).

IV. PROPOSED REVISIONS TO THE ISOC PROGRAM

Q. WHAT ARE THE PROPOSED REVISIONS TO THE COMPANY'S ISOC PROGRAM?

A. At a high level, the Company's proposed changes are a result of changes in modeled generation technology that is a key input in the design of the program and the two options (Within-Ten Minute and One-Hour Notice) available today. In re-evaluating the ISOC program, as the Commission ordered, the Company is proposing to grandfather its existing Within Ten-Minute Program, offer a new Within Ten-Minute Program, and eliminate the Company's One-Hour Notice program. Attachment BGD-2 is an illustrative tariff of the changes that capture the changes that I describe in this section and in Sections V and VI.

Q. DID THE COMMISSION IMPOSE ANY REQUIREMENTS ON PUBLIC SERVICE FOR THIS DSM STRATEGIC ISSUES PROCEEDING REGARDING THE COMPANY'S ISOC TARIFF?

A. In Decision No. C15-0766, Proceeding No. 13A-686EG, the Commission ordered the Company to reexamine its ISOC tariff in the next DSM strategic issues filing. Consistent with the Commission's directive, the Company has evaluated its ISOC program, goals, and credit value. Based on that evaluation, the Company recommends certain changes to the program as discussed below.

Q. HOW ARE CREDITS TO EXISTING CUSTOMERS CURRENTLY CALCULATED UNDER PUBLIC SERVICE'S ISOC PROGRAM?

A. Customers currently enrolled in the program receive credits for the estimated cost of generation assets (with adjustments) the Company avoids as a result of the customer's participation in the ISOC program.

Q. IS THE COMPANY PROPOSING TO CHANGE THE METHODOLOGY FOR CALCULATING THE ISOC CREDIT?

A. Not for existing Within Ten-Minute Notice customers. These customers continue to help offset the annual cost of the generation assets that would have been in the Company's generation resource portfolio back when the ISOC program was first initiated. Specifically, the cost that continues to be avoided is the annual cost of an installed GE LMS100 CT.

Q. WHAT GENERATION TECHNOLOGY IS MODELED IN THE CURRENT ISOC PROGRAM?

A. When the One-Hour Notice Program was initiated in 2009, a GE Frame 7FA CT represented a reasonably equivalent generating technology for assessing the value of interruptible load that requires one hour's advance notice for curtailment. At that time, Frame CT technology was commonly used for peaking service, but did not have rapid start capability. The rapid start technology of the GE LMS100 was used to model the value of the Within Ten-Minute program.

Q. WHAT GENERATION TECHNOLOGY IS THE COMPANY PROPOSING TO USE FOR CALCULATING ISOC PROGRAM CREDITS IN THE FUTURE?

A. We propose using the Siemens 5000F CT to set the value for the Within Ten-Minute interruptible load. Additionally, the Company is proposing to eliminate any comparable technology from the One-Hour Notice Program.

Q. WHY WAS THE SIEMENS 5000 CT SELECTED?

A. All new CT generation assets are capable of quick start. Therefore, a generation asset that serves a planning reserve requirement that allows a notification period of one hour costs the same as a generation asset that supports operating reserve requirements that have to be executed within a ten-minute notification period. This means that there is no business basis for providing new customers a credit option at a lower credit rate for a one-hour notification option.

In addition to the advances in CT technology, the cost of a Siemens 5000F CT is similar in cost to the Frame 7FA used for One-Hour Notice and less expensive than LMS100 used for the Within Ten-Minute Notice program. Therefore, the Company proposes to eliminate the One-Hour Notice program and reflect that the Siemens 5000F with the quick-start feature is the current industry standard.

Q. WHAT IMPACT DOES THE NEW MODELED GENERATION HAVE ON THE CREDIT VALUE FOR THE ISOC PROGRAM?

A. The new modeled generation results in a lower credit for new customers. As discussed below, this is because the modeled generation cost is lower for those customers. The Foundational Cost for the new Siemens 5000F is $11.27/kW-month, whereas the Foundational Cost for the GE LMS100 CT was $15.97/kW-month.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE ISOC CREDIT FOR NEW PARTICIPANTS GOING FORWARD?

A. The Company proposes only one adjustment to the existing formula, which is to remove the Credit Adjustment Factor. Accounting for this proposed change, the new formula is:

Credit $/kW-month = Foundational Value x Ca x Slf x Winter/Summer Factor

Where:

(1) Foundational Value is the cost per kW-month of the generating unit;

(2) The Capacity Availability Factor (“Ca”) is the amount of capacity of time offered by the customer;

(3) System Loss Factors (“Slf”) are loss factors that vary depending upon the voltage level of delivery to the customer; and

(4) Summer/Winter Seasonal Adjustment Factors are seasonal ratios to adjust between the summer and winter rate differentials.

Q. PLEASE EXPLAIN HOW THE CALCULATION OF FOUNDATIONAL VALUE HAS CHANGED FROM THE EXISTING PROGRAM?

A. The calculation of the credit is mostly unchanged, but we removed energy adjustments and added monthly operations and maintenance (“O&M”) and capital expenditures to the calculation. Table BGD-D1 below provides a side-by-side comparison of the existing program and the Company's proposed program. Each row shows a component of the adjustment to the kW-month credit and the impact up or down the component has on the Foundational Value.

Table BGD-1: Side-By-Side Comparison of Existing, Grandfathered and New ISOC Credit Factors

Interruptible Service Option Credit		A EXISTING Retired	B EXISTING Grandfathered	C PROPOSED New
	Notice	1 hr	<10 min	<10 min
	Unit	Frame CT(1)	Quick Start CT-OLD(2)	Frame CT(3)
Adjustments	O&M-CapX	no	no	yes
	Energy	yes	yes	no
	Reactive Power	yes	yes	yes
	Automatic Gen Control (AGC)	yes	yes	yes
	Transmission Loss	yes	yes	yes
	Reserve Margin	yes	yes	yes
	Reliability - 160/80/40 hrs	yes	yes	yes
		(1) GE 7FA	*(2) GE LMS100*	*(3) Siemens 5000F*

Q. PLEASE EXPLAIN WHY THE ENERGY ADJUSTMENT IS REMOVED FROM THE FORMULA.

A. ISOC is a demand response program that is limited to either 160, 80, of 40 hours during the entire year. As a result, the program focuses on avoiding kW (i.e., demand) rather than kWh (i.e., energy). For this reason, the Company is proposing to eliminate avoided energy in determining the rate for new customers.

Q. WHY ARE MONTHLY O&M AND ONGOING CAPITAL EXPENDITURES ADDED TO THE CALCULATION?

A. In addition to the cost to construct a CT, O&M and ongoing capital expenditures are additional CT-related costs the ISOC program helps avoid.

Q. HOW DOES THE INSTALLED COST ESTIMATE OF THE SIEMENS 5000F CT COMPARE TO THE PREVIOUS METHOD?

A. Previously, the foundational value calculation started with the overnight construction cost of the CT. For example, based on the Company's 2016 Electric Resource Plan ("ERP"), the overnight construction cost of a 192.1 MW Siemens 5000F installed cost would be $140.1 million (2014$). The cost would then be escalated to 2019 values based on the Company's general inflation/escalation assumption of 2 percent per year and then reduced, as in the ERP, to reflect the midpoint between a greenfield and brownfield facility, which would result in a $135.4 million cost in 2019 dollars, or $1,163/kW. Under the new calculation proposed by the Company, the $/kW installed cost estimate would be $705/kW, a considerable decrease from $1,163/kW.

Q. WHAT WERE THE NEXT STEPS TAKEN BY THE COMPANY TO CALCULATE THE FOUNDATIONAL VALUE (COST PER $/KW MONTH) OF THE SIEMENS 5000 CT?

A. The $/kW installed cost estimate is multiplied by a fixed charge rate of 10.3 percent, which is developed from the Company's revenue requirement model and updated with information concerning the Company's capital structure, financial rates, tax rates, and other fixed costs, to yield a levelized annual revenue requirement. This value approximates the annual levelized cost to the utility's customers if the Company were to construct a Frame CT and place its investment in rate base. The product of the $705/kW installed cost and the 10.3 percent fixed charge rate (which equals $72.24/kW-year or $6.02/kW-month) represents the total annual fixed costs of the CT.

This monthly cost was then adjusted up by $2.14/kW-month for monthly fixed O&M, on-going capital expenditures, and gas demand charges that would normally be incurred for a CT on the Company's system. Thus, the net costs of the CT amount to $8.16/kW-month to date. In addition, because only 83 percent of the 5000F's total capacity is available within ten minutes due to the ramp rate availability in Colorado's high altitude, the monthly cost was adjusted upward (due to the decrease in the kW available) by $1.67/kW-month ($8.16 – ($8.16 * 83%) = $1.67/kW-month), which resulted in a net cost of $9.48/kW-month.

Q. DID THE COMPANY MAKE ANY ADDITIONAL ADJUSTMENTS TO THE COST PER $/KW MONTH TO DETERMINE THE APPROPRIATE FOUNDATIONAL VALUE OF THE SIEMENS 5000 CT?

A. Yes. The Company also made an adjustment to recognize that interruptible customers do not provide the same reactive power or automatic generation control ("AGC") capabilities that peaking generation resources may provide. Each of these services has been valued at $0.25/kW-month and $0.10/kW-month, respectively, based on the Company's transmission formula rate Schedule 2 and

3. Thus, a combined $0.35/kW-month was subtracted for each of these services from the net cost of the CT, yielding a value of $9.48/kW-month. This same adjustment is reflected in the Company's current ISOC credits.

Second, the Company made an adjustment to account for system-level transmission losses that interruptible loads avoid. The current transmission loss factor for the Company is 2.2 percent. Therefore, 100 MW of interruptible load is equivalent to 102.2 MW of additional supply-side resources, i.e., the amount of additional generating capacity that would be needed to supply 100 MW of load after transmitting the power across the transmission system and incurring transmission losses of 2.2 percent. Thus, on a per-MW basis, interruptible load has a higher value than a generating resource. As a result, the $9.48/kW-month value was multiplied by 1.022 to yield a value of approximately $9.69/kW-month.

Third, in comparing the respective values of interruptible loads and supply-side generation, it is important to recognize the impact of each class of resource on Public Service's reserve margin. The Company seeks to maintain its current 16.3 percent reserve margin. To meet this reserve margin for 100 MW of load, the Company needs to develop or acquire 116.3 MW of firm capacity. If that load is interruptible, the Company can avoid developing or acquiring 116.3 MW of generation facilities. Thus, 100 MW of interruptible load is equivalent to 116.3 MW of supply-side capacity. As was the case with the transmission losses described above, interruptible load has a correspondingly higher value than a generating resource on a per-MW basis. The $9.69/kW-month value was multiplied by 1.163 to yield a value of approximately $11.27/kW-month, the new Foundational Value credit for the Within Ten-Minute Notice ISOC program. These calculations are reflected in Attachment BGD-2, which contains an illustrative example of our proposed changes to the ISOC tariff.

Q. PLEASE EXPLAIN THE CHANGES MADE TO THE CAPACITY AVAILABILITY FACTORS IN THE FORMULA.

A. The Capacity Availability (“Ca”) factors are percentages based on the Number of Interruptible Hours (“Ha”) set forth in the Interruptible Service Option Agreement. The C factors are split into four buckets, with three options of interruptible hours available in each bucket (40, 80, 160 hours). The four buckets include 4-hour Minimum and No 4-hour Minimum calls (4-hour Minimum calls are interrupted for at least 4-hours, No 4-hour Minimum can be interrupted for less) and then Unconstrained or Constrained for either 4-hours or No-4 hour. Constrained means that the customer can only be interrupted once every 24-hours. With the current ISOC program there are 12 different options for the Ca factor – all shown in Table BGD-2 below.

Table BGD-2: Changes to the Capacity Availability (Ca) Formulas

Interruption Hours Ha	Ca Unconstrained* No 4-hour Minimum	Ca Unconstrained* 4-hour Minimum
40 hours	77%	76%
80 hours	88%	88%
160 hours	95%	95%
Ha	Ca 4-hr/24-hr No 4-hour Minimum	Ca 4-hr/24/hr 4-hour Minimum
40 hours	70%	69%
80 hours	77%	76%
160 hours	80%	79%

Q. HOW IS THE COMPANY PROPOSING TO CHANGE THE CALCULATION OF THE CA FACTORS?

A. The Company proposes to eliminate the two No 4-hour Minimum buckets due to lack of customer participation. Otherwise, the methodology is essentially the same, with updated data and the energy adjustment removed.

This process is simpler and more accurate. In both the current and previous methods, the calculation was based on historic loss of load probability (“LOLP”) and the ability for the ISOC products to provide load relief during the top 40, 80, and 160 LOLP hours. Previously, the historic LOLP was a vector of future LOLPs mapped into the historic test years by highest load hours (future LOLP values were the only values available). In the current method, the historic LOLP are calculated directly using actual load, variable energy resources (“VER”) profiles, and forced outage rates. Further, the LOLP calculation is calibrated to a one in ten standard (as is done for all wind and solar capacity valuations), ensuring no one test year disproportionately affects the final outcome. Second, a linear program was used to identify the top 40, 80, and 160 highest LOLP hours. Constraints were formulated to ensure event duration, frequency of events, and total hours were absolutely maintained for the program being valued.

The data was also updated. The evaluation period was from 2012 to 2016. Ca factors were calculated for each year, each program, and number of hours. A simple average across the five-year evaluation period determined the final result for each program and number of hours.

Last, the energy adjustment has been removed. As previously noted, the proper focus is avoided capacity – not energy. For customers participating in the ISOC program, demand is delayed rather than eliminated. Delayed or shifted non-deployable energy does not save (or only marginally saves) energy costs. Due to the complexity of the calculation, and the likely negligible (or, more likely, non-existent) savings, the energy component should be eliminated.

Q. HOW DO THE NEW CA FACTORS COMPARE TO THE PREVIOUS FACTORS?

A. The Ca factors are generally lower with less change as the number of interruptible hours increase. These updated adjustments will decrease the total credit more than the current program. The existing and proposed Ca factors are shown in Table BGD-3 below.

Table BGD-3: Existing and Proposed Ca Factors

Capacity Availability (Ca):	EXISTING	PROPOSED
Unconstrained: 4-hr minimum - 40 hrs	76%	56%
Unconstrained: 4-hr minimum - 80 hrs	88%	74%
Unconstrained: 4-hr minimum - 160 hrs	95%	90%
Constrained: 4-hr/24-hr 4-hr minimum - 40 hrs	69%	54%
Constrained: 4-hr/24-hr 4-hr minimum - 80 hrs	76%	69%
Constrained: 4-hr/24-hr 4-hr minimum - 160 hrs	79%	77%

Q. HAVE THE SYSTEM LOSS FACTORS CHANGED?

A. The methodology has not changed, but the factors have been updated based on the Company's most recent Phase II electric rate case.[8] Table BGD-4 contains the updated System Loss Factors (Slf):

Table BGD-4: Updated System Loss Factors (Slf)

System Loss Factors (Slf)

The System Loss Factors are as follows:

Delivery Level	Slf
Secondary Distribution Voltage	1.0678
Primary Distribution Voltage	1.0375
Transmission Voltage	1.0000

Q. HAVE THE SUMMER/WINTER FACTORS CHANGED?

A. The factors have been updated with the summer ratio of 126.3 percent and the winter ratio of 86.8 percent. These ratios were based on the Company's filed weighted Transmission General (Schedule TG) demand rate differentials in its most recent Phase II electric rate case.[9]

Q. HOW ARE THE SUMMER/WINTER FACTORS CALCULATED?

A. A weighted average for both the summer and winter TG rate is calculated based on number of ISOC customers in each delivery voltage level class. The weighted average ("WA") rate for each season is then divided by the seasonal weighted sum of the summer and winter rate (e.g. Summer WA times 4 months plus Winter WA times 8 months) divided by 12. A detailed calculation of the summer/winter factors is shown in Table BGD-5 below.

[8] Proceeding No. 16AL-0048E.
[9] Proceeding No. 16AL-0048E.

Table BGD-5: Summer/Winter Factors

2016 ISOC Customers	#
Secondary	51
Primary	32
Transmission	5
Sum	88

TG Rates ($/kW-mo)	Summer	Winter	
Secondary	$ 14.02	$ 9.82	
Primary	$ 14.26	$ 9.55	
Transmission	$ 12.32	$ 8.26	
Weighted Avg. (Based on # ISOC Customers)	$ 14.01	$ 9.63	
Summer Weight	1.263		$= \text{Summer Rate}_{WA}/(((SR_{WA}*4)+(WR_{WA}*8))/12)$
Winter Weight	0.868		$= \text{Winter Rate}_{WA}/(((SR_{WA}*4)+(WR_{WA}*8))/12)$

V. ELIMINATION OF ONE-HOUR NOTICE OPTION

Q. IS THE COMPANY PROPOSING TO ELIMINATE ANY SERVICE OPTIONS?

A. Yes. Based upon the analysis described earlier in my testimony, the One-Hour Notice program will no longer be offered beginning in 2019.

Q. WILL THESE CUSTOMERS BE ABLE TO CHOOSE A NEW PROGRAM?

A. Yes. One-Hour Notice customers will have the ability to move to the new Within Ten-Minute program, PPR, or CPP programs.

Q. DOES THE COMPANY ANTICIPATE ADDING MORE ISOC LOAD AS A RESULT OF THE PROPOSED CHANGES TO THE CREDIT LEVELS, SERVICE OFFERING AND CONDITIONS OF SERVICE?

A. No, not at this time.

VI. GRANDFATHERING OF EXISTING WITHIN TEN-MINUTE NOTICE CUSTOMERS

Q. IS THE COMPANY PROPOSING TO GRANDFATHER EXISTING WITHIN TEN-MINUTE ISOC CUSTOMERS?

A. Yes. As a means of acknowledging past and continued participation, we are proposing to require those customers commit to the grandfathered program by December 31, 2018, and commit their same kW load shed commitment for a period of ten years, or through 2028.

Q. DOES THE GRANDFATHERING INCLUDE ALL EXISTING WITHIN TEN-MINUTE PARTICIPANTS?

A. Yes. All existing Within Ten-Minute participants as of July 2018 will have the grandfathering option available to them.

Q. WHAT OTHER REQUIREMENTS WILL APPLY TO GRANDFATHERED CUSTOMERS?

A. If grandfathered customers wish to leave the program, they will be required to provide the Company with three years' notice. If these customers wish to leave the program prior to the termination of their ten-year commitment, they will be subject to an early termination penalty that amounts to 36 months of credits. There are no penalties if a customer terminates operations.

Q. CAN GRANDFATHERED CUSTOMERS ADD TO THEIR COMMITTED LOAD?

A. Yes, but the incremental amount of load will be placed under the New Within Ten-Minute program.

Q. IS THE COMPANY PROPOSING ANY OTHER PROGRAM CHANGES FOR THE GRANDFATHERED WITHIN TEN-MINUTE PROGRAM?

A. No. In order to keep the program truly "grandfathered," the Company believes that only minimal program requirements should change.

Q. WHAT WOULD BE THE IMPACT IF THE PROPOSED GRANDFATHERED CUSTOMERS WERE TO FALL UNDER THE NEW PROPOSED CREDIT?

A. Participating customers would see an average decrease in credits of approximately 17 percent, or $69,000.

Q. WHAT WOULD BE THE IMPACT TO NON-PARTICIPATING CUSTOMERS IF THE PROPOSED GRANDFATHERED CUSTOMERS WERE TO FALL UNDER THE NEW PROPOSED CREDIT?

A. Non-Participating customers would not materially benefit. The Company estimates that the rate per kWh would go down by about $0.00014 per kWh used. For residential customers, this would result in a reduction to their annual bill of about 99 cents, or about a 0.10 percent reduction.

VII. NEW WITHIN TEN-MINUTE NOTICE ISOC PROGRAM

Q. CAN YOU SUMMARIZE THE NEW WITHIN TEN-MINUTE NOTICE ISOC PROGRAM?

A. Yes. The new Within Ten-Minute Notice Program will be open to new participants beginning on January 1, 2019. Also, the program will be available to existing or grandfathered program participants whose load shed commitment has increased. The program will be offered with a five-year commitment and a rolling 18-month termination notice requirement. Early termination penalties will be equal to 18 months of credits.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE NEW WITHIN TEN MINUTE NOTICE PROGRAM MIGHT WORK?

A. Yes. Assume customer X commits 20 MW of load-shed beginning on January 1, 2019. The customer will need to sign the necessary ISOC contract and be held to that commitment until December 31, 2023. The customer could issue a termination notice 18 months prior to the full five-year commitment, or in June 2021, and leave the program without any penalties in March 2023. However, if the customer leaves the program early without properly noticing its termination, it will be subject to an early termination penalty equal to the 18 months of credits it received.

VIII. DSM DISPATCH PROCEDURES

Q. PLEASE EXPLAIN THE COMPLIANCE REQUIREMENT INVOLVING THE COMPANY'S DEMAND RESPONSE DISPATCH PROCEDURES.

A. As part of the settlement agreement in the 2017/2018 DSM Plan, Public Service agreed to sponsor testimony in this proceeding addressing: how and why each demand response product in the DSM portfolio is dispatched, incremental dispatch cost assumptions, any proposed changes to dispatch procedures, and the number and type of events called for each demand response product during prior years.[10]

Q. WHAT IS THE COMPANY'S CURRENT DSM DISPATCH PROCEDURE?

A. The Company currently uses its demand response programs for economic, contingency, or emergency events. These terms can be defined as:

(1) Economic: an event the Company believes that calling an interruption will lower its overall system costs compared to what the overall system cost would be in the absence of the interruption;

(2) Contingency: an event where when the Company believes, in its sole discretion, that interruption is necessary for the Company to be able to recover from a loss of generation; and

(3) Emergency: an event where the Company believes that generation or transmission capacity is not sufficiently available to serve its firm load obligations.

[10] Settlement Agreement at p. 25.

Q. HOW OFTEN DOES THE COMPANY CALL ECONOMIC, CONTINGENCY, AND EMERGENCY EVENTS?

A. Attachment BGD-D1 provides the number of and type of events called for the last four years.

Q. WHEN THE COMPANY CALLS AN EVENT, DOES IT ACTIVATE ALL OF ITS DEMAND RESPONSE RESOURCES OR JUST CERTAIN RESOURCES?

A. The number and type of resources activated depends on both the type of event and the scale of the event. For economic events, the Company would only activate resources where their marginal costs of activation were less than the marginal cost to start up a generation resource.

For contingency events such as the loss of a transmission element or generation resource, the Company would activate a level of Within Ten-Minute Notice resources to meet the disturbance or return the system to pre-disturbance levels. In some cases, One-Hour Notice resources may also be called to ensure enough resources remain available to meet the forecasted demand for several hours after the contingency event. For emergency events, the Company would activate a combination of Within Ten-Minute notice and One-Hour Notice demand response to maintain adequate reserves.

For emergency events, the Company would activate all available demand response.

In the case of all other events (i.e., capacity, contingency, or economic), the Company would activate only the necessary capacity to avoid the event. For example, if the Company were confronted with an economic event where it could avoid 100 MW of incremental capacity, it would likely call only 100 MW of capacity within its programs.

Q. IS THE COMPANY PROPOSING TO MODIFY THE TYPES OF EVENTS IT CALLS OR ITS PROCEDURES ASSOCIATED WITH HOW IT DISPATCHES DEMAND RESPONSE PROGRAMS?

A. No. At this time, there is no incremental value to dispatching the programs differently or changing the definition of the events for which the Company will use its demand response programs.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Brian G. Doyle

As the Team Lead, Strategic Segment of Xcel Energy Services Inc., I am responsible for Demand Response programs and portfolios in all eight of Xcel Energy Service Inc.'s state jurisdictions with active demand response programs. I provides strategic direction and oversee the team responsible for managing the Interruptible Service Option Credit, Peak Partner Rewards, Critical Peak Pricing Pilot, Saver's Switch® and Smart Thermostats programs for Public Service Company of Colorado, one of four utility operating company subsidiaries of Xcel Energy Inc. My duties include the daily management, tracking, and reporting of these programs as well as implementing the long-term strategy for Demand Response across all state jurisdictions.

I have fourteen years of experience at Xcel Energy Services, Inc. in a variety of areas and positions. These include Market Research Analyst, Product Developer and Product Development Platform Lead, Product Development Emerging Markets Lead, and Senior Product Portfolio Manager (leading Demand Response efforts).

Since 2015, I have been leading the Public Service Company of Colorado Demand Response efforts.