ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, Utah 84116

February 27, 2024

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

Re: Docket No. 24-035-09
In the Matter of the Application of Rocky Mountain Power Requesting Approval for Adjustments to the Irrigation Load Control Program

PacifiCorp, dba Rocky Mountain Power ("PacifiCorp" or the "Company"), submits this application ("Application") to the Public Service Commission of Utah ("Commission") requesting approval for adjustments to the Irrigation Load Control Program. Table 3 of the Application, and Exhibits A through C to the Application, are confidential in their entirety and are provided in accordance with Public Service Commission of Utah Rules 746-1-602 and 746-1-603.

In addition to the Application, enclosed with this letter is the Confidential Information Certificate the Company desires parties in this docket to execute prior to obtaining access to confidential information.

Informal inquiries may be directed to me at (801) 220-4214.

Sincerely,

Michael S. Snow
Manager, Regulatory Affairs

cc: Division of Public Utilities
Office of Consumer Services

Enclosures

CERTIFICATE OF SERVICE

Docket No. 24-035-09

I hereby certify that on February 27, 2024, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services

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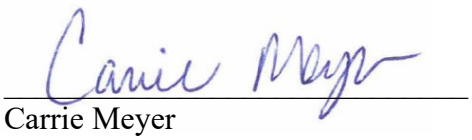

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Attorney for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of The Application of Rocky Mountain Power Requesting Approval for Adjustments to the Irrigation Load Control Program	DOCKET NO. 24-035-09 **APPLICATION**

PacifiCorp, dba Rocky Mountain Power ("PacifiCorp" or the "Company"), submits this application ("Application") to the Public Service Commission of Utah ("Commission"), requesting approval of a new demand-side management ("DSM") contract with a third party for continued delivery of the Irrigation Load Control Program ("ILC Program"). In support of its Application, the Company states as follows:

1. PacifiCorp is an Oregon corporation that provides electric service to customers in the states of Utah, Wyoming and Idaho, as Rocky Mountain Power. The Company is a public utility in the state of Utah and is subject to the jurisdiction of the Commission with respect to its rates and service.

2. Communications regarding this Application should be addressed to:

Michael S. Snow
Manager, Regulatory Affairs
Rocky Mountain Power
1407 West North Temple, Suite 330
Salt Lake City, UT 84116
Email: Michael.Snow@PacifiCorp.com

Joseph Dallas
Senior Attorney
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232
Email: Joseph.Dallas@PacifiCorp.com

In addition, the Company respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By mail: Data Request Response Center
825 NE Multnomah St., Suite 2000
Portland, Oregon 97232

Informal inquiries may be directed to Michael Snow, Regulatory Affairs Manager at (801) 220-4214.

BACKGROUND

3. On February 12, 2013, the Company filed an application in Docket No. 13-035-20 requesting authority to cancel Electric Service Schedule No. 76A, Dispatchable Irrigation Load Control Credit Rider Program, and approve a 10-year DSM contract with EnerNoc, now known as Enel X North America, Inc. ("Enel X"), to administer the ILC Program.

4. On December 7, 2012, the Company filed an application in Idaho Case No. PAC-E-12-14 requesting authority to cancel Electric Service Schedule Nos. 72 and 72A Irrigation Load Control tariffs and approve a new 10-year contract with EnerNoc, Inc., now known as Enel X North America, Inc. ("Enel X"), to administer the ILC Program under Electric Service Schedule No. 105, Irrigation Load Control Program ("Schedule 105").

5. On March 15, 2013, the Commission issued an Order approving the Company's application in Docket No. 13-035-20.

IRRIGATION LOAD CONTROL PROGRAM

Contract Terms

6. The ILC Program has remained materially the same over the past decade. Irrigators on Electric Service Schedule 10 who choose to enroll in the ILC Program can earn cash incentives for curtailing electricity during peak demand periods. The 10-year contract term with Enel X approved in Docket No. 13-035-20 has lapsed. In order to continue administering the ILC Program to Utah customers, a new, updated contract with Enel X is needed. Attached hereto as Confidential Exhibit A is a new contract ("Contract") with Enel X for the administration of the ILC Program through 2033. The Contract consists of the following components:

- Master Professional Services Contract Agreement ("MSA") between PacifiCorp and Enel X dated February 22, 2022.
- Task Order Release Agreement ("TOA") between PacifiCorp and Enel X dated December 20, 2023.

The MSA serves as a general terms agreement between PacifiCorp and Enel X that will apply to any services provided by Enel X across PacifiCorp's service territory. Task Order Release Agreements authorize specific work under the MSA terms and provide detailed scopes of work and pricing that pertain to any given project under the MSA. The TOA provided in Confidential Exhibit A includes the defined services and pricing for the ILC Program. The ILC Program TOA has an initial 5-year term through 2028, with an option to extend an additional 5 years through 2033 if agreed to by both parties.

Program Design

7. Enel X works with Company customers to enroll irrigation pumps that best fit the ILC Program and provide the greatest financial incentive to customers. During the ILC Program season, Enel X provides irrigators with a notice at least two hours prior to upcoming load control events with an option to opt-out. Enel X's load control devices shut off irrigation pumps automatically at the start of a dispatch event and release control of the pumps at the end of the event, allowing them to restart. Enel X pays irrigators in the fall after the season has ended based on average available load during program hours, adjusted for the percentage of events in which customers participated.

Incentive Structure

8. Dispatch events that customers are incentivized to participate in are split into two categories: Mandatory and Voluntary. Mandatory Events are events that occur during the Mandatory Season dispatch parameters, as shown in Table 2 below. Voluntary events are any events that occur outside of the Mandatory Season dispatch parameters. The ILC Program will continue to be a pay-for-performance structure that compensates irrigators for the average available load, measured in kilowatts (kW), that a pump can reliably shut-off during program hours, adjusted for event participation.. This average available load per pump will then be multiplied by the applicable incentive rate, according to Table 1 below. The average load for each pump is measured by the load control devices on each pump. It is the average energy demand during all program hours (weekdays, 2:00pm – 9:00pm), excluding days when events are called. A pump's available load depends on its size and how often it is running. If a customer chooses to opt-out of a load control event, the available load is adjusted down by the percent of events in which they elected to opt-out, and they will receive the Base Incentive

Rate as defined in Table 1. If a customer participates in all mandatory events, with no opt-outs, they are eligible to receive the Bonus Incentive Rate shown in Table 1, as well as the maximum Base Incentive Rate. In addition to the Base and Bonus Incentive Rates, customers participating in Mandatory Events will also receive a separate, additional incentive payment based on the actual load reduced multiplied by the Mandatory Event Energy Reduction Payment ("ERP") Rate specified in Table 1. For customers who participate in Voluntary Events, they will earn a separate ERP for each event in addition to their incentive for participation in the Mandatory Events. The Voluntary Event ERP will be equal to the actual load reduced during the Voluntary Event multiplied by the voluntary ERP rate of $0.38/kWh.

Table 1 – ILC Program Incentives (Mandatory Season)

Program Year	Base Incentive Rate ($/kW)	Bonus Incentive Rate ($/kW) *if Customer Participates in all Mandatory Events	Mandatory Event Energy Reduction Payment Rate
2024	$32.50	$39.00	$0.075/kWh
2025	$33.31	$39.98	
2026	$34.15	$40.97	
2027	$35.00	$42.00	
2028	$35.87	$43.05	
2029	$36.77	$44.13	
2030	$37.69	$45.23	
2031	$38.63	$46.36	
2032	$39.60	$47.52	
2033	$40.59	$48.71	

Participating customers may choose to opt-out of any or all voluntary events with no penalties or reductions to their financial compensation for Mandatory Events.

Dispatch Parameters

9. The Company will continue to dispatch mandatory and voluntary events in compliance with Schedule 105, Irrigation Load Control Program. While Schedule 105 allows the Company to establish a mandatory season from May 1 through September 30, the

Company's implemented Mandatory Season has been June 1 through August 15. Mandatory Season dispatch parameters for the ILC Program in Table 2 have been in place for several years, and will remain intact for the ILC Program for the foreseeable future. If the Mandatory Season dispatch parameters need to expand beyond criteria in Table 2, the Company will either post a notice on its website after discussing with the DSM Steering Committee and customers, or it will submit a filing for Commission approval if necessary.

Table 2 – ILC Program Dispatch Parameters - Mandatory Season

Irrigation Load Control Program Mandatory Season	
Dispatch Period	Week including June 1 through August 15
Available Dispatch Hours	2:00 PM to 9:00 PM Mountain Time
Maximum Dispatch Hours	52 hours per Mandatory Season
Dispatch Duration	Not more than four hours per Dispatch Event or twelve hours per week
Dispatch Event Frequency	Limited to one Dispatch Event per day
Dispatch Days	Monday through Friday, excluding holidays

In the event of a system emergency, Rocky Mountain Power may, at its discretion, expand the dispatch criteria beyond the parameters described herein. Emergency events may be used to satisfy requirements of the North American Electric Reliability Corporation standard BAL-002- WECC-2 for Contingency Reserve Obligation, and may be deployed when the Company is experiencing a qualifying event as defined by the Northwest Power Pool.

Projected Participation and Costs

10. The ILC Program currently has approximately 12 megawatts ("MW") of curtailable demand response and is projected to maintain approximately 12 MW of curtailable demand response through 2033. Confidential Table 3 provides a breakdown of estimated costs for the ILC Program through 2033, and Table 4 provides an estimate of ILC Program participation.

Confidential Table 3 – Estimated ILC Program Costs by Category

Year	Program Admin and Marketing	Customer Incentives	Utility Admin	Total
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
Total NPV	[redacted]	[redacted]	[redacted]	[redacted]

Customer incentive costs assume all customers from the previous year continue to participate in the following years, and 80 percent of enrolled capacity receives the bonus payment. Total costs in Table 3 leverage a net present value ("NPV") calculation, with an assumed discount rate of 6.77 percent.

Table 4 – Estimated ILC Program Participation

Estimated Site Participation	Estimated Customer Participation	Estimated MW
130	25	12

Data Tracking and Reporting

11. The Company currently reports on the ILC Program in its annual Demand Side Management reporting, due by June 1st annually ("DSM Report"). The Company's DSM Report includes program descriptions, program performance and major achievements for the ILC Program, as well as detailed information on called events. The Company will continue to provide this same level of detail for the ILC Program with the DSM Report.

Program Management

12. Changes to the ILC Program over the past 10 years have been minimal. The Company anticipates minimal changes will be needed going forward. However, in order to help manage the ILC Program and the TOA Contract with Enel X, the Company may make periodic adjustments to incentives, dispatch parameters, and other program design elements as needed to improve the ILC Program and ensure the ILC Program runs as intended and remains cost effective, similar to how other DSM programs within the Company's portfolio are managed. The Company will continue to discuss the ILC Program with the DSM Steering Committee and customers, and will post notices to the Company's website and/or submit filings for Commission approval as needed for future ILC Program adjustments.

Changes in Program Design from Previous Contract

13. The Company included increased incentives for customers in the new ILC Program contract. The new incentive for customers beginning in 2024 will be increased by 30 percent over previous years, with an additional 2.5 percent increase each subsequent year. The Company believes that maintaining the same incentives that have been offered the past ten years will cause participation in the ILC Program to decline. The ILC Program has already been seeing a general decline in available load reduction as shown in Figure 1 below, largely due to the following factors:

- Abnormally dry years. Dry years increase average availability as more irrigation pumping is required compared to an average year, which increases the load the Company has available to curtail. However, for abnormally dry years, irrigators may determine it is not financially viable to curtail their load if they see this having a non-negligible impact on growing patterns. Increased incentives are anticipated to mitigate this concern. (See Figure 2 below for Salt Lake City, Utah precipitation over the last 10 years.)

- Inconsistent weather throughout the season. High variability of weather conditions throughout a season can lead to inconsistent availabilities that are difficult to forecast. Variability within a year may impact when an irrigation season begins and ends, and this timing may not align with the timing of the ILC Program.

- Inflation and rising costs of living. With the high level of variability in inflation over the past few years, the costs of goods and services have increased significantly. As a result, it may be less lucrative for irrigators to participate in the ILC Program if incentives are not increased. Irrigators need to weigh the benefits of being compensated for their participation against downsides such as possible loss of profit if changing irrigation patterns reduce crop output or increases labor costs.

The Company believes that the increased incentives will allow the ILC Program to retain its current enrollment of customers and may encourage other irrigation customers who have previously unenrolled from the ILC Program to rejoin.

Figure 1 – Maximum Weekly Average Available Load Reduction

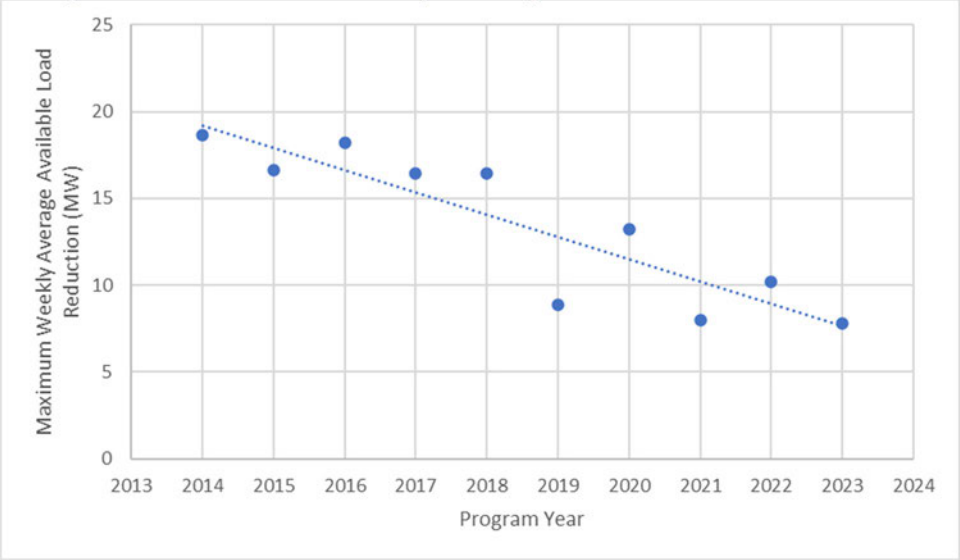
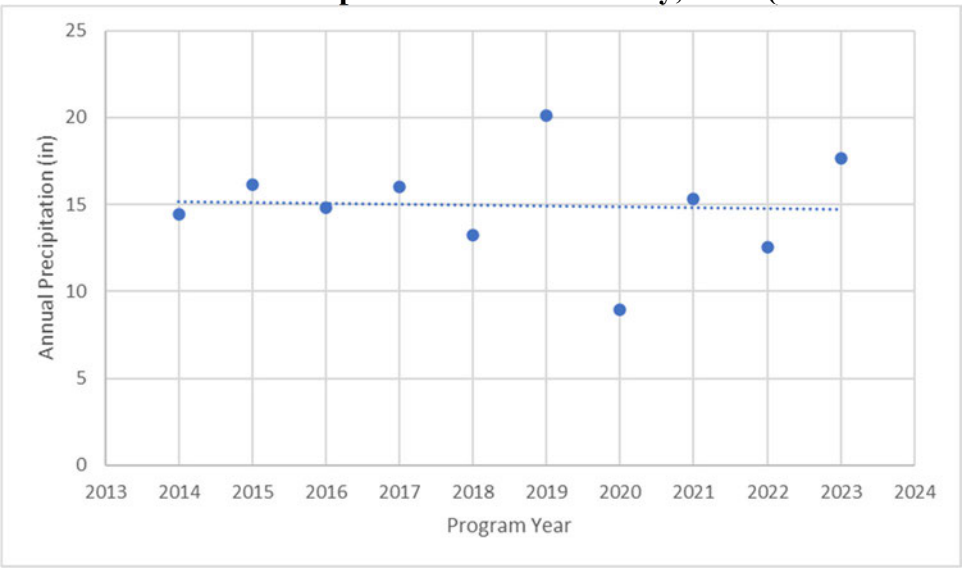


Figure 2 – Total Annual Precipitation – Salt Lake City, Utah (www.weather.gov)



14. The Company modified the Contract to allow for a two-hour notification in lieu of a four-hour notification for called events. The ILC Program also may move to a more real-time structure in the coming years. The Company intends to maintain a four-hour notice for the 2024 season, but included the options for two-hour notices and/or more real-time scenarios to allow flexibility for a faster acting resource. The Company will discuss the change to a two-hour notice or real-time events with irrigators and the DSM Steering Committee, and post notices to the ILC Program website and/or make other communications to customers prior to implementation if it is determined that this adjustment is necessary for the ILC Program.

COST EFFECTIVENESS

15. Cost effectiveness analyses for the ILC Program are attached hereto as Confidential Exhibit B. The benefits used in the model generally follow guidelines outlined in the California Public Utility Commission 2016 DR cost effectiveness protocols,[1] where applicable. The avoided cost analysis for demand response resources is also similar to what is

[1] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness.

done for energy efficiency in Utah and relies primarily on outputs from the 2023 IRP. The following benefit streams are used for valuation of demand response benefits for the ILC Program:

- Avoided generation capacity costs.
- Avoided energy costs.
- Avoided transmission and distribution capacity costs.

Additionally, the Company applies the avoided cost benefit streams to account for parameters specific to the ILC Program, accounting for the following components when assessing the realization of benefits:

- Load impacts, in MW
- Hours of dispatch
- Availability of dispatch hours (i.e. when an event can be called)
- Duration of events
- Expected availability of load

16. As avoided costs are considered proprietary on load control programs, the cost effectiveness results are provided below with a "pass" designation, which equates to a benefit to cost ratio of 1.0 or better. Due to the nature of demand response, and consistent with the cost effectiveness methodology for other demand response programs, the Participant Cost Test is not applicable. The ILC Program is expected to be cost effective under the other benefit/cost tests. Workpapers in support of the cost effectiveness analysis are provided as Confidential Exhibit C.

Table 5 – ILC Program Cost Effectiveness

Benefit/Cost Test	Benefit/Cost Ratio
PacifiCorp Total Resource Cost Test (PTRC) + Conservation Adder	Pass
Total Resource Cost Test (TRC) No Adder	Pass
Utility Cost Test (UCT)	Pass
Rate Impact Test (RIM)	Pass
Participant Cost Test (PCT)	N/A

CONCLUSION

17. WHEREFORE, the Company respectfully requests the Commission issue an Order approving the continuation of the Irrigation Load Control Program, administered through Schedule 105 and the new 10-year contract with Enel X, as described herein, with a May 1, 2024 effective date.

DATED this 27th Day of February 2024.

Respectfully submitted,

By 

Joseph M. Dallas
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Portland, Oregon 97232
Email: joseph.dallas@pacificorp.com

Attorney for Rocky Mountain Power

EXHIBIT A IS CONFIDENTIAL IN ITS ENTIRETY
AND IS PROVIDED UNDER SEPARATE COVER

EXHIBIT B IS CONFIDENTIAL IN ITS ENTIRETY
AND IS PROVIDED UNDER SEPARATE COVER

EXHIBIT C IS CONFIDENTIAL IN ITS ENTIRETY

AND IS PROVIDED UNDER SEPARATE COVER AS AN EXCEL (WORKPAPERS)