Rocky Mountain Power
Exhibit RMP___(RPN-1)
Docket No. 16-035-36
Witness: Rohit P. Nair

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Rohit P. Nair

Advanced Resiliency Management System (ARMS)

March 2019

An Investment Appraisal for

Advanced Resiliency Management System (ARMS)

Utah Innovative Technologies Team

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Rocky Mountain Power

1 Executive Summary

As part of the Sustainable Transportation Energy Plan (STEP), a Utah statute, Rocky Mountain Power (the Company) should request $16,520,000 to develop and deploy an advanced outage management system that includes, but is not limited to, the ability to receive outage notifications from existing ERT[1] electric meters and installing line sensors and communicating faulted circuit indicators on distribution circuits connecting critical customers to enable real-time information exchange with the Company's control center. This project will provide information to control center operators during major outages to enable restoration to emergency facilities responsible for public safety and emergency response as well as outage information for most other customers in Utah. For the purposes of this project, critical facilities will be defined as major emergency facility centers such as hospitals, trauma centers, police and fire dispatch centers, etc. Another benefit of this project is the ability to provide residential and small commercial customers with interval energy data. The anticipated net benefit to Utah customers is $67.6m over the 25 year period of this project.

2 Purpose and Necessity

The ability to remotely monitor, measure and control various distribution line equipment is a necessity to build a progressive grid that inherently improves safety, reliability and customer service. This project is expected to help the Company understand ways to address the following challenges:

- Limited visibility of real-time status of distribution line equipment, circuit loading levels, and event information leads to increased outage duration and restoration times.
- Lack of information from distribution line equipment creates inefficiencies in managing outage response situations. Predictive outage management and fault locating software rely on loss of service reports from multiple customer locations in order to estimate fault locations. Changing customer behavior and expectations are decreasing the number of reports received for each outage event thereby reducing the effectiveness of current systems.
- Currently outage information from customer meters cannot be sent to the Company's control center due to absence of any intermediary communication devices.
- Lack of interval data available for customers to make financial decisions based on energy usage.
- The proliferation of distributed energy resources can exacerbate load imbalance on a distribution circuit, causing three phase voltage imbalance issues and increasing the potential for unintended circuit breaker operations from elevated neutral currents.

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[1] *An encoder receiver transmitter (ERT) is a technology that allowed manual meter reading to be replaced by a human driving an automobile equipped with a special computer and radio receiver capable of receiving each meter's consumption data transmitted through a simple digital radio protocol. This general technique has come to be known as automated meter reading, or AMR.*

- The company is in the process of striving to make the grid more progressive and this project will enable a greater understanding of these innovative solutions.

3 Background

Rocky Mountain Power completed the installation of a mobile automated meter reading (AMR) system in the state of Utah in 2010. The AMR system is an Itron solution using their Centron C1SR electric meters that utilize ERT technology to transmit consumption data. The meters installed during, and subsequent to, the project are read once per month and provide energy and demand billing determinants for all residential and small commercial customers.

Meters for large commercial and industrial customers, as well as meters where interval data is required (e.g. load research, schedule 136, etc.) cannot be read by the mobile AMR solution currently deployed. These meters have not been replaced and continue to be read manually. These are the most expensive meters to read. The number of installations requiring interval data for billing purposes continues to increase dramatically and the need to find a cost effective solution for reading these meters is important to control costs.

To address this need, in late 2017, the Company issued a request for proposal for the installation of an AMI network. This network is designed to avoid the high cost of manually reading large commercial, industrial and interval meters. The network will mitigate the associated increase in manpower as interval meter numbers continue to increase.

In October 2018 the Company awarded a contract to Itron for their OpenWay Riva AMI solution (OW RIVA). The installation of an Itron AMI system in Utah will provide the basic field area network required to automate approximately 18,000 manually read meters as well as all current and future meters associated with schedule 136 (customer generators). Once installed, and in addition to providing daily interval data, this network will be capable of receiving outage detection notices from meters connected to the AMI system. To maximize the effectiveness of the AMI system, it will be necessary to replace an additional 138,000 meters with RIVA meters to cohesively bind the mesh network. The vast majority of these meters being replaced are Centron C1SR meters. The remaining 764,000 meters cannot be read by the Riva AMI network today.

The value of the Centron C1SR meters is their ability to be read by handheld or vehicle-mounted receivers or a fixed network meter reading system. The AMR meters transmit energy and demand data every 30 seconds allowing for the accumulation and parsing of the data stream to provide hourly interval data. When read by a FN, they would provide AMI quality meter reads without the need to replace the existing meters.

The meters also transmit a power outage notification signal in the event of a loss of power as well as a power restoration notification when service is restored. Both of these signals go undetected in a mobile meter reading environment but could be received by a fixed network and used by outage management systems.

4 Project Overview

This project proposes to utilize STEP funds to provide for the installation of line sensors and communicating faulted circuit indicators (CFCIs) on distribution circuits connecting critical customers to enable real-time information exchange with the Company's control center and to develop and deploy the necessary field equipment needed to receive outage detection notices from the existing Centron C1SR meters. For the purposes of this project critical facilities will be defined as major emergency facility centers such as hospitals, trauma centers, police and fire dispatch centers, etc.

Line sensors provide real-time circuit line loading information that can be used to enable the restoration power from an alternate source after a faulted section has been isolated. CFCIs provide real time information on fault current flow thereby enabling crews to locate the location of the fault quicker and isolate or repair the damage. These new devices will make information available to control center operators during major outages to enable faster restoration to emergency facilities responsible for public safety and emergency response to reduce their outage times.

Limiting this technology to critical facilities will allow the company to test and refine the technology with a limited investment and will assist the company in those areas of highest concern. As the technology matures and costs decrease, the ability to install these devices on more circuits will become cost effective.

Line sensors and CFCIs provide real-time information to improve efficiencies in locating faults thereby allowing line crews to focus on the specific affected areas, rather than patrolling the entire circuit, to locate, isolate and restore power in a timely manner. The company will explore methodologies to connect the line sensors and CFCIs to the OW RIVA network wherever possible and use cellular communications in cases when this is not practical. The estimated cost to deploy this technology is $5,230,000.

Itron, the supplier for the AMR system, has developed an "ERT Gateway" field device that interfaces with their OW RIVA system that collects and transmits data from ERT equipped gas and water meters. This field device is not currently available for electric meters. Itron will develop the electric ERT Gateway when a project large enough to justify the investment is approved. Itron has stated that they will develop the device if Rocky Mountain Power commits to coverage for the existing Centron C1SR meters in Utah. A six-month development window is required after contract execution. Software integration and management services will also be required. The estimated cost for developing and deploying this technology is $11,290,000.

5 Benefits

The Utah advanced outage management project will provide an estimated $930k in annual O&M reductions following the first full year of implementation (2022) increasing slightly each year for the 25 years of the project.

The outage management system will provide the following benefits:

- Reduction of seven meter reading/collection FTEs and associated overheads by eliminating manual and mobile metering requirements.
- Provide the ability to detect instances of meter tampering. This ability will improve Rocky Mountain Power's ability to detect and prevent theft.
- Provides interval usage data to Utah customers through the Company's website.
- Provides a platform that can be leveraged for future grid modernization applications including distribution automation, outage management, data analytics and demand-response programs.
- Reduces employee exposure to safety hazards, customer property visits and reduced driving miles.
- Reduces CO_2 emissions through fewer Rocky Mountain Power vehicles on the road.
- Improve outage response operations by leveraging real-time information from distribution line devices as well as help determine safe switching procedures and cost effective capital improvement and maintenance plans.
- Provide better customer service by using fault data, voltage and current to evaluate power quality performance of the distribution circuit and address customer complaints, if any.
- Improve reliability metrics such as Sustained Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI).
- Leverage real-time information collected from distribution line equipment to augment predictive capability of existing outage management systems and reduce Company reliance on customer reporting for outage notification.
- Reduce operations and maintenance costs by eliminating the need for manual load reading performed on circuits that do not have sophisticated meters with remote communication capabilities.
- Improve optimization opportunities for capital costs and system losses by providing measurements of per-phase vector quantities for voltage and current.
- Identify service quality issues early and allow timely development and implementation of cost effective mitigation.

6 Public Interest Justification

Improved Reliability

Real-time data availability from field devices will enable the Company provide higher levels of reliability and improve outage restoration efforts, particularly during major storms. Modern distribution line sensors are equipped with technology that may allow PacifiCorp to detect minute disturbances on the grid and use this information to isolate faults, detect defective equipment before it fails, and analyze the unique patterns of these events to predict the likelihood of future outages. The level of service provided by the Company (actual and perceived) is highly dependent on outage duration and frequency. Real time device data has the potential to facilitate a significant decrease in the time associated with fault detection and fault location. Company resources expended during service restoration will potentially decrease: labor, vehicle mileage, and fuel consumption.

Customer Service

The ERT Gateway system will enable customers in Utah to be able to access automated, timely, and accurate bills, regardless of weather conditions or property access limitations, which traditionally hamper collection of meter information. Once properly configured, the ERT Gateway system will allow the Company to generate more consistent and accurate bills automatically, with fewer recording errors and customer complaints. The data will be available in 15-minute increments and customers will be able to access this data on the Company's website. This is expected to help customers reduce their monthly bills and have greater control on usage. It also provides the Company an opportunity to plan for proactive, digital, multi-channel, direct engagement with their customers to educate, inform, and protect them.

Financial Prudence

While the costs of the entire project cannot be justified based on company benefits alone (Net Present Value of -$2.8m), the economic costs that power interruptions impose on businesses and residences are considerable. The Interruption Cost Estimation (ICE) Calculator, developed by the Lawrence Berkeley National Laboratory, provides the information needed to analyze those economic costs of power interruptions. Based on more than 20 years of utility-sponsored surveys on the costs of power interruptions to customers, Berkeley Lab developed the tool through close partnerships with industry. To ensure its continued effectiveness, the Berkeley Lab continues to augment it with research on the latest methods for collecting and developing information on the economic consequences of power interruptions on businesses, residences, and society at large.

The calculator tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The calculator is available online at https://eaei.lbl.gov/tool/interruption-cost-estimate-calculator.

Figure 1 shows the calculated results for customers in Utah with a 2.15% improvement in SAIDI. This improvement produces a Net Present Value customer benefit of $71.1 million over the next 25 years.

https://icecalculator.com/reliability-improvement

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Distribution of Benefits

Sector	# of Customers	Total Benefit (2020$)	Benefit Per Customer (2020$)
Residential	878,564	$925,769.23	$1.05
Small C&I	97,665	$35,455,935.32	$363.04
Medium and Large C&I	16,498	$34,715,842.88	$2,104.25
All	**992,727**	**$71,097,547.43**	**$71.62**

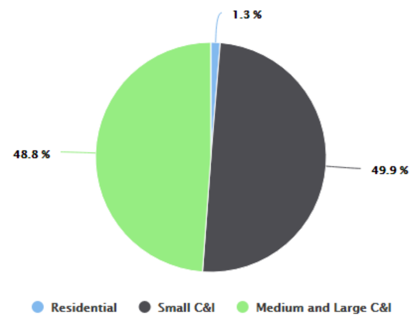

Figure 1

<u>Situational Awareness</u>

Information collected from distribution line equipment as well as residential and commercial meters through the ERT Gateway systems will help boost situational awareness enabling the Company to detect abnormal operating conditions and pinpoint faulted line segments.

<u>Maintain Grid Integrity</u>

Communication-enabled distribution line equipment can help maintain the integrity and reliability of the electrical system during massive load characteristic changes being experienced as increasing levels of distributed energy resources are interconnected to the distribution system.

<u>Modernized Grid</u>

Data collection, synthesis and interpretation is a cornerstone for building a smarter energy infrastructure that will enable accurate load/generation forecasting and planning as well as help understand the status and interaction of the various distribution line equipment installed in the field. This project will further help the Company understand the needs and challenges of deploying a distribution automation architecture.

<u>Security</u>

This program will comply with all NERC CIPS requirements.

7 Compliance with SB115

Section 54-20-107 (Other programs) of the Sustainable Transportation and Energy Plan Act states:

The commission may authorize a large-scale electric utility to establish a program in addition to the programs described in this chapter if the Commission determines that the program is cost-effective and in the public interest. Pursuant to this section, Rocky Mountain Power requests that the Utah Public Service Commission authorize $16,520,000 to develop and deploy an advanced outage management system to benefit customers in the state of Utah.

8 Alternatives Considered

Alternatives considered that do not resolve the critical issues/needs:

- Do nothing. However, this will not provide the Company, or critical facilities, with advanced outage restoration methods that become critical during large scale outages. In addition, it does not allow the Company to provide interval data to its customers and utilize residential and commercial meters to streamline the outage management process.

9 Purpose and Necessity – Risk Analysis

Company Impacts without this project:

- During outage conditions, lack of real-time circuit and line equipment information on equipment status introduces assumptions and inaccuracies while determining safe switching procedures and dispatching crews to restore outage and.
- Lack of fault location data increases outage restoration times and adversely impacts reliability and customer service.
- Lack of interval data does not allow the Company to provide meaningful insights and efficiency actions for customers, thereby limiting the Company's ability to provide better reliability, customer service and community engagement.
- Limited meter/equipment information available to detect power thefts.
- Potential distribution automation and similar grid modernization projects to be considered in future will be adversely affected.
- Limited data analytics and operational system automation will not allow the Company to reduce operational costs by eliminating manual processes and better prioritizing resources.
- Absence of asset monitoring using sensors and meters may impede efforts to improve asset health which is required to provide safe and reliable power to customers and communities.
- Limited reduction in air quality and CO2 emissions.

Customer Impact without this project:

- Challenges in improving efficiency for handling customer calls due to lack of data in the absence of critical technology such as ERT gateways and line sensors.
- Unable to provide load profile data to help customers understand energy usage patterns and impact of tariffs on their monthly bills.
- Limited visibility of distribution line equipment status and operation might negatively impact outage restoration efforts for the critical facility.

- During major storms, fast recovery of critical facilities is highly necessary and limited without this technology.
- Increased customer dissatisfaction and reduced public safety due to slower recovery times during outages.

10 Major Project Milestones

FY 2019

- Finalize contracts and project timeline with product vendors for line sensors and ERT Gateways.
- Identify Critical Response Facilities, worst performing distribution circuits, utility assets, and communication modules.
- Finalize locations where line sensors will be deployed.
- Initiate data integration tasks with the Company's IT team and vendor software providers

FY 2020

- Work with Itron to finalize ERT Gateway requirements prior to manufacturing, testing and deployment.
- Finalize locations where ERT Gateways will be deployed.
- Hardware Deployment and Data Integration into the Company's Energy Management System (EMS) and CADOPS outage management tool.
- Perform hardware and software system upgrades, if required.

FY 2021

- Deploy ERT Gateway system and integrate data into the Company's IT network.
- Continue hardware deployment and data integration into the Company's Energy Management System (EMS) and CADOPS outage management tool.
- Verify communication of end devices with the software head-end system.

This project has multiple in-service dates related to the installation of the communication devices on existing line equipment and installation of line sensors on distribution circuits. Additional work will include the integration of data from line devices into the Company's control center which will require complex software modifications in addition to purchase and installation of new software packages.

The project team is aware of the need to record the assets as technically complete in SAP as the assets are put into service. The Work Breakdown Structure (WBS) will be setup accordingly.

11 Program Closure, Retirement and Removal Information

In 2021, the Company will report back to the Utah Public Service Commission regarding lessons learned and how it plans to maintain and manage the infrastructure deployed as part of this program. If it is necessary to report more often to comply with the STEP statute or other reporting requirement, the Company will comply with those requirements.

12 Project Delivery Risk Factors

The project will be managed to mitigate typical project risks (design and construction resources, permitting material deliveries, weather, etc.) as it applies to scope, schedule, and budget. Appropriate documentation will be created, tracked and communicated to properly manage the project. The appropriate risk mitigation measures will be identified and resolved in the project development phase.

A few critical and unusual project risk factors have been identified that will need special attention in the project development and execution phases:

- If the ERT Gateway network is not sized properly, processes will not complete in a timely manner, including meter reads, connection/disconnection of service, presentation of portal data and the ability to ping meters.
- If the vendors experience a production problem and is unable to deliver equipment according to schedule.
- Risk associated with the integration of data management software with the field-deployed devices

13 Target Costs

Costs	Prior Years	2019	2020	2021
10 Year Plan Budget:-STEP discretionary funding	N/A	xxx	xxx	xxx
APR (Gross):	N/A	$1.43m	$5.69m	$9.40m
- Reimbursements:	N/A	N/A	N/A	N/A
- Contingency:	N/A	N/A	N/A	N/A
APR (Net):	**N/A**	**$1.43m**	**$5.69m**	**$9.40m**

Description	Capital Costs	O&M Costs	Total
Labor	$5.30m	$0.27m	$5.57m
Material	$9.02m		$9.02m
Purchase Services	$1.06m	$0.87m	$1.93m
Totals	**$15.38m**	**$1.14m**	**$16.52m**

14 Accounting Issues or Regulatory Recovery Issues

All expenses towards this project will be recovered through the accounting workflow setup for the Utah Innovative Technologies under the Sustainable Transportation and Energy Plan.

15 Financial Analysis

It is recommended to spend $16.52 million to develop and deploy an advanced outage management system that includes, but is not limited to, the ability to receive outage notifications from approximately 764,000 existing ERT electric meters and installing line sensors and communicating faulted circuit indicators on distribution circuits connecting critical customers to enable real-time information exchange with the Company's control center

The following outlines the key financials of the project:

- Capital Project Spend = **$15,120,000**
- O&M Project Spend = **$1,140,000**
- Project Contingency = **$260,000**
- Internal rate of return = **4.09%**
- Net present value @ 6.92% = (**$2,750,000)**
- Present value revenue requirements = **$3,470,000**
- Customer outage management benefits = **$71,100,000**
- Net customer benefits (customer outage benefits minus PVRR) = **$67,600,000**

The financial analysis was based on the following assumptions:

- The financial analysis was completed over 25 years.
- The communication assets are allocated to Utah.
- The in-service dates are December 2020 and December 2021.
- The financial analysis results presented below are based on the project's revenue requirement. This is based on a capital structure of 49% debt and 51% common with a 5.23% debt and a 9.74% common rate.
- A 1.26% Utah property tax rate was used.
- A 6.92% discount rate was used.
- A 24.59% tax rate was used.
- Outage management and demand response related costs and benefits will move to the AMI project in 2022.

16 Procurement and Project Delivery Strategy

- In order to satisfy business requirements, ensure best value, and minimize risk, purchases and construction contracts shall be procured through a competitive bid process.
- Project specifications shall be developed in accordance with applicable engineering specifications and standard designs.
- Bidders shall be screened to meet credit and procurement requirements. This process is being managed by the PacifiCorp procurement department.
- Project delivery strategy to be determined by project team.

17 Recommendation

- Purchase and install line sensors on pre-determined distribution circuits that serve critical facilities.
- Purchase and install ERT Gateway systems.
- Implement a data management system to automatically download, analyze and interpret data from all line sensors.
- Install communication radios on distribution line equipment including but not limited to line reclosers and transfer trip switches.
- Purchase and install required software packages that will allow data integration of line equipment and Itron meters into the Company’s control center.
- Update control center hardware and software to enable display of real-time information from communication-enabled distribution line equipment, line sensors and Itron meters.