BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE 600 MW RUSH CREEK WIND PROJECT PURSUANT TO RULE 3660(H), A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RUSH CREEK WIND FARM, AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE 345 KV RUSH CREEK TO MISSILE SITE GENERATION TIE TRANSMISSION LINE AND ASSOCIATED FINDINGS OF NOISE AND MAGNETIC FIELD REASONABLENESS.	)	**PROCEEDING NO. 16A-0117E**

DIRECT TESTIMONY AND ATTACHMENTS OF
ALICE K. JACKSON

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

MAY 13, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE 600 MW RUSH CREEK WIND PROJECT PURSUANT TO RULE 3660(H), A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RUSH CREEK WIND FARM, AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE 345 KV RUSH CREEK TO MISSILE SITE GENERATION TIE TRANSMISSION LINE AND ASSOCIATED FINDINGS OF NOISE AND MAGNETIC FIELD REASONABLENESS.	))))))))))))))))	**PROCEEDING NO. 16A-0117E**

SUMMARY OF THE DIRECT TESTIMONY OF ALICE K. JACKSON

Ms. Alice K. Jackson is Regional Vice President, Rates and Regulatory Affairs of Xcel Energy Services Inc. In this position she is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc. Her duties include, among other things, the design and implementation of Public Service’s regulatory strategy and programs, and directing and supervising Public Service’s regulatory activities, including oversight of rate cases. Ms. Jackson is the Company's policy witness in this Application.

In December 2015, President Obama signed into law the Omnibus Appropriations Act (the "Act"). This act extended the Production Tax Credit ("PTC") afforded to wind projects built within a certain timeframe on a stepped down basis. The modification to the continued availability of the PTC in combination with existing Colorado law regarding renewable energy (§40-2-124, C.R.S.) has allowed Public Service to evaluate a unique opportunity to continue its renewable energy stewardship and invest in an economic resource on its system for the benefit of our customers and the State of Colorado. However, such evaluation should be performed on an expedited basis to ensure the Company may access the full PTC benefit and may provide the financial benefit to our customers as discussed throughout our testimonies.

Within this proceeding, we present the 600 MW Rush Creek Wind Project ("Project") and request the Commission's authorization to develop and own this eligible energy resource and associated transmission pursuant to Rule 3660(h).The Project consists of two wind development areas – Rush Creek I and Rush Creek II – that are being constructed as a single project with an in service date of October 31, 2018. The Project also includes associated transmission facilities including a 345 kV radial transmission line that will enable the Company to interconnect these facilities with Public Service's existing transmission system at the Missile Site substation on the Pawnee-Daniels Park 345 kV transmission line. The project will be located in six counties in Colorado and 100% of the turbines have been sourced from Vestas, a Colorado based wind turbine manufacturer. Over the life of the project customers are anticipated to save over $400 million in power supply costs on a present value basis.

As the Company's policy witness, Ms. Jackson introduces the Company's other witnesses submitting Direct Testimony and brings together the various pertinent parts of the overall presented testimonies and attachments to provide an overview of the project. This presentation demonstrates how the Company has conducted a thorough and conservative evaluation of the costs associated with developing, owning, and operating this project. Additionally, while this project was not competitively bid through a traditional request for proposal process, the Company shows that the resulting project reflects evaluations of alternatives and processes which compared options available to the Company that ultimately result in a cost effective project for Public Service's customers.

Ms. Jackson lays out the numerous statutory, rule, and decision based requirements that the Company is required to adhere to in the presentation of this opportunity through its Application and provides direction on where and how those requirements were met in the Company's Application, Direct Testimony, and attachments. As part of this, Ms. Jackson presents the Company's inventory of eligible energy resources which shows that absent the currently requested 600 MW, the cumulative level of eligible energy resources currently on the Company's system is approximately 2,056 MW. Thus, provided the Commission approves the Company's application for the additional 600 MW, the Company will own 22.6 percent of the eligible energy resources acquired after March 27, 2007. Ms. Jackson also discusses the independent evaluator ("IE") report and how the Company interacted with the IE in the development of their report.

For the financial aspects of the Application, Ms. Jackson presents the Company's plan on financing the project, how it will impact the capital structure on an ongoing basis and ultimately presents the Company's proposal for cost recovery of this investment. We are not creating the cost recovery proposal from whole cloth, but instead took note of what cost recovery was utilized in another recently approved cost recovery arrangement for a utility owned renewable energy resource. Pursuant to statute the Company is afforded certain cost recovery, but it is not proposing to utilize all of the available incentives. Ms. Jackson details what cost recovery options were contemplated and ultimately the final proposal to initially recover the costs of the project after it is in service through the Electric Commodity Adjustment and the Renewable Energy Standard Adjustment until the first electric base rate case after the Project's in service date.

Finally, Ms. Jackson identifies and explains the Company's specific requests and explains why the Commission should find that the Company's requests in this proceeding are in the public interest. Ms. Jackson shows that the Project is in the public interest because it: (1) is economically beneficial for our customers; (2) aligns with our customers' long-term expectations to add incremental renewable resources; (3) comports with statutory requirements, as implemented by the Commission through its rules; (4) contributes to the maintenance of a healthy utility; (5) promotes compliance with future environmental standards; and (6) is beneficial for the State of Colorado. While some of these considerations standing alone may not justify the project being approved, when taken together they tell a compelling story as to why the Company's proposed Project is in the public interest and should be approved without modification.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE 600 MW RUSH CREEK WIND PROJECT PURSUANT TO RULE 3660(H), A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RUSH CREEK WIND FARM, AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE 345 KV RUSH CREEK TO MISSILE SITE GENERATION TIE TRANSMISSION LINE AND ASSOCIATED FINDINGS OF NOISE AND MAGNETIC FIELD REASONABLENESS.	))))))))))))))))	**PROCEEDING NO. 16A-0117E**

DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON

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LIST OF ATTACHMENTS

Attachment AKJ-1	IRS Guidance Regarding Safe Harbor for PTC
Attachment AKJ-2	Eligible Energy Resource Inventory

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
$/kW	Dollars per kilowatt
$/MW	Dollar per Megawatt
2017 Rate Case	Public Service's base rate case to be filed in 2017
Act	Omnibus Appropriations Act
AFUDC	Allowance for Funds Used During Construction
BVEM	Best Value Employment Metrics
CACJA	Clean Air Clean Jobs Act
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
DG	Distributed Generation
ECA	Electric Cost Adjustment
ELCC	Effective Load Carrying Capacity
ERP	Electric Resource Plan
FMB	First Mortgage Bonds
GDP	Gross Domestic Product
IE	Independent Evaluator
IPP	Independent Power Producer
IREA	Intermountain Rural Electric Association
LCI	Load Commutated Inverter

Acronym/Defined Term	**Meaning**
LCOE	Levelized Cost of Energy
Leidos	Leidos Engineering LLC
MWh	Megawatt-Hour
NCF	Net Capacity Factor
NEB	Net Energy Benefit
NOI	Notice of Intent
O&M	Operations and Maintenance
PPA	Purchased Power Agreement
Project	The Rush Creek Wind Project inclusive of generation and transmission
PTC	Production Tax Credits
Public Service or Company	Public Service Company of Colorado
PVRR	Present Value Revenue Requirements
QRUs	Qualified Retail Utilities
RAP	Resource Acquisition Period
RE Plan	2017-2019 Renewable Energy Plan
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
Rush Creek Gen-Tie	The transmission necessary to interconnect the Rush Creek Wind Project generation facilities
SOW	Statement of Work

Acronym/Defined Term	**Meaning**
TCA	Transmission Cost Adjustment
Vestas	Vestas Wind Systems
WACC	Weighted Average Cost of Capital
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION

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DIRECT TESTIMONY AND EXHIBITS OF ALICE K. JACKSON

I. INTRODUCTION, QUALIFICATIONS, REQUESTED APPROVALS, AND REQUESTS FOR WAIVER

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alice K. Jackson. My business address is 1800 Larimer Street, Suite 1400, Denver CO 80202.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as Regional Vice President, Rates and Regulatory Affairs. 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 “Company”) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service’s regulatory strategy and programs, and directing and supervising Public Service’s regulatory activities, including oversight of resource proceedings such as this proceeding, rate cases, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint response. I frequently testify in proceedings before the Colorado Public Utilities Commission (“Commission”) as the Company’s policy witness. I have included a Statement of Qualifications after the conclusion of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am the Company’s policy witness in support of our request for authorization pursuant to §40-2-124(1)(f)(I), C.R.S., and Commission Rule 3660(h) to develop and own the 600 MW Rush Creek Wind Project

("Project"). The Project consists of two wind development areas – Rush Creek I and Rush Creek II – that are being constructed as one project with an in service date of October 31, 2018, and associated transmission facilities including a 345 kV radial transmission line. I discuss many aspects of the Project and our requests in this case and after those discussions recommend that our development and ownership of this Project be found in the public interest and should be approved by the Commission.

More specifically, I will discuss the following topics in my Direct Testimony:

- Introductory matters including: (1) the identification of the Company's other witnesses, (2) a list of the specific approvals we are requesting, and (3) procedural issues including our request for expedition, our requests for waivers, and the interplay of this proceeding with our upcoming 2016 electric resource plan ("ERP") filing;
- An overview of the Project, including: (1) how it comports with applicable statutes (§40-2-124(1)(f)) and Commission rules (Rule 3660(h)); (2) how an analysis of the cost and benefits of the Project demonstrate that it is a "no regrets" investment; and, (3) how it fits into broader initiatives such as the Company's Our Energy Future initiative;
- The Company's inventory of eligible energy resources and a discussion of the obligations that flow from that inventory;
- The independent evaluator ("IE") process through the retention of Leidos Engineering LLC ("Leidos") and how in addition to the IE process the Company conducted its own comparison of cost competitiveness on a levelized cost of energy ("LCOE") basis and also compared the construction cost of Rush Creek I and II on a $/kW installed basis to other wind projects;
- Financial matters including how: (1) the Company intends to finance the Project through a combination of internally generated

funds, short and long-term debt, and equity investments from its parent, Xcel Energy Inc.; and, (2) the capital necessary for this project will not alter commitments made by the Company in its settlement agreement in its most recent electric rate case (Proceeding No. 14AL-0660E)**;**

- The Company's proposal for cost recovery of the Project including a discussion of the future net economic benefit calculation;
- Impacts of this Project on the Renewable Energy Standard Adjustment ("RESA");
- Why the Company's proposal is in the public interests; and,
- Provide a list of the specific approvals the Company is requesting of the Commission.

Q. PLEASE ELABORATE ON HOW THE PROJECT COMPORTS WITH THE COMPANY'S "OUR ENERGY FUTURE" INITIATIVE?

A. There are many components of the Our Energy Future initiative. Some have either been decided by the Commission already (Proceeding No. 15A-0847E, addressing Stapleton Battery Project and Panasonic Microgrid Project), others are pending before the Commission (Proceeding No. 16AL-0048E, Phase II Electric Rate Case; Proceeding No. 16A-0053G, Cost of Service Gas Program; Proceeding No. 16A-0055E, Solar*Connect; Proceeding No. 16A-0139E, 2017 Renewable Energy Plan, or "RE Plan"), or will be filed with the Commission in the near-term (our 2016 ERP and our Advanced Grid Intelligence and Security CPCN). We have developed this initiative to (1) embrace developing technologies; (2) empower customer choice; and, (3) power the economy. By continuing to embrace wind technologies and finding ways to keep prices reasonable, we continue to power the economy of Colorado. Additionally, we are continuing to meet our customers' desire for more renewable energy investment in an economical and cost effective manner. Our investment in the Project will help facilitate compliance with pending federal environmental initiatives and it is consistent with the policy of the State of Colorado, which encourages the development of renewables beyond minimum target levels.

Q. AT A HIGH LEVEL, PLEASE SUMMARIZE WHY THE COMPANY'S APPLICATION IS IN THE PUBLIC INTEREST.

A. The Project is economically beneficial for our customers, as shown through the various pieces of testimony provided in support of our application. It will save our customers over $400 million in power supply costs on a present value basis. The Project aligns with the long term "Our Energy Future" in that it is meeting the expectations of our customers for us to add renewable resources on our system in a way that is cost effective. We expect that the Project will move us closer to compliance with future federal environmental regulations, but irrespective of those, the policy embodied in the Renewable Energy Statute, §40-2-124, C.R.S, favors the addition of renewable energy resources beyond minimum target levels if cost effective. This statute also recognizes that utility ownership of renewable resources is beneficial and provides an incentive for utilities to develop and own these facilities.

Overall, we believe that pursuit of the Project is consistent with the "no regrets" approach that David Eves discussed with the Commission at its Commissioner Information Meeting in December 2015. As stated above and shown below, the economics of the Project for our customers are good, but the economics are also good for the State of Colorado. Through the incremental taxes, jobs created, and sourcing of materials for the Project, the Company has ensured that Colorado will benefit from this project long term. Throughout our supporting testimony we provide details regarding these benefits listed above for examination by stakeholders and the Commission.

Q. PLEASE IDENTIFY THE COMPANY'S OTHER WITNESSES WHO ARE FILING DIRECT TESTIMONY IN SUPPORT OF THE COMPANY'S APPLICATION AND THE AREAS THEY ARE COVERING.

A. In addition to myself, the Company is sponsoring ten witnesses in support of our Application. The following table identifies these witnesses and the areas that they are covering:

Witness	Area of Testimony
Riley Hill Senior Vice President of Energy Supply	• Describes the Rush Creek Wind Project facilities. • Supports the site selection and contracts. • Discusses the Company's role in constructing the project and due diligence activities undertaken. • Presents and supports project costs, project construction schedules and associated milestones. • Compares the construction cost of the Project with other facilities.
James Hill Director, Resource Planning	• Discusses the Company's evaluation of the Project's cost-reasonableness compared to wind resources recently offered to Public Service from the market. • Describes the Company's evaluation of the Project's cost-effectiveness to customers. • Discusses the interrelationship between this application and the Company's need for additional resources in its upcoming 2016 ERP.
Matt Hendrickson Global Manager of Energy Assessment of 3TIER by Vaisala Corporation	• Introduces and describes two reports issued by 3TIER by Vaisala, which analyze the expected energy performance of the Project.
Bill Zawacki Plant Director of Energy Supply	• Presents and discusses operation and maintenance activities concerning the Project. • Describes the Xcel Energy's experience with wind projects.

Witness	Area of Testimony
John Welch Director, Power Operations	• Discusses wind integration and operation of the Public Service electric system. • Presents information regarding wind ramp events and management of wind ramp events, and curtailment issues including presentation of the Company's flex reserves. • Supports the continued reliable operations associated with integrating 600 MW of wind onto the system.
Betty Mirzayi Manager, Transmission Planning	• Supports the Company's Application for a CPCN for the Rush Creek Gen-Tie transmission facilities. • Presents the transmission planning need, feasibility study and construction schedule associated with the Rush Creek Wind Project transmission facilities. • Presents an overview of FERC's large generator interconnection process.
Brad Cozad Manger, Transmission Engineering	• Discusses the planned engineering design for the Gen-Tie transmission facilities necessary for the Project. • Presents the noise and magnetic fields studies required for the Gen-Tie.
John Lupo Manager, Siting and Land Rights	• Discusses transmission siting, permitting and contract activities associated with the Rush Creek Wind Project.
Debbie A. Blair Director, Revenue Analysis	• Discusses the revenue requirement associated with the Project.
Tim Sheesley Chief Economist	• Introduces and discusses a University of Colorado Leeds School of Business Study demonstrating the economic benefits to the State of Colorado of the Rusk Creek Wind Project.

Q. WHY IS EXPEDITED TREATMENT OF THIS APPLICATION NECESSARY?

A. On December 18, 2015, the Omnibus Appropriations Act ("Act") was signed into law by President Obama. The Act includes a five-year extension of the Production Tax Credits ("PTC") for wind and other eligible renewable energy projects. While the PTC has been extended for five years, its decline begins after December 31, 2016. Eligible projects that meet IRS safe harbor requirements for beginning construction, i.e., expenditures of 5 percent of the total project cost by December 31, 2016 and in service by December 31, 2020, will qualify for the 2016 PTC level of 100 percent.

Q. HAS THE IRS RECENTLY ISSUED REVISED GUIDANCE ON THE SAFE HARBOR AND CONTINUITY SAFE HARBOR?

A. Yes. On May 5, 2016 the IRS updated its safe harbor guidance. Attachment AKJ-1 to my Direct Testimony is the guidance document issued by the IRS. The revised safe harbor guidance defines the "begin construction" standard the same as past guidance, but extends the deadline for "continuous construction" requirements. Specifically, rather than the facility needing to be in service two years after beginning construction, the IRS has extended that requirement to four years. Thus, the deadline for the in service date of the facility in order to qualify for the

PTC at 100 percent has been changed from year end 2018 to year end 2020.

Q. DOES THIS REVISED GUIDANCE CHANGE THE COMPANY'S PLAN OR NEED TO EXPEDITE APPROVAL OF THE RUSH CREEK WIND PROJECT?

A. No. Regardless of the change to the second requirement for the in service date of the Project, we still need to qualify for the safe harbor by the end of 2016. When we decided to go forward with the Project earlier this year, we reasonably looked to the past two PTC-related guidance documents in establishing proposed timelines and determining what contractual arrangements we needed. As a result, we had to proceed expeditiously in order to take full advantage of the PTCs. Our commercial transactions related to this Project were premised upon those guidance documents, i.e., with a safe harbor and then two years to put the facility in service. The tight timeline required in the IRS past guidance documents necessitated making commercial arrangements well before the time the revised guidance document was issued. Provisions in these commercial arrangements could allow us to extend the timeline for construction of this Project, however, those extensions would have adverse financial impacts on the Project cost and our customers. Delaying the Project would likely also reduce the projected savings that our Application shows will benefit our customers.

Q. WHAT IS THE IMPACT ON CUSTOMERS IF INSTEAD THE SAFE HARBOR IS SECURED FOR AN 80 PERCENT PTC VERSUS A 100 PERCENT PTC?

A. As detailed in the Direct Testimony of Mr. James Hill, if the Commission approves the Project within the timeline proposed by the Company, our customers are expected to save $443 million ("PVRR"), net of all costs, over a 40 year planning horizon by taking advantage of the 100 percent PTC benefit. At the 80 percent PTC benefit customers would be foregoing approximately $125 million of these savings. In order for the Company to meet the first of the safe harbor requirements prior to the end of calendar year 2016, the decision is needed on or before November 10, 2016. Under these circumstances, it will be important to obtain Commission review of our Application on an expedited basis.

Q. DOES THE COMPANY BELIEVE THAT THIS APPLICATION PROCEEDING SHOULD BE CONSOLIDATED WITH THE ELECTRIC RESOURCE PLAN ("ERP") PROCEEDING OR ANY OTHER PROCEEDING?

A. No. While certain data and studies are informative to both the 2016 ERP and this current proceeding, we have been careful to identify those pieces of data or studies that are necessary to evaluate this current proceeding in this proceeding, and have submitted that data and those studies for the Commission's review and consideration in this proceeding. To the extent that the same study or data are informative to the 2016 ERP, the results of their examination and Commission action will be available to the 2016 ERP in an appropriate timeframe for inclusion, if the sequencing of proceedings we have suggested is accepted.[1] We clearly lay this out in our updated Notice of Intent ("NOI") filed shortly after this proceeding and will file the same NOI as required by the Commission in our 2016 ERP. Thus, we are submitting with this Application all information that we believe necessary to support our requests, and are not relying on the Commission's disposition of any issues in other proceedings.

Q. SPECIFICALLY, WHAT STUDIES ARE YOU REQUESTING BE EVALUATED WITH THIS 3660(h) PROCEEDING VERSUS IN THE 2016 ERP AS WOULD HAVE OCCURRED "NORMALLY"?

A. In the Technical Inputs and Assumptions proceeding (Proceeding No. 16A-1038E) at the time of its filing, we noted certain studies that had yet to be completed. Where a study is relevant to both this proceeding and the 2016 ERP proceeding, we have proposed that the study be addressed in this proceeding since it will go to hearing first if the Commission accepts our procedural suggestion. These include the studies addressing wind integration, wind ELCC, wind-induced coal cycling costs, and flex resource adequacy, which are discussed in the Direct Testimonies of Company witnesses Mr. James Hill and Mr. John Welch.

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[1] *See* Response of Public Service Company of Colorado to the Commission's Questions Dated April 25, 2016.

Q. WHAT IS THE COMPANY'S POSITION IF THE COMMISSION DOES CONSOLIDATE THIS APPLICATION WITH THE ERP OR OTHER PROCEEDING?

A. If the Commission decides to consolidate any other proceeding with this proceeding, we would ask that the entire consolidated proceeding be decided on an expedited basis, no later than November 10, 2016, in order for our customers to benefit from the full PTC credit. We believe that deciding a larger consolidated proceeding on an expedited basis will be harder to accomplish than if it is limited to the Rule 3660/CPCN proceeding, which is why we do not favor consolidation.

Q. WILL THE COMPANY'S PROPOSED PROJECT BE REFLECTED IN ITS 2016 ERP?

A. Yes, it will. When the Commission modified Rule 3615 and other ERP Rules in Decision No. C10-0958, it noted that it expected utilities would seek authorization to acquire utility-owned renewable resources through a separate application, such as this one, even though they are required to be identified in a resource plan. The relevant Commission discussion is as follows:

> We will adopt the change set forth in the NOPR so that utility investments in renewable energy resources pursued under § 40-2-124(1)(f)(I), C.R.S., would no longer be exempt from an ERP. We find that an ERP filing must indeed address the acquisition of utility-owned new renewable energy resources greater than 30 MW, even if the utility intends to acquire that resource without competitive bidding. Although we understand the concerns expressed by Black Hills that this change might

> prevent or slow down the acquisition of additional utility-owned renewable resources between ERP filings, we note that the RES Rules nonetheless require the utility to file an application whenever it seeks to develop such assets absent competitive bidding.

Q. HOW IS THE COMPANY'S APPROACH CONSISTENT WITH DECISION NO. C10-0958?

A. Decision No. C10-0958 puts in place two requirements: (1) a utility-owned eligible energy resource must be addressed in an ERP, and (2) the utility must file an application under the RES Rules to acquire the resource absent competitive bidding. We are proceeding consistent with Decision No. C10-0958 because we are filing an application to develop and own eligible energy resources pursuant to the RES Rules and specifically Rule 3660(h). At the same time, our proposal to develop and own the Rush Creek Wind Project will be addressed by being reflected in our 2016 ERP, which we expect to file within a couple of weeks of our present application and no later than June 1, 2016. Additionally we have reflected the Project in our most recently approved ERP, the 2011 ERP, as shown in analysis by Mr. James Hill.

Q. ARE THE ERP RULES AND RES RULES CONSISTENT WITH ONE ANOTHER AS APPLIED TO APPLICATIONS FOR UTILITY OWNERSHIP OF ELIGIBLE ENERGY RESOURCES?

A. There appears to be inconsistency between the requirements of Rule 3660(h) and Rule 3611(e). Decision No. C10-0958 and the underlying rulemaking in that proceeding did not reconcile the alternative method of resource acquisition pursuant to Rule 3611(e) with bringing forward an eligible energy resource pursuant to § 40-2-124(1)(f)(I), C.R.S. and Rule 3660(h).

We have sought to reconcile the inconsistencies between the various Rules, and through our approach I believe we have satisfied the requirements of Rule 3660(h) and Rule 3611(e). We have done so by filing an application as required by Rule 3660(h) and seeking a CPCN for the new utility-owned eligible energy resource consistent with Rule 3660(i). By filing an application for a CPCN pursuant to Rule 3660(i), we have satisfied the CPCN requirement in Rule 3611(e). Moreover, although it was not feasible to quantify and present the costs of alternatives in the form described in Rule 3611(e), we do discuss the alternatives that we considered in developing our proposal.

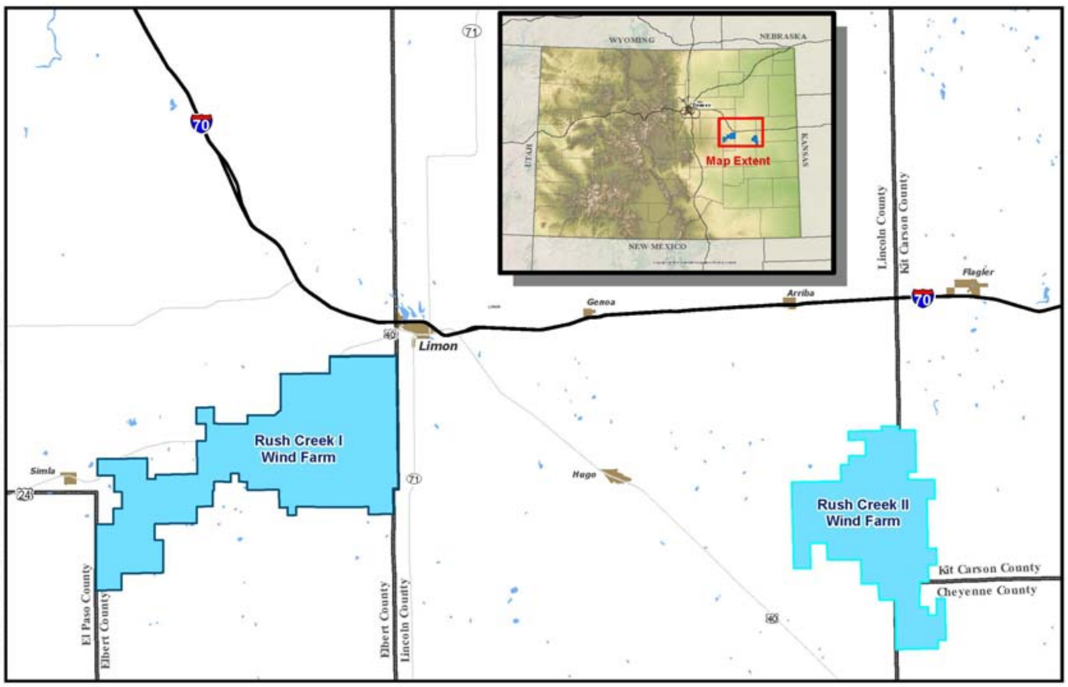
Q. IF THE COMPANY'S APPROACH IS CONSISTENT WITH BOTH THE RES RULES AND THE ERP RULES, WHY IS THE COMPANY SEEKING LIMITED WAIVERS OF THE ERP RULES IN THIS PROCEEDING?

A. The inconsistencies between the RES Rules and the ERP Rules have led us to take a cautious approach. We have asked for certain waivers of the Commission's ERP Rules in our Application due to timing issues created by the incongruity between the two subsets of Commission Rules. This issue is explained further in our motion seeking expedited treatment and limited waivers accompanying this Application. We have tried to fashion an approach that satisfies the intent of the RES Rules and the ERP Rules despite the inconsistencies between them. I believe our approach satisfies all applicable requirements as between these Rules and gives parties a meaningful opportunity to evaluate the Rush Creek Wind Project in this standalone proceeding, while still having it addressed in the ERP to the extent it impacts our broader resource need in that forward-looking proceeding.

II. THE RUSH CREEK WIND PROJECT

Q. PLEASE DESCRIBE THE RUSH CREEK WIND PROJECT.

A. The Rush Creek Wind Project will include a 600 MW wind farm located on 90,000 acres of land south of Limon and spanning Elbert, Lincoln, Cheyenne and Kit Carson counties as depicted in the figure below.



The Project's components include 400 MW of Vestas Wind Systems ("Vestas") wind turbines in Elbert County ("Rush Creek I"), and 200 MW of Vestas wind turbines in the Eastern Plains of Colorado, specifically Lincoln, Cheyenne, and Kit Carson counties ("Rush Creek II"), as well as the transmission and switching station facilities that will be built to connect the wind generation output from the turbines to our Missile Site Substation in Arapahoe County, Colorado. 300 Vestas model V110 turbines, which are built in Colorado and have a nameplate capacity of 2 MW each, will be used for the project. Additionally, the Company has entered into an agreement with Invenergy to help develop and construct the Project, should the Commission approve this application. The Direct Testimony of Mr. Riley Hill describes in more detail the Rush Creek Wind Project facilities at both Rush Creek I and Rush Creek II, including anticipated project costs and project construction schedules.

In order to deliver the energy produced from the wind turbines to customers, the 345 kV Rush Creek Gen-Tie and other transmission-related facilities will also need to be constructed. The Gen-Tie will be approximately 90 miles in length, from the Rush Creek II site to a new Rush Creek Switching Station and from the Rush Creek I site to the Switching Station then to the Missile Site Substation. The Direct Testimonies of Betty Mirzayi, Brad Cozad, and John Lupo describe the facilities, siting, engineering, construction schedule, and other details of the transmission facilities associated with the Project and the information necessary for the transmission CPCN. Maps of the Project are included as attachments to the Direct Testimony of Mr. Riley Hill.

Q. THE COMPANY FILED A PETITION REGARDING THE PAWNEE DANIELS PARK 345 KV PROJECT TO START CONSTRUCTION IN 2017. HOW DOES THAT EFFECT THE DELIVERY OF THE RUSH CREEK PRODUCTION?

A. The Company has performed a feasibility study that indicates the additional generation production from the Rush Creek Wind Project can be accommodated by the system as an energy resource. Our dispatch organization, as explained by Mr. John Welch, believes that we reliably manage the delivery of this energy to our load by using the dispatch tools they use today to manage wind on the system. We believe the level of curtailment will be manageable and will not pose a reliability risk to the system. Further, these curtailments are not expected to be material to the overall cost-effectiveness of the Project. Mr. James Hill discusses the Strategist modeling cost of wind curtailments in his Direct Testimony. The Public Service system is becoming more flexible in its ability to accommodate increased levels of wind generation. This increased flexibility is the result of a combination of retiring Valmont Unit 5 and converting Cherokee 4 to gas which support the reduction in wind curtailments.

In addition, on April 29, 2016 the Company filed a petition for the Commission to allow the Company to begin construction of the Pawnee Daniels Park transmission project as early as 2017. If the Commission approves our petition, the Rush Creek production will be able to be delivered on firm transmission.

Q. WHAT IS THE ESTIMATED COST OF THIS PROJECT?

A. The total cost of the Project is estimated to be $1.036 billion. Of that total amount, the total cost of the wind facilities is $915 million and the cost of the transmission line to interconnect the Project is $121.4 million. When looking at the project on a nameplate dollar per kilowatt ("$/kW") basis the wind generation facilities is $1,525/kW and the 345 kV transmission is another $202/kW. At a levelized cost of energy ("LCOE") of $28.68/MWh, the Project is less than 3 cents per kWh (even with 90 miles of new 345 kV transmission costs) – which, if approved, would be the lowest cost wind resource on our Colorado system. Although Rush Creek I and II will not use the full capacity of the 345 kV Gen-Tie, we took a conservative approach and include the full transmission line costs when evaluating the cost of the project.

Q. HOW ABOUT ONGOING COSTS?

A. Operations and maintenance ("O&M") costs for the Project are factored into the LCOE cost estimate above. That LCOE estimate includes O&M over the estimated life of Rush Creek I and II as well as the transmission O&M costs for the Rush Creek Gen-Tie.

Q. DID THE COMPANY COMPARE THE COST OF THE PROJECT TO OTHER COMPARABLE PROJECTS?

A. Yes. In addition to the evaluation performed by the IE, Company witness Mr. Riley Hill shows that the construction costs for Rush Creek I and II compare favorably to construction costs of other wind energy resources available in the market. Additionally, Mr. James Hill demonstrates that the Rush Creek Wind Project is being proposed at a cost that is reasonable compared to the costs of (1) the over 12,000 MW of similar new wind facilities that have been made available to Public Service from the market in recent years and (2) the 2,566 MW of existing wind PPAs that were acquired through Commission approved processes and proceedings. We therefore demonstrate in our Application and testimonies that the Project is reasonably priced compared with market alternatives from both a LCOE standpoint and a construction cost standpoint. We have satisfied the reasonable construction cost standard set forth in § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h)(I), as our analysis and the analysis of the IE both independently establish.

Q. WHAT IS THE CONSTRUCTION AND IN-SERVICE DATE TIMELINE FOR THE RUSH CREEK WIND PROJECT?

A. The Company has requested expedited treatment of this application such that a decision of the Commission is received on or before November 10, 2016. This will allow the Company to begin construction by the end of the year so that the 100% PTC may be obtained. Mr. Riley Hill discusses the construction timeline for Rush Creek I and II, which are anticipated to be in service by October 31, 2018. Ms. Betty Mirzayi discusses the construction timeline for the Rush Creek Gen-Tie which will reach construction completion by August 31, 2018. Ms. Mirzayi will also discuss the interplay of the Pawnee Daniels Park transmission project which will not reach completion until October 2019.

Q. HAS THE COMPANY CONSIDERED ALTERNATIVES TO THE PROJECT AND ITS NECESSARY TRANSMISSION FACILITIES?

A. As we have pursued the development of the Project, we have evaluated various alternatives or options. In particular, instead of developing our own site, we investigated pre-developed sites and ultimately purchased two owned by Invenergy that were in an advanced pre-development stage. It can take several years to get a site to this stage, and therefore this option was favorable given that time was of the essence with the short window to commence construction and take advantage of the 100% PTC for customers. Before selecting Invenergy, we considered sites that were under development by other wind developers as well. Mr. Riley Hill discusses the selection process further in his testimony.

With regard to the transmission facilities necessary to interconnect the wind turbines to the system, the Company considered both a 230 kV solution as well as a 345 kV solution. The 230 kV solution provides sufficient capacity to deliver the output of the proposed Rush Creek Wind Project; however, for a slightly higher initial cost, the transmission can be built at 345 kV and ultimately result in cost savings to customers while also enabling other resources to be developed in this area. The net effect of constructing the Rush Creek Gen-Tie at 345 kV versus 230 kV that we have quantified in our analysis is an approximate $6 million in customer benefit. In addition to these energy related customer benefits, there are additional benefits that would come with the 345 kV alternative that were not quantified in our evaluation, such as the future opportunity to interconnect additional generation capacity to the 345 kV line, and the ability to utilize the 345 kV line as a network resource in the larger interconnected transmission system. This examination and presentation of transmission options is further presented by witnesses – Ms. Betty Mirzayi, Mr. James Hill, and Mr. Riley Hill.

Q. PLEASE DISCUSS THE COMPANY'S OWNERSHIP, OPERATIONS, AND MAINTENANCE OF THE PONNEQUIN WIND FACILITY?

A. The Ponnequin Wind facility was the first wind farm constructed in Colorado when the wind market and wind turbine technologies were immature. We acknowledge that there have been operational issues associated with the Ponnequin Wind Farm. However, there have been significant advancements in wind turbine technology, making a comparison of Ponnequin to the Rush Creek Wind Project inappropriate.

The Company presents witness Mr. Zawacki regarding the O&M we will perform on the Rush Creek Wind Project, including the numerous points of monitoring we will have available to us which were not available for the Ponnequin project.

Q. WHY IS PUBLIC SERVICE PROPOSING TO DEVELOP THIS PROJECT AT THIS TIME?

A. As noted above, with the extension of the PTC, the Company has another great opportunity to invest in a resource for the benefit of its customers, a "no regrets" investment. We believe the Rush Creek Wind Project will bring savings to our customers, is consistent with state public policy encouraging utility investment in eligible energy resources, and furthers Public Service's environmental stewardship efforts. The Rush Creek Wind Project will lower emissions; however, we have not quantified these on a $/MWh basis for purposes of showing more benefit. Thus, after evaluating our options, we actively pursued the opportunity to bring this resource to fruition.

Q. HOW DOES THE RUSH CREEK WIND PROJECT FURTHER PUBLIC SERVICE'S ENVIRONMENTAL STEWARDSHIP EFFORTS?

A. Public Service and its parent company, Xcel Energy, are recognized leaders in reducing emissions, integrating renewable power and ensuring the responsible transition to a cleaner energy future. Xcel Energy is the number one wind energy provider in the nation for the last twelve consecutive years. Clean energy from renewable resources account for more than 20 percent of Xcel Energy's total energy supply.

The Rush Creek Wind Project allows us to continue delivering on our environmental stewardship efforts, including continued reduction of carbon emissions each year from the Public Service power supply system. We remain committed to expanding the use of renewable energy in the most economical way for our customers.

Q. HOW WILL THE RUSH CREEK WIND PROJECT AFFECT PUBLIC SERVICE'S RESOURCE NEEDS GOING FORWARD?

A. The Company's proposal will not eliminate its need to acquire additional resources. In its 2016 ERP, Public Service will propose an 8-year Resource Acquisition Period ("RAP"). The proposed Rush Creek I and II have been included in that 2016 ERP evaluation of loads and resources. The resource need over the 8-Year RAP is reflected in the technical inputs and assumptions filed in Proceeding No. 16A-1038E and reflects an ongoing need in the latter years of the RAP. While Rush Creek I and II contributes to the resources component of the loads and resources evaluation, its contribution to reducing the overall need in the latter years is minimal as discussed further by Mr. James Hill.

Q. HAS THE COMPANY TAKEN A CONSERVATIVE APPROACH TO ESTIMATING THE COST OF THE RUSH CREEK WIND PROJECT?

A. Yes, as I indicated above we have imputed the full cost of the 345 kV Rush Creek Gen-Tie in the $1,727/kW of the total Project costs being compared to market.

Q. IS THIS THE ONLY CONSERVATIVE ESTIMATE OR ACTION THE COMPANY HAS TAKEN IN DEVELOPING THE PROJECT COST?

A. No. There are actually a number of other actions or estimates that we would consider to have been conservative in our calculations. Some of the costs are reflected in the capital cost or $/kW evaluation while other measures would increase the cost effectiveness of the project.

Related to the project capital costs, we have included the full cost of the Gen-Tie rather than only the portion necessary to serve the project, and we are not seeking construction work in progress ("CWIP") Rule 3660(i).

With respect to project cost effectiveness and the conservative nature of our proposal, we: (1) maintained our current capital structure; (2) performed sensitivity analysis on the Project's cost effectiveness assuming it generates below the expected level of generation as discussed by Mr. James Hill; and, (3) did not include all potential tax benefits of the Internal Revenue Code Section 199 domestic production tax deduction in the calculation.

III. STATUTORY AND PROCEDURAL HISTORY, REQUIREMENTS, AND FULFILLMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. Both the statute and the Commission's Rules lay out a number of requirements where a qualified retail utility pursues ownership of renewable resources outside of a competitive process. In this section of my Direct Testimony I will discuss these requirements, as well as how the Company has met its obligation to meet each of these requirements. Specifically, this section is divided into two parts: (1) statutory and procedural history and requirements; and (2) fulfillment of requirements.

A. Statutory and Procedural History and Requirements

Q. WHAT PROCEDURAL AND STATUTORY HISTORY HAS PRECIPITATED THE COMPANY BRINGING FORWARD THIS APPLICATION?

A. The Company is filing this Application pursuant to Rule 3660(h). On March 27, 2007, the Colorado Generally Assembly passed House Bill 07-1281 ("HB 07-1281"). This legislation increased the Renewable Energy Standard ("RES") percentage requirements for investor-owned utilities and also implemented separate RES percentage requirements for electric cooperatives. As part of increasing the RES targets across the state, the

General Assembly also included a provision in HB 07-1281 directed at incenting utility ownership of eligible energy resources.[2]

Q. WHAT DOES THE STATUTE PROVIDE REGARDING THE STATE'S RENEWABLE ENERGY PLAN AND COMPANY OWNERSHIP OF ELIGIBLE ENERGY RESOURCES?

A. The relevant provision of HB 07-1281, codified at § 40-2-124(1)(f)(I), C.R.S. reads as follows:

> (f) Policies for the recovery of costs incurred with respect to these standards for qualifying retail utilities that are subject to rate regulation by the commission. These policies must provide incentives to qualifying retail utilities to invest in eligible energy resources and must include:
>
> (I) Allowing a qualifying retail utility to develop and own as utility rate-based property up to twenty-five percent of the total new eligible energy resources the utility acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007, if the new eligible energy resources proposed to be developed and owned by the utility can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market. The qualifying retail utility shall be allowed to develop and own as utility rate-based property more than twenty-five percent but not more than fifty percent of total new eligible energy resources acquired after March 27, 2007, if the qualifying retail utility shows that its proposal would provide significant economic development, employment, energy security, or other benefits to the state of Colorado. The qualifying retail utility may develop and own these resources either by itself or jointly with other owners, and, if owned jointly, the entire jointly owned resource shall count toward the percentage limitations in this subparagraph (I). For the resources addressed in this subparagraph (I), the qualifying retail utility shall not be required to comply with the

[2] Rule 3652(n) defines an eligible energy resource as "renewable energy resources or facilities that generate recycled energy or greenhouse gas neutral electricity generated using coal mine methane or synthetic gas."

> competitive bidding requirements of the commission's rules; except that nothing in this subparagraph (I) shall preclude the qualifying retail utility from bidding to own a greater percentage of new eligible energy resources than permitted by this subparagraph (I). In addition, nothing in this subparagraph (I) shall prevent the commission from waiving, repealing, or revising any commission rule in a manner otherwise consistent with applicable law.[3]

The statute sets up two different standards that must be satisfied depending upon the ratio of utility ownership of eligible energy resources that will result from the development and ownership of the proposed resource. For up to 25 percent of the cumulative total eligible energy resources acquired or developed and owned since March 27, 2007, the applicable standard is determining "if the new eligible energy resources proposed to be developed and owned by the utility can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market." If the utility ownership proposal will result in more than 25 percent and up to 50 percent of the cumulative total eligible energy resources acquired or developed and owned since March 27, 2007, then the statute requires that the reasonable cost showing be made and the utility must establish that the "proposal would provide significant economic development, employment, energy security, or other benefits to the state of Colorado."

[3] § 40-2-124(1)(f)(I), C.R.S. (2016).

Q. HOW HAS THE COMMISSION IMPLEMENTED THESE STATUTORY REQUIREMENTS IN COMMISSION RULES?

A. Consistent with the directive of the General Assembly, the Commission undertook rulemakings in Proceeding No. 07R-166E and Proceeding No. 08R-424E to implement HB 07-1281. This resulted in the implementation of and modification to numerous rules; however, most relevant to this proceeding and fundamental to our application is Rule 3660(h). Rule 3660(h) was implemented by Decision No. C07-622 in Proceeding No. 07R-166E.[4] Rule 3660(h)(I)-(III) put in place the percentage thresholds and applicable standards contemplated by the statute as follows:

> (h) An investor owned Qualified Retail Utilities ("QRU")[5] may propose to develop and own, in whole or in part, a new eligible energy resource by filing an application with the Commission. The Commission may set the matter for hearing, if appropriate, under the Commission's Rules of Practice and Procedure. For the purpose of this paragraph 3660(h):
>
> (I) A QRU shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in rule 3656, up to twenty-five percent of the total new eligible energy resources that the QRU acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007 if the Commission determines that the QRU-owned new eligible energy resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market.
>
> (II) A QRU shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in rule 3656, up to fifty percent of the total new eligible energy resources that the QRU acquires from

[4] Decision No. C07-0622, at ¶¶ 45-54, Proceeding No. 07R-166E (mailed July 23, 2007) (adopting Rule 3660(e), which is now Rule 3660(h)).
[5] QRU means a qualifying retail utility.

entering into power purchase agreements and from developing and owning resources after March 27, 2007 if the Commission determines that the QRU-owned new eligible energy resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market and that the proposed new eligible energy resource would provide significant economic development, employment, energy security, or other benefits to the state of Colorado.

(III) The QRU shall be allowed to develop and own as utility rate-based property more than the percentages of total new eligible energy resources set forth in rules 3660(h)(I) and (h)(II), if the QRU bids to own the new eligible energy resources in a competitive solicitation and is selected as a winning bidder in that competitive solicitation.[6]

Q. DO THE COMMISSION'S RULES HAVE ADDITIONAL PROCEDURAL REQUIREMENTS BEYOND THOSE SET FORTH IN STATUTE?

A. Yes. Rule 3660(h)(I)-(III) track the standards set forth in the statute, and through the rulemaking conducted in Proceeding No. 07R-166E, the Commission added the Independent Evaluator ("IE") requirement that exists in Rule 3660(h)(V). Rule 3660(h)(V) requires the IE to "develop a report to the Commission on its assessment of whether the proposed new eligible energy resources can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market."[7] Further, Rule 3660(i) indicates that the Commission expected that a utility would file a CPCN application for those eligible energy resources that it proposed to develop and own, a requirement not found in the statute.

[6] 4 C.C.R. 723-3-3660(h)(I)-(III).
[7] 4 C.C.R. 723-3-3660(h)(V).

Q. WHAT ARE THE SPECIFIC REQUIREMENTS PROVIDED IN RULE 3660(h) FOR THE COMMISSION TO CONSIDER THE COMPANY'S OWNERSHIP REQUEST?

A. The QRU must show that the applicable standard set forth in either Rule 3660(h)(I) or Rule 3660(h)(II) is satisfied by the proposed new eligible energy resource. In addition, in advance of filing an application under Rule 3660(h), the QRU must seek Commission approval of an IE to conduct a reasonable cost analysis consistent with the discussion above. The proposed IE must satisfy the eligibility requirements of Rule 3660(h)(V). Once the IE has developed its report, the IE report must be filed with the QRU's application for approval of the proposed new eligible energy resource. Further, "[t]he evaluator's report shall contain the evaluator's views on whether the proposed new eligible energy project can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market."

Q. ARE THERE ANY OTHER REQUIREMENTS OF THE COMPANY ASIDE FROM THOSE LAID OUT IN RULE 3660(h)?

A. Yes. In Decision No. R09-0413, the Commission stated that a utility must make available at the time it files an Application to develop and own eligible energy resources pursuant to Rule 3660(h) an inventory of the total new eligible energy resources that it acquires after March 27, 2007: (1) through PPAs and (2) developed and owned by the utility. The cumulative figure in the inventory is then used by the utility in determining its § 40-2-124(1)(f)(I), C.R.S., ratio and the applicable standard that must be satisfied.

Q. HAS THE COMMISSION GIVEN ANY GUIDANCE REGARDING HOW OWNERSHIP PERCENTAGES ARE TO BE DETERMINED FOR THE PURPOSES OF APPLYING §40-2-124(1)(f), C.R.S. AND RULE 3660(h)?

A. Yes. The Commission recently found in Proceeding No. 16D-0168E that the appropriate standard to apply under § 40-2-124(1)(f)(I), C.R.S., is based on a comparison of the proposed project capacity and the cumulative capacity of the total new eligible energy resources the utility acquires since March 27, 2007, including the proposed project.[8]

Q. IN THIS SUBSECTION YOU HAVE BEEN DISCUSSING A NUMBER OF REQUIREMENTS THAT THE QRU MUST FULFILL IN PRESENTING AN APPLICATION TO THE COMMISSION PURSUANT TO RULE 3660(h). WOULD YOU PLEASE PROVIDE A LIST OF EACH OF THESE REQUIREMENTS?

A. Yes. Below is Table AKJ-1 containing the requirements we believe are laid out in statute and/or rule that the Company as a QRU must fulfill in its 3660(h) Application.

[8] *See* Decision No. C16-0362, Proceeding No. 16D-0168E (mailed Apr. 26, 2016).

1 **Table AKJ-1 Application Requirements**

Requirement Reference	Statutory/Rule Reference	Description
A	§ 40-2-124(1)(f)(I), C.R.S.; Rule 3660(h)(I); Rule 3660(h)(II)	File application under the RES Rules to develop and own an eligible energy resource
A.1	Decision R09-0413	Inventory of eligible energy resources after March 27, 2007
A.2	§ 40-2-124(1)(f)(I), C.R.S.; Rule 3660(h)(I); Rule 3660(h)(II); Decision No. C16-0362	Determination of percentage of eligible energy resources acquired or developed and owned after March 27, 2007
A.3	Rule 3660(h)(I)	Support for 25% or less ownership through reasonable cost comparison test
A.4	Rule 3660(h)(II)	Support for 50% or less ownership through reasonable cost comparison test and economic benefit
B	Rule 3660(i)	The QRU must file a CPCN for its resource
C	Decision No. C10-0958	Proposed Rule 3660(h) resource reflected in the ERP and file a separate application under the RES Rules
D	Rule 3660(h)(V)	Acquisition and report of the independent evaluator
D.1	Rule 3660(h)(V)	Propose IE and have IE approved by Commission prior to Application
D.2	Rule 3660(h)(V)	Presentation of IE report concurrent with Company's application
D.3	Decision No. C07-0735; Decision No. C16-0267-I	IE available for cross-examination by Commission, intervenors and Company

B. Requirement Fulfillment

1. Fulfillment of Requirement A

Q. HAS THE COMPANY COMPLIED WITH THE INVENTORY REQUIREMENT?

A. Yes. I have included the inventory as Attachment AKJ-2.

Q. PLEASE DESCRIBE HOW ATTACHMENT AKJ-2 IS LAID OUT.

A. Attachment AKJ-2 includes all resources acquired through PPAs and also includes distributed generation ("DG") resources and Community Solar Garden resources. In doing so, it captures the universe of eligible energy resources that should be included in the cumulative calculation under the statute.

Q. DID THE COMPANY USE THIS INVENTORY IN CALCULATING ITS OWNERSHIP PERCENTAGE FOR THE PURPOSES OF RULE 3660(h)?

A. Yes. The Commission recently found in Proceeding No. 16D-0168E that the appropriate standard to apply under § 40-2-124(1)(f)(I), C.R.S., is based on a comparison of the proposed project capacity and the cumulative capacity of the total new eligible energy resources the utility acquires since March 27, 2007 including the proposed project.

Q. WHAT TOTAL CAPACITY OF ELIGIBLE ENERGY RESOURCES HAS PUBLIC SERVICE ACQUIRED SINCE MARCH 27, 2007?

A. As shown in Attachment AKJ-2, after performing the required inventory Public Service will have acquired 2,056 MW of installed capacity from eligible energy resources prior to the in-service date of Rush Creek I and II. This is reflected on line 32 of Attachment AKJ-2. This inventory reflects the following quantities of resources:

Eligible Energy Resource Type:	**MW Acquired After 3/27/2007**
Wind:	1,538.4 MW
Large Scale Solar	250.0 MW
Distributed Solar	260.0 MW
Hydro & Biomass:	7.7 MW
Total:	2,056.1 MW

Q. WHAT PERCENTAGE OF OWNERSHIP WOULD THAT MEAN THE COMPANY WOULD HAVE IF THE RUSH CREEK WIND PROJECT IS APPROVED?

A. The results of our calculation reflect the Company would have a 22.6 percent ownership in eligible energy resources pursuant to the statute and rule if the Rush Creek Wind Project is approved. We derived the 22.6 percent through the following analysis. The Company currently has 2,056.1 MW of eligible energy resources owned by third parties and purchased by the Company that were acquired after March 27, 2007.[9] Using the cumulative eligible energy resource approach approved by the Commission, this results in the following calculation:

[9] The Company has preexisting resources, which are utility-owned, that are not included in any § 40-2-124(1)(f)(I), C.R.S. calculation because these resources are outside the scope of the statute. Specifically, they were developed and owned prior to March 27, 2007.

600 MW
(Company's proposal)

2,656.1 MW
(existing 2,056.1 MW + 600 MW proposal)

Accordingly, the result is that Public Service will own 22.6 percent of the total new eligible energy resources the utility acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007, once the Rush Creek Wind Project is complete

Q. DOES THE CALCULATION ABOVE INCLUDE DISTRIBUTED GENERATION?

A. Yes, and we believe it is proper to include DG resources in the calculation. However, if we back out the 260.0 MW of DG resources, the percentage of ownership of eligible energy resources is 25.0 percent.

Q. WHY DOES THE COMPANY BELIEVE IT IS APPROPRIATE TO INCLUDE DG RESOURCES IN ITS CALCULATION UNDER § 40-2-124(1)(f)(I), C.R.S., AND RULE 3660(h)?

A. Eligible energy resources are to be included in the calculation of "the total new eligible energy resources" under the statute and rule. Rule 3652(n) defines an eligible energy resource as "renewable energy resources or facilities that generate recycled energy or greenhouse gas neutral electricity generated using coal mine methane or synthetic gas." This broad definition would include DG resources, and therefore we felt it was appropriate to include these resources in the calculation.

Q. WHAT SUBPART OF RULE 3660(h) DOES THE COMPANY BELIEVE IS THE REQUIREMENT THAT IT MUST ADHERE TO WITH THE CALCULATED PERCENTAGE OF OWNERSHIP?

A. As noted above, different criteria apply to a proposed project depending on the cumulative ownership level that will be achieved – that is, either up to 25 percent (Requirement A.3) or up to 50 percent (Requirement A.4). Because we are seeking to own total new eligible energy resources at the 22.6 percent amount, we must meet what is listed as Requirement A.3 in the table above. This means that the Company must show that the resource can be constructed at a reasonable cost as compared to similar resources in the market under § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h)(I).

Q. HAS THE COMPANY SET FORTH EVIDENCE THAT IT SATISFIES REQUIREMENT A.3?

A. Yes. As discussed throughout my testimony and the testimony of other Company witnesses, we prove that the Rush Creek Wind Project "can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market." The testimony of Company witness Mr. James Hill establishes that the cost of the Rush Creek Wind Project on a levelized cost of energy ("LCOE") basis is reasonable with similar wind resources made available to Public Service in the market, and the testimony of Mr. Riley Hill shows that the construction cost of Rush

Creek I and Rush Creek II is reasonable as compared to the construction costs of similar wind resources.

Q. DID THE COMPANY PERFORM ANY ANALYSES WITH RESPECT TO REQUIREMENT A.4?

A. Yes. While Rule 3660(h)(I) applies to this application because, inclusive of the 600 MW wind project, we will own 22.6 percent of the total eligible energy resources the Company acquires after March 27, 2007, we have also conducted a study consistent with Requirement A.4. This study shows the "significant economic development, employment, energy security, or other benefits to the state of Colorado" as set forth in Rule 3660(h)(II). I discuss some of the benefits in addition to Company witness Mr. Sheesley addressing the economic and employment benefits associated with the Project, which would justify a higher level of utility developed and owned eligible energy resources even if Rule 3660(h)(II) applied.

2. <u>Fulfillment of Requirement B</u>

Q. DID THE COMPANY FILE A CPCN WITH ITS APPLICATION?

A. Yes, the Company has included a request for two CPCNs in this application; a CPCN for Rush Creek I and II ("generation CPCN") consistent with Rule 3660(i) and a CPCN for the 345 kV Rush Creek Gen-Tie ("Transmission CPCN").

Q. WHAT ARE THE COMMISSION RULES APPLICABLE TO THESE CPCNS?

A. Rule 3102 provides the requirements for CPCNs to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., that is not in the ordinary course of business. Rule 3102(b) provides the information that must be included in a CPCN application, which includes:

- Facts showing the public convenience and necessity require the granting of the application;
- A description of the facilities;
- Estimated cost of the facilities;
- Construction timeline;
- A map showing where the facilities will be constructed;
- As applicable, electric one-line diagrams; and,
- Information on alternatives studied.

Additionally, for transmission facilities:

- Compliance with Rule 3206;
- Under Rule 3102(c) cost effective noise mitigation information; and,
- Under Rule 3102(d) information regarding prudent avoidance with respect to magnetic fields.

Additionally for generation facilities:

- Compliance with Rule 3205; and
- Information concerning Best Value Employment Metrics under Rule 3102(e).

Q. WHERE IN THE COMPANY'S DIRECT TESTIMONY IS THE REQUIRED INFORMATION PROVIDED?

A. For the generation CPCN, the information required by Rule 3102 is provided in the application and through the Direct Testimony of Mr. Riley Hill. For the transmission CPCN, Mr. Brad Cozad addresses the transmission cost estimate and the information required by Rule 3102 is provided in the application and through the Direct Testimonies of Ms. Mirzayi, Mr. Cozad, and Mr. Lupo. For both CPCNs, the facts showing that the public convenience and necessity merits granting the CPCNs are supported by all the witnesses that filed testimony in this proceeding, as well as by the IE report. I address the public interest of the project in my testimony as well as Mr. James Hill addresses this topic in his Direct Testimony.

Q. HAS THE COMPANY MADE A RULE 3205 FILING CONCERNING THE RUSH CREEK WIND GENERATION FACILITIES?

A. Yes. As required by Rule 3205(c), the Company has filed its Rule 3205 report for new construction or expansion of existing generation that will result in an increase in generating capacity of ten megawatts or more. While Rule 3205 does not state which projects are *not* in the ordinary course of business, Rule 3205(b)(II) states that new construction or expansion of existing generation that will result in an increase in generating capacity of less than ten megawatts *is* within the ordinary course of business. The proposed 600 MW Rush Creek Wind Project is considerably larger than 10 MW.

Q. HAS THE COMPANY MADE A RULE 3206 FILING CONCERNING THE TRANSMISSION FACILITIES ASSOCIATED WITH THE RUSH CREEK WIND PROJECT?

A. Yes. As required by Rule 3206(d), the Company has filed its annual report for planned transmission facilities, which includes the 345 kV Rush Creek Wind Gen-Tie transmission line. This is also discussed further by Company witness Ms. Betty Mirzayi.

Q. WHY IS A SEPARATE CPCN NEEDED FOR THE GEN-TIE TRANSMISSION LINE FACILITIES?

A. The Company is taking a conservative approach by requesting a separate CPCN for the transmission facilities. Rule 3206(b)(I) indicates that a CPCN application is required for:

> Transmission facilities designed at 230 kV or above, even if initially operated at a lower voltage. However, a radial transmission line designed at 230 kV or above that serves a single retail customer and terminates at that customer's premises will not require a CPCN application.

The minimum voltage necessary for the Gen-Tie transmission line to support the 600 MW of generation from the Rush Creek I and II wind turbines would be 230 kV however on an economic basis the 345 kV is more cost effective. In addition, if the Gen-Tie was sized at 230 kV, the line would be serving only one wholesale customer, the Energy Supply division of Public Service.

As proposed, the Gen-Tie transmission line is sized at 345 kV, first because it will result in cost savings to customers. As an ancillary benefit, sizing the transmission line at 345 kV will accommodate future growth of the system if and when additional wind power is constructed in the future in this region of Colorado. A 345 kV transmission line has fewer losses than a 230 kV transmission line.

Mr. Riley Hill and Ms. Mirzayi discuss the transmission interconnection requests made by the Company as well as the construction costs of both a 230 kV and a 345 kV transmission line. As stated above, Mr. James Hill discusses the cost effectiveness of a 345 kV transmission interconnection over a 230 kV to be about $6 million in customer benefit over a 40 year planning horizon. Knowing that transmission facilities have a much longer life, the cost effectiveness could exceed the $6 million. Ms. Mirzayi provides testimony concerning the general interest shown by developers in interconnection requests in eastern Colorado.

Q. HAS THE COMPANY REQUESTED BEST VALUE EMPLOYMENT METRICS AND PROVIDED IT TO THE COMMISSION?

A. Yes. Commission Rule 3102(e) requires that the following best value employment metrics ("BVEM") information be provided: (1) the availability of training programs, including training through apprenticeship programs; (2) the employment of Colorado workers as compared to importation of out-of-state workers; (3) long-term career opportunities; and (4) industry-standard wages, health care, and pension benefits. As discussed by Mr. Riley Hill, the BOP contractor will construct the generation facilities. While a BOP contractor has not been selected, the Company will request that potential BOP bidders provide best value employment metrics information with their bids. Consistent with Rule 3102(f), we will provide this information to the Commission upon receipt by filing it in this proceeding. As required by Rule 3102(f), we will provide a status report within 45 days after a contract is awarded and parties may comment on this status report within 15 days

3. <u>Fulfillment of Requirement C</u>

Q. HAS THE COMPANY COMPLIED WITH REQUIREMENT C?

A. Yes. As discussed earlier in my testimony, the Project will be reflected in the Company's 2016 ERP. In addition, the Company has gone back to the models used to evaluate the selected portfolio under the 2013 All-Source Solicitation to show that even under that approved ERP Plan, this project is costs effective. Finally, consistent with Decision No. C10-0958, we are filing a separate Application under the RES Rules 3660(h) for approval of the Rush Creek Wind Project.

4. Fulfillment of Requirement D

Q. HAS THE COMPANY SATISFIED REQUIREMENT D?

A. Yes. The Company began this proceeding by seeking approval of an IE, and the Commission approved one IE by Decision No. C16-0267-I on March 29, 2016, and two alternate IEs (as well as necessary waivers for one of the IEs, Leidos Engineering, LLC ("Leidos")) by Decision No. C16-0302-I on April 7, 2016.

Q. DID PUBLIC SERVICE HIRE AN IE TO EVALUATE THE RUSH CREEK WIND PROJECT?

A. Yes. Decision No. C16-0302-I in this proceeding approved Leidos as an alternate IE, and shortly after Decision No. C16-0302-I issued, we entered into a contract with Leidos to be the IE required under Rule 3660(h). I discuss later in my testimony the IE's analysis of the Project and the IE report finding that the Project as proposed has a reasonable cost as compared to similar eligible energy resources in the market.

Q. DID THE COMPANY INCLUDE AN IE REPORT WITH ITS APPLICATION?

A. Yes. The IE's report is included as Attachment 1 to Public Service's Application in this proceeding. This report offers Leidos' "assessment of whether the proposed new eligible energy resources can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market," as required by Rule 3660(h)(V). I provide more detail about Leidos' scope of work and a summary of its report later in my testimony.

IV. COST COMPARISON WITH SIMILAR RESOURCES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my testimony is to discuss the cost comparison the Company conducted to establish that, as required by § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h)(I), the Rush Creek Wind Project "can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market." In addition, I address the report of the IE, which reaches the same conclusion that we do: the Rush Creek Wind Project costs are reasonable.

A. The Company's Cost Comparison

Q. CAN THE RUSH CREEK WIND PROJECT BE CONSTRUCTED AT REASONABLE COST COMPARED TO THE COST OF SIMILAR ELIGIBLE ENERGY RESOURCES AVAILABLE IN THE MARKET?

A. Yes. We conducted two sets of analyses to establish that the Rush Creek Wind Project satisfies the reasonable cost standard of Rule 3660(h). First, Company witness Mr. James Hill provides a detailed analysis comparing the levelized cost on a dollar per megawatt-hour ("MWh") of similar resources to the Rush Creek Wind Project. Second, Mr. Riley Hill demonstrates that the Rush Creek I and II construction costs are reasonable on a dollar per MW basis as compared to the construction costs of similar resources in the market. And, as discussed below, the IE reached the same conclusion.

Q. IS THE RUSH CREEK WIND PROJECT COST EFFECTIVE FOR PUBLIC SERVICE'S CUSTOMERS?

A. Yes. Company witness Mr. James Hill shows that, under the base assumptions for electric sales and natural gas prices, the addition of the Rush Creek Wind Project showed substantial customer savings over a 40 year planning period ($443 million PVRR). $310 million, or about 70 percent, of these Project savings occur in the first 10 years of operation, with the remaining savings occurring in years beyond 2029. A substantial portion of these savings relate to the PTC, indicating the importance of securing the 100 percent PTC level by obtaining Commission approval in time to secure the PTC safe harbor.

Mr. James Hill demonstrates in his testimony that customer savings from the Rush Creek Wind Project continue to be present across numerous sensitivities, including a range of natural gas prices.

Finally, Mr. James Hill tested the economics of the Rush Creek Wind Project within a framework fully vetted by parties in a litigated ERP and approved by the Commission, the 2011 ERP. The results of this analysis showed customer savings of $431 million PVRR which are very much in line with the $443 million derived for this proceeding using updated modeling assumptions.

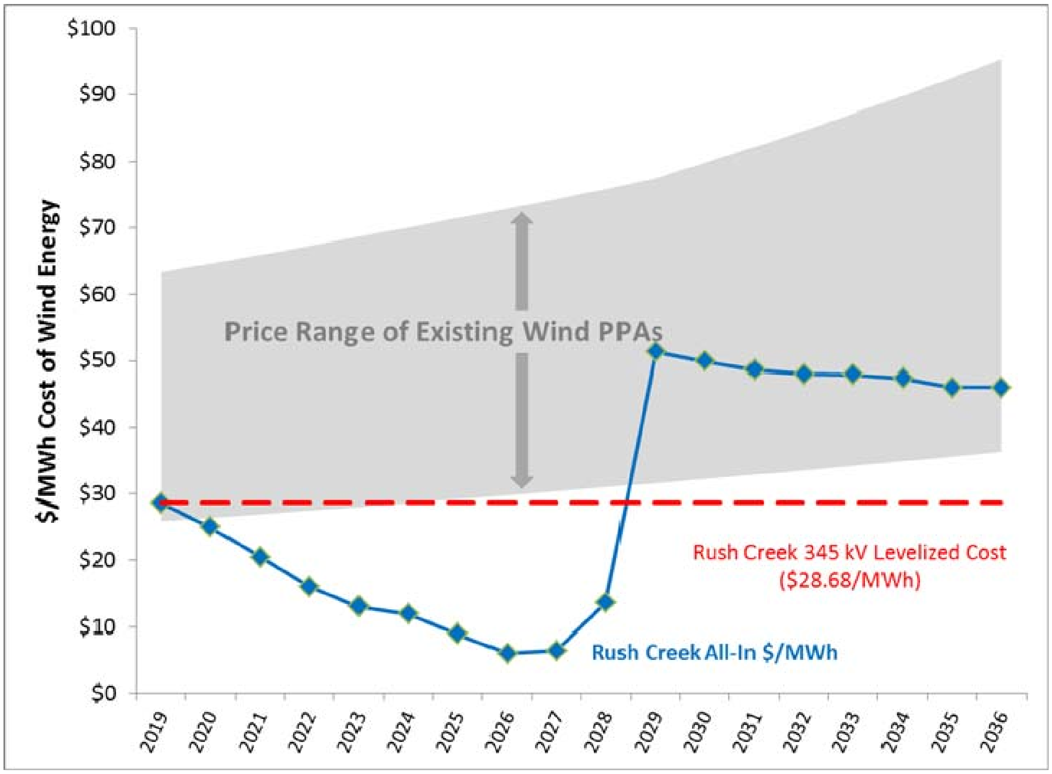
Q. HOW DO THESE SAVINGS COMPARE TO PROJECTS RECENTLY APPROVED BY THE COMMISSION?

A. These savings are more than twice the approximate $230 million in savings associated with the 450 MW of wind approved by the Commission in our 2013 All-Source Solicitation (i.e., the 200 MW Limon 3 and 250 MW Golden West projects). The Company projects customer savings under all sensitivities examined concerning natural gas prices, wind levels, and other factors.

Q. DID MR. JAMES HILL COMPARE THE RUSH CREEK WIND PROJECT ON AN ANNUAL COST BASIS WITH PUBLIC SERVICES 2,566 MW OF EXISTING WIND POWER PURCHASE AGREEMENTS?

A. Yes. He compared the annual $/MWh costs for the Rush Creek Wind Project with the annual $/MWh pricing of the existing 2,566 of wind PPAs currently operating on the Public Service system. The figure below (Figure JFH-3 from Mr. James Hill's testimony) contains a graphical depiction of this comparison along with the Project LCOE for comparison purposes.

$/MWh Comparison Rush Creek & Existing Wind PPAs



The all-in annual cost of energy from the Project is well below that of all existing PPAs over its first 10 years of operation, then for the remaining 15 years of the Projects life, its all-in costs track below the median $/MWh cost of existing PPAs. This amply demonstrates that the Project costs are "reasonable cost" compared to the cost of similar eligible energy resources Public Service has acquired from the market.

Q. CAN THE RUSH CREEK WIND PROJECT BE CONSTRUCTED AT A REASONABLE COMPARATIVE COST ON A CAPITAL COST BASIS?

A. Yes. The projected capital cost of the Wind Project is $915 million for the wind generation, which as Mr. Riley Hill describes, results in a cost of $1,525/kW installed. Mr. Riley Hill compares this $/kW installed figure cost with the cost of three Company affiliate projects in Minnesota and North Dakota, and this cost is competitive with the construction costs of those projects. Moreover, Mr. Riley Hill also analyzes a broader set of wind resources from a data set compiled by the Lawrence Berkeley National Laboratory. As explained in his testimony, Mr. Riley Hill finds that the $1,525/kW installed is competitive with the costs of the resources in the report in 2014 and the anticipated costs for 2015, as these 2015 costs are not yet available. Mr. Riley Hill's analysis further establishes that the Project satisfies the reasonable cost standard in Rule 3660(h)(I).

B. Independent Evaluator

Q. DID LEIDOS CONDUCT AN ASSESSMENT AND ISSUE A REPORT CONCERNING THE RUSH CREEK WIND PROJECT?

A. Yes. The Leidos IE Evaluation Report is attached to our application in this proceeding.

Q. WHAT WAS THE SCOPE OF WORK THAT LEIDOS WAS ASKED TO PERFORM REGARDING THE RUSH CREEK WIND PROJECT?

A. Public Service and Leidos executed a Statement of Work ("SOW") to develop and execute the methodology that supports a cost comparison and engineering assessment in accordance with Rule 3660(h)(V). This methodology includes, but should not be limited to, methods and criteria for comparing:

- Construction costs of similar wind energy resources available in the market, that considers, but is not limited to, costs associated with: land purchase and lease payments during construction of the wind project, wind farm development costs, new access roads and road improvements, wind turbine generating equipment, collector systems and collector substations.
- Construction costs of similar wind energy farms available in the market that are either in active development, have been approved for construction, are under construction, or in commercial operation.
- Levelized cost of wind energy projects on a $/MWh basis that has or can be delivered directly to the Public Service of Colorado system.
- Viability to complete the proposed wind energy project as proposed.

Land acquisition and permitting costs were not evaluated due to the lack of available information in the 12 sampled comparable wind farm projects. Further, in accordance with the SOW the Independent Evaluator shall:

- Review the Company's proposed wind project detailed design, construction estimates, timelines, equipment procurement, and wind resource analysis of the project;
- Perform all work necessary to research, identify, gather and review appropriate data that is needed to conduct the assessment;

- Bring to the Commission, essential and unbiased information concerning national and regional construction costs for new renewable resources; and
- Initiate contact with the Company as often as necessary to identify, clarify, and/or obtain any data necessary to conduct the assessment

The SOW specifies that the IE shall deliver a final written report to the Company to be filed with the CPUC, and that any supporting testimony is independent and not on behalf of the Company.

Q. DID LEIDOS WORK WITH PUBLIC SERVICE TO REVIEW THE DESIGN, CONSTRUCTION ESTIMATES, TIMELINES, EQUIPMENT PROCUREMENT, AND WIND RESOURCE DATA CONCERNING THE RUSH CREEK WIND PROJECT?

A. Yes. Leidos requested specific project documents including, but not limited to, construction estimates, contracts, project schedules, engineering, construction and procurement documentation, the Vaisala Wind Resource Analysis, revenue requirement estimates, customer benefit estimates, and maps. Company experts were made available, at the IE's request to review, clarify and explain these materials.

Information sharing of written materials was made exclusively through a Microsoft SharePoint website ("IE website") with controlled access. Telephonic communications between the Company and the IE were closely managed by the Leidos Project Manager, and the Company's Rush Creek Project Manager. On-site visits were limited to a project kick-off data review and a detailed Levelized cost of energy review.

Q. PLEASE SUMMARIZE THE IE'S ASSESSMENT CONCERNING THE RUSH CREEK WIND PROJECT.

A. The Independent Evaluator concludes that:

- The turbine and Balance of Plant costs are approximately 4.6% less than the average costs for comparable projects on a dollar per kW basis.

- The total estimated construction costs are 4.7% higher than the average cost for comparable projects, on a dollar per kW basis, due to the more expensive proposed interconnection and transmission facilities.

- The estimated operating costs are less than the average cost for comparable projects.

He also concluded that:

- The expected LCOE of the Rush Creek Project is lower than any of the existing PSCo Wind Purchased Power Agreements ("PPA").

- The expected LCOE is projected to have a 90% probability of being lower than four of the five sampled Wind PPAs.

And finally, "Leidos concludes that the proposed Project by PSCo is reasonably likely to be developed, constructed, and operated at a lower levelized cost than the projects PSCo is currently purchasing from, which represent the best information available regarding the wind energy market available to PSCo."

Q. IS LEIDOS AVAILABLE TO SUPPORT ITS INDEPENDENT ASSESSMENT AND REPORT IN THIS PROCEEDING?

A. Yes, the IE has been made aware that it must be available in this proceeding for discovery and cross-examination by not only any intervenor, but also by the Company.

V. PROJECT FINANCING

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. This section of my testimony addresses how the Company intends to finance the development of the Project.

Q. PLEASE GIVE AN OVERVIEW OF HOW THE COMPANY INTENDS TO FINANCE THE WIND FARM INVESTMENT.

A. Public Service utilizes a combination of internally generated funds, short and long-term debt, and equity investments from its parent, Xcel Energy, to fund its capital expenditures. Public Service plans to finance this large-scale project in the same manner that it funds its baseline capital investment plan, which is approximately $5 billion over the 2016 – 2020 timeframe.

The incorporation of this additional capital investment into the five-year capital plan will drive incremental financing needs; however, the financing of the investment is straight forward and will occur over the next three years as the project is constructed. Moreover, with the next general rate case scheduled to be filed in 2017, the long-term debt issuances and resulting impacts of the projected low-cost debt will be incorporated into Public Service's overall long-term cost of debt in a timely manner for the benefit of the customers.

Q. PLEASE DESCRIBE THE ACCESS THE COMPANY HAS TO SHORT-TERM DEBT FINANCING.

A. Public Service issues commercial paper backed by its existing $700 million revolving credit agreement which expires in October 2019 to finance short-term funding requirements. Public Service also participates in the Utility Money Pool through which it can lend and borrow short-term funds from other Xcel Energy utility subsidiaries. Public Service has authorization from the Commission to access up to $250 million of short-term financing from that source. Short-term debt is used for the short-term funding requirements and is generally 'termed' out by the issuance of long-term debt, which is then used to pay down the short-term debt balance.

Q. PLEASE DESCRIBE PUBLIC SERVICE'S LONG-TERM DEBT FINANCING CAPABILITIES.

A. Public Service plans to issue an incremental $450M - $500M of First Mortgage bonds ("FMB") in 2017 and 2018 depending on the exact timing of capital expenditures and cash flow generation by the overall business. This incremental financing is above our current baseline financing forecast, which currently includes an issuance in 2018 that is necessary to refinance a maturing bond. Public Service generally alternates between 10-year FMBs and 30-year FMBs in order to maintain a diversified long-term debt portfolio and will assess the market conditions at the time of issuance to determine if it is more beneficial to issue a 10-year FMB or a 30-year FMB.

Public Service currently has $450 million remaining under the current authorization from the Commission to issue debt securities through December 31, 2016 (Decision No. C13-0227 under Docket 13A-0057SEG). Public Service will file a new financing application prior to the expiration of the current authorization, which will contain additional detail covering the 2017-2019 financing plan.

Q. PLEASE DISCUSS PUBLIC SERVICE'S EQUITY INFUSIONS FROM ITS PARENT AS A FINANCING METHOD.

A. Public Service will also receive equity investments from its parent as required to manage its capital structure and fund the wind farm investment. This is consistent with how Xcel Energy currently infuses equity for its normal capital investment plan.

Q. WHAT ARE THE EXPECTED TERMS FOR THE BOND THAT THE COMPANY PLANS TO ISSUE?

A. Public Service plans to issue both 10-year and 30-year FMBs to help finance the investment. Currently, Public Service plans to issue a 10-year FMB in 2017 and a 30-year FMB in 2018; however, as stated previously, Public Service will assess the market closer to the issuance date. The projected coupon for a 10-year FMB in 2017 is estimated at 3.5 percent while the coupon for a 30-year FMB in 2018 is estimated at 4.6 percent.

This coupon is based on a recent Global Insights treasury yield forecast of approximately 2.60 percent for the 10-year U.S. Treasury Bond in Q3 of 2017 and 3.40 percent for the 30-yr U.S. Treasury Bond in Q2 of 2018 plus the current indicative credit spread of approximately 90 bps for a 10-year FMB and 120 bps 30-year FMB.

Under these projected coupons, Public Service's overall cost of long-term debt would decline as the coupon for both of these issuances is projected to be near or below the current authorized cost of Public Service's long-term debt portfolio (Authorized cost of 4.67 percent in Proceeding No. 14AL-0660E). As mentioned before, the timing of this investment aligns well with the next general electric rate case proceeding in which the benefits of the projected low-cost debt will be passed on through to customers as the long-term debt issuances will be reflected in the overall long-term debt portfolio.

Q. HOW WILL THE COMPANY'S CAPITAL STRUCTURE BE AFFECTED BY THE ACQUISITION OF THE RUSH CREEK WIND PROJECT?

A. In the Company's most recent electric rate case (Proceeding No. 14AL-0660E) the Company reached a comprehensive settlement agreement with the parties. As part of that settlement agreement, the Company made two commitments in regards to capital structure. First, that for the purposes of the earnings sharing tests and other riders during the pendency of the settlement, that the equity component would be capped at 56 percent. Additionally, the Company committed to "manage the equity component of the capital structure so that when rates become effective as a result of the 2017 Rate Case, the equity component of the actual capital structure will be lower than 56%."[10] The incremental addition of the capital necessary for this project will not alter that commitment made by the Company in its settlement agreement. However, lowering the capital structure would lower the LCOE.

[10] Proceeding No. 14AL-0660E. Settlement Agreement Section II.B (page 22)

VI. COST RECOVERY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to set forth our proposed method of cost recovery for the Rush Creek Wind Project. First, I will address the cost recovery mechanisms available to the Company for this eligible energy resource. Second, I set forth the Company's proposed cost recovery approach for the Rush Creek Wind Project, including the RESA impacts of the proposed approach. Third, I discuss which of the cost recovery mechanisms Public Service is forgoing and the associated cost impacts. And fourth, I address and the Company's proposed semi-annual reporting process, which we have successfully used in other proceedings.

A. Background – Cost Recovery of Utility-Owned Eligible Energy Resources

Q. PLEASE DESCRIBE THE STATUTES AND RULES THAT PROVIDE FOR COST RECOVERY OF INVESTMENTS IN ELIGIBLE ENERGY RESOURCES.

A. Colorado law and Commission Rules provide several favorable cost recovery mechanisms designed to "provide incentives to qualifying retail utilities to invest in eligible energy resources …."[11] The general categories

[11] § 40-2-124(1)(f), C.R.S.

of cost recovery incentives, as well as the statutory basis and relevant Commission Rule for each, are as follows:

- *Earning a return at the most recent Commission authorized rate of return.* § 40-2-124(1)(f)(III), C.R.S., and Rule 3660(g) provide that utilities may earn their most recent Commission authorized rate of return on investments in eligible energy resources. Utilities are allowed this cost recovery regardless of whether the eligible energy resource provides a net economic benefit to customers.

- *Earning an extra profit on investments in eligible energy resources that provide a net economic benefit to customers.* § 40-2-124(1)(f)(II), C.R.S., and Rule 3660(g) allow a utility to earn an extra profit on utility-owned eligible energy resources that provide a net economic benefit to customers. On an annual basis, the bonus may be up to 50 percent of the net economic benefit (in addition to the return on investment at the most recent Commission authorized rate of return). Rule 3660(g)(I)-(III) provide specifics regarding the net economic benefit calculation and accounting treatment of the net economic benefit.

- *Earlier and timely recovery of investments in eligible energy resources.* § 40-2-124(1)(f)(IV), C.R.S., and Rule 3660(i) allow for earlier and timely cost recovery when a utility files an application for a CPCN for a utility-owned eligible energy resource. These include (1) the use of rate adjustment clauses until the costs associated with the eligible energy resource are included in base rates, and (2) a current return on capital expenditures during construction at the utility's weighted average cost of capital, including the most recently authorized rate of return on equity. This latter cost recovery is available "during the construction, startup, and operation phases of the eligible energy resource."[12]

B. Overview of the Proposed Cost Recovery Approach

Q. WILL THE COMPANY ULTIMATELY RECOVER THE COSTS OF THE PROJECT THROUGH BASE RATES?

A. Yes. The Company is proposing that costs of the Rush Creek Wind Project will eventually be recovered through base rates, with the exception

[12] § 40-2-124(1)(f)(IV)(B), 4 C.C.R. 723-3-3660(i).

of the PTC as described below. As part of the first rate case following the Project reaching commercial operation, we intend to include the Project as part of the overall revenue requirement and recover the cost through base rates. However, prior to such time we are recommending initial cost recovery through the ECA and the RESA. This cost recovery approach is consistent with another QRU-owned wind resource that is currently being recovered through base rates in Colorado. Specifically, the Commission approved this initial treatment for the 50 percent ownership share of Black Hills/Colorado Electric Utility Company, LP in the Busch Ranch Wind Project in Proceeding No. 14AL-0393E.

Q. PLEASE DESCRIBE THE TIMEFRAMES RELEVANT TO THE COMPANY'S PROPOSED COST RECOVERY APPROACH.

A. The Company has three discrete timeframes in which cost recovery for the Rush Creek Wind Project will occur. As reflected below, we will file our next base rate case in 2017 for rates expected to go into effect no earlier than January 1, 2018 ("2017 Rate Case"). If we propose and receive approval of a multi-year rate plan, then the timing of including the Rush Creek Wind Project in base rates would wait until the following electric rate case. The commercial operation date of the Rush Creek Wind Project is anticipated to be October 31, 2018. Based on an assumed three year multi-year rate plan, we then would expect to file a rate case in 2020 for rates that would be effective the following year ("2020 Rate Case"). With this background, our cost recovery approach breaks out into three timeframes:

- Timeframe 1: from commencement of construction to estimated commercial operation on October 31, 2018;
- Timeframe 2: from the estimated commercial operation date of October 31, 2018 to the effective date of new rates from the next rate case (anticipated to be a 2020 Rate Case); and
- Timeframe 3: from the effective date of new rates from the anticipated 2020 Rate Case going forward.

Q. ARE THE TIMEFRAMES IN THE ABOVE LIST LOCKED DOWN?

A. No. The timeframe structure is what the Company is proposing, not the specific dates or rate case methodologies. The dates included in the timeframe structure above are illustrative so that parties may evaluate the three periods presented conceptually.

Q. HOW LONG COULD THE PROJECT BE COLLECTED THROUGH THE ECA AND RESA IF YOU DON'T FILE A RATE CASE IN 2020?

A. Regardless of when a rate case is filed, we propose that the costs of the Project be rolled into base rates no later than five (5) years after the Project is placed into commercial operation.

1. Rush Creek Wind Project Cost Recovery –Timeframe 1

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE RUSH CREEK WIND PROJECT DURING TIMEFRAME 1?

A. Rule 3660(i) provides as follows:

> When an investor owned QRU applies for a certificate of public convenience and necessity, the Commission shall consider rate recovery mechanisms that provide for earlier and timely recovery of costs prudently and reasonably incurred by the QRU in developing, constructing, and operating the eligible energy resource, including: *(a) rate adjustment clauses until the costs of the eligible energy resource can be included in the utility's base rates; and (b) a current return on the utility's capital expenditures during construction at the utility's most recently authorized weighted average cost of capital, including its cost of debt and its most recently authorized rate of return on equity, during the construction, startup, and operation phases of the eligible energy resource*. (emphasis added)

The Commission's public policy posture in recent decisions has reaffirmed the intent of this rule. For example, in Decision No. C14-0280 in Proceeding No. 13AL-0816E, the Commission stated that "the public utilities law and Commission rules reflect Colorado's strong policy to allow recovery of prudently incurred costs to acquire eligible energy resources." In this proceeding, we have brought forward, among other things, a CPCN application for the Project. Because the Project qualifies as an eligible energy resource under Rule 3652(n) and we are seeking a CPCN, we are eligible for the early and timely cost recovery treatment set forth in this rule.

Nevertheless, we do not intend to seek to recover CWIP and a current return on CWIP at the most recently authorized weighted average cost of capital ("WACC") through the RESA during construction of the Rush Creek Wind Project. We will forgo our right to cost recovery until the Project is in commercial operation and instead accrue interest at the Allowance for Funds Used During Construction ("AFUDC") rate. I discuss this decision – and the effects of this decision – in more detail later in my testimony.

Q. WHAT AFUDC RATE DOES THE COMPANY PROPOSE TO USE?

A. We will use the calculated AFUDC rate as it automatically adjusts. For comparison sake, the table below reflects our actual AFUDC rate over the past four years.

Table AKJ-2: Historical AFUDC Rates

	2012	**2013**	**2014**	**2015**
Historical AFUDC	7.98%	7.71%	6.21%	6.55%

Q. IS THIS HOW THE COMPANY TYPICALLY ACCRUES AFUDC ON CAPITAL PROJECTS?

A. Yes, with the exception of our Clean Air Clean Jobs Act ("CACJA") projects. For the recovery associated with the CACJA projects, we used our WACC as the AFUDC rate, but we are not proposing to do that here.

2. Rush Creek Wind Project Cost Recovery – Timeframe 2

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE PROJECT DURING TIMEFRAME 2?

A. Following the commercial operation date, we propose to recover the costs of the Project through a mix of the ECA and RESA. Our Timeframe 2 approach allows for cost recovery for this eligible energy resource through rate adjustment clauses between base rate cases, as contemplated by § 40-2-124(1)(f)(IV), C.R.S. and Rule 3660(i). Under this approach, the costs of the resource at and below system avoided costs will be recovered through the ECA while incremental costs will be recovered through the RESA. We would proceed with this recovery approach until the Project is placed in base rates following the earlier of five (5) years or following the first base rate case after the Project is in service.

Q. PLEASE DESCRIBE THE PROCESS NECESSARY TO ALLOCATE THE PORTION OF THE REVENUE REQUIREMENTS RECOVERED IN THE ECA VERSUS THE RESA.

A. The process is necessary to identify the correct split between the ECA and the RESA and is accomplished through a detailed modeling process. The modeling for cost recovery between the ECA and RESA during Timeframe 2 will be conducted according with the modeling process set forth in Rule 3661(h), which provides the basic method of determining the retail rate impact of eligible energy resources over the cost of non-eligible energy resources.[13] This process is known as the RES/No-RES modeling. Rule 3661(h) details the methodology by which Public Service is to use its computer models to estimate the incremental costs associated with the addition of eligible energy resources.

Generally speaking, the Rule 3661(h) methodology requires modeling of the total electric system costs of two alternative scenarios or models of electric resources over a planning period. The first modeling scenario, i.e., the RES, includes the eligible energy resources that are present or projected to be added on the Public Service system. The second modeling scenario, i.e., the No-RES, is comprised of a sufficient amount of "non-renewable resources reasonably available" that would be needed to replace the "new" eligible energy resources in the RES component of the modeling. The difference in annual system costs between these two scenarios for any particular year is referenced as the modeled incremental costs of the eligible energy resources.

Q. HOW WOULD THE TRADITIONAL RES/NO-RES MODELING WORK IN THE CONTEXT OF THIS PROCEEDING?

A. Given the limited scope of our application in this proceeding, the RES/No-RES modeling is straightforward. In the RES scenario we would add the 600 MW of wind resources and associated costs from the Rush Creek Wind Project. In the No-RES scenario the Rush Creek Wind project and the other new eligible energy resources are removed, and the model

[13] 4 C.C.R. 723-3-3661(h).

replaces the energy and capacity with conventional generation resources (or non-eligible energy resources). The delta between the annual system costs of the two models is the incremental costs of the new eligible energy resources, and the portion of these incremental costs associated with the Rush Creek Wind Project would be recovered through the RESA. The remaining revenue requirements, which are equivalent to the avoided costs of the wind generation, would be recovered through the ECA.

Q. WHAT INPUTS SPECIFIC TO THE RUSH CREEK WIND PROJECT WOULD BE INCLUDED IN THE RES/NO-RES MODELING?

A. The inputs include net rate base, the return on rate base, the total O&M associated with Project, depreciation, taxes, taxable income, and the PTC. The estimated generation patterns of the Rush Creek Wind Project are also used as a model input. The rate base component also includes the Gen-Tie portion of the costs for the project.

Q. HAS THE COMMISSION ALLOWED THESE TYPES OF REVENUE REQUIREMENTS TO BE RECOVERED THROUGH THE ECA AND RESA IN THE PAST?

A. Yes, as discussed above, the Commission approved this recovery treatment of a utility owned wind plant by Black Hills. Also, the Commission approved the recovery of the Company's owned portion of the Ponnequin Wind Farm revenue requirements and earnings through a combination of ECA and RESA. Finally, the cost recovery of the purchased power agreements for other eligible energy resources are exclusively recovered through the ECA and RESA.

Q. WHEN WILL THE ALLOCATIONS BETWEEN THE ECA AND RESA BE CALCULATED?

A. The allocation methodology of costs for the Rush Creek Wind Project between the ECA and the RESA will be established in this proceeding. Also, for the years 2017 through 2019 the Company proposes to calculate the ECA and RESA cost allocation of the Rush Wind Project in this proceeding. For the remaining years in Time period 2, the Company proposes to calculate the ECA and RESA cost allocation in a future RE Plan. Although the allocations may change by year based on the output of the RES and No-RES models, consistent with Commission Rule 3661(h)(V), the modeling output will be locked down for the period of each RE Plan.

Q. WHY WILL THIS PROCEEDING ONLY LOOK AT YEARS 2017 AND 2019 FOR THE RESA CALCULATION?

A. Currently before the Commission in Proceeding No. 16A-0139E is the Company's proposal for its RE Plan for calendar years 2017 through 2019. To achieve alignment with that filing and consistency with Rule 34661(h)(V), we are addressing the 2017 through 2019 period here. Of note, however, the Project will not be in service until late in 2018.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL CONSIDERATIONS TO THE ALLOCATION OF COST BETWEEN THE ECA AND RESA OF THE RUSH CREEK WIND PROJECT?

A. Yes. Given the relatively large size of the Rush Creek Wind Project, the health of the RESA deferred balance, as well as the cost effective nature of the Project, the Company believes it is appropriate to consider the cost allocation for the Rush Creek Wind Project differently than we have for other eligible energy resources in the past. Specifically, the Company proposes that to the extent that (1) the RESA deferred balance is positive and (2) the modeled avoided costs for the Rush Creek Wind Project exceed the actual costs in a given year (e.g. the Project is financially beneficial to customers), the Company be permitted to pass on the full net benefit directly to Customers through the ECA for that year, and exclude the resource from the RESA calculation. Conversely, should the actual costs be greater than the modeled avoided costs in a given year or if the RESA deferred balance is negative (e.g. the Project is a net cost to customers), the incremental costs of the Project would be allocated to the RESA.

Q. HOW IS THIS ALLOCATION METHODOLOGY DIFFERENT THAN WHAT THE COMPANY DOES FOR ITS OTHER ELIGIBLE ENERGY RESOURCES?

A. Under the RES/No-RES methodology that the Company has employed in previous RE Plans, the RES/No-RES calculations examine all of the new eligible energy resources in total, and evaluate their collective costs effectiveness as one large group of resources. If a single eligible energy resource in the group is cost effective, meaning that the actual cost of the resource is less than the avoided cost, the benefits of that cost effective resource serve to offset the incremental cost of other more expensive eligible energy resources and the net incremental cost which is allocated to the RESA is reduced. Employing this treatment for the Rush Creek Wind Project would mean that any benefits that the resource would bring to the system would first serve to reduce the costs allocated to the RESA from the ECA, and would not directly flow to customers. It would only be after the net incremental costs of all eligible energy resources reached zero, and no costs would need to be allocated to the RESA from the ECA, that the benefits of the cost effective eligible energy resources would be passed on to customers.

Q. WHY DOES THE COMPANY BELIEVE THAT THIS ALLOCATION METHODOLOGY FOR THE RUSH CREEK WIND PROJECT WOULD BE BENEFICIAL TO CUSTOMERS?

A. This allocation methodology would provide customers the greatest benefit in all scenarios; the Company would be able to immediately pass through the net benefits of the Project as they are incurred, while also providing customers the cost protections by virtue of the RESA should the Project impart incremental costs to the system. As illustrated by Figure JFH-6 in the Direct Testimony of Mr. Hill, it is the Company's expectation that the Project will provide a net benefit to the system in nearly every year of operation.

Q. DURING A RENEWABLE ENERGY PLAN PROCEEDING, HOW WOULD THE COMPANY DETERMINE IF THE RUSH CREEK WIND PROJECT PROVIDES AN ANNUAL NET BENEFIT OR AN ANNUAL NET COST?

A. The Company would model two different No-RES scenarios, one in which the Rush Creek Wind Project is removed with the other new eligible energy resources, and another in which the Project remains in the No-RES scenario. Both No-RES scenarios would be compared against the RES scenario, and on an annual basis the No-RES scenario resulting in the higher incremental cost would be used for calculating the RESA impact. In essence, the calculation is testing if the inclusion of the Rush

Creek Wind Project increases costs for customers or decreases costs for customers. If in a given year the inclusion of the Project decreases costs, it will be excluded from the RESA calculation and its full benefits will immediately flow to customers. If in a given year the inclusion of the Project increases costs, its contribution to the net incremental costs will be allocated to the RESA and customers will only pay the avoided costs through the ECA. It is the Company's expectation that in all but a few years of the Project's life it will decrease costs for customers.

In the years the Rush Creek Wind Project is beneficial to customers, the Company would only pass on the full benefits of the Project to the ECA if the RESA deferred balance is positive, and is projected to remain so over the RE Plan period. If the RESA deferred balance is projected to become negative over the RE Plan period, then the Company will revert to the traditional RES/No-RES allocation treatment for the Rush Creek Wind Project. It is the expectation that with the aforementioned allocation methodology that the RESA deferred balance will remain positive over the current 2017 RE Plan period of 2017 through 2019.

Q. HOW WILL THIS ALLOCATION BETWEEN THE RESA AND THE ECA IMPACT THE COMPANY'S RECOVERY OF COSTS?

A. It will not. The sum of the costs recovered from the RESA and the ECA for the Rush Creek Wind Project will not be in excess of the actual revenue requirements. This allocation mechanism only serves to allocate costs in excess of the avoided costs to the RESA, and permit the Company to directly pass through to customers any net benefit of receiving power from a renewable resource that costs less than existing generation. To be clear, the modeling shows that the Project is expected to provide a net benefit to the system beginning in 2020. At that point in time, the Rush Creek Wind Project would fully be recovered in the ECA and the net benefit of the cost effective wind generation would be directly passed on to customers.

Q. HAS THE COMPANY MODELED THE RESA DEFERRED BALANCE USING THE PROPOSED TREATMENT OF THE RUSH CREEK WIND PROJECT?

A. Yes it has. Table AKJ-3 provides an estimate of the RESA Deferred balance under the following scenarios; (1) with the Rush Creek Wind Project with the traditional RES/No-RES treatment of the resource and (2) with the Rush Creek Wind Project using the treatment the Company has proposed in this proceeding. I have also provided in the Table below the estimated RESA deferred balance under each of these scenarios, as well as the estimated RESA deferred balance as it was filed in the Company's 2017 RE Plan in Docket No. 16A-0139E.

Table AKJ-3 – Estimated RESA Deferred Balance

	Estimated RESA Deferred Balance		
	Without Rush Creek (As Filed 16A-0139E)	With Rush Creek (Traditional RESA Allocation)	With Rush Creek (Preferred RESA Allocation)
2015	$ 39,583,522	$ 39,583,522	$ 39,583,522
2016	$ 64,638,011	$ 64,737,690	$ 64,737,690
2017	$ 36,188,360	$ 35,365,066	$ 35,365,066
2018	$ 36,210,223	$ 37,175,355	$ 32,391,211
2019	$ 56,574,095	$ 56,318,127	$ 35,672,883
2020	$ 113,768,841	$ 130,382,804	$ 71,433,857
2021	$ 191,921,872	$ 206,229,257	$ 143,283,571
2022	$ 275,846,948	$ 286,515,066	$ 219,301,662
2023	$ 367,596,986	$ 370,600,755	$ 298,830,282
2024	$ 466,818,329	$ 460,655,104	$ 384,018,593
2025	$ 573,011,274	$ 556,549,099	$ 474,716,633
2026	$ 688,239,085	$ 658,749,117	$ 571,368,410

Q. WHAT RES/NO-RES MODEL BASELINE DID YOU START WITH TO EVALUATE THE IMPACT ON THE RESA IN TABLE AKJ-3?

A. The baseline RES/No-RES model is the same as the results presented in the Company's 2017-2019 Renewable Energy Plan ("RE Plan") and is currently being processed by this Commission in Proceeding No. 16A-0139E. This is so that the Commission and interested intervenors may see how these resources layer into the RESA and the net impact of all resources.

Q. WHAT ASSUMPTIONS IS THE COMPANY USING FOR THIS MODELING?

A. We are using the same assumptions filed in Proceeding No. 16A-0138E, consistent with Decision No. C16-0127. These technical assumptions are largely the same assumptions employed in the 2011 ERP, but have been updated to reflect current market conditions. The updating of these assumptions is consistent with how the Company updated the Commission approved assumptions prior to the 2013 All-Source Solicitation. Similarly, the Company included the 2013 assumptions in the RES/No-RES modeling for the acquisition of the wind and solar resources selected as a result of the 2013 All-Source Solicitation.

Q. WHAT ARE THE ESTIMATED BILL IMPACTS WHILE THE COSTS ARE BEING RECOVERED THROUGH THE RESA AND ECA, PRIOR TO BEING PLACED IN BASE RATES?

A. A customer's initial bill impact will be limited to any incremental transmission network upgrades as I discuss later in my testimony. It is the Company's expectation that by using the RESA treatment proposed previously in my testimony; customers should enjoy bill decreases beginning as early as 2020, and minimal if any bill increase prior to 2020 because of how the RESA functions.

Q PLEASE ELABORATE.

A. Customers are already paying the full 2 percent RESA amount and the incremental costs of the Rush Creek Wind Project will be covered by this surcharge, to the extent there are incremental costs and excluding network transmission upgrades. As proposed previously, if in a given year the avoided costs are greater than actual costs, the full net benefit will be recovered through the ECA.

Q. ARE THERE ANY INCREMENTAL TRANSMISSION COSTS THAT THE COMPANY WILL INCUR OTHER THAN THE GEN-TIE?

A. Yes. A small investment (approximately $6.5 million) is required to build out the transmission bus at the Missile Site substation. Ms. Betty Mirzayi discusses this integration cost for the Project.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER THIS TRANSMISSION COST?

A. As is typical when a resource such as the Rush Creek Wind Project is interconnecting to our transmission system, there are network upgrades or work that must be completed to allow that interconnection. Thus, this cost will be collected through the normal course of the transmission cost adjustment ("TCA").

Q. WILL THE COLLECTION OF THESE NETWORK UPGRADES CAUSE A BILL IMPACT ON CUSTOMERS?

A. Yes. All other items held constant, the customers would see an increase in the TCA associated with this cost. However, as demonstrated by the modeling in the Direct Testimony of Mr. Hill, this small increase in the TCA is expected to be offset by decreases in the ECA.

Q. WHY IS THIS AN APPROPRIATE TREATMENT?

A. The proposed treatment for this cost recovery is consistent with how the Company has incurred and recovered such costs historically. We are not deviating from past approved practices.

3. Rush Creek Wind Project Cost Recovery –Timeframe 3

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE PROJECT DURING TIMEFRAME 3?

A. Beginning in Timeframe 3, the Rush Creek Wind Project would go into base rates, other than recovery of the PTC. In other words, the Rush Creek Wind Project would be placed into base rates following the earlier of either five (5) years or following the Company's first rate case after the Project is in service (e.g., 2020 Rate Case). However, we recommend the PTC remain in the ECA.

Q. WHAT AMOUNTS ACTUALLY GO INTO RATE BASE?

A. We will recover the entire cost of the Rush Creek Wind Project through base rates. Again, as in Timeframe 2, if the actual costs of Rush Creek

Wind Project in any given year are less than our modeled avoided costs from the RES/No-RES modeling, the Company will only recover the actual revenue requirements, and the net benefit would flow to customers through the ECA. If there is an incremental cost, we would still recover the entire cost of the resource through base rates. However, to accurately reflect the Rush Creek Wind Project costs from an accounting standpoint and under the RES Rules, we would have a revenue credit to rate base from the RESA in the amount of the incremental cost. This way, we would debit the RESA for the incremental cost to appropriately account for the costs of the resource from an avoided and incremental cost perspective.

Q. DOES THE COMPANY ANTICIPATE SIGNIFICANT INCREMENTAL COSTS FROM THE RUSH CREEK WIND PROJECT?

A. No, as discussed, we anticipate the opposite. The Rush Creek Wind Project is expected to result in net savings to customers and based on our modeling, we anticipate an incremental cost associated with the Project over the first two years of the Project, then incremental savings (i.e., actual cost below the avoided cost) because Project costs will be below the avoided cost over nearly all the remaining estimated life of the asset. The Company's modeling shows that these incremental savings will outweigh the incremental costs of the Project over its estimated life, which will result in estimated benefits to customers of over $400 million PVRR.

Q. WHAT ARE THE ESTIMATED BILL IMPACTS ONCE THE PROJECT IS PLACED IN BASE RATES?

A. We do not anticipate any bill increases when this project is moved into base rates during Timeframe 3. Additionally, by virtue of the RESA treatment I have previously described, customers will have the opportunity to directly benefit from any cost savings provided by the Project as they are incurred.

Q. HOW DOES THE PTC FACTOR IN AND HOW WILL CUSTOMERS BENEFIT FROM THE PTC ONCE THE PROJECT IS IN BASE RATES?

A. The PTC will reduce the cost of the Project over the first ten years of the Project's operation. These reduced costs will be flowed through to customers beginning in 2018 when the Project achieves commercial operation. This will occur through a credit to the ECA. To reiterate, the Company is proposing to continue to flow the PTC to customers through the ECA even after the Project is placed in base rates. This credit ensures that customers obtain the benefit of the PTC over the first ten years of Project operation as the benefit is received.

Q. HOW WILL THE TRANSMISSION PORTION OF THE PROJECT IMPACT YOUR WHOLESALE CUSTOMER'S RATES?

A. The majority of the transmission costs are associated with the Gen-Tie for the Project. These costs are classified as production costs; therefore, they will not impact our wholesale transmission customer's transmission rates. However, the small network system transmission costs, estimated to be around $6.5 million, as mentioned previously, would be included in the formula which determines the production costs for our wholesale customers.

Q. ARE THERE ANY OTHER WHOLESALE CUSTOMER CONSIDERATIONS OF WHICH THE COMMISSION NEEDS TO BE AWARE?

A. Yes. Pursuant to the Power Purchase Agreement between the Company and Intermountain Rural Electric Association (“IREA”), the Company is obligated to offer IREA participation in qualified new generation project(s) in Colorado that the Company builds and owns. We have communicated with IREA management regarding this wind generation facility and their option and will be providing them the recently finalized cost information for this Project shortly. We will provide the response from IREA as soon as they have evaluated their option and made their decision. As a nonprofit cooperative that ordinarily does not pay income taxes, IREA would not benefit from the PTC that lowers the cost of the project for the Company; therefore we do not expect IREA to exercise its option to participate.

4. Rush Creek Wind Project Cost Recovery –Timeframe 3

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE PROJECT DURING TIMEFRAME 3?

A. Beginning in Timeframe 3, the Rush Creek Wind Project would go into base rates, other than recovery of the PTC. In other words, the Rush Creek Wind Project would be placed into base rates following the 2020 Rate Case and we recommend the PTC remain in the ECA.

Q. WHAT AMOUNTS ACTUALLY GO INTO RATE BASE?

A. We will recover the entire cost of the Rush Creek Wind Project through base rates. Again, as in Timeframe 2, if the actual costs of Rush Creek Wind Project in any given year are less than our modeled avoided costs from the RES/No-RES modeling, the Company will only recover the actual revenue requirements, and the net benefit would flow to customers through the ECA. If there is an incremental cost, we would still recover the entire cost of the resource through base rates. However, to accurately reflect the Rush Creek Wind Project costs from an accounting standpoint and under the RES Rules, we would have a revenue credit to rate base from the RESA in the amount of the incremental cost. This way, we would debit the RESA for the incremental cost to appropriately account for the costs of the resource from an avoided and incremental cost perspective.

Q. DOES THE COMPANY ANTICIPATE SIGNIFICANT INCREMENTAL COSTS FROM THE RUSH CREEK WIND PROJECT?

A. No, as discussed, we anticipate the opposite. The Rush Creek Wind Project is expected to result in net savings to customers and based on our modeling, we anticipate an incremental cost associated with the Project in its first full year of operation (2019), followed by incremental savings (i.e., actual cost below the avoided cost) for the remainder of its life. The Company's modeling shows that these incremental savings will outweigh the incremental costs of the Project by over $400 million on a present value basis.

Q. WHAT ARE THE ESTIMATED BILL IMPACTS ONCE THE PROJECT IS PLACED IN BASE RATES?

A. We do not anticipate any bill increases because the cost of the Project is estimated to be less than the cost of conventional generation over the estimated life of the project. Additionally, by virtue of the RESA treatment I have previously described, customers will have the opportunity to directly benefit from any cost savings provided by the Project as they are incurred.

Q. HOW DOES THE PTC FACTOR IN AND HOW WILL CUSTOMERS BENEFIT FROM THE PTC ONCE THE PROJECT IS IN BASE RATES?

A. The PTC will reduce the cost of the Project over the first ten years of the Project's operation. These reduced costs will be flowed through to customers beginning in 2018 when the Project achieves commercial operation. This will occur through a credit to the ECA. This credit ensures that customers obtain the benefit of the PTC over the first ten years of Project operation.

C. Additional Cost Recovery Considerations

Q. AT THE BEGINNING OF THIS SECTION OF YOUR TESTIMONY, YOU DISCUSSED THE VARIOUS COST RECOVERY MECHANISMS AVAILABLE TO THE COMPANY. WHICH OF THESE MECHANISMS DOES THE COMPANY UTILIZE IN ITS PROPOSED COST RECOVERY APPROACH?

A. I outlined three general categories of cost recovery mechanisms available where a utility proposes to develop and own an eligible energy resource. During Timeframe 2, we propose to use the ECA and RESA to allow for cost recovery until the Project is placed in base rates. Accordingly, we would use rate adjustment clauses to allow for cost recovery between base rate cases as provided for by § 40-2-124(1)(f)(IV), C.R.S., and Rule 3660(i). We also intend to recover a return on our investment in the Rush Creek Wind Project at the most recent Commission authorized rate of return, consistent with § 40-2-124(1)(f)(III), C.R.S., and Rule 3660(g).

Q. WHICH COST RECOVERY MECHANISMS WILL THE COMPANY DECLINE TO USE?

A. As I described earlier in my testimony, we do not propose to seek to recover CWIP and a current return on CWIP at the most recently authorized WACC through the RESA during construction of the Rush Creek Wind Project. To be sure, we have the ability to do so pursuant to the express language of § 40-2-124(1)(f)(IV), C.R.S., and Rule 3660(i). However, we have decided not to do so.

Q. WHY IS THE COMPANY FORGOING THESE STATUTORY COST RECOVERY RIGHTS?

A. Our priority in bringing the Rush Creek Wind Project forward is harnessing the 100 percent PTC benefit for our customers. As discussed throughout my testimony, we believe this project is cost-effective, will result in significant savings to customers, and satisfies the standard set forth in § 40-2-124(1)(f)(I), C.R.S., and Rule 3660(h)(I). Forgoing CWIP and a return on CWIP in the specific circumstances of our present proposal keeps our RESA healthy and makes the Project even more cost effective for customers.

Q. WHAT IS THE REVENUE IMPACT TO THE COMPANY FROM FORGOING THIS OPPORTUNITY TO CURRENTLY RECOVER CWIP AND A RETURN ON CWIP?

A. The revenue impact to the Company of this decision is approximately $43.6 million, based on the present value difference of earning on CWIP vs. capitalizing AFUDC over the 25 year revenue requirement. From an earnings perspective considering the benefit of capitalizing AFUDC prior to in-servicing the project, the impact would be approximately $9.4 million.

D. Net Economic Benefit ("NEB")

Q. DOES THE STATUTE AND RULE CONTEMPLATE ANY OTHER TYPE OF INCENTIVE FOR THE COMPANY TO OWN AN ELIGIBLE ENERGY RESOURCE?

A. Yes. Under § 40-2-124(1)(f)(II), C.R.S., and Rule 3660(g), the QRU "shall be entitled to earn an extra profit on the QRU's ownership investment in a specific eligible energy resource if that eligible energy resource provides net economic benefits to customers." The statute and rule go on to clarify that the QRU must be (1) in compliance with the rules implementing the RES and (2) that the maximum amount the QRU may receive is 50 percent of the calculated net economic benefit.

Q. DOES THE STATUTE OR COMMISSION RULE SPECIFY HOW THAT NET ECONOMIC BENEFIT IS TO BE CALCULATED?

A. The statute does not. However, Rule 3660(g)(I)-(III) sets forth some general parameters on how that NEB would be calculated.

Q. PLEASE SUMMARIZE THE DIRECTION REGARDING NEB AS LAID OUT IN RULE 3660(g)(I)-(III).

A. Rule 3660(g)(I) sets out the high level standard of how the net economic benefit is to be calculated. It states that the specific eligible energy resource that the QRU owns must result in an average retail rate impact less than the rate impact that would have resulted from the acquisition of an alternative eligible energy resource meeting the same component of the RES and would have been selected absent the QRU's investment. This part of the rule goes on to state that the QRU must set forth the proposed calculation of the NEB in a compliance plan filing, an annual compliance reporting filing, or a QRU rate filing, or an application.

Rule 3660(g)(II) contemplates the use of computer modeling to establish the net economic benefit. To the extent modeling is utilized the assumptions approved in the most recent ERP shall be utilized unless otherwise approved by the Commission.

Rule 3660(g)(III) states that any approved net economic benefit will be charged against the RESA account.

Q. GIVEN THAT THE RUSH CREEK WIND PROJECT IS ANTICIPATED TO PROVIDE SIGNIFICANT NET SAVINGS TO CUSTOMERS, IS THE COMPANY SEEKING A PORTION OF THE NET ECONOMIC BENEFIT AS PERMITTED UNDER COLORADO LAW AND COMMISSION RULES?

A. No, not at this time. However, we are asking that the Commission establish a baseline and a methodology in this proceeding that would be used to determine the potential level of NEBs if we make a future request under Rule 3660(g). Although the rule does not make a provision for the establishment of a baseline, it does require that a QRU set forth its calculation of net economic benefits. We do not believe it is possible to calculate net economic benefits without comparison to some baseline level of costs, and we believe the most appropriate time to establish that baseline is in this proceeding given the showing we have had to make that the Project is cost effective relative to other similar eligible energy resources available in the market.

Q. IS THE COMPANY IN COMPLIANCE WITH THE RULES OF THE RENEWABLE ENERGY STANDARD?

A. Yes. In fact, not only is the Company in compliance with the RES rule and requirements, we have exceeded the minimum requirements of the rule. Because of this we have met the threshold to evaluate if there is a NEB and how to determine that amount.

Q. PLEASE ELABORATE ON THE BASELINE THAT YOU MENTIONED.

A. One of the requirements of the Company's opportunity to own the proposed eligible energy resource absent a competitive bidding process is the identification and finding that the proposed project can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market. In this filing, we have not only met that standard through our own analysis, but also as required pursuant to the Rules, the IE has also stated this fact. Thus, I believe that it is reasonable that the baseline for future analysis regarding if a NEB dollar amount is available should be the approved cost of the Company's Project. Effectively, the LCOE values that we have submitted to establish that the Project meets the requirement of Rule 3660(h) that it "can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market," serves as a conservative proxy for the costs of an alternative eligible energy resource for purposes of calculating NEB under Rule 3660(g)(I).

Specifically, the baseline that I am suggesting the Commission utilize for future analysis regarding the presence of a NEB is the LCOE analysis that is a result of any final approval of this Project. Pursuant to Rule 3660(g), the Company may file for a NEB in a later filing. The Company would on an annual basis compare the recently completed year's actual annual cost of energy for the Project to that same year's forecasted LCOE. To the extent the actual annual cost of energy for the Project is lower than the LCOE for that calendar year, the difference multiplied by the generation output is the eligible NEB. The percentage of that NEB, i.e., the appropriate percentage of the NEB that the Company should recover based on the particular circumstances in a given year, would be the subject of the Company's annual filing.

Q. WHAT WILL HAVE TO BE DECIDED IN THE FUTURE PROCEEDING THAT THE COMPANY MAY BRING TO RECEIVE THE NEB?

A. In the future proceeding a few items will have to be analyzed and decided. First, is the Company's calculation of the annual cost of energy for this Project accurate? Second, was the comparison of the annual cost of energy to the estimated cost of energy in the LCOE calculation performed correctly? Third, how much NEB is there for customers that may be available to the Company as an additional benefit of developing this resource. And finally, what percentage of that NEB should the Company have the opportunity to have during that year.

E. Reporting Processes

Q. DOES THE COMPANY PROPOSE ANY REPORTING PROCESSES RELATED TO THE CONSTRUCTION OR COST RECOVERY THROUGH THE RESA BEFORE THE PROJECT IS PLACED IN BASE RATES?

A. Yes. We propose to use the semi-annual reporting process we have used with the individual components of our approved Clean Air-Clean Jobs Act (“CACJA”) emission reduction plan. While not required by the Commission, the Company filed these semi-annual progress reports for its Pawnee emission controls, Cherokee 2X1 combined cycle, and Hayden emission controls projects following their respective approvals by the Commission. These semi-annual progress reports have and continue to provide useful information and increased transparency with regard to the costs of these projects. The process has further assured that disclosures of cost information are not confined to rate case proceedings.

Accordingly, we propose to use the same process for the Project to achieve the same transparency we have had for our CACJA project costs. This will provide details to the Commission and interested parties regarding how we are progressing in the construction of the Project and how actual CWIP costs compare to forecasted costs.

VII. PUBLIC INTEREST

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my testimony I will summarize the benefits of the project for customers as well as the Company to illustrate why approval of the Application as proposed by the Company is in the public interest.

Q. WHAT IS THE PUBLIC INTEREST STANDARD?

A. I am not a lawyer, but I believe it is fair to say that the "public interest" standard is the usual standard by which a utility's actions or proposed actions are assessed by regulators. I believe the standard is very broad and allows for a wide variety of factors to be considered, including costs and benefits, and various other impacts including environmental impacts and benefits. Oftentimes governing statutes specify factors that the Commission must consider in assessing whether a utility's actions or proposed actions are in the public interest. We believe that to be true for § 40-2-124(1)(f), C.R.S., where the General Assembly specifically directed that the Commission adopt policies for qualifying retail utilities that are subject to rate regulation to provide for incentives for qualifying utilities to invest in eligible energy resources. I believe that proposals that satisfy the standards set forth in § 40-2-124(1)(f), C.R.S., and Rule 3660(h) should be deemed to be in the public interest.

Q. HOW DO YOU BELIEVE THAT THE COMPANY'S PROPOSAL MEETS THE PUBLIC INTEREST STANDARD?

A. The Company has shown through this Application that the proposed Project meets the public interest standard because, it: (1) is economically beneficial for our customers; (2) aligns with our customers' long-term expectations to add incremental renewable resources; (3) comports with statutory requirements, as implemented by the Commission through its rules; (4) contributes to the maintenance of a healthy utility; (5) promotes compliance with future environmental standards; and (6) is beneficial for the State of Colorado. Collectively I believe they tell a compelling story as to why our proposed Project is in the public interest. On that basis I recommend approval of the Company's Application to the Commission.

Q. HOW IS THE PROJECT "ECONOMICALLY BENEFICIAL" FOR PUBLIC SERVICE'S CUSTOMERS?

A. As mentioned previously and further supported by Mr. James Hill, the Project is anticipated to save our customers over $400 million in power supply costs on a net present value basis. Further, the availability of an additional 1000 MW of injection capability into the 345 kV Gen-Tie should result in additional low cost wind energy for our customers in the future.

Q. HOW DOES THE PROJECT "ALIGN" WITH YOUR CUSTOMER'S LONG-TERM EXPECTATIONS TO ADD INCREMENTAL RENEWABLE ENERGY RESOURCES?

A. Through discussions with our customers[14] and communities it has become increasingly apparent that there is continued interest in further investment in renewable resources. This interest manifests itself in requests for our base service offering to incorporate more economic renewable energy resources but also for specific programs or offerings to go above and beyond our base service offering. This filing offers economic renewable resources for all customers, which increase the amount of renewable energy available for our base service offering.

Q. HOW DOES THE PROJECT "COMPORT WITH STATUTORY GUIDANCE"?

A. As discussed in detail in Section III of my Direct Testimony, the Company's proposed Project and accompanying Application and supporting Direct Testimony show how we have met the obligations and opportunities within the statute and rules. Additionally, the policy embodied in the Renewable Energy Statute, § 40-2-124, C.R.S, favors the addition of renewable energy resources beyond minimum target levels if

[14] The Company has conducted surveys to gauge customer interest as well as tracked participation in its offered programs. Additionally, at events that are either hosted by the Company or a Company representative presents, customers have made requests for incremental renewable resources.

cost effective. At the time the statute was passed and the implementing rules were promulgated (and subsequently updated), it was believed that the goals established were somewhat lofty. The Company has and continues to show how these renewable energy investments can be made safely, economically and reliably in the best interest of our customers. This proposed Project is no different.

Q. HOW DOES THE PROJECT "CONTRIBUTE TO THE MAINTENANCE OF A HEALTHY UTILITY"?

A. The statute discussed above also recognizes that utility ownership of renewable resources is beneficial and provides an incentive for utilities to develop and own these facilities. Beyond the statutory reasoning however, it is important to recognize the valuable role in economic development, employment, as well as individual customer affordability a healthy utility plays. A healthy utility has access to funding through debt or equity in order to maintain its system and expand when necessary for customer load growth. This access to funding for a healthy utility comes at a lower cost, which is subsequently included in the calculation of rates. Thus, customers benefit from having a healthy utility through lower rates.

Finally, there is some benefit to having a healthy balance between contracted-for and equity-based generation. This was explained by Pat Vincent, former CEO of Public Service, who stated to the Colorado

Legislature at the time that House Bill 07-1281 (the legislation enacting § 40-2-124(1)(f)) was being considered, as follows:

> It's important to us to have 1281 because it provides us the flexibility to invest in Colorado. The other states in which we do business, Minnesota, New Mexico and Texas all have some similar regulatory flexibility and standards and this gives us the opportunity to compete for capital internally to build projects in Colorado. The ownership ability helps us with the credit rating agencies; unfortunately how the credit rating agencies look, if we buy a purchase power contract from another entity they act like we own that and give us debt on our balance sheet, which costs our customers. So we want to increase our investment in these resources here in Colorado. The ownership option gives us flexibility to work in partnership with others, to bring other benefits to Colorado such as economic development and good jobs and we welcome the part ... in the renewable energy economy.[15]

Q. ARE THERE OTHER REASONS NOT DISCUSSED ABOVE THAT SHOW IT IS IN THE PUBLIC INTEREST FOR PUBLIC SERVICE TO HAVE OWNERSHIP OF THE PROJECT AS PROPOSED?

A. Yes. First, when a utility proposes to develop and own a generation project, the costs and risks of the project are limited to actual costs with a regulated return and are more transparent to customers and the Commission than in the Independent Power Producer ("IPP") setting.

Second, Rush Creek Wind I and II has a service life of 25 years, but with improved technology it is possible that the turbines will be able to operate beyond that time period. To the extent this occurs, the Company's customers will benefit by having a fully depreciated asset continue to

[15] Testimony of Patricia Vincent-Collawn, Colorado House of Representatives Transportation and Energy Committee, Room 107, at approx. 3:19 p.m. on Feb. 13, 2007 (available at Colorado Archives).

provide low cost generation. In contrast, if an IPP-owned generation asset is able to operate beyond a contract period (typically 20 or 25 years) with a utility, the asset will need to be contracted for again.

Q. HOW DOES THE PROJECT "PROMOTE COMPLIANCE WITH FUTURE ENVIRONMENTAL REGULATIONS"?

A. The Commission is directed to consider the potential costs of carbon dioxide regulation when evaluating utility proposals to acquire resources pursuant to § 40-2-124(1)(b), C.R.S., which provides that "[t]he commission may give consideration to the likelihood of new environmental regulation 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 resources."

One of the most impactful environmental regulations, recently stayed by the U. S. Supreme Court, is the Clean Power Plan. While there is some expectation that this environmental regulation will be reinstated near its original form, even if it does not, there is an expectation of continued change and drive toward lower emitting generation resources. Under either of the evaluation methodologies for the stayed guidelines, the Company's proposed Project would move the Company and the State of Colorado toward compliance. Additionally, we will continue to advocate for our "no regrets" projects, such as our proposed Rush Creek Wind Project, to be given full credit in any future environmental regulation.

Q. IS THE PROJECT BENEFICIAL TO THE STATE OF COLORADO PURSUANT TO RULE 3660(h)(II)?

A. Yes. Rule 3660(h)(II) requires that any project proposed at the over 25 per cent and up to 50 percent ownership level "provide significant economic development, employment, energy security, or other benefits to the state of Colorado." Although this rule does not apply to the Project, it nevertheless satisfies this standard. In addition to the many positive effects of the Project I have described concerning electric generation, customer savings, and environmental stewardship, Mr. Tim Sheesley details the Project's effect on economic development, employment, energy security, and other benefits to the State of Colorado, based on a study done by the Leeds School of Business at the University of Colorado. These benefits provide even further support that the Project as a whole, i.e., Rush Creek I and II and the Rush Creek Gen-Tie, are in the public interest. In turn, this further supports the approval of the Project pursuant to Rule 3660(h) and a grant of the two respective CPCNs necessary for the Project.

Q. HOW WOULD APPROVAL OF THE RUSH CREEK WIND PROJECT PROVIDE SUBSTANTIAL ECONOMIC DEVELOPMENT, EMPLOYMENT, ENERGY SECURITY, AND OTHER BENEFITS TO THE STATE OF COLORADO?

A. As noted in the Leeds study, the Project will be designed, manufactured, constructed and owned in the State of Colorado. Vestas Wind Systems will provide 300 2 MW wind turbines, manufactured in Brighton, Pueblo and Windsor, Colorado. This project will nearly triple the amount of Vestas wind turbines installed in Colorado today. Further, Public Service will invest approximately $1.1B into the regional economy.

The Leeds analysis found positive net economic benefits of the Rush Creek Wind Project to the State of Colorado. The proposed 600 MW of wind generation additions resulted in 7,136 more job years over the 25-year analysis period as compared to the base case resource plan, which equates to an additional 285 jobs per year on average. The study also found that 600 MW of additional wind generation will produce a $45 million per year net gain in state gross domestic product ("GDP") output over the 25-year period, based on real 2015 dollars.

Q. DO YOU BELIEVE THAT THE PROJECT IS IN THE PUBLIC INTEREST?

A. Yes. As supported in my and the other Company witnesses' Direct Testimonies, the Project as proposed is in the public interest and I recommend to the Commission that the Company's Application be approved without modification.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE THE REQUESTS THE COMPANY IS MAKING OF THE COMMISSION.

A. As detailed in my testimony and the testimonies of the other Company witnesses, the Rush Creek Wind Project is in the public interest and we believe should be approved by the Commission without modification. The Company is requesting that the Commission enter the following findings into its decision approving the Rush Creek Wind Project:

1. Approval to develop, own and operate the Rush Creek Wind Project pursuant to § 40-2-124(1)(f)(I), C.R.S. and Rule 3660(h).
2. Approval of the CPCN for Rush Creek I and II.
3. Approval of the CPCN for 345 kV Rush Creek Gen-Tie and Associated Noise and Magnetic Fields.
4. Approval of the Company's Cost Recovery Proposal.
5. Approval of the Baseline for Future Net Economic Benefits Calculations.
6. Approval of select studies (Wind ELCC, Coal Cycling Study, Wind Integration Costs and Flex Reserves).
7. Approval of the Company's requested waivers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Alice K. Jackson

As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service"). My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies.

I accepted the RVP position with Public Service in November 2013 after holding the same position in another Xcel Energy Inc. ("Xcel Energy") subsidiary, Southwestern Public Service Company, for two and a half years. Prior to my employment with Xcel Energy, I had been employed in the energy industry for over 10 years. In 2001, I was employed by Enron Energy Services, where I provided software application design and support to a variety of departments within that company.

In December 2001, I began working as a contract employee for Oxy Services, Inc., a subsidiary of Occidental Petroleum Corporation ("Oxy"), and transitioned to permanent employee status in January 2002. I held positions of increasing responsibility as a software programmer supporting Occidental Energy Marketing, Inc., the trading organization within Oxy, where I designed, developed and implemented an application used by Oxy for the operations of their Retail Electric Provider ("REP") in the Electric Reliability Council of Texas ("ERCOT").

In June of 2004, I accepted a promotion to work for Occidental Energy Ventures Corp. ("OEVC") as Manager, Texas REP. In this position I was responsible for front office (procurement, monitoring, and regulatory), mid office (data processing and billing) and back office (accounting and reporting) operations of Oxy's wholly owned REP in the ERCOT region. In 2010, I became Director Energy for OEVC and was responsible for the regulatory activities of Oxy's facilities located within the New York Independent System Operator, the Southwest Power Pool ("SPP"), and ERCOT. My responsibilities for these jurisdictions included: (1) direction of Oxy's participation in utility cases at both state and federal levels; (2) direction and participation in federal initiatives impacting Oxy's business (*e.g.*, FERC Notices of Proposed Rulemaking); (3) maintenance of regulatory filings required of Oxy's REP and generation assets at the state and federal level; (4) administration of Occidental Power Marketing, L.P. as a registered North American Electric Reliability Corporation Load Serving Entity in the SPP; and (5) evaluation of, and participation in, rule and protocol updates, revisions and additions before State Commissions, Regional Independent System Operators, and Regional Transmission Organizations ("RTOs").

In May 2011, I accepted a position with Xcel Energy Services Inc. ("XES") as Director, Regulatory Administration, and the position was transferred to SPS effective January 1, 2012. I was subsequently promoted to Regional Vice-President, Rates and Regulatory Affairs, and in that capacity I devote my time to regulatory issues in SPS's Texas, New Mexico, and FERC jurisdictions.

I graduated from Texas A&M University in 2001, receiving a Bachelor of Business Administration degree with a major in information and operations management. I have testified before this Commission and the New Mexico Public Regulation Commission and provided written testimony a number of times before the Public Utility Commission of Texas.