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corix.com

May 4, 2026

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 Administrator

Dear Mr. Widerburg

RE: **Docket No. 26-2666-01**
Corix Utah City Heating and Cooling LLC
Utah City District Energy Utility

Application for an order authorizing the utility to set its initial thermal rates and charges and approving the utility's initial thermal tariff

Corix Utah City Heating and Cooling LLC ("Corix" or the "Utility") hereby submits this application to the Public Service Commission of Utah ("PSC") requesting an order authorizing the utility to establish its initial thermal rates and charges, and approving the utility's initial thermal tariff for the Utah City District Energy Utility ("UCDEU") system in Vineyard, Utah ("Application").

Enclosed with the Application is Attachment 1: Supplement to Application (with Appendices). Attachment 1 was written by or at the direction of Corix's supporting witnesses and it consolidates all of the information and support for all aspects of this rate case filing. In addition to the Application and Attachment 1, Corix also submits its proposed Thermal Tariff containing the proposed rates and terms and conditions of service. Corix's filing is supported by direct testimony and accompanying exhibits from the following seven witnesses:

- Errol South
- Douglas Chong
- Maxwell Wang (Confidential)
- Josh Figueroa (Confidential)
- Derek Nelson
- Johan Grueso-Baron
- Hang Hockley

Corix also includes information in compliance with the complete filing standard set forth in Utah Admin. Code R746-700-1 and -10, as well as the additional GRC Filing Requirements established for this UCDEU GRC Application by the PSC's Order in this docket dated March 26, 2026. Corix Exhibit 2.1, an Excel spreadsheet submitted with the Direct Testimony of Errol South, lists each filing requirement and the location of the responsive information.

Corix respectfully requests that all informal correspondence and requests for additional information regarding this filing be addressed by email to regulatory@corix.com.

Respectfully submitted,

Corix Utah City Heating and Cooling LLC

Per:

Errol South
Vice President, Regulatory Affairs

Encls.

cc: A. McGavin
P. Russell

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Attorneys for Corix Utah City Heating and Cooling LLC

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF CORIX UTAH CITY HEATING AND COOLING LLC TO ESTABLISH A THERMAL TARIFF WITH RATES AND TERMS OF SERVICE	Docket No. 26-2666-01

APPLICATION

Pursuant to Utah Code Ann. §§ 54-4-1, 54-4-4 and 54-7-12 and Utah Admin. Code R746-1-101, et seq. and R746-700-1, et seq., Corix Utah City Heating and Cooling LLC ("Corix" or "Utility") hereby respectfully requests that the Public Service Commission of Utah ("PSC") issue an order approving Corix's proposed thermal tariff and establishing rates and terms of service for the Utah City District Energy Utility ("UCDEU") system.

Enclosed with this general rate case application ("Application") is Attachment 1: Supplement to the Application, which provides a comprehensive discussion of the relief Corix requests and the basis for that relief. In support of its requested relief, Corix also submits its proposed Thermal Tariff (Corix Exhibit 1.0) along with direct testimony and supporting exhibits from seven witnesses.

I. PRELIMINARY MATTERS

a. Corix Utah City Heating and Cooling LLC

Corix Utah City Heating and Cooling LLC is a Delaware limited liability company formed on October 30, 2024. Corix's formation documents, and its Utah Foreign Registration Statement are on file with the Commission. Corix is a "heat corporation," as defined by Utah Code Ann. § 54-2-1(16)(a), offering heating and cooling services operated in combination. Corix will provide thermal energy as a district energy utility. Its first thermal project in Utah is the UCDEU in Vineyard, Utah. The UCDEU plans to serve its first customer connection beginning in August 2026.

b. CPCN

On August 1, 2025 Corix filed an application with the PSC requesting a Certificate of Public Convenience and Necessity ("CPCN") to operate the UCDEU in Vineyard, Utah.[1] The PSC issued an order on February 2, 2026 granting a conditional CPCN authorizing Corix "to provide heating and cooling services as a 'heat corporation' pursuant to Utah Code Ann. § 54-2-1(16) within the State of Utah."[2] The CPCN was issued subject to Corix satisfying the conditions set forth in the PSC's February 2, 2026 Order, which directed Corix to "file with the PSC all Required Approvals and other items required by applicable law for the construction and operation of the UCDEU system."[3] Corix submitted a compliance filing in the CPCN Docket on March 13, 2026 in which it provided all Required Approvals obtained as of the date of that filing. As indicated in that filing, Corix will continue to provide additional approvals and related materials as they are obtained.

The CPCN was "further conditioned upon the creation of an acceptable regulatory framework in the forthcoming rate design and terms of service docket that protects just and reasonable rates and service quality standards and recourse for the ultimate end users of the UCDEU system (tenants)."[4] As set forth below, the thermal tariff proposed in this Application satisfies this requirement.

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[1] *See In the Matter of the Application of Corix Utah City Heating and Cooling LLC for a Certificate of Public Convenience and Necessity for a Heat Corporation to Provide Heating and Cooling Services within the State of Utah*, Docket No. 25-2666-01 ("CPCN Docket").
[2] CPCN Docket, Certificate No. 2666 issued Feb. 2, 2026.
[3] CPCN Docket, Feb. 2, 2026 Order at 9.
[4] *Id*. at 9-10.

c. Thermal Tariff

This Application includes the initial thermal tariff (Corix Exhibit 1.0), which proposes just and reasonable rates and service quality standards that provides protections for tenants of the Utah City development that the UCDEU system will serve. The thermal tariff provides the rates, terms, and conditions of service and is supported by the direct testimony of Corix witness Hang Hockley (Corix Exhibit 8.0).

d. Communications

Communications regarding this filing should be addressed to:

Allan McGavin
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1188 W Georgia St #1160
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545 East Broadway
Salt Lake City, Utah 84102
Telephone: (801) 363-6363
prussell@jdrslaw.com
spuzzo@jdrslaw.com

Corix Regulatory Team:
regulatory@corix.com

Corix requests that all data requests regarding this Application be sent in Microsoft Word format via email to the above listed email addresses.

II. ATTACHMENT 1: SUPPLEMENT TO APPLICATION

Enclosed with this Application is Attachment 1: Supplement to Application, which provides a comprehensive discussion of the relief Corix requests in this matter and the basis for that relief. The various sections of Attachment 1 were prepared by or at the direction of the Corix witnesses that have filed testimony supporting this Application and those sections are incorporated into the testimony of the Corix witnesses.

III. APPLICATION FOR APPROVAL TO ESTABLISH INITIAL THERMAL RATES

a. Proposed Rate Structure for the Recovery of the Cost of Service

Corix proposes a Capacity Charge and an Energy Charge billed monthly for the recovery of the utility's cost of service. The Capacity Charge, measured in kilowatts (kW), recovers the Utility's fixed delivery costs. The Energy Charge, measured in kilowatt hours (kWh), recovers the Utility's variable energy supply costs.

The proposed rates are explained in the Application in Attachment 1 and Direct Testimony is provided by Errol South (Corix Exhibit 2.0) and Douglas Chong (Corix Exhibit 3.0).

b. Rate-making: Unbundled and Decoupled Revenue Requirements

Corix proposes a rate-making approach with an unbundled and decoupled revenue requirement for the thermal utility that separates the utility's total revenue requirement into two component parts, as follows:

Total Revenue Requirement - The Utility's total revenue requirement is the sum of the delivery revenue requirement plus the energy supply revenue requirement.

Delivery Revenue Requirement - The delivery revenue requirement pertains to the delivery cost of service for the thermal utility. The delivery revenue requirement comprises the Utility's fixed costs and includes O&M, depreciation, return on equity, cost of debt, and income taxes. The cost of service is calculated using rate base.

Energy Supply Revenue Requirement - The energy supply revenue requirement pertains to the energy supply cost of service for the thermal utility. The energy supply revenue requirement comprises the Utility's variable pass-through costs directly related to the consumption of the heating and cooling thermal energy. The energy supply revenue requirement includes any balance arising from the Energy Cost Reconciliation Account (ECRA) that decouples the energy supply revenue requirement from actual customer consumption to allow the utility to fully recover its incurred energy supply costs without markup.

The proposed rate design and rate structure is addressed in Attachment 1, Section 3. The direct testimony on the proposed rates is provided by Errol South (Corix Exhibit 2.0) and Douglas Chong (Corix Exhibit 3.0).

c. Rate Levelization Plan with a Deferral Account for the Capacity Charge

UCDEU is a greenfield thermal utility that is being built to provide thermal service to the Utah City development. Corix expects to connect to and begin serving its first building in the Utah City development in August of 2026. The buildout of the Utah City development will continue over the next two decades. Corix expects to connect to the last building in the Utah City development in 2044. The Customer[5] and Corix have agreed to a rate structure that includes a long-term rate levelization plan utilizing a long-term deferral account called the Revenue Deficiency Deferral Account ("RDDA").

The rate levelization plan takes into account the build-out schedule of the Utah City development, the costs to construct the infrastructure, and the expected capacity and load demands of the buildings as they are added to the system. In the early years the billed revenue will be less than the annual revenue requirements, and the difference will be added to the RDDA. As new buildings are added over time, rates are gradually increased and the annual billed revenue in the future will eventually be at the same level as the annual cost of service. Once this level is reached there are no more annual deficits being added and the RDDA balance is at its peak. However, at the peak the RDDA would have built up a balance that needs recovery in the remaining period. In this recovery period when the RDDA balance is being drawn down, the billed revenues are higher than the annual revenue requirement. Eventually, the RDDA will be fully recovered to which the rates will then be gradually adjusted so that the billed revenue equals the annual revenue requirement where a steady state is reached.

[5] The Customer of the utility is Flagborough L.L.C. or its affiliates (collectively, Flagborough). Flagborough is the Developer of the Utah City development project. At the time of the application, the utility essentially has only one customer, the Developer.

The RDDA captures the difference between the actual delivery revenues and the allowed delivery costs. The RDDA deferral mechanism is explained in the Application in Attachment 1, Section 25 and direct testimony is provided by Douglas Chong (Corix Exhibit 3.0).

d. Necessity of the Relief Sought

As a greenfield utility, Corix does not currently have approved customer rates to recover the costs of providing thermal service or to earn a reasonable rate of return on its investments necessary to provide that service. Therefore, Corix requests that the PSC find, pursuant to Utah Code Ann. § 54-4-4, that the current rates are insufficient and to determine just and reasonable rates for the provision of service by UCDEU to its customer.

e. Test Period

Corix proposes a 12-month test period from August 1, 2026 to July 31, 2027, using a mid-period average rate base. The beginning of the proposed test period coincides with the UCDEU's provision of service to its first connected building and best reflects the thermal service to be provided during the rate-effective period. Corix's selection of the proposed test period and support for that proposed period is provided in the direct testimony of Errol South (Corix Exhibit 2.0).

f. Basis for Determination of Rate Relief

As set forth more fully in the direct testimonies submitted with this Application, Corix developed its operations and associated costs, revenues, plant, and deferrals in collaboration with its customer and in accordance with the Utah City development's build-out and the rate levelization plan. The Utility considered and forecast all the expected material changes the Utility knows or reasonably expects to occur during the test period based on the development's build-out schedule.

g. Cost of Capital

The Utility's cost of capital is calculated based on the capital structure funding of debt and equity for the rate base, the return on equity, and the cost of debt. In this Application, Corix proposes a capital

of structure based on 50% equity and 50% debt, a return on equity of 10.5%, and a cost of debt of 7.49%.

Consistent with applicable law, for Corix to meet its public-service obligation to its thermal customers, it must be given a reasonable opportunity to earn rate of return, including a return on equity ("ROE"), commensurate with returns realized by investors on capital investments of similar risk in the capital markets. The forecast cost of debt in the test period is a negotiated figure that will be trued up to the actual cost of debt based on a negotiated formula based on the actual prevailing interest rate for short term debt. The Direct Testimony of Maxwell Wang included with this GRC Application as Corix Exhibit 4.0 explains cost of capital components (capital structure, return on equity (ROE), and cost of debt) negotiated with the customer.

In addition, Corix provides direct testimony from Josh Figueroa of The Brattle Group included as Corix Exhibit 5.0. The testimony of Mr. Figueroa reviews the negotiated capital structure, ROE, and cost of debt to a proxy group of companies with traded market information, considers the relative risk, and then assesses its reasonableness to a greenfield small thermal utility that is fair and appropriate in today's financial marketplace.

Corix negotiated with its customer to establish the cost of capital components and rates proposed in this Application. The Fee Framework in the Lease Agreement between the parties reflects this agreement. The Lease Agreement is attached as Exhibit A to the Infrastructure Agreement, which is submitted herewith as Highly Confidential Corix Exhibit 3.1. The Fee Framework is included as Schedule D to the Lease Agreement. The cost of capital components proposed in this Application are the same as those negotiated with the customer in the Lease Agreement. In addition, Corix's customer supports the use of these cost of capital components in the rates established by the PSC in this docket. A letter from the customer supporting the proposed rates, rate structure, and cost of capital components is submitted herewith as Corix Exhibit 6.1.

h. Summary of Test Period and Rate Impact

i. Test Period Rates

Corix proposes the following rates effective August 1, 2026:

- Capacity Charge of $15.85 per kilowatt (kW) per month; and
- Energy Charge of $0.0417 per kilowatt-hour (KWh).

These thermal rates take into account the annual cost of service and the rate levelization plan.

The proposed rates for the test period are explained in the Attachment 1, Section 9 (Energy Charges) and Section 26 (Capacity Charges) and in the direct testimony provided by Errol South in Corix Exhibit 2.0.

ii. Customer Financial Impact

A typical residential building with a floor area of 23,500 square feet (sq. ft.) (2,183 m^2) and a design capacity of 2,820 kW would have a total bill of $717,918 for 12 months of service, based on the anticipated energy consumption for a typical residential building. Of this bill $536,364 would be for the Capacity Charge portion of the bill and $181,554 would be for the Energy Charge portion of the bill. This would equate to a total monthly cost of $59,826 for thermal heating for space heating and domestic hot water and thermal cooling combined. The above information is found in Attachment 1, Appendix A, Schedule 18 provides an example of bill impacts using a typical residential building. Bill impacts will vary based on the size, peak demand and energy consumption characteristics of each building.

IV. PROPOSED DEFERRAL ACCOUNTS

In this Application, Corix requests approval of two deferral accounts, as follows:

- Revenue Deficiency Deferral Account (RDDA)
- Energy Cost Reconciliation Account (ECRA)

Further information on the deferral account requests can be found in Attachment 1, Sections 10.6 (ECRA) and Section 23 (RDDA). These deferral accounts are also discussed in the direct testimony of Douglas Chong (Corix Exhibit 3.0).

V. THERMAL TARIFF

In this Application, Corix requests approval of the Utility's thermal tariff as enclosed in Corix Exhibit 1.0. The thermal tariff includes the following sections:

- Definitions
- Terms and Conditions
- Standard Fees and Charges Schedule
- Energy Cost Reconciliation Account
- Rate Schedule

The thermal tariff is discussed in the direct testimony of Hang Hockley (Corix Exhibit 8.0).

VI. COMPLETE FILING

Corix submits it has filed a complete filing for establishment of initial rates for a heating corporation that satisfies the Utah Code Section 54-7-12 and is in accordance with Utah Admin. Code R746-700-1, R746-700-10, and the other requirements established via PSC Order dated March 26, 2026 in this docket.

Corix has provided the necessary information which must be contained in an application, testimony, exhibits, evidence, data, and any other informational documents filed with a general rate case application for the application to be considered a complete filing applicable for a heating corporation. The Application's comprehensive Attachment 1 and accompanying exhibits with direct testimony contains all the necessary information required for the rate application and the establishment of thermal rates.

Corix Exhibit 2.1 contains an index outlining how it has met the requirements of Utah Admin. Code R746-700-10 and PSC Order dated March 26, 2026 for Docket No. 26-2666-01.

VII. CONFIDENTIAL INFORMATION

Information and documents submitted with this Application containing confidential and commercially sensitive material have been designated as Confidential and Highly Confidential in accordance with Utah Admin. Code R746-1-601 and have been filed with the PSC through its secure SFTP server.

VIII. SUPPORTING TESTIMONY

In this GRC Application Corix has filed direct testimony from seven individuals in Corix Exhibits 2.0 to 8.0. Attachment 1, Appendix D provides a list of the seven testimonies and the various information provided by each witness. Attachment 1, Appendix E provides the list of pre-filed exhibits.

IX. RELIEF REQUESTED

WHEREFORE, by this Application, Corix respectfully requests that the Commission:

1. Schedule a time and place for a hearing on this Application and give appropriate notice in accordance with Utah law.

2. Approve a rate-making approach segmenting the total revenue requirement into a delivery revenue requirement and an energy supply revenue requirement, as described in the Application. The delivery revenue requirement along with its Revenue Deficiency Deferral Account would be used to set the Capacity Charge rate. The energy supply revenue requirement along with its Energy Cost Reconciliation Account would be used to set the Energy Charge rate.

3. Approve a test period based on a 12-month period from August 1, 2026 to July 31, 2027.

4. Authorize the establishment of the initial thermal Energy Charge rate at $0.0417 per kW, effective August 1, 2026 (see Attachment 1, Appendix A1, line 18).

5. Approve the proposed Energy Cost Reconciliation Account (ECRA) for pass-through energy costs.

6. Approve a total energy supply revenue requirement of $268,629 for the test period (see Attachment 1, Appendix A1, line 7).

7. Approve a methodology for subsequent changes to the Energy Charge rate based on an annual ECRA pass-through rate setting mechanism, as described in the Application.

8. Authorize the establishment of the initial thermal Capacity Charge rate at $15.85 per kW per month, effective August 1, 2026 that is based on the test period delivery revenue requirement and the rate levelizing impact of the RDDA (see Attachment 1, Appendix A, Schedule 17, line 2).

9. Approve a total delivery revenue requirement of $4,639,486 for the test period (see Attachment 1, Appendix A, Schedule 1, line 3).

10. Approve a total billed revenue of $1,126,119 for the test period that reflects the rate levelization of the Revenue Deficiency Deferral Account (RDDA) (see Attachment 1, Appendix A, Schedule 1, line 4). The difference of the total delivery revenue requirement and the delivery billed revenue in a $3,513,368 addition to the RDDA in the test year (see Attachment 1, Appendix A, Schedule 1, line 5).

11. Approve a deemed capital structure of 50% equity and 50% debt.

12. Approve a return on equity (ROE) of 10.5%.

13. Approve a cost of debt of 7.49% for the test period that is trued up to the actual cost of debt based on current short-term market interest rates.

14. Approve the proposed RDDA that provides rate stabilization and levelized rates over the development build-out period of the utility.

15. Approve the proposed thermal tariff including terms, conditions, rates, and charges.

X. REQUEST TO ESTABLISH INTERIM RATES

Corix will separately file in this docket a Request to Establish Interim Rates. The interim rate request will be filed shortly after the filing date of this Application.

DATED this 4th day of May 2026.

Respectfully submitted,

CORIX UTAH HEATING AND COOLING LLC

/s/

Phillip J. Russell
Sarah Puzzo
JAMES DODGE RUSSELL & STEPHENS, P.C.

Allan McGavin
Chief Legal Officer and Counsel
for Corix Utah Heating and Cooling LLC

Attorneys for Corix Utah City Heating and Cooling LLC

ATTACHMENT 1: SUPPLEMENT TO APPLICATION

CORIX UTAH CITY HEATING AND COOLING LLC
GENERAL RATE CASE APPLICATION
Attachment 1: Supplement to the Application
Docket No. 26-2666-01

Submitted To:

Public Service Commission of Utah
201 South Main Street, Suite 1800
Salt Lake City, Utah 84111

Attention:

Gary Widerburg
Commission Administrator

Submitted From:

Corix Utah City Heating and Cooling LLC
Suite 1160, 1188 West Georgia Street
Vancouver, BC, Canada V6E 4A2

Contact: regulatory@corix.com

Date Submitted: May 4, 2026

Table of Contents

List of Tables

Executive Summary

Corix Utah City Heating and Cooling LLC ("Corix") hereby applies to the Public Service Commission of Utah ("PSC") in its initial general rate case Application for approval of its thermal tariff and rates and conditions of service for the Utah City District Energy Utility ("UCDEU") system in Vineyard, Utah ("Application" or "GRC Application").

Corix requests that the PSC approve the Thermal Tariff included as Corix Exhibit 1.0 in this GRC Application. The Thermal Tariff sets forth Corix's proposed initial rates and terms of service for UCDEU.

To support this GRC Application, Corix includes various exhibits and direct testimonies. Corix also includes Attachment 1: Supplement to Application that provides a comprehensive explanation of the GRC Application and requests for relief. Additionally, Corix provides an index in Corix Exhibit 2.1 that demonstrates for each general rate case filing requirement how UCDEU has met its filing requirements for a complete application.

Background

Flagborough L.L.C. ("Developer" or "Customer") is constructing the Utah City development located on 350 acres of land in Utah County, situated between Utah Lake and the Front Runner rail line, which connects Utah City to locations all along the Wasatch Front. Utah City has a long-term build-out. UCDEU expects the first customer building to connect on August 1, 2026 and for the last customer building to connect in 2044. This greenfield thermal utility with a long-term build-out is a unique aspect to this utility that affects rates. A prime concern of the Customer is a predictable and stabilized rate structure that reflect the long-term build-out of the development.

Rate Design and Regulatory Frameworks

Corix requests that the PSC approve a two-part rate structure for the recovery of the cost of service, which separates the fixed delivery costs from the variable energy supply related costs. Corix proposes that the fixed delivery revenue requirement be recovered through the Capacity Charge and that the energy supply revenue requirement be recovered through the Energy Charge.

Corix proposes that the Capacity Charge be set based on cost of service with rate levelization. Rate stabilization is preferred by the Customer and is permitted by Utah Code § 54-4-4.1(2)(b). To implement its proposal for long-term rate stabilization, Corix seeks approval of its proposed Revenue Deficiency Deferral Account (RDDA), which defers the collection of revenues in the early years of utility operations to stabilize rates. Corix proposes that the RDDA have a target full recovery date of December 31, 2041 to match the Customer's forecasted build-out period. Future general rate case applications would modify the Capacity Charge to collect delivery revenue requirement consistent with the RDDA deferral mechanism.

Corix proposes that once the Energy Charges have been approved in this GRC Application, that any changes to energy supply related costs be recovered in pass-through applications to be filed annually. To enable the pass-through of costs, Corix proposes an Energy Cost Reconciliation Account (ECRA).

Test Period and Indicative Years

The 12-month test period of this GRC Application is from August 1, 2026 to July 31, 2027. The test period starts on the expected connection date of the first building and ends 12 calendar months later. Corix has also included in its Financial Schedules calendar year forecasts from 2026 to 2041. Corix has included indicative years beyond the test period to allow for a better understanding of the rate stabilization period and its full forecast recovery in 2041.

The Delivery and Energy Supply Revenue Requirements

Corix has calculated the cost of service/revenue requirements for each of the delivery revenue requirement and the energy supply revenue requirement.

The delivery revenue requirement is based on traditional rate base cost of service. However, for setting of the Capacity Charge rate arising from the delivery revenue requirement, Corix has implemented rate stabilization through the RDDA. The cost of service includes certain cost of capital inputs to which the Customer has agreed.

For setting of the Energy Charge rate from the energy supply revenue requirement, Corix has proposed a rate based on the latest known energy supply costs and the forecasted consumption volume.

Customer Support Letter

Corix submits herewith in Corix Exhibit 6.2 a letter of support from the Customer indicating its support for Corix's proposed rates, rate design, cost of capital, and deferral mechanisms proposed in this Application. Specifically, the Customer's letter supports:

- The GRC Application including proposed thermal rates
- Corix's upcoming request for interim rates
- The proposed rate stabilization through the Revenue Deficiency Deferral Account RDDA)
- The negotiated cost of capital matters regarding capital structure, return on equity, and cost of debt

The Customer is the only customer of the thermal services to be provided by UCDEU and represents all of the buildings in the Utah City development.

Issues Addressed arising from the Conditional CPCN Approval

On February 2, 2026 the PSC approved a conditional CPCN for Corix in Docket No. 25-2666-01. In that Order, the PSC stated: "The CPCN is further conditioned upon the creation of an acceptable regulatory framework in the forthcoming rate design and terms of service docket that protects just and reasonable rates and service quality standards and recourse for the ultimate end users of the UCDEU system (tenants). Once these conditions have been satisfactorily met before the PSC." In this Application, Corix submits it has addressed the creation of an acceptable regulatory framework, rate design, terms of service, service quality standards, and recourse for ultimate end users (tenants) of the UCDEU system as contemplated by the PSC in its Order in Docket No. 25-2666-01.

Under separate cover: Request for Interim Rates

As noted herein, Corix expects to begin providing service to the Customer on August 1, 2026. Corix understands that this GRC Application may not receive a final order before that date. As such, Corix will file a request for interim rates in this docket pursuant to Utah Code § 54-7-12(4) shortly following the filing of this GRC Application seeking approval of interim rates and terms and conditions of service subject to the PSC's right to order a refund or surcharge.

General Rate Case Application

1 Background and Overview

1.1 Attachment 1: Supplement to Application

In support of the Application, Corix includes this Attachment 1: Supplement to Application.

Attachment 1 is a comprehensive document containing materials that provide additional support for the requests in the Application. Where necessary, Corix has incorporated exhibits and appendices to Attachment 1 that pertain to the Application.

Attachment 1 addresses issues unique to establishing an initial tariff and rates for a first-of-its-kind utility in Utah. It is meant to be comprehensive, broad, detailed, and accessible. This approach allows the reader to understand the thermal utility holistically and each of its inter-related components individually.

Attachment 1 includes a Table of Contents and also related Appendices to explain UCDEU's GRC Application. Within Attachment 1, in each section Corix has cross referenced any direct testimony relevant to each section. The objective of Attachment 1 is to provide a comprehensive single document for all parties in the GRC proceeding to gain a full understanding of the thermal utility and its approach to rate-making that is appropriate for a small start-up greenfield thermal utility.

1.1.1 Appendices to Attachment 1

The Appendices to Attachment 1 include the financial schedules, maps, listing of direct testimonies, and list of acronyms and glossary. The full details of the appendices found be found in the Table of Contents for Attachment 1.

1.2 General Information

1.2.1.1 Corporate Information

The Applicant's legal name is "Corix Utah City Heating and Cooling LLC". The Applicant may be reached at its principal place of business:

Corix Utah City Heating and Cooling LLC
1160 – 1188 West Georgia Street
Vancouver, BC, Canada V6E 4A2

The Applicant is a Delaware limited liability company formed on October 30, 2024. The Company has also obtained a Certificate of Authority to transact business in Utah. The formation documents and the certificate are on file with the Commission.

1.2.2 Contact Information

All requests for information and other communications pertaining to this Application should be directed to the following:

Errol South Vice President, Regulatory Affairs Corix 1160 – 1188 West Georgia Street Vancouver, BC, Canada V6E 4A2 regulatory@corix.com	Allan McGavin Chief Legal Officer Corix 1160 – 1188 West Georgia Street Vancouver, BC V6E 4A2 allan.mcgavin@corix.com
Phillip J. Russell Sarah J. Puzzo James Dodge Russell & Stephens, P.C. 545 East Broadway Salt Lake City, Utah 84102 Telephone: (801) 363-6363 prussell@jdrslaw.com spuzzo@jdrslaw.com	

1.3 Public Utility Legislation and Relevant PSC Rules

1.3.1 Utah Public Utilities Legislation

1.3.1.1 2025 Changes to Public Utilities Legislation

During the 2025 General Session, the Utah Legislature enacted House Bill No. 350: District Energy Amendments ("HB 350"). Effective May 7, 2025, Utah Code § 54-2-1 now includes "a heating plant and a cooling plant operated in combination" in its definition of a "heat corporation." Utah Code § 54-2-1(16).

1.3.1.2 Utah Code § 54-4-25 Certificate of Convenience and Necessity

Under Utah Code § 54-4-25, except as provided in Section 11-13-304 a heat corporation must obtain from the Commission a certificate of convenience and necessity.

1.3.1.3 Utah Code Sections Regarding Rates

Title 54 of the Utah Code governs the PSC's authority to regulate rates. Pertinent chapters include:

Utah Code § 54-4-1, vesting the PSC with "the power and jurisdiction to supervise and regulate every public utility in this state," and to do all things that are "necessary or convenient in the exercise of such power and jurisdiction." Utah Code § 54-4-1.

Utah Code § 54-4-4, authorizing the PSC to conduct hearings determining whether "rates, fares, tolls, rentals, charges, or classifications" sought by public utilities or the "rules regulations, practices, or contracts affecting" them are "unjust, unreasonable, discriminatory, preferential, or otherwise in violation of any provisions of law. Utah Code § 54-4-4(1).

Utah Code § 54-4-4.1, permitting the PSC to promulgate rules and issue orders adopting methods of rate regulation. Utah Code § 54-4-4.1. Under § 54-4-4.1(2), these methods can include rate designs utilizing "volumetric rate components; demand rate components; fixed rate components; and variable rate components." *Id.* Additional rate design methods include "rate stabilization methods; decoupling methods; incentive-based mechanisms; and other components, methods, or mechanisms approved by the commission." *Id.*

Utah Code § 54-7-12 governing the procedure by which a public utility applies to the PSC for a rate increase or decrease. Utah Code § 54-7-12.

Summary:

Overall the Utah Code permits the PSC to regulate rates utilizing a number of rate designs (volumetric, demand, fixed rate, variable rate), rate stabilization methods, decoupling methods, and other mechanisms that are consistent with Title 54, in the public interest, and just and reasonable.

As a greenfield thermal utility applying to the PSC for the implementation of its rates, Corix herein relies on a combination of these approaches to ensure its application demonstrates its ability to meet its customer's needs in a manner that is just, reasonable, and in the public interest.

1.3.2 PSC Rules for a GRC Filing

The PSC has Annualization of test-year data rules applicable to various public utilities including a heat corporation as noted in R746-407-1(A).

As identified above the PSC has general rate application (GRC) rules applicable to all utilities in Rule R746-700.

- R746-700-1. General Provisions
- R746-700-10. Test Period Information to Be Included With a General Rate Case Application

1.3.3 PSC Rulemaking for Complete Filing Requirements in Applications of Heat Corporations in General Rate Cases

On February 20, 2026 the PSC issued a notice of a virtual conference regarding rulemaking for complete filing requirements in applications by heat corporations in general rate cases. On February 27, 2026, a virtual conference was held to discuss issues relating to the promulgation of appropriate rules governing applications under Utah Code Ann. § 54-7-12, Utah's general rate case statute, for "heat corporations" under Utah law.

On March 2, 2026 the PSC directed Corix, DPU, and OCS (the "Parties") to file on or before April 1, 2026 submissions regarding (1) proposed language of an administrative rule governing at least "what constitutes a complete filing" for purposes of a heat corporation's application in a general rate case (e.g., the specific information which must be contained in an application, testimony, exhibits, evidence, data, and any other informational documents filed with an application); (2) anything else the Parties deem relevant to the foregoing; and, if desired, (3) potential alternative routes consistent with Utah law, citing applicable legal authority, to streamline and/or expedite the rulemaking process in this docket.

On March 17, 2026 Corix and the DPU filed joint comments. The OCS filed a partial joinder to the joint comments.

The PSC by Order on March 26, 2026 issued UCDEU GRC Filing Requirements for Corix in its Docket No. 26-2666-01. In Attachment 1, Appendix F Corix has included the UCDEU GRC Filing Requirements. Corix notes that it has also included an Index, submitted as Corix Exhibit 2.1, which identifies each of the GRC filing requirements and the appendices, exhibits, and attachments to this application where those filing requirements are located.

1.4 Legislation, PSC Rules, and Other GRC Filings has Informed the Corix Rate Application

This Application has been prepared to satisfy PSC requirements necessary for the approval of rates and charges for a new thermal energy company (i.e. a heat corporation). Corix has reviewed the legislation and regulation applicable to a heat corporation, as well as those governing rate applications by telecommunications corporations water corporations, gas corporations, and electrical corporations.

1.5 CPCN Application and Subsequent Conditional Approval

1.5.1 CPCN Application

On July 31, 2025 Corix filed its Certificate of Public Convenience and Necessity (CPCN) Application. The CPCN Application was assigned Docket No. 25-2666-01. On August 28, 2025 the PSC issued a scheduling order. The hearing was held on December 9, 2025.

1.5.2 PSC Grants Conditional CPCN

In its February 2, 2026 Order, the PSC approved Corix's CPCN application on a conditional basis in Docket No. 25-2666-01.[6]

In Directive No. 1 the PSC stated: "Corix is granted the conditional CPCN attached as Exhibit A, incorporated by reference into this Order. Corix is directed to file with the PSC all Required Approvals and other items required by applicable law for the construction and operation of the UCDEU system, after they are obtained and before construction and operation of the UCDEU system begins. Once these conditions have been satisfactorily met before the PSC, the CPCN will no longer be conditional as to this point."[7]

In Directive No. 2: the PSC stated: "The CPCN is further conditioned upon the creation of an acceptable regulatory framework in the forthcoming rate design and terms of service docket that protects just and reasonable rates and service quality standards and recourse for the ultimate end users of the UCDEU system (tenants). Once these conditions have been satisfactorily met before the PSC, the CPCN will no longer be conditional as to this point."[8]

1.5.3 Actions taken by the utility: CPCN Condition No. 1

On March 13, 2026, Corix submitted to the PSC materials responsive to CPCN Condition No. 1. The filing included eight permits and authorizations that had been obtained by Corix by the date of the submission. Corix will continue to file additional approvals and related materials as they are obtained.

[6] Order, Docket No. 25-2666-01 (Feb 2, 2026), available at https://pscdocs.utah.gov/misc/25docs/25266601/343643252666601o2-2-2026.pdf.
[7] PSC Order dated February 2, 2026, Docket No. 25-2666-01, page 9, Order Directive No. 1
[8] PSC Order dated February 2, 2026, Docket No. 25-2666-01, page 9, Order Directive No. 2

1.5.4 Actions taken by the Utility: CPCN Condition No. 2

This GRC Application satisfies CPCN Condition No. 2, which aims to create an acceptable regulatory framework. This GRC Application includes the following to address Condition No. 2:

- rate design:
  - Attachment 1, Section 4
- terms of service:
  - Exhibit 1.0 Thermal Tariff: Section A – Definitions, Section B – Terms and Conditions, Section C – Standard Fees and Charges Schedule, Section D: Energy Cost Reconciliation Account, and Section E – Rate Schedule 1: General Service.
- service quality standards:
  - Exhibit 1.0 Thermal Tariff (various sections)
  - Attachment 1, Section 28
- recourse for the ultimate end users of the UCDEU system (tenants):
  - Exhibit 1.0 Thermal Tariff, Section B, Sub-sections 3 (Use of Thermal Energy), 6 (Meters), 7 (Sub-meters for Cost Allocation), and 30 (Dispute Resolution)
  - Attachment 1, Sections 27.2 (Fair Treatment of End-user Tenants) and 27.2.1

1.6 Thermal Utilities and Utah City District Energy Utility

1.6.1 The Nature of Thermal Utilities

A district energy system (DES) has a central energy plant (CEP) that services the thermal customers through a distribution piping system (DPS) and the thermal energy at the energy transfer station (ETS) is transferred to the in-building thermal system. The nature of thermal utilities has the following characteristics.

- Relatively small neighborhood district systems. Thermal energy companies are small utilities.
- The technology and design are selected based on the needs of the local customer. Additionally, the energy supply is based on local availability of economic energy sources. The typical energy mix includes electricity and natural gas. However, in North America other thermal energy sources have included geo-exchange, waste-heat recovery, sewer heat recovery, waste-to-energy, biomass, heat recovery chillers, deep lake, and river water.
- District energy utility customers typically own entire buildings. Sometimes a building's ETS can be designed to service multiple occupant types within the buildings, for example both commercial and residential. Utility thermal service to an individual residential suite in an apartment building is rare in the industry.
- Given the nature of thermal energy, it is a business-to-business model where the utility has relatively larger-volume customers (e.g. equivalent to small commercial or large commercial customers of a gas or electric utility). A typical electric and gas utility would service both 1) low-volume customers (e.g. residential single detached homes or individual suites in apartments) and 2) larger-volume customers (e.g. small commercial, large commercial, or institutional/industrial).
- Thermal customers make the initial decision to opt into taking thermal service.

- Once the decision is made, they become economically captive customers. Captive customers can enter bilateral long-term contracts or can be rate regulated by a government agency with regulatory authority.

1.7 Utility Project Overview

Corix is in the business of developing, constructing, operating and maintaining thermal energy services. Corix's intention is to operate a regulated thermal energy utility in Vineyard, Utah.

1.7.1 Utah City District Energy Utility

Flagborough L.L.C. ("Developer" or "Customer") is a Delaware limited liability company. Developer is constructing the Utah City development located on 350 acres of land in Utah County, situated between Utah Lake and the Front Runner rail line, which connects Utah City to Salt Lake City and Provo.

Corix will develop, own, and operate the thermal energy utility known as Utah City District Energy Utility. The Utility is rate-regulated by the PSC. A map depicting the UCDEU Service Area relevant to this rate application is attached as Appendix C of this Attachment 1.

1.7.2 Relationship Between Fee Framework in the Infrastructure Agreement and Regulated Thermal Tariff Rates

Corix and the Developer have a signed an Infrastructure Agreement dated as of January 16, 2025 ("Infrastructure Agreement" or "IA"). The IA has been included in this GRC proceeding as Corix Exhibit 3.1, in both Highly Confidential and Redacted forms. The IA defines the roles and responsibilities of the relevant parties for the creation and ongoing operation of UCDEU.

Corix and the Developer have negotiated a Cost of Service Fee Framework (Fee Framework) in the Infrastructure Agreement. The Fee Framework will be replaced by a PSC-approved tariff containing the terms and conditions of service, including rates.

1.7.3 Intent of Corix and Customer to Convert the Terms in the Fee Framework into a Regulated Thermal Tariff

As noted above, the Fee Framework was intended to provide structure and certainty for the parties during preliminary negotiations of the Utah City development. It was the intent of the parties that the Utility's heating and cooling services would eventually be regulated in a manner generally consistent with the key terms in the Fee Framework, particularly in regard to cost-of-service items, rate design, and rate smoothing, which includes the revenue deficiency deferral account (RDDA, also known as the rate stabilization account). However, at the time the parties executed the Infrastructure Agreement the Utah Code did not include "cooling services" in its definition of a heat corporation. Accordingly, the parties were unclear whether the PSC could regulate both the Utility's heating services and cooling services.

The parties intended that if heating and/or cooling services were not regulated, then the Fee Framework would be in force. The definition of "heat corporation" in Title 54 of the Utah Code was amended in 2025 to include cooling services when operated in combination with heating services. As a result of this change, along with the PSC's conditional approval of Corix's CPCN in Docket No. 25-2666-01, UCDEU is a regulated public utility subject to the jurisdiction of the PSC with regard to both heating and cooling services it will provide to the Developer. Given the

PSC's full jurisdiction for the combined heating and cooling utility, the negotiated Fee Framework terms were converted into the regulated Thermal Tariff that is proposed in this GRC Application.

1.7.4 Combined Thermal Utility

Corix provides thermal service in the form of heating and cooling. As a combined integrated utility, it has one rate base and one utility service, which is the provision of thermal energy to the Developer.

1.8 GRC Application Exhibits

Corix's UCDEU is a small utility. As a small utility the Application has been prepared by a limited number of personnel responsible for different sections of this Application.

1.8.1 Corix Exhibit 1.0 (Thermal Tariff)

Corix Exhibit 1.0 contains Corix's proposed Thermal Tariff for Utah City District Energy Utility.

1.8.2 Corix Direct Testimony Exhibits

In Attachment 1, Appendix D, Corix includes a list of the pre-filed direct testimony from seven witnesses that is submitted in support of the Application, which are labeled as Exhibits 2.0 to 8.0.

1.8.3 List of Pre-filed Exhibits

The full list of pre-filed Exhibits including direct testimonies can be found in Attachment 1, Appendix E.

1.8.4 Corix Exhibit 6.1 (Customer Letter of Support)

Corix Exhibit 6.1 contains the Customer Support Letter from Flagborough L.L.C ("Flagborough"). Further discussion of the Customer Letter of Support is found in Section 6 of this Attachment 1.

1.9 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 1 has been prepared by Douglas Chong and the information in this section is further supported by the Corix Exhibit 3.0 - Direct Testimony of Douglas Chong.

2 Test Period

2.1 Test Period for GRC Application

Corix proposes a 12-month future test year from August 1, 2026 to July 31, 2027 (Test Period) for this GRC Application.

2.2 Utah Code § 54-4-4(3) Test Period

The Utah Code § 54-4-4(3) addresses the test period. Based on Utah Code § 54-4-4(3), Corix understands the PSC has the following three options when utilizing a test period.

1. A future test period on the basis of projected data not exceeding 20 months from the date a proposed rate increase or decrease is filed with the commission;
2. A historic test period adjusted for known and measurable changes; or
3. A hybrid test period based on historic data and future projections.

Accordingly, Corix understands that: .

1. Utah uses a single 12-month (1 year) test period rather than multi-year test periods common in other jurisdictions.
2. The use of a future test period is limited to 20 months from the filing date of the application to the last day of the 12-month test period. This means that the rate filing cannot occur more than 8 months from the start date of the 12-month test period.
3. All General Rate Cases have a test year, so a rate case cannot be filed more than 8 months prior to the start of the 12-month test period.

2.3 Anticipated Commencement of Utility Service

Corix's first customer is currently scheduled to begin receiving thermal service on August 1, 2026. As a public utility under the jurisdiction of the PSC, Corix requires approval from the PSC to charge rates for this service from the commencement date onwards.

2.4 Choice of the Test Period

The GRC's test period from August 1, 2026 to July 31, 2027 was chosen for the following reasons.

- It starts on the scheduled service commencement date of August 1, 2026.
- It covers a full 12 months of operations for revenues and costs.
- It uses a future test year approach, since UCDEU is a greenfield thermal utility with:
    - no historical operating record; and

- a rate levelization and rate smoothing approach for its Capacity Charge, driven by the timing of customer connections through to full buildout of the system.

This GRC's test period is in accordance with R746-700-10 when a future test period is used.

2.5 Presentation of Forecast Data

The Financial Schedules included in Attachment 1, Appendix A includes all the relevant regulatory schedules to establish the revenue requirement and proposed rates for the test period, and provides forecast information in a variety of ways to facilitate a detailed regulatory review of this application. The Financial Schedules present the relevant data in the following periods.

a) 12-month Test Period forecast from August 2026 through July 2027, comprised of:
   - August 1, 2026 to December 31, 2026; and
   - January 1, 2027 to July 31, 2027.

b) 5-month period forecast following the test year from August 1, 2027 to December 31, 2027.

c) Full calendar year forecasts from January 1st to December 31st for each year from 2026 through 2041.

2.6 Inclusion of Indicative Years for the Rate Stabilization

While the Test Period ends in 2027, Corix also included in Attachment 1, Appendix A additional indicative years from 2028 onwards that cover the full rate stabilization period via the Revenue Deficiency Deferral Account (RDDA) from its establishment, additions, recoveries, and full recovery date.

The RDDA is expected to be fully recovered by December 31, 2041. Following the year in which the RDDA is fully recovered the Capacity Charge will be adjusted downwards to gradually bring down rates so the billed revenues equal the annual delivery revenue requirement.

2.7 UCDEU GRC Filing Requirements

As discussed in Section 1.3.3, the Commission has established UCDEU GRC Filing Requirements in this docket. In Attachment 1, Appendix F Corix has included the UCDEU GRC Filing Requirements. In Exhibit 2.1 Corix has provided a spreadsheet Index outlining its compliance with the UCDEU GRC Filing Requirements.

2.8 Direct Testimony: Corix Exhibit 2.0 - Errol South

This Section 2 has been prepared by Errol South. See the Direct Testimony in Corix Exhibit 2.0 – Errol South.

3 Relief Sought

3.1 Relief Sought in GRC Application

The specific approvals requested can be found in Section IX Relief Requested of the GRC Application.

3.2 Filed Subsequently: Request to Establish Interim Rates

Utah Code § 54-7-12(4)(a) allows for a request for interim rates to be made. In Docket 26-2666-01 Corix will be making a request to establish Interim Rates for the General Rate Case Application. Corix intends to file this interim rate in May 2026, some time after the filing of the GRC Application. This timing will allow for a regulatory process on the interim rate request and allow interim rates to be effective August 1, 2026.

3.3 Direct Testimony: Corix Exhibit 2.0 - Errol South

This Section 3 has been prepared by Errol South. See the Direct Testimony in Corix Exhibit 2.0 – Errol South.

4 Rate Design

Rate design for a thermal utility revolves around the utility's rate structure and how the utility's revenue requirement is recovered from customers. It requires consideration of the nature of the utility and the nature of its customers.

A thermal utility has a central energy plant with a network of pipes delivering thermal energy to buildings at the energy transfer stations located within the serviced buildings. The business model of district energy systems is business-to-business (B2B) rather than business-to-customer (B2C). The customers are typically building owners. It is atypical for a thermal customer to be an individual residence or an individual apartment unit.

A thermal utility typically has two distinct cost categories: one that is infrastructure related which contains the utility's "fixed costs" and another that is thermal energy supply and which contains the utility's "variable costs". The vast majority of costs in a thermal utility are infrastructure-related fixed costs, and a smaller portion are variable thermal energy supply costs.

In the case of UCDEU the utility incurs energy supply costs including natural gas and electricity to provide heating and cooling. These energy supply costs are passed through to the customers based on consumption.

4.1 Bonbright Principles

Utilities are typically expected to design rates that take into account Bonbright's criteria of a desirable rate structure.[9]

The eight Bonbright Principles are:

a) Price signals that encourage efficient use and discourage inefficient use (*economic efficiency*);
b) Fair apportionment of costs among customers (*fairness*);
c) Avoid undue discrimination (*fairness*);
d) Customer understanding and acceptance, practical and cost effective to implement (*practicality*);
e) Freedom of controversies as to proper interpretation (*practicality*);
f) Recovery of the revenue requirement (*stability*);
g) Revenue stability (*stability*); and
h) Rate stability (*stability*).

Corix organizes each of the eight Bonbright Principles above into four categories: (i) economic efficiency; (ii) fairness; (iii) practicality; and (iv) stability.

Corix notes there is no priority ordering of the principles. All the Bonbright Principles are to be considered when designing rates, establishing revenue requirements, and setting rates. However, the importance and relevance of a particular principle depends on the situation faced by the utility in each particular circumstance.

For example, in an environment of unexpected rising costs leading to high rate increases the principles that would be more important to consider are the stability principles: f) Recovery of the revenue requirement; g) Revenue stability; and h) Rate stability. In contrast, when designing rates the Bonbright principles that are most relevant

[9] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961.

would be a) Price signals that encourage efficient use and discourage inefficient use (economic efficiency); b) Fair apportionment of costs among customers (fairness); c) Avoid undue discrimination (fairness); and d) Customer understanding and acceptance, practical and cost effective to implement (practicality).

4.2 Two-part Rate Structure – Fixed and Variable

As permitted in Utah Code § 54-4-4.1(a), Corix proposes a two-part thermal rate: a fixed rate and a variable rate. As permitted in Utah Code § 54-4-4.1(b), Corix proposes a rate stabilization method through the use of a Revenue Deficiency Deferral Account (RDDA) to levelize rates during the period when the Utility is building out its infrastructure.

As shown in Table 1, the UCDEU Energy Revenue Requirement can be segmented into the capacity related and energy supply related portions of the revenue requirement.

TABLE 1 – TOTAL REVENUE REQUIREMENT BREAKDOWN

Total Revenue Requirement	**Delivery Revenue Requirement**	Fixed	Capacity-related
	+		
	Energy Supply Revenue Requirement	Variable	Commodity-related

The delivery revenue requirement and the energy supply revenue requirement represent the fixed costs and variable energy supply costs, respectively.

- The Delivery Revenue Requirement involves the fixed infrastructure costs of the utility that is measured by the capacity needs of the customers and is recovered through a Capacity Charge in kW (kilowatt).
- The Energy Supply Revenue Requirement involves variable costs due to customer consumption that drives the utility to acquire energy resources (commodities) that is recovered through an Energy Charge in kWh (kilowatt-hour).

In this GRC, Corix is establishing for the test period the Total Revenue Requirement for both the Delivery and Energy Supply portions and the resulting rates for each portion. With regards to the Delivery Revenue Requirement the billed amount will also reflect the rate stabilization that levels rates from the Revenue Deficiency Deferral Account (RDDA).

Given the above, Corix has designed the following thermal two-part rate structure for recovering the cost of providing thermal service

TABLE 2 – UCDEU RATE STRUCTURE

CHARGES FOR SERVICE	THERMAL SERVICE	REVENUE REQUIREMENT
Fixed (non-energy)	**Capacity Charge** *($ per kilowatt)*	Delivery Revenue Requirement (with rate stabilization)
Variable (consumption)	**Energy Charge** *($ per kilowatt-hour)*	Energy Supply Revenue Requirement

The Capacity Charges recover the delivery (or "non-energy") costs of the utility, subject to the rate stabilization plan. The rate stabilization plan includes a method to levelize rates through an RDDA. The Capacity Charge will be a monthly rate.

The Energy Charges recover the variable/commodity related energy supply costs of the utility for the customer's consumption of thermal energy. The Energy Charges are decoupled from the test year as the actual customer consumption can change the actual revenues and costs.

Customers would be billed on a monthly basis. The monthly energy charge bill varies depending on consumption demand of customers (kWh).

4.3 Subsequent setting of rates

Given the unbundled approach to the delivery revenue requirement and the energy supply revenue requirement, the subsequent setting of rates would involve separate regulatory processes.

4.3.1 Delivery Revenue Requirements (in future General Rate Case Applications)

Any future setting of the delivery revenue requirement would occur through general rate case applications with a future test period. These future GRC applications will have a 12-month test period.

Corix expects filing its future GRC application to have a test period that aligns with the calendar year. To do so, the next GRC filing would have a test period of January 1, 2028 to December 31, 2028 with also an effective date of the thermal rates to be January 1, 2028. However, given the 20-month limitation of the filing date for a future test period the next GRC cannot be filed earlier than May 1, 2027. With these limitations and a preference to include actuals that end in a quarter end, the next GRC application would need to be filed sometime in Summer 2027. If this were the case, the Thermal Tariff would have had thermal delivery rates effective from August 1, 2026 to December 31, 2027.

Once Corix's GRC rate applications are aligned with the calendar year the next test period would then be from January 1, 2029 to December 31, 2029 with delivery rates effective January 1, 2029. The above are the expectations of the utility. However, as this new utility begins operations and actual events unfold the above plans may change.

4.3.2 Energy Supply Revenue Requirements (in future Energy Supply Pass Through Applications)

This GRC requests approval for the initial energy supply revenue requirement and the associated Energy Charge. Once the Energy Charge is established this GRC proposes an annual energy cost reconciliation account (ECRA) rate-setting mechanism to set the thermal energy charge on an annual basis while also reconciling any balance in the ECRA. The UCDEU ECRA approach is very similar in concept the Enbridge Gas Utah Pass-Through Application for forecast commodity costs and the amortization of the commodity portion of 191 Account balance.

Section 10 provides further details on the regulatory framework for thermal energy supply costs and cost recovery.

4.4 Rate Class

The establishment of the initial thermal tariff for UCDEU involves the identification of a rate class for the Utah City service area approved in Docket 25-2666-01 where the PSC granted a CPCN for the 64 lots/buildings receiving heating and cooling thermal service.

There is one rate class for thermal energy service at UCDEU it is called Rate 1: General Service.

4.4.1 General Service

Corix has included in the thermal tariff the following rate class:

- Rate Schedule 1: General Service.

All lots/buildings in Utah City service area approved in Docket 25-2666-01 are within the same rate class.

4.5 Thermal Charge Components

As discussed above in Table 2 the UCDEU Rate Structure is composed of a fixed and variable charge. They are described below.

4.5.1 Capacity Charge (fixed)

Corix has included a Capacity Charge ($/kilowatt or $/kW) per month in the thermal tariff. This delivery rate recovers the delivery revenue requirement of the utility. It is a fixed charge that does not vary by customer consumption.

To arrive at the Capacity Charge annual revenues the Capacity Charge at $/kW is multiplied by the Building Design Capacity of each lot/building and then summed for the 12 months. The total annual Capacity Charge revenues can change when there are new customer connections in the year.

The Capacity Charge is directly related to the Delivery Revenue Requirement. Given the RDDA the Capacity Charge for UCDEU is also rate stabilized given the nature of this start-up greenfield thermal utility.

4.5.2 Energy Charge (variable)

Corix has included an Energy Charge ($/kWh) in the thermal tariff. This energy supply rate recovers the energy supply requirement of the utility. It is a variable charge that varies by customer consumption.

Each customer in its monthly bill will have its thermal energy consumption measured. The total Energy Charge annual revenues will be the Energy Charge ($/kWh) multiplied by the customer consumption for each lot/building and then summed for the 12 months. The total annual Energy Charge revenues will change depending on the customer consumption for the period.

The Energy Charge is directly related to the Energy Supply Revenue Requirement. The Energy Charge and energy supply costs are decoupled with a pass through of actual incurred costs.

4.6 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 4.0 has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

5 Project Development Progress and Operations

5.1 Utility Preparations

In the Direct Testimony of Derek Nelson in Corix Exhibit 6.0 the following matters regarding utility preparations are discussed:

- The construction and operational milestones completed before the first customer connects to the district energy system.
- Establishment of local Utah office
- Update on permits and authorizations
- Description of the Interim Energy Center (IEC) including design and construction
- Description of the Distribution Piping System (DPS) including design, configuration, specifications
- Description of the Energy Transfer Station (ETS) including its major components, design, fabrication, and contracting

5.2 How users experience receiving thermal energy

In the Direct Testimony of Derek Nelson in Corix Exhibit 6.0 the following matters regarding how users experience receiving thermal energy are discussed:

- Description of how the system operates to deliver thermal energy to buildings
- Temperature of supply and return
- The energy transfer station and thermal energy measurement
- SCADA monitoring
- Service boundary
- Thermal energy in individual units
- Responsibility of the building distribution system

5.3 Utility Safety and Response

In the Direct Testimony of Derek Nelson in Corix Exhibit 6.0 the following matters regarding utility safety and response are discussed:

- Discussion of utility safety and response
- Phone number to call for outage matters
- Natural combustion safety
- Piping System Integrity and Testing
- Electrical Safety
- Chemical and Water Treatment Safety

- Cooling Tower Safety — Legionella Risk
- Thermal Burn and Scalding Safety
- Seismic Safety (ETS)
- Permitting, Regulatory Compliance, and Air Emissions
- 24/7 SCADA Monitoring and System-Wide Safety

5.4 Direct Testimony: Corix Exhibit 6.0 - Derek Nelson

This Section 5 has been prepared by Derek Nelson. See the Direct Testimony in Corix Exhibit 6.0 - Derek Nelson.

6 Customer Letter of Support

Corix Exhibit 6.1 contains the Customer Letter of Support from Flagborough L.L.C ("Flagborough"). Flagborough and its affiliates as a group represent all the customers UCDEU will serve in the Utah City development. The Customer Support Letter shows that Flagborough supports this GRC and the proposed Thermal Tariff including rates and terms of service. Flagborough is also in support of the Request for Interim Rates proposed by Corix.

Flagborough and its affiliates own all the lots/buildings within the project area of the conditionally approved CPCN in Docket 25-2666-01.

Flagborough as the customer of UCDEU notably provides support for the following:

- Proposed Thermal Rates in the Thermal Tariff for the Test Period
- Terms and Conditions in the Thermal Tariff
- Thermal Rate Design
- Cost based rates with rate stabilization that take a long-term view of the actual cost of service
- Rate Stabilization with Deferral Account (RDDA)
- Cost of capital
    - Capital structure of 50.0% debt and 50.0% equity;
    - Return on equity (ROE) at 10.5%; and
    - Cost of debt at 7.49%.
- Request for Interim Rates

Corix notes that the entirety of the customer base has provided its support for the thermal utility's GRC application.

6.1 Direct Testimony: Corix Exhibit 6.0 - Derek Nelson

This Section 6 has been prepared by Derek Nelson. See the Direct Testimony in Corix Exhibit 6.0 - Derek Nelson.

7 Forecast Customers, Peak Load, and Energy Demand

This section summarizes the customer buildout, peak load, and energy demand forecast for the test period and the indicative years of this Application. The detailed methodology, assumptions, and supporting analysis are set forth in the Direct Testimony of Johan Grueso-Baron and the Direct Testimony of Derek Nelson. The engineering basis for the load and demand assumptions is documented in the Ramboll workpaper filed as Corix Exhibit 6.2.

Corix and Utah developer Flagborough have partnered to develop an innovative low-carbon district energy system for Utah City, a groundbreaking urban development positioned to become a leading destination for living, working, entertainment, and exploration. The UCDEU will ultimately serve approximately 20 million square feet of connected floor space at full buildout, with a heating capacity of 64 MW and a cooling capacity of 90 MW.

7.1 Buildout Schedule

The UCDEU is scheduled to be commissioned in 2026, with the first connected customer expected on August 1, 2026. Total connected floor area grows from approximately 425,000 square feet in the first partial year of operations (2026) to approximately 737,366 square feet by the end of the test period, predominantly residential floor area. Beyond the test period, the buildout continues through 2044, ultimately reaching approximately 17.9 million square feet. Total connected floor area forecast is outlined in line 14 of Schedule 16 in the Financial Schedules (Attachment 1, Appendix A).

The detailed buildout schedule is set out in Highly Confidential Corix Exhibit 7.3. The schedule identifies each block within the Utah City development area, its development phase, floor area by building type, peak demand intensity, and projected connection year.

7.2 Peak Load Forecast

The determination of peak loads for the Utah City District Energy Utility (UCDEU) is performed on a block-by-block basis. This process involves applying per-unit peak demand intensities to the projected gross floor area of each block within the development. By calculating peak loads in this manner, the assessment accurately reflects the anticipated maximum demand for heating and cooling at each stage of the buildout.

Following the estimation of block-level peak loads, a 70% demand diversification factor is applied to the system. This factor accounts for the statistical non-coincidence of individual building peak demands at the district scale, ensuring that the overall system sizing reflects real-world operational diversity rather than simply summing each building's maximum load. The technical basis for both the peak demand intensities and the diversification factor is grounded in engineering studies developed by Ramboll, and the results of these studies are documented and filed as Corix Exhibit 6.2.

The application of this methodology yields diversified peak loads for the test year of 2.9 MW for heating and 1.9 MW for cooling, as outlined in Schedule 16 in the Financial Schedules (Attachment 1, Appendix A).

7.3 Energy Served Forecast

Annual energy served is calculated using Energy Use Intensities ("EUI") by building typology, as established by Ramboll and documented in Corix Exhibit 6.2. For the test year, the EUI-based estimates are further refined in the ECRA Financial Model (filed as Highly Confidential Corix Exhibit 7.2) to account for residential occupancy ramp-up and hourly load modeling. The full methodology is described in Corix Exhibit 7.0, the Direct Testimony of Johan Grueso-Baron.

The total projected annual energy served for the test year is 6,442.76 MWh, consisting of 4,170.44 MWh for heating (approximately 65% of total energy served) and 2,272.32 MWh for cooling (approximately 35% of total

energy served). Schedule 16 in the Financial Schedules (Attachment 1, Appendix A) provide the long-term forecast thermal energy demand from 2026 through to 2041.

7.4 Link to Revenue Requirement

Forecasts for customer buildout, peak load, and annual energy served are used to determine thermal consumption volumes for calculating energy supply costs and the Energy Charge revenue requirement. Additionally, these forecasts establish the diversified peak capacity needed to size rate base assets and inform the calculation of the Capacity Charge component within the Delivery Revenue Requirement.

7.5 Direct Testimony: Corix Exhibit 7.0 - Johan Grueso-Baron

This Section 7 has been prepared by Johan Grueso-Baron and the information in this section is further supported by the Corix Exhibit 7.0 - Direct Testimony of Johan Grueso-Baron.

8 Energy Supply Costs and Energy Supply Revenue Requirement

8.1 Energy Supply Costs for the Test Period and the indicative years

Energy supply costs are variable costs directly correlated with the production of thermal energy for heating and cooling. Higher customer thermal consumption results in higher energy supply costs, and vice versa. Because of this direct link between actual consumption and actual costs, energy supply costs are modeled and recovered separately from the delivery revenue requirement through the ECRA mechanism.

Energy costs for the test year, along with the operation of the ECRA mechanism, are projected within the UCDEU ECRA Financial Model (Highly Confidential Corix Exhibit 7.2) and its public version (Corix Exhibit 7.3). Forecasts for the long-term and indicative years following the test period are included in the UCDEU GRC Financial Model (Highly Confidential Corix Exhibit 7.1).

8.2 Thermal Energy Supply Costs

The thermal energy supply costs include electricity, natural gas, water and sewer, and chemicals, safety, and testing. The engineering assumptions used to translate customer thermal demand into electricity, natural gas, and water consumption — including equipment efficiencies, coefficients of performance, pumping factors, distribution losses, and water consumption factors — are described in the Direct Testimony of Johan Grueso-Baron (Corix Exhibit 7.0), and Ramboll engineering study documented in Corix Exhibit 6.2.

8.2.1 Electricity

Electricity is required for chiller operation (cooling) and system pumping (heating and cooling). Total electricity consumption is estimated as 747,010 kWh for the test year by applying the equipment efficiencies and operating parameters to the forecast thermal demand. The electricity rate schedule is based on the current Rocky Mountain Power ("RMP") Schedule 6 — General Service, which is the applicable tariff schedule for the UCDEU's service classification during the test year.

UCDEU may participate in RMP’s Electric Demand Response program to earn credits that lower electricity costs. At the time of this filing, insufficient information is available to produce a reliable forecast of demand response savings. Corix will consider including a demand response credit in future pass-through applications as operational experience accumulates.

8.2.2 Natural Gas

Natural gas is the primary fuel used to provide space heating and domestic hot water, produced using natural gas boilers. Natural gas consumption is based on the forecast heating demand and the applicable boiler efficiency and distribution loss factors. Natural gas consumption is estimated in 18,857 Dth (dekatherms equivalent to 10 therms or 1 MMBtU) for the test year. The natural gas rate schedule reflects the current applicable Enbridge Gas Utah tariff schedule. For the initial period of operations, the model applies the General Service schedule rate, transitioning to the Firm Service schedule beginning in 2027 as contracted volumes increase with the development buildout.

8.2.3 Water and Wastewater

The district energy system requires water for the heating and cooling services. Water consumption volumes are derived from engineering factors documented in Corix Exhibit 6.2 and priced at the City of Vineyard Commercial Water Usage Rates.

8.2.4 Chemicals/Safety/Testing

The district energy system requires chemical treatment of the hydronic loops and periodic water quality testing and safety compliance activities. These costs are modeled as annual amounts based on system size and operating requirements during the test period.

8.2.5 Total Energy Supply Costs Summary

The total energy supply costs for the test period, as derived from the ECRA Financial Model (Highly Confidential Corix Exhibit 7.2), are set out in Schedule 14 in the Financial Schedules (Appendix A) and summarized in Table 3 below.

TABLE 3 – ENERGY SUPPLY COSTS – TEST YEAR

Energy Supply Costs	Test Year	2026	2027	2028	2029	2030
Electricity	97,367	24,769	144,278	298,094	606,359	1,627,552
Natural Gas	144,830	58,368	210,329	373,634	764,038	1,837,017
Water and Wastewater	18,842	3,660	28,615	58,052	117,927	324,929
Chemicals, Safety & Testing	7,179	1,877	9,372	19,750	37,359	93,879
Total Energy Supply Costs	268,218	88,674	392,594	749,530	1,525,683	3,883,377

8.3 ECRA Financial Model

The ECRA Financial Model is filed as Highly Confidential Corix Exhibit 7.2 and also as Corix Exhibit 7.3 which is the public version. The ECRA Financial Model contains the Excel file that was used to calculate the energy supply costs and the proposed Energy Charge.

8.4 Direct Testimony: Corix Exhibit 7.0 - Johan Grueso-Baron

This Section 8 has been prepared by Johan Grueso-Baron and the information in this section is further supported by the Corix Exhibit 7.0 - Direct Testimony of Johan Grueso-Baron.

9 Proposed Energy Charges for Test Period

9.1 Energy Supply Costs and the Energy Charge

Corix proposes to recover its energy supply costs as a flow-through cost to customers. This will be achieved via the:

- Energy Charge
- Energy Cost Reconciliation Account (ECRA) and
- a streamlined rate-setting mechanism that allows an annual adjustment to the Energy Charge.

The streamlined rate-setting mechanism would be used to adjust the Energy Charge on an annual basis, based on the existing and forecast balance in the ECRA.

Energy supply costs are discussed in Section 8 above, while the process to flow through energy supply costs to customers is discussed in detail in Section 10 that follows.

9.2 Unit of Measurement

Corix proposes to use an Energy Charge that will be calculated as a cost in dollars per kilowatt-hour ($/kWh). This will be charged to customers on their monthly bills based on their metered consumption in kilowatt-hours for the previous month.

The basis for the measurement of thermal energy consumed (kWh) is used at other district energy utilities owned and operated by Corix and keeps our internal processes standardized and streamlined.

9.3 Energy Supply Costs Summary

Schedule 14 in the Financial Schedules (Appendix A) provides the long-term forecast energy supply costs from 2026 through to 2041. The Test Period energy supply costs is forecast to be $268,218 excluding carrying costs (Schedule 14, line 7).

Table 4 below summarizes the total annual energy supply costs for the first five calendar years of operations.

TABLE 4 - SUMMARY OF TOTAL ANNUAL ENERGY SUPPLY COSTS

	2026	2027	2028	2029	2030
Energy Supply Costs ($)	88,674	392,594	749,530	1,525,683	3,883,377

The medium-term energy supply costs shown above, as well as the long-term energy supply costs included in Schedule 14 of the Financial Schedules are indicative only, since the ECRA Model provides a detailed forecast of the short-term thermal energy demand and associated energy supply costs and is updated each year based on the latest information available at the time of the update.

For details surrounding the calculation of the annual energy supply costs for the test period, please refer to the ECRA Financial Model, submitted in Highly Confidential Corix Exhibit 7.2.

9.4 Thermal Energy Demand

Schedule 16 in the Financial Schedules (Appendix A to this Attachment 1) provide the long-term forecast thermal energy demand from 2026 through to 2041. The Test Period thermal energy demand is forecast to be 6,442,762 kWh (Schedule 16, line 72).

Table 5 below summarizes the total annual thermal energy demand for the first five calendar years of operations.

TABLE 5 - SUMMARY OF TOTAL ANNUAL ENERGY DEMAND

Energy Demand	2026	2027	2028	2029	2030
Heating (kWh)	1,216,131	6,547,497	11,668,773	23,166,303	54,607,824
Cooling (kWh)	411,239	3,317,845	6,739,652	13,266,690	37,166,152
Total (kWh)	1,627,371	9,865,343	18,408,426	36,432,993	91,773,976

The medium-term thermal energy demand shown above, as well as the long-term thermal energy demand included in Schedule 16 of the Financial Schedules, are indicative only, since the ECRA Model provides a detailed forecast of the short-term thermal energy demand and associated energy supply costs and is updated each year based on the latest information available at the time of the update.

For details surrounding the calculation of the thermal energy demand for the test period, please refer to the ECRA Financial Model, submitted in Highly Confidential Corix Exhibit 7.2.

9.5 Proposed Energy Charge for Test Period

Based on the energy supply costs and thermal energy demand forecast for the Test Period, Corix proposes to set the Energy Charge to $0.0417 per kWh (Schedule 17, line 4).

The proposed Energy Charge would remain in effect until the subsequent rate change to the Energy Charge is approved through the newly established streamlined rate-setting mechanism. This process will ensure that energy supply costs are flowed through to customers without markup.

9.6 Direct Testimony: Corix Exhibit 2.0 - Errol South

This Section 9 has been prepared by Errol South. See the Direct Testimony in Corix Exhibit 2.0 – Errol South.

10 Regulatory Framework for Thermal Energy Supply Costs and Cost Recovery

10.1 Energy Supply Pass Through Costs

Corix is proposing once the initial rates are established that the Energy Supply Revenue Requirement process be addressed subsequently through an annual Energy Cost Reconciliation Account (ECRA) regulatory process for these pass-through costs. The annual ECRA process would review Energy Charge rates for heating and cooling based on the Energy Supply Revenue Requirement and would include a request to change rates based on the pass-through of energy supply costs.

This approach is consistent with Utah Code § 54-4-4.1(c) which allows for decoupling methods for pass-through costs and Utah Code § 54-7-12(1)(a)(ii)(B) which allows for a balancing account to implement the pass through of energy supply costs. The proposed ECRA process for thermal energy is conceptually equivalent to Utah Code § 54-7-13.5 energy balancing accounts which are applicable to electrical and natural gas corporations.

The pass through of energy supply costs is sometimes called decoupled rates. Decoupled rates or revenue decoupling breaks the traditional link between a utility's revenue and rates set on a forecast basis and the actual volume of energy sold by the utility. In a decoupled rate structure the utility does not make more revenue and more profit if there were a difference in volume sold.

In the case of energy supply costs there is no "profit" made by the utility. The utility energy charge revenue reflects the actual energy supply costs after accounting for any carrying costs whether the balancing account is in a surplus or deficit position. To achieve this result any difference between actual energy charge revenues and the actual energy supply costs is captured in a deferral account.

10.2 Pass-through costs permitted under the Utah Code

10.2.1 UCDEU's ECRA similar in concept to EGU's 191 Account

Utah Code § 54-7-13.5 presently provides energy balancing accounts for electrical corporations and gas corporations.

The approach taken by Corix for its ECRA is conceptually the same as Enbridge Gas Utah's (EGU) 191 Account. EGU in its tariff states: "The purpose of the Gas Balancing Account is to recover, on a dollar-for-dollar basis, purchased gas costs and gas-cost-related expenses."[10] Both EGU and UCDEU are utilities with pipe infrastructure providing utility service to customers. UCDEU's Energy Cost Reconciliation Account is conceptually the same as EGU's Gas Balancing Account Adjustment Provision. The ECRA is designed to recover, on a dollar-for-dollar basis the costs of thermal energy supply.

Additionally, Rocky Mountain Power (RMP) has approved Electric Service Schedule No. 94 for an Energy Balancing (EBA).

[10] Enbridge Gas Utah, Utah Natural Gas Tariff, Section 2.06 Gas Balancing Account Adjustment Provision, PSCU 700, page 2-9.

10.2.2 PSC jurisdiction to approve energy balancing accounts

The Utah PSC has a history of approving energy balancing accounts as noted in *Division of Public Utilities v. Public Ser. Comm'n*, 720 P.2d 420 (Utah 1986) ("EBA case"). In the Notes paragraph 4 it states:

> "The EBA, on the other hand, takes into account revenue items as well something well outside the purposes of the pass-through legislation. The only relation that we can discern between the pass-through legislation and the EBA is that in between general rate-making proceedings the PSC uses pass-through proceedings to adjust the fuel cost component of the EBA. We find no authorization for the establishment of EBA's in the pass-through legislation; rather, we assume that the EBA order was promulgated under the Commission's ample general power to fix rates and establish accounting procedures. U.C.A., 1953, § 54-7-1 (Repl.Vol. 6A, 1974, Supp.1985)."[11]

Corix is not aware of any specific statute regarding energy balancing accounts for heating corporations. However, Utah Code § 54-7-13.5 does provide guidance for the regulatory process on how pass-through deferral accounts can be structured for a heating corporation. Applying the EBA Case, the PSC has the general power to fix rates and establish accounting procedures for an energy cost reconciliation account for heating corporations absent any specific statue regarding pass through energy supply deferral accounts for heating corporations.

10.3 Energy Cost Reconciliation Account and Energy Cost Rate Setting Mechanism

The proposed thermal tariff for UCDEU includes an Energy Cost Reconciliation Account found in Section D – Energy Cost Reconciliation Account.

Within the Energy Cost Reconciliation Account section of the thermal tariff, it explains the following:

- Applicability
- Reconciliation Account Accrual
- Energy Charge Rate Determination
- Unrecovered Energy Supply Costs Account Entries
- Audit Procedures
- "Two-Way" Carrying Charge

The proposed UCDEU ECRA is similar in concept and approach to the 191 Account used by Enbridge Gas Utah.

10.3.1 Notable matters in the Proposed UCDEU ECRA

Cost of Energy Supply:

Corix proposes that the Cost of Energy Supply include the following:

1) electricity expenses;

[11] Utah Dept. of Bus. Reg. v. PUBLIC SERVICE COM'N, 720 P.2d 420, May 22, 1986, Accessed April 24, 2026, https://law.justia.com/cases/utah/supreme-court/1986/720-p-2d-420.html

2) natural gas expenses;
3) water expenses;
4) sewer expenses; and
5) chemicals, safety and testing expenses

All of the above costs of energy supply are directly related to the consumption of thermal energy (heating and cooling). In a heating service only utility the cost of energy supply primarily involves electricity and natural gas purchases with a minor amount for water and sewer. However, with the addition of cooling service there are additional material costs for water, sewer, chemicals, safety and testing. The use of evaporative cooling technology requires material amounts of water to offer cooling. Safe operation of cooling requires chemicals, safety and testing for water quality testing and legionella monitoring and also testing for the permitting and operation of the cooling towers.

Energy Charge Rate Determination:

UCDEU's proposed Energy Charge for thermal service is an all-inclusive rate for recovering the Energy Charge. When calculating the Energy Charge it is inclusive of any ECRA starting balance for the test period. The ECRA starting balance plus anticipated energy supply costs in the test period is the total energy supply costs to be recovered by the end of the test period.

Corix's approach does not include any trackers or rate riders for the ECRA balance. The ECRA balance is recovered in the single Energy Charge for the utility.

10.4 The initial Energy Charge for thermal service

In Section 8 of Attachment 1 it describes how the Energy Charge is calculated. Section 9 requests the proposed the proposed Energy Charge of $0.0417 per kWh, effective August 1, 2026.

Additionally, the proposed Energy Charge can also be found in Exhibit 1.0 Thermal Tariff, Section E – Rate Schedule 1: General Service.

10.5 Proposal for Energy Charge rate setting mechanism for subsequent rate changes

Corix proposes that no less frequently than annually, the Utility will file with the Commission an application for determination of the Energy Charge rate. This Energy Charge rate will be determined by (1) adding the projected test period energy supply costs from all supply sources and any ECRA balance, and (2) dividing by the projected test-period thermal sales.

Corix proposes that following this GRC Application Corix file for an updated Energy Charge rate effective January 1, 2028. To allow for sufficient time for review and approval Corix proposes to submit the ECRA filing before December 1, 2027. All other subsequent ECRA filings will follow the same pattern.

Corix proposes that given the establishment of the thermal tariff and the transition year, the Energy Charge rates made effective in this GRC Application remain effective for all of 2027.

10.6 Request for Energy Supply Deferral Account

To enable the decoupling of Energy Charge rates and the recovery of the energy supply costs, Corix requests the creation of an Energy Cost Reconciliation Account (ECRA).

Further information on the ECRA can be found in Exhibit 1.0 Thermal Tariff in Section D – Energy Cost Reconciliation Account.

10.7 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 10 has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

11 Calculation of Carrying Charge

In Section C – Standard Fees and Charge Schedule of the Thermal Tariff, Corix has included an interest rate for accounts that is based on the Calculation of Carrying Charge.

Corix proposes the following:

> On or before December 1 of each year, the Utility shall calculate an annual carrying charge and file a letter with the Commission reflecting this rate, to be effective on January 1 of each year. This charge is calculated based on the average daily interest rate for the 12-month preceding period from September to October as published by the Federal Reserve of St. Louis for the ICE BofA BBB US Corporate Index Effective Yield (BAMLC0A4CBBBEY).
>
> The calculated rate shall be applied to the following accounts:
>
> - Unrecovered energy supply costs
> - Customer deposits (to be credited to the Customer's account in January of each year.)
> - Over-billing or under-billing on customer accounts
> - Capacity charge deferred payment plans (CCDPP)
> - Deferred payment arrangements (DPA)

11.1 Carrying Charge Calculation for August 1, 2026

Corix has calculated the initial Carrying Charge to be 4.88%.

This 4.88% figure is based on the daily published information by the Federal Reserve of St. Louis for the ICE BofA BBB US Corporate Index[12] Effective Yield (BAMLC0A4CBBBEY). The daily calculation is included in Corix Exhibit 3.2 which contains the spreadsheet to calculate the daily interest average for the past 12 months (April 1, 2025 to March 31, 2026).

11.2 Next Amendment to Carrying Charge

Given the timing of this GRC proceeding. This proposed initial interest rate would be effective until the next amendment. Corix proposes to file the next updated Carrying Charge rate by November 1, 2027 for an effective January 1, 2028 date. This means the initial rate would be effective from August 1, 2026 to December 31, 2027. When the rate is updated for January 1, 2028 the subsequent updates to the carrying charge would be filed annually on or before November 1 of each year

11.3 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 11 has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

[12] Federal Reserve Bank of St. Louis, ICE BofA BBB US Corporate Index Effective Yield (BAMLC0A4CBBBEY)
https://fred.stlouisfed.org/series/BAMLC0A4CBBBEY

12 Regulatory Framework for Thermal Delivery Costs and Cost Recovery

12.1 Thermal Delivery Costs

The thermal delivery costs are the Delivery Revenue Requirement for the Utility which exclude the energy supply costs. The Delivery Revenue Requirement are the traditional non-commodity costs that is used for the recovery of the invested capital infrastructure of the utility and its operating costs.

The Delivery Revenue Requirement is composed of the following:

- Operation and Maintenance
- Administrative and General
- Depreciation/Amortization
- Return on Equity
- Cost of Debt
- Taxes Other Than Income Tax
- Income Taxes

Rate Base is an important part of the calculation of the Delivery Revenue Requirement. Rate base is the invested capital of the utility that is funded by both debt and equity. Rate base includes the net plant of the utility, the net contributions in aid of construction, deferral accounts, working capital, and accumulated deferred income tax (ADIT). The cost of service arising from rate base is reflected in the annual revenue requirement thorough depreciation/amortization which are return of capital, return on equity, cost of debt, and income tax on earnings.

12.2 Ratemaking for a Traditional Mature Utility

In a traditional mature utility, the cost of service or revenue requirement is the basis to set the utility revenues. In other words, the forecast annual cost of service (forecast revenue requirement) equals the billed revenues from customers in that year. Mature utilities are typically not subject to rate stabilization or levelized rates since the customer base is very stable and typically the expected costs are fairly predictable with relatively minor variances.

12.3 Challenges of a Greenfield Utility with a long-term buildout schedule

The Utah City development is unique since it is not a discrete single project where a limited number of buildings being constructed over a short period in which customers are quickly stabilized. When the customers are stabilized the utility quickly matures and resembles traditional gas and electric utilities with a mature customer base and a mature rate base with limited incremental annual changes.

Instead, the Utah City development spans a long period with the first customer connection occurring in 2026 and the last connection forecast to be in 2044. The development plan has 64 lots/buildings connections to the district energy system. As such the utility customer base is not stable from year to year. For each additional building UCDEU must deploy infrastructure to meet its expected customer demand before each building is connected.

Once the new building is added, revenues and rate base will increase, as will the revenue requirement. Unfortunately, the exact timing of each new building is not known in advance due to construction timing and market development of new buildings. Corix expects that its short term forecasts will be relatively accurate but expects wider variances between forecasts and actuals over the longer period.

12.3.1 UCDEU has a continuous project buildout

The Utah City development is in a continuous project the buildout schedule since new buildings are constantly being added from 2026 to 2024 until all the 64 lots are completed.

Utah Code Section 54-7-13.4 states the following: “Major plant addition" means any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1% of the gas corporation's or electrical corporation's rate base, based on the gas corporation's or electrical corporation's most recent general rate case determination.” When the 1% threshold is met the gas or electrical corporation can implement a deferral of the net revenue requirement arising from the impact of a major plant addition.

In the case of Utah City, each new building represents incremental costs that exceed the 1% rate base threshold in the major plant addition statute. Also, UCDEU it is in a continuous state of major plant additions whenever it adds a new building because the new load is relatively large when compared to the existing load requirements. For example, if there were four buildings and the utility added one new building, the new building would be 25% of the existing customers. This is well beyond the 1% threshold.

When a new UCDEU customer building is added it impacts revenues, plant balances/rate base, depreciation/amortization, return on equity, cost of debt, taxes, etc. that are well beyond a 1% threshold.

12.4 Customer Preference for stabilized rates (rate levelization)

In Corix Exhibit 6.1 the Customer Letter of Support from Flagborough explains the customer preference of stabilized rates also known as levelized rates. Flagborough represents all of the 64 lots/buildings approved in the CPCN Application in Docket No. 25-2666-01. All the customers in this GRC application have expressed a preference for rate stabilization.

12.4.1 Traditional rate-making with non-levelized rates leads to very high and unstable rates

Rate levelization is necessary because the traditional approach of setting the billed revenues in a test period to be equal to the cost of service/ revenue requirements leads to very high and unstable rates. Very high rates negatively impact on affordability and would be unfavorable with regards to the Bonbright Principle of rate stability.

Corix has provided a comparison of rates between a levelized rate and a non-levelized rate in Corix Exhibit 3.3 Levelized and Non-Levelized Capacity Rates. As can be seen in the exhibit, the levelized rate has a steady and growing rate for each of the years based on the long term cost of service and the long term revenues. In the non-levelized rate, the rate is based on the traditional cost of service/revenue requirements where the billed revenue collected from the customer equals the calculated annual revenue requirement. A traditional approach would set the initial rate at $58.66 per kW per month instead of the applied for rate of $15.85 per kW per month. The traditional approach gradually falls each year from $58.66 to a lower amount as new buildings are added to the system.

The traditional approach when the revenue requirements equals the customer billed revenue would create a number of issues for Corix and the Developer. They include:

- Very high annual rates in the early years of the Utility when there are few buildings.
- The initial un-levelized cost of service rate is so high that it makes the Utility unviable because the rates exceed the levelized rate by almost 4 times and are higher than alternative energy sources such as electricity/gas.
- The first buildings bear a disproportionate cost of the fixed costs of the Utility when compared to future buildings. Corix utilizes a just-in-time approach to deploying its fixed infrastructure.
- When a greenfield utility is first constructed the initial capital infrastructure deployed is not only for the first building that connects but also for other buildings that are also connecting in a short period of time. It would be unfair to charge the first building for all the annual costs when the infrastructure is also for the other buildings that are connecting a little later.
- If a utility is not mature, as new customers are added the costs are spread over a larger base and the unitized cost declines.
    - In a traditional utility sometimes matters arise involving inter-generational equity matters where costs incurred today are not fully paid for by current customers and passed on to future customers. This assumes the cost incurred pertains to only the current customers where the current customers received the benefits of the expenditure but is not fully paying for it.
    - UCDEU faces the opposite situation from a traditional utility. There are current capital additions that relate not only to current buildings but also to future buildings added in the next few years. A current customer could take the view it shouldn't pay in current rates the cost of future customers who have yet to connect. Instead, the cost recovery should occur when the future customer connects to allow for a fairer approach to rate making.

12.5 The Utah Code permits rate stabilization

In Utah Code § 54-4-4.1 Rules to govern rates states that the PSC may, by rule or order, adopt any method of regulation that is consistent with Title 54, in the public interest, and just and reasonable. In accordance with Subsection 54-4-4.1(1) a method of rate regulation may include "rate stabilization methods".

12.6 Rate Stabilization with a Deferral Account

To implement a rate stabilization method for a public utility to requires a regulatory body to approve a deferral account. In the case of UCDEU this would be the Revenue Deficiency Deferral Account (RDDA).

An approved regulatory account would be consistent with Generally Accepted Accounting Principles (GAAP) and the FASB Accounting Standards Codification 980 (ASC 980) which allows the utility to include the rate making effects of the deferral account into the financial statements of the utility. In order words, when a deferral account is created and approved by a regulator, under ASC 980, the rate regulator's powers to alter the cash flows and/or revenues is fully reflected in the financial statements.

12.6.1 Utah Code provides guidance on rate stabilization and deferral accounts

Utah Code Section 54-7-13.4 applies to major plant additions for a gas corporation or an electrical corporation. Subsection 54-7-13.4(6) states the following:

(a) Deferral or collection of the state's share of the net revenue requirement impacts of a major plant addition under this section shall commence upon the later of:
    (i) the day on which a commission order is issued approving the deferral or collection amount; or
    (ii) the in-service date of the major plant addition.
(b) The deferral described in this section shall terminate upon a final commission order that provides for recovery in rates of all or any part of the net revenue requirement impacts of the major plant addition.
(c) If the commission authorizes deferral under Subsection (5)(a), the amount deferred shall accrue a carrying charge on the net revenue requirement impacts as determined by the commission.

Section 54-7-13.4 does not apply to a heat corporation, but its deferral mechanism can inform how rate stabilization can be implemented. Under Utah Code Section 54-7-13.4, the alternate cost recovery will affect the rates paid by the customer and it is necessary to defer cost recovery through an approved deferral account.

Given the above example, Corix's proposal to utilize rate stabilization under Utah Code § 54-4-4.1 will also require a deferral account. The use of a deferral account for rate stabilization is consistent with other sections of the statute that attempt to defer recovery of costs. Eventually the deferred costs are recovered in rates through the base rates, rate riders, or other tracker mechanisms.

12.6.2 The RDDA stabilizes rates for a growing greenfield utility

The RDDA is a deferral account that in simple terms captures the difference between the actual billed delivery revenues and the actual delivery costs.

Under a rate stabilized approach to rate-making the customer is charged an initial levelized rate that then increases annually at a steady rate. The levelized rate over the long term reflects the long-term cumulative cost of service.

12.6.2.1 The Various RDDA Phases

The long-term rate levelization plan has a number of phases until maturity/stability is reached:

Build-up Phase: When rate levelization is implemented, in the early years the annual cost of service is higher than the billed revenue. In the early years, there is a cash flow shortfall (RDDA debits) that is added to the RDDA balance.

Peak RDDA: As rates are gradually increased each year, in a future year the annual cost of service equals the billed revenue. This is the point that the RDDA balance peaks.

Recovery Phase: In subsequent years, the annual cost of service is lower than the billed revenue. In these later years, there is a cash flow surplus (RDDA credits) that reduces the RDDA balance.

Target Recovery Year: The RDDA eventually is fully recovered in the RDDA Target Recovery year. In this year the surpluses from the prior years reduces the balance to nil.

Adjustment Phase: At the RDDA Target Recovery year the rates at this time will have billed revenues exceeding the annual cost of service. This means a short rate adjustment period will be needed so that the annual cost of service equals the billed revenues.

Stable Phase: Annual cost of service = Annual billed revenues. This phase is common in most stable mature utilities. Rates are set so the billed revenues equal 100% of the cost of service. The RDDA is no longer needed at this stage unless a future major capital addition is anticipated.

12.6.2.2 The RDDA can be implemented for one-time major capital additions or for continuous major capital additions

The RDDA approach can be utilized in a utility for continuous capital additions. UCDEU is a greenfield utility with a long-term buildout in which customer connections and asset additions are continuous.

Given the continuous major capital additions due to the long-term buildout of the Utah City development, the RDDA implantation would be longer than a one-time major capital addition. However, continuous connections have challenges when forecasting test years. The actual customer connection dates can differ from forecast. In the short-term connection dates can differ to construction timing. In the longer term market development can speed up or delay the customer connection date.

Continuous customer connections have a direct impact on the utility's capital expenditures, capital additions, rate base, revenues, and cost of service. If new building connections are frequent the cost of service will be different each year. For example, if the first year has two connected buildings and the second year has a total of four connected buildings, the cost of service in year one is different from year two. The best predictor of the second year's cost of service will be based on service to four buildings. It would be incorrect to use a historical approach assuming the year one cost of service will be the year two cost of service sine the customer base doubled which leads to higher plant assets, rate base, and cost of service.

12.6.2.3 The RDDA for UCDEU allows for long-term cost based stabilized rates

The RDDA for UCDEU allows for long-term cost based stabilized rates. The rates and cost recovery reflect the actual/allowed costs incurred over the build-out period. The RDDA takes a balanced approach to risk and reward. The actual return on equity reflects the actual prudent invested capital. The achieved ROE does not include any forecast differences that arise between actuals differing from forecast approved for uncontrollable revenues and costs. The shareholder is at risk for approved test period controllable costs. The shareholder is also at risk for imprudent expenditures. When implementing the RDDA, the shareholder is willing to defer cost recovery of a portion of the full cost of service in the early years.

12.6.3 Thermal Tariff: Revenue Deficiency Deferral Account

The Thermal Tariff in Corix Exhibit 1.0, Section E – Rate Schedule 1: General Service, subsection 'Revenue Deficiency Deferral Account' outlines the following details of the RDDA:

- Applicability
- Purpose
- RDDA Impact to the Delivery (Capacity) Rate Determination
- Calculation of the RDDA
- RDDA Balance Mitigation Measures
- RDDA Full Repayment Date Extension
- Audit Procedures

12.6.3.1 Applicability

The RDDA is applicable to all customer accounts in Rate Schedule 1: General Service.

12.6.3.2 Purpose

The RDDA allows for a long-term rate smoothing plan.

The implementation of an RDDA applies cost of service rate-making for revenue requirements over a long-term period rather than a single year. The RDDA is a mechanism that bridges the annual forecast test year period rate-making process with the actual long-term buildout of the development. In periods where the actual revenue billed is less than the revenue required to earn the allowed rates of return, the RDDA asset will accumulate. As the thermal energy system matures, the actual revenue billed is expected to exceed the revenue required to earn the allowed rates of return and the RDDA is drawn down. The draw down occurs until the RDDA is fully recovered on the RDDA recovery date.

12.6.3.3 RDDA Impact to the Delivery (Capacity) Rate Determination

The RDDA impacts the rates charged to customers by implementing a rate levelization plan.

The RDDA smooths the Capacity Charges for each year. In the early years of the rate plan the actual billed delivery revenues are lower than the allowed delivery cost of service. The difference in revenues is captured in the RDDA. The RDDA balance is recovered in a future period of the rate levelization plan.

In the later years of the rate plan, actual billed delivery revenues are higher than the allowed delivery cost of service. In this period the RDDA balance is being drawn down.

12.6.3.4 Calculation of the RDDA

The Calculation of the RDDA section explains the details of the calculation of the RDDA activity and balance each year.

The RDDA captures the difference between (a) the actual delivery revenues and (b) the total allowed delivery cost of service.

The actual delivery revenues are the actual delivery revenues from all rate classes.

The total allowed delivery cost of service is the sum of:

i. actual non-controllable delivery costs;

ii. forecast approved controllable delivery costs; and

iii. forecast approved costs for those delivery costs.

Non-controllable delivery costs are costs which the Utility has a) no reasonable ability to control, b) costs which are influenced by factors outside its control, or c) costs that are not reasonably predictable. Non-controllable costs include the following:

- All delivery costs including O&M that are not controllable delivery costs.
- Unforeseen labor costs due to meeting operational compliance requirements.
- Insurance costs.
- External regulatory costs.
- Taxes other than income taxes.
- Income taxes.
- Depreciation and amortization on actual plant account balances.
- Amortization of other approved delivery deferral account balances, if any.
- Debt interest costs on the debt portion of actual rate base.
- Allowed return on equity on the equity portion of actual rate base.

Controllable delivery costs are costs which the Utility has a reasonable ability to control and minimize with reasonable care and effort following prudent utility operational practice. Controllable costs include the following:

- Internal labor.
- O&M costs arising from regional costs allocations.
- O&M costs arising from corporate costs allocations.

In the calculation of the actual RDDA activity for each year, the allowed regional cost allocations and corporate cost allocations are based on the forecast approved test year amounts.

The RDDA is included in rate base. The actual RDDA additions or deductions for the year are calculated following the end of each fiscal year.

12.6.3.5 RDDA Balance Mitigation Measures

The target date by which the RDDA balance shall be fully repaid is December 31, 2041.

The RDDA balance can vary if there are customer connection delays that lower revenue or changes in construction costs. To mitigate against material and sustained variances from forecast there is a mitigation measure regarding the RDDA balance becoming too high relative to the plant net book value or if the RDDA balance is not expected to be fully recovered by its target date. If the thresholds are not expected to be met, the Utility has options to improve the financial position of the utility.

If the forecast RDDA balance in a year exceeds 20% of the forecast plant net book value of the Utility or the forecast RDDA balance is not expected to be fully recovered by the RDDA full repayment date, the Utility is permitted to (1) increase the Monthly Capacity Rates, (2) require a customer revenue contribution (e.g. rate rider recovery or lump sum payment), (3) require a customer cash contribution; (4) require an asset contribution in aid of construction, or (5) a combination of the foregoing, all subject to Commission approval.

Corix has included in this GRC proceeding Corix Exhibit 3.4 RDDA Balance Relative to NBV that shows the forecast RDDA percentages relative to net book value of plant.

12.6.3.6 RDDA Full Repayment Date Extension

The Utility may extend the target RDDA repayment date based on build-out delays or higher capital costs. Any extension would require approval of the Commission.

12.6.3.7 Audit Procedures

The Audit Procedures section outlines that all RDDA items records are subject to regulatory audit.

12.7 Appropriate Risk and Reward

Corix has designed the RDDA by taking a balanced approach to risk and reward for a greenfield utility with a continuous buildout where the customer base is not stable and major projects are continually being completed during its buildout period.

The Corix approach also considers the opportunity of the shareholder to earn on its prudently invested capital while also ensuring the Utility is at risk for controllable costs.

The customer with its continuous new connections to the district energy system has a very material impact on the thermal utility. As new buildings are connected, the customer base materially increases. Before each building is connected the utility must invest in the asset infrastructure that includes ensuring there is sufficient thermal capacity at the central energy plant, completing any required distribution piping system, and constructing the energy transfer station that is sized for the new building. Once the customer connects, the Customer would be paying revenue and the new assets related to that building would be placed into service. There would be also operating costs to serve each new building.

The key factor that drives UCDEU's thermal utility costs and revenues is the speed at which new buildings are added to the Utah City development. This means that the cost of service/revenue requirements is highly dependent on an external factor over which UCDEU has no control. The Utility is highly dependent on the Flagborough development progress for completing new buildings and its expected capacity and load consumption. The utility is constructing the thermal infrastructure based on the needs and expectations of the Developer.

12.7.1 Non-Controllable Delivery Costs

In the start-up of UCDEU there is high uncertainty of the initial start date of the utility offering thermal service since it depends on when the first customer connects. The connection of the first building triggers placement of placement of plant into service (and rate base), the receipt of billed revenue from the customer, depreciation of plant in rate base, return on equity, and interest costs, as well as operation and maintenance expenses. When the second customer connects, it leads to additional revenues and further plant placed into rate base. Subsequent customer connections continue the cycle of costs and revenues. These items described above are non-controllable costs since the costs are dependent on an external factor to which the utility cannot control: the timing of actual customer connections.

It is possible to forecast customer connections and its related revenues and costs. However, the actual revenues and costs highly depend on the actual timing of the customer connection. In a start-up greenfield utility there are

high expected variances between forecast revenues and costs and actual revenues and costs that are directly related to the actual timing of the customer connection.

12.7.2 Controllable Delivery Costs

For the purposes of the RDDA, there are controllable delivery costs that the utility has control over. These costs involve internal labor and the allocations arising from regional services and corporate services. For these controllable costs the RDDA will hold these costs at approved test period amounts. This means that if the actual costs for these items differ from the forecast approved amounts, the RDDA calculation will hold these amounts at approved amounts thus no variance would be borne by the ratepayer.

12.8 Prudent Expenditures and Regulatory Oversight

The proposed regulatory framework for delivery revenue requirements and the functioning of the RDDA continue to have the same approach to regulation as traditional gas and electric utilities. Only prudent expenditures (capital and operating) are to be recovered from ratepayers. Any RDDA additions include only prudent expenditures of capital and operating costs. To ensure prudent expenditures the PSC has regulatory oversight of the heating corporation.

12.8.1 Regulatory Audits

All items recorded in the RDDA are subject to regulatory audit to ensure prudency of expenditures and adherence to all previous PSC orders.

12.9 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 12.0 Regulatory Framework for Thermal Delivery Costs and Cost Recovery has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

13 Overview of Corporate Structure, Organizational Structure, and Utility Resourcing

13.1 Corporate Structure – Ownership Chart

Corix Utah City Heating and Cooling LLC is ultimately owned by British Columbia Investment Management Corporation, a pension fund manager. To provide information on ownership, Corix has included:

- Simplified Ownership Chart for Corix Utah City Heating and Cooling LLC in Corix Exhibit 2.2; and
- Simplified Ownership Chart with relevant affiliates in Corix Exhibit 2.3.

Both charts indicate the regulatory status of each entity included in the chart.

13.2 Organizational Structure – Services Provided to UCDEU

Corix Utah City Heating and Cooling LLC does not have employees in its own name. Its labor resources are provided from affiliates that are ultimately owned by the same parent company as UCDEU (parent affiliates).

Corix Exhibit 2.4 shows the Support Services Diagram where Corix Utah City Heating and Cooling LLC receives services from two affiliates. This diagram can be viewed in conjunction with the diagram presented in Corix Exhibit 2.3, which includes these two affiliates and the ownership structure.

13.3 Resources provided from Parent Affiliates

13.3.1 Parent Funding

Affiliates of the parent provide both debt and equity funding for Corix Utah City Heating and Cooling LLC. Details of the parent funding can be found in Corix Exhibit 4.0 Testimony of Maxwell Wang.

13.3.2 Affiliated Services provided to UCDEU

There are four types of services provided to UCDEU from or through affiliates. They are as follows.

1. Corporate shared support services, charged using the Corporate cost allocation methodology (see Corix Exhibit 2.6 Corporate Cost Allocation Manual)
2. Regional shared support services, charged using the Regional cost allocation methodology (see Corix Exhibit 2.5 Regional Cost Allocation Manual)
3. Cost recoveries (from cost pooling to gain scale and buying power), charged on the basis of cost causation
4. Local utility labor resources, charged by direct cross charge

Section Support Services Cost Allocations19 explains in more detail Items 1 and 2 regarding shared support services for UCDEU.

Item 3 Cost recoveries (from cost pooling to gain scale and buying power) are related to certain costs such as insurance and billing software expenses. To gain scale and buying power certain costs are purchased by an affiliate from a third-party vendor. This pooled cost is then recovered through direct charges to the entities receiving the service on the basis of cost causation.

Item 4 Local utility labor resources are costs directly charged to UCDEU since UCDEU doesn't have its own direct employees. Local utility labor resources are provided by another affiliated entity and cross charged to UCDEU. The labor amounts charged are fully loaded.

13.4 Direct Procurement of Outside Services

Corix Utah City and Cooling LLC does directly purchase certain outside service and materials from third party vendors. Such purchases would include electricity and natural gas from the local utility providers and any other equipment, supplies and services that can not be provided in-house.

Competitive procurement processes are used to acquire goods and services to manage costs and ensure the best value, and we endeavor to select local vendors wherever possible.

13.5 Direct Testimony: Corix Exhibit 2.0 - Errol South

This Section 13 has been prepared by Errol South. See the Direct Testimony in Corix Exhibit 2.0 - Errol South.

14 Capital Expenditures and Asset Life

The capital expenditures necessary to design, build, and place the plant into service is built up from the following components:

- Direct Costs – include all expenditures directly attributable to the physical construction and installation of the asset. These costs consist of major equipment purchases, construction labor, civil and mechanical works, permitting and inspection fees, and third-party engineering and design services required to deliver the asset in accordance with applicable technical, safety, and regulatory standards. The direct costs were derived from the applicable supply contract for the assets that will be capitalized in 2026 and for subsequent assets, it was estimated based on Ramboll's unit cost estimates (Corix Exhibit 6.2).
- Project Management ("PM") Costs – Project Management costs represent internal labor and resources dedicated to planning, coordinating, and overseeing the execution of the project. These costs include internal project management activities necessary to manage schedules, budgets, contractors, and quality control throughout the construction period. Internal resource planning could be found in Derek Nelson's testimony (Corix Exhibit 6.0).
- Construction Insurance – Construction insurance is applied at 0.15% of Direct Costs and reflects coverage required during the construction phase to mitigate risks associated with property damage, liability, and other project-related exposures.
- Contingency Allowance – A contingency allowance equal to 15% of Direct Costs is included to account for normal uncertainties inherent in the construction process, such as unforeseen site conditions, design refinements, or market-driven cost variability. The contingency is intended to support prudent project execution and cost control and is only utilized as necessary.
- Development, Start-Up, Transaction, Due Diligence, and Regulatory Costs – all associated costs related to the Certificate of Public Convenience and Necessity ("CPCN") proceeding, the Company's first General Rate Case ("GRC"), and the development, start-up, transaction, due diligence, and regulatory costs.

During the construction period, all capital expenditures associated with individual construction projects are tracked in Construction Work in Progress ("CWIP"). These costs include all capital expenditures necessary to design, build, and commission the plant and related utility infrastructure. CWIP accumulates project-level costs until the assets are completed, tested, and determined to be used and useful in providing regulated service.

14.1 Capital Expenditures

14.1.1 Capital expenditures up to first service connection

The table below summarizes the Utility's Pre-Test Year capital expenditures by major construction project. As discussed above, these amounts represent total project costs recorded to Construction Work in Progress ("CWIP") during the construction period and include Direct Costs, internal Project Management support, and Construction Insurance. The development, start-up, transaction, due diligence, and regulatory-related costs associated with the CPCN and this first GRC is tracked in a separated CWIP project that will be allocated to the initial production assets.

The project-level presentation provides transparency into how the total Pre-Test Year capital program is allocated among the IEC1 (two supply contracts), and the customer connection infrastructure (ETS and DPS for the first three buildings).

TABLE 6 - CAPITAL EXPENDITURE – PRE-TEST YEAR

Capital Expenditure	Pre-Test Year
By construction projects	
IEC1 Supply contract	12,470,020
IEC1 Siteworks preparation	1,147,227
Dev., Start-Up, Transaction, Due diligence, and Reg. Costs	3,081,915
ETS to connect first 3 buildings	1,040,257
DPS first trench	5,557,782
Total Capital Expenditure	**23,297,201**

14.1.2 Capital expenditures in the test year

During the test year, the expected capital expenditure is related to the trailing cost of the initial assets, the capital required to connect the customers during the test year and the expansion of the cooling capacity in the IEC1 to support the demand of customers connecting in 2027 to 2029.

TABLE 7 - CAPITAL EXPENDITURE - TEST YEAR

Capital Expenditure	Test Year
By construction projects	
IEC1 Supply contract	1,051,872
IEC1 Siteworks preparation	-
Dev cost, regulatory, startup	407,045
ETS to connect first 3 buildings	160,039
DPS to connect first 3 buildings	132,743
Cooling additional capacity in 2027	2,709,019
ETS to connect building in 2027	2,439,782
DPS to connect building in 2027	1,480,860
DPS to connect building in 2028	96,098
Total Capital Expenditure	**8,477,460**

14.1.3 Outlook for capital expenditures after test year to buildout

This section provides the Utility's forecasted capital expenditure outlook after the Test Year to support continued system buildout and expected growth in customer demand. The forecast reflects the timing of production capacity expansions and related network infrastructure necessary to reliably serve forecast load.

To meet longer-term demand growth, the Utility forecasts a second Interim Energy Center ("IEC") in 2029. In addition, the Utility forecasts three Permanent Energy Centers ("PECs") to be placed in service in 2030, 2034, and 2037, as required to meet expected increases in heating and cooling demand over the long term.

Capital expenditures for Energy Transfer Stations (“ETS”) and the Distribution Piping System (“DPS”) are timed directly to the customer buildout and connection schedule. As customers are added, corresponding ETS and DPS investments are required to interconnect new buildings and extend the distribution network. Accordingly, ETS and DPS capital costs are forecast based on the timing and scale of customer connections.

The long-term capital program relies on Ramboll’s unit-cost estimating framework. Ramboll estimates IEC and PEC costs using scalable cost drivers expressed as: (i) dollars per MW of heating capacity ($/MW Heating), (ii) dollars per MW of cooling capacity ($/MW Cooling), and (iii) dollars per square foot of built area ($/sq. ft.). DPS costs are estimated using dollars per meter of installed distribution piping ($/m of DPS), and ETS costs are estimated using dollars per customer connection ($/connection). Additional detail regarding these cost estimates and underlying assumptions is provided in Corix Exhibit 6.2 - Ramboll technical memorandum.

The Utility will continue to refine these long-term capital forecasts as customer commitments, engineering design, and construction sequencing progress. The post–Test Year outlook presented herein provides a transparent and reasonable basis for forecasting Plant in Service growth consistent with the Utility’s expected buildout requirements.

14.2 Asset Service Lives and Classification

For the purpose of forecasting depreciation expense and supporting the Utility’s long-term capital plan within this Application, expected service lives have been assigned to the plant in service. Assets are categorized under Production and Distribution, with further grouping into asset classifications that align with their function and anticipated replacement cycle.

Both Production and Distribution assets are assigned useful lives of 50, 25, 10, 5, and 3 years, reflecting the diversity of equipment, infrastructure, and their respective operational requirements.

The determination of service lives for these assets was based on a combination of expert opinion and manufacturer-recommended useful lives. This approach incorporates industry expertise and technical guidance from manufacturers to develop a reliable basis for asset management and depreciation forecasting.

Attachment 1, Appendix A in Schedule 6 (Capital Expenditures and AFUDC) and Schedule 7 (Depreciation and Amortization Rates) provide further information on this section.

14.3 Direct Testimony: Corix Exhibit 6.0 - Derek Nelson

This Section 14 has been prepared by Derek Nelson. See the Direct Testimony in Corix Exhibit 6.0 - Derek Nelson.

15 Capital Additions

The UCDEU's Plant in Service included in rate base and the treatment of capital costs associated with the construction of utility facilities. During the construction period, the Utility will incur capital expenditures necessary to design, build, and place the plant into service. Consistent with regulatory accounting requirements, these construction-related costs accrue Allowance for Funds Used During Construction (AFUDC), reflecting the cost of financing the project prior to it becoming used and useful.

After the built assets meet all necessary requirements—such as being completed, ready for operation and actively used to deliver thermal energy services—the Utility records a capital addition to Plant in Service, which is then included in the rate base. This approach ensures customers benefit from fully operational assets and allows UCDEU to recover prudent capital expenses according to regulatory guidelines.

15.1 Capital Costs

Upon completion of construction and satisfaction of the criteria to be placed in service, the accumulated CWIP balance is capitalized and reclassified into permanent asset accounts based on the nature and function of the underlying facilities. Utility plant assets are classified into the following categories:

Production Assets: include central and interim energy plant facilities that generate thermal energy for distribution to customers. These assets include major generation equipment and associated infrastructure required to produce heating and cooling energy.

Distribution Assets: include the Distribution Piping System ("DPS") and Energy Transfer Stations ("ETS") assets, which together transport and deliver thermal energy from the production facilities to customer premises. These assets form the backbone of the utility's thermal network and are necessary to reliably convey energy to end-use facilities.

General Plant assets: include support assets that are not directly involved in energy generation or distribution but are necessary for overall utility operations. These assets include vehicles, office furniture and equipment, information technology hardware, and other general support infrastructure.

Once capitalized into these respective asset categories, the plant is recorded as Plant in Service and included in rate base, consistent with applicable regulatory and accounting requirements.

The staging methodology and specific in-service timing are described in the Direct Testimony of Johan Grueso-Baron (Corix Exhibit 7.0) and the Direct Testimony of Derek Nelson (Corix Exhibit 6.0).

15.2 Capital Expenditure, Capital Additions and CWIP balance in the test period

The Table 8 summarizes the Utility's capital expenditures incurred during the construction period that precedes e the Test Year and Test Year, as well as the resulting capital additions placed into service, prior to the application of Allowance for Funds Used During Construction ("AFUDC"). Capital expenditures are presented by functional plant category—Production, Distribution, and General Plant—and reflect costs recorded to Construction Work in Progress ("CWIP") during the construction period. Upon completion and placement of assets into service during the Test Year, accumulated CWIP is transferred to Plant in Service as capital additions. The table also presents the ending CWIP balance remaining under construction at the close of the Test Year.

TABLE 8 - SUMMARY OF CAPITAL EXPENDITURE, CAPITAL ADDITIONS AND CWIP BALANCE EXCLUDING AFUDC

Capex and Additions excl. AFUDC	Pre-Test Year	Test Year
Total Capital Expenditure	**23,297,201**	**8,477,460**
Additions - Production		20,785,269
Additions - Distribution		9,568,648
Additions - General Plant		81,830
Total Capital Additions	**-**	**30,435,747**
CWIP Balance (Excl. AFUDC)	**23,297,201**	**1,338,914**

15.3 Capital Expenditures, Capital Additions and CWIP in the indicative years

The Table 9 below presents the summary forecast of capital expenditures, capital additions, and Construction Work in Progress (“CWIP”), each excluding Allowance for Funds Used During Construction (“AFUDC”), through 2030. Capital expenditures reflect annual investments made to construct the utility plant, while capital additions represent the portion of completed projects that are transferred from CWIP to Plant in Service. The CWIP balance shown for each year reflects the net carry forward of ongoing construction projects not yet completed as of year-end. This presentation illustrates the timing differences between capital spending and the placement of assets into service.

TABLE 9 – CAPITAL EXPENDITURE, CAPITAL ADDITIONS, AND CWIP BALANCE EXCLUDING AFUDC

Capex and Additions excl. AFUDC	<=2026	2027	2028	2029	2030
Capital Expenditure Excluding AFUDC	28,667,217	8,589,225	34,534,069	47,625,584	29,716,550
Capital Additions Excluding AFUDC	24,648,802	6,936,104	2,480,986	40,927,401	51,151,925
CWIP Balance (Excluding AFUDC)	**4,018,414**	**5,671,536**	**37,724,619**	**44,422,801**	**22,987,427**

15.4 Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the cost of capital — both debt and equity — used to finance utility construction during the period before an asset is placed in service. The AFUDC rate used in the GRC Financial Model is calculated using the utility's weighted average cost of capital to Construction Work in Progress ("CWIP") balances. AFUDC accrues monthly on CWIP balances throughout the construction period. Previously accrued AFUDC that remains in CWIP is included in the balance on which subsequent AFUDC is calculated, consistent with standard compounding treatment. AFUDC ceases to accrue when the asset is placed in service. Upon commissioning, the total accumulated CWIP balance — comprising direct capital costs plus capitalized AFUDC — is transferred into Plant in Service. The capitalized AFUDC is then included in rate base and depreciated over the asset's useful life.

The AFUDC accrual assumptions and resulting balances are reflected in the capital additions and CWIP schedules set out in Schedule 5 and 6 in the Financial Schedules (Appendix A) and summarized in Table 10 and Table 11 below.

TABLE 10 - AFUDC IN THE TEST YEAR

AFUDC	Pre-Test Year	Test Year
AFUDC accrued on CWIP	1,100,175	296,913
AFUDC Capitalized in assets	0	1,354,211
AFUDC in CWIP Balance	1,100,175	42,877

TABLE 11 - AFUDC IN THE INDICATIVE YEARS

AFUDC	<=2026	2027	2028	2029	2030
AFUDC accrued on CWIP	1,276,626	245,854	1,314,999	2,011,626	1,358,941
AFUDC Capitalized in assets	1,130,542	257,417	99,631	1,529,685	2,014,549
AFUDC in CWIP	146,083	134,520	1,349,887	1,831,828	1,176,220

15.5 Future Sustainment / Replacement Capital

Replacement capital reflects the expected reinvestment required to maintain the reliability, safety, and functionality of existing utility plant as individual asset components reach the end of their respective useful lives. For modeling purposes, replacement capital expenditures are estimated using an indicative, long-term methodology rather than a project-specific construction plan. Direct replacement costs—such as equipment, materials, and installation labor—are assumed to be fully incurred upon the expiration of an asset's useful life. These costs represent the physical replacement of worn or obsolete components necessary to restore the asset to its intended operational condition.

Other capital cost components, including project management, engineering design, and similar indirect costs, are assumed to be replaced at 50 percent of their original level. This treatment reflects the nature of replacement activity, which is expected to involve the substitution of subcomponents within existing facilities rather than full greenfield construction. As a result, certain development-phase activities associated with the initial build—such as detailed engineering design, permitting, and comprehensive project management—are not expected to be required to the same extent for replacement work.

The replacement plan presented in this Application represents a long-term, indicative assumption intended to support rate base forecasting and revenue requirement development. Replacement capital does not materially affect Plant in Service during the early years of the forecast period. Instead, replacement additions begin to emerge after year 10, when initial asset components with an assumed ten-year useful life are expected to reach the end of serviceability and require reinvestment. Accordingly, replacement capital primarily influences Plant in Service and rate base in the outer years of the forecast horizon.

This approach provides a reasonable and transparent basis for estimating long-term sustainment investment while recognizing that actual replacement timing and scope will continue to be evaluated through ongoing asset management practices and future regulatory proceedings.

15.6 Total Capital Additions

Table 12 and Table 13 below present the forecast of total capital expenditures inclusive of AFUDC, total capital additions to Plant in Service, and the resulting CWIP balances over periods prior to the test year, the test year period, and the forecast period through 2030.

TABLE 12 - SUMMARY OF CAPITAL EXPENDITURE, CAPITAL ADDITIONS AND CWIP BALANCE IN THE TEST YEAR

Capex and Additions	Pre-Test Year	Test Year
Total Capital Expenditure + AFUDC	24,397,375	8,774,373
Total Capital Additions	0	31,789,958
CWIP Balance	**24,397,375**	**1,381,790**

TABLE 13 - SUMMARY OF CAPITAL EXPENDITURE, CAPITAL ADDITIONS AND CWIP BALANCE IN THE INDICATIVE YEARS

Total Capital Additions	<=2026	2027	2028	2029	2030
Total Capital Expenditure + AFUDC	29,943,842	8,835,079	35,849,068	49,637,210	31,075,491
Total Capital Additions	25,779,345	7,193,521	2,580,617	42,457,086	53,166,475
CWIP Balance	**4,164,497**	**5,806,056**	**39,074,506**	**46,254,630**	**24,163,647**

15.6.1 Total Capital Costs Comparison to CPCN Forecast

Compared to the Certificate of Public Convenience and Necessity (“CPCN”), in this GRC UCDEU is reducing significantly the 2026 capital cost additions. The reason for this reduction is the lower capital expenditure due to the procured supply contract for the construction projects in the IEC, the initial trench of DPS and the ETS to connect the initial three customers. After 2026, both forecasts rely on the unit cost estimated in the engineering studies presented in Corix Exhibit 6.2. Variations in 2027 and following years are due to changes in timing of customer connections which has been communicated by Flagborough as the future plans move from high level estimates to more refined and accurate plans. Table 14 below presents the annual and cumulative capital additions in the first 5 years of the forecast in this GRC application and compares it with the forecast capital additions included in the CPCN. This comparison provides transparency into how the updated GRC capital plan differs from prior CPCN assumptions and the resulting impact on Plant in Service for ratemaking purposes.

Compared to the Certificate of Public Convenience and Necessity (“CPCN”), the General Rate Case (GRC) for UCDEU shows a significant reduction in the 2026 capital cost additions. This reduction is attributed to lower capital expenditure, which results from the procured supply contracts for construction projects in the IEC, the initial trench of DPS, and the ETS required to connect the first three customers.

Following 2026, both the GRC and CPCN forecasts are based on unit cost estimates derived from engineering studies, as presented in Highly Confidential Corix Exhibit 7.4. The variations observed in 2027, and subsequent years, are primarily due to changes in the timing of customer connections. Flagborough has communicated these changes as project plans move from high-level estimates to more refined and accurate schedules.

Table 14 below presents the annual and cumulative capital additions for the first five years of the forecast in this GRC application and compares them to the forecast capital additions included in the CPCN. This comparison offers transparency regarding how the updated GRC capital plan differs from earlier CPCN assumptions and illustrates the resulting impact on Plant in Service.

TABLE 14 - CAPITAL COSTS COMPARISON TO CPCN FORECAST

Total Capital Additions	2026	2027	2028	2029	2030
Annual capital additions					
GRC 2026 ($)	25,779,345	7,193,521	2,580,617	42,457,086	53,166,475
CPCN ($)	30,546,925	8,234,050	4,018,919	40,077,868	52,457,498
Cumulative capital additions					
GRC 2026 ($)	25,779,345	32,972,866	35,553,483	78,010,569	131,177,044
CPCN ($)	30,546,925	38,780,975	42,799,894	82,877,762	135,335,261
Annual Variance ($)	-4,767,580	-1,040,529	-1,438,302	2,379,218	708,976
Cumulative Variance ($)	-4,767,580	-5,808,110	-7,246,411	-4,867,193	-4,158,216

15.7 Direct Testimony: Corix Exhibit 7.0 - Johan Grueso-Baron

This Section 15 has been prepared by Johan Grueso-Baron and the information in this section is further supported by the Corix Exhibit 7.0 - Direct Testimony of Johan Grueso-Baron.

16 Contributions in Aid of Construction (CIAC)

CIAC represents amounts contributed by third parties to fund utility capital investments. When received, CIAC is recorded as a reduction to gross Plant in Service for ratemaking purposes, such that the contributed portion of the asset is not included in rate base and is not recovered from customers through rates.

At this time, the UCDEU is not expecting to receive any CIAC. Accordingly, the GRC Financial Model reflects Plant in Service on a gross basis, with no reductions to capital recovery components associated with CIAC. If CIAC were to be received in the future, the financial model would be updated in a subsequent General Rate Case to reflect the appropriate ratemaking treatment.

16.1 Direct Testimony: Corix Exhibit 7.0 - Johan Grueso-Baron

This Section 16 has been prepared by Johan Grueso-Baron and the information in this section is further supported by the Corix Exhibit 7.0 - Direct Testimony of Johan Grueso-Baron.

17 Depreciation and Amortization

This section describes the depreciation and amortization ("D&A") methodology used to develop the Utility's depreciation expense and accumulated depreciation for ratemaking purposes. Depreciation expense is included in the revenue requirement as the systematic recovery of the cost of Utility Plant over the period the plant provides service. Accumulated depreciation is reflected as a reduction to gross Plant in Service in the determination of net rate base.

The Utility applies the straight-line depreciation method, which spreads the depreciable cost of an asset evenly over its estimated useful life. Depreciation starts in the month after the asset is put into service and is listed as Utility Plant in Service. Assets recorded as Construction Work in Progress ("CWIP") are not depreciated until they are moved to Plant in Service. No salvage value is assigned to any category of assets.

17.1 Depreciation Rates and Amortization Rates

For this Application, the Utility does not apply a single composite depreciation rate to broad plant groupings (e.g., Production, Distribution, and General Plant). Instead, the Utility developed subcategory depreciation rates that align to the estimated useful lives of the underlying asset components.

A composite rate would blend assets with materially different service lives into one average rate. For a district energy system, major facilities are comprised of components that do not wear out on the same schedule. For example, structures and piping are long-lived, while major mechanical equipment and controls typically have shorter replacement cycles. A single composite rate would therefore misalign cost recovery—over-depreciating long-lived components and under-depreciating short-lived components—resulting in depreciation expense that does not reflect how the plant is consumed in service.

Using subcategories improves the accuracy and transparency of depreciation for ratemaking purposes by:

- Matching depreciation expense to service life. Each component is depreciated over a period consistent with its expected useful life, reducing the risk of mismatched cost recovery.
- Improving rate base measurement. Accumulated depreciation better reflects the remaining service value of the plant components included in rate base.
- Supporting long-term reinvestment planning. Component-level depreciation aligns with expected replacement cycles and provides a clearer linkage between plant consumption and future sustainment needs.

This subcategory approach provides a reasonable and supportable depreciation structure for the UCDEU's plant composition and expected asset life cycles.

17.1.1 Thermal Energy Production Assets

Thermal Energy Production Assets consist of central and interim plants for thermal energy, divided into four sub-categories. Heating modules and cooling modules each have three sub-categories. Table 15 shows depreciation rates for all subcategories.

TABLE 15 - THERMAL PRODUCTION ASSETS – DEPRECIATION RATES

Asset Component	Depreciation rate
Plant heating equipment structures	2%
Boiler plant equipment (gas)	4%
Miscellaneous heating plant equipment (devices)	10%
Plant cooling equipment structures	2%
Chillers	4%
Cooling towers	4%
Miscellaneous cooling plant equipment (devices)	10%
Plant thermal equipment structures	2%
Thermal plant equipment	4%
Miscellaneous thermal plant equipment (devices)	10%
Plant siteworks	10%

17.1.2 Thermal Energy Distribution Assets

Thermal Energy Distribution Assets include the Distribution Piping System (“DPS”) and Energy Transfer Stations (“ETS”), which transport and deliver thermal energy to customer facilities. Table 16 shows depreciation rates for all subcategories.

TABLE 16 - THERMAL DISTRIBUTION ASSETS – DEPRECIATION RATES

Asset Component	Rate
Energy Transfer Station (“ETS”)	2%
Heat exchanger (“HEX”) installations on customers’ premises	4%
Meters	10%
Distribution Piping System (“DPS”)	2%

17.1.3 General Plant Assets

General Plant Assets include supporting property used in utility operations and administration, such as vehicles, office furniture and equipment, communications and IT hardware, software, and miscellaneous support equipment. Table 17 below present the depreciation rates applied to each component category.

TABLE 17 - GENERAL PLANT ASSETS – DEPRECIATION RATES

Asset Component	Rate
Office furniture and equipment	10%
Vehicles	20%
Hardware & communication equipment	20%
Computer software	33%
Miscellaneous equipment	20%

17.2 Depreciation and amortization expenses in the revenue requirement

The annual depreciation expense calculated using the rates and methodology described in this section is included as a component of the Utility's cost of service and is reflected in the proposed revenue requirement. Accumulated depreciation, representing the cumulative depreciation recognized since the placement of each asset into service, is deducted from gross Plant in Service in the calculation of net Plant in Service for rate base purposes.

17.3 Depreciation and amortization expenses in the test period and the indicative years

Table 18 and Table 19 below summarize the Test Year and the indicative years D&A expense by functional plant category—Production, Distribution, and General Plant—consistent with the Utility's proposed depreciation rates and asset classifications. As shown, total Test Year depreciation expense is $883,020, with the majority attributable to Production plant, reflecting the relative scale of investment in thermal energy generation facilities compared to distribution and general support assets.

TABLE 18 - DEPRECIATION & AMORTIZATION IN THE TEST PERIOD

Depreciation & Amortization expense	Test Year
Production	713,347
Distribution	157,160
General Plant	12,513
Total Depreciation Expenses	**883,020**

TABLE 19 - DEPRECIATION & AMORTIZATION IN THE INDICATIVE YEARS

Depreciation expense	2026	2027	2028	2029	2030
Production	248,201	813,888	836,982	1,947,031	3,053,628
Distribution	46,639	212,997	303,902	468,826	913,161
General Plant	4,550	13,651	13,651	23,448	24,592
Total Depreciation Expenses	**299,391**	**1,040,535**	**1,154,535**	**2,439,304**	**3,991,382**

Further financial information regarding this section can be found in Appendix A in Attachment 1, Schedules 4, 5, and 7.

17.4 Direct Testimony: Corix Exhibit 7.0 - Johan Grueso-Baron

This Section 17 has been prepared by Johan Grueso-Baron and the information in this section is further supported by the Corix Exhibit 7.0 - Direct Testimony of Johan Grueso-Baron.

18 O&M

18.1 O&M Costs for Test Period

Operating expenses included in the delivery revenue requirement represent the recurring costs required to operate and administer the utility on a day-to-day basis. They include direct labor costs, maintenance costs, insurance costs, office-related expenses, customer billing costs, regulatory costs, allocated Regional and Corporate services costs, and other miscellaneous operating expenses. The Table 20 below summarizes the O&M for the test period.

TABLE 20 - SUMMARY OF O&M IN THE TEST PERIOD BY CONCEPT

Operating & Maintenance Expenses	Accounts recorded	Test Year
Direct Labor costs	Thermal production, distribution, Administrative Operation	361,004
Maintenance costs	Thermal production, distribution	19,051
Insurance	Administrative and General Expenses Operation	129,138
Regulatory cost	Administrative and General Expenses Operation	45,845
Office rental	Rents	57,017
Customer billing software	Customer Accounts Expenses	2,178
Miscellaneous costs	Administrative and General Expenses Operation	51,458
Regional Services	Corporate and Regional Allocated Costs	553,531
Corporate Services	Corporate and Regional Allocated Costs	762,680
Total Operating & Maintenance Expenses		**1,981,902**

18.2 General Inputs and assumptions

Table 21summarizes the escalation factors applied in the GRC Financial Model (Highly Confidential Corix Exhibit 7.1) to forecast key cost drivers over the forecast period. These escalation assumptions are used to project expenses from the base period into future years in a manner that is transparent and consistent with expected inflationary and market trends. As shown, the Utility applies CPI-based escalation to general O&M in 2027 and 2028–2030, transitioning to a long-term inflation assumption[13] thereafter. Certain cost categories are escalated using targeted factors where experience and market conditions indicates cost growth differs from general inflation, including insurance, labor, and billing software costs. These escalation factors are applied to the applicable expense line items as part of the development of the forecast cost of service.

[13] Long-term inflation assumptions are base on the Federal Reserve projections: The Fed - March 18, 2026: FOMC Projections materials, accessible version

TABLE 21 - INFLATION FACTOR ASSUMPTIONS FOR THE O&M

Escalation Factors	2027	2028-2030	Long Term
CPI	3.0%	2.4%	2.0%
O&M escalator	3.0%	2.4%	2.0%
Insurance escalator	7.5%	7.5%	3.0%
Labour costs escalator	3.0%	3.0%	3.0%
Billing software cost escalator	5.0%	5.0%	2.0%

18.3 Direct Labor O&M

As discussed in Section 13.2 Utah City Heating and Cooling LLC has no employees. UCDEU is a small utility that resources its operational personnel from an affiliate. UCDEU is not yet large enough to hire employees that work only for UCDEU. As a small utility the employees who work for UCDEU also work on non-UCDEU activities.

The direct labor costs of UCDEU are from labor employed by a Corix affiliate that directly charges labor to UCDEU. UCDEU receives from the affiliate a fully loaded cost. Corix is able to provide granularity on the labor resourcing and the components of the loaded cost.

18.3.1 Direct Labor FTE

The necessity and appropriateness of the FTE resources included in the financial model are assessed in the testimony of Derek Nelson (Corix Exhibit 6.0 - Direct Testimony of Derek Nelson).

18.3.2 Direct Labor Total Salary and Benefits

Annual base salaries for each position are established using labor market benchmarks appropriate for the roles required to support utility operations. Benefits, incentive, and payroll taxes are calculated as a function of the base salary for each position, resulting in a fully loaded annual labor cost for each FTE. The direct labor total costs are reflected in Schedules 13 of the Financial Schedules (Appendix A). Corix has included its short term incentive plan in Highly Confidential Exhibit 7.7.

Labor costs are assigned to various accounting codes based on the specific tasks carried out by employees. For Direct Operations Positions (such as Director of Operations, Operations Manager, Operations Supervisors, and Operators), costs are divided into thermal production – Operation (70%), thermal production – Maintenance (10%), Distribution – Operation (10%), and Distribution – Maintenance (10%). Consequently, direct labor is shown in Schedule 12 of the Financial Schedules (Appendix A) on lines 5, 11, 26, 36, and 69.

18.4 Production O&M

This group includes labor expenses related to operating and maintaining thermal production, as well as the materials, supplies, and external maintenance contracts required for both preventive and reactive maintenance of the plant facilities.

18.5 Distribution O&M

This group includes labor expenses related to operating and maintaining the distribution system, as well as the materials, supplies, and external maintenance contracts required for both preventive and reactive maintenance of the Distribution piping system, the Energy transfer stations and the energy meters.

18.6 Admin and General O&M

This group includes direct labor expenses and external consultants' costs related to the Regulatory proceedings, Property, General liability and other insurance costs, office rent, office and mmiscellaneous expenses, and corporate and Regional allocated services.

18.6.1 Corporate and Regional Allocated Costs

The allocated costs included in total OM&A is discussed in Section 19 below.

18.7 Total OMA

The operating and Maintenance expenses are reflected in Schedules 12 and 13 of the Financial Schedules (Appendix A). Table 22 presents the summary of the O&M Expenses for the Test Year.

TABLE 22 - SUMMARY OF O&M IN THE TEST PERIOD BY ACCOUNTS

	Test Year
Thermal Production - Operation	
Thermal Production - Operation	181,761
Thermal Production - Maintenance	39,791
Total Thermal Production - Operation	**221,551**
Distribution - Operation	
Distribution - Operation	25,966
Distribution Maintenance	31,192
Total Distribution - Operation	**57,158**
Total Customer Accounts Expenses	**2,178**
Administrative and General Expenses	
Administrative and General Expenses Operation	327,787
Corporate and Regional Allocated Costs	1,316,211
Rents	57,017
Total Administrative and General Expenses	**1,701,015**
Total Operation	**1,981,902**
Adjustments for Delivery Revenue requirement	-719,965
Total Operation and Maintenance Expenses	**1,261,937**

For further financial information on this section see Appendix A in Attachment 1, Schedules 12 and 13.

18.8 Direct Testimony: Corix Exhibit 6.0 – Derek Nelson

Please see Corix Exhibit 6.0 Direct Testimony of Derek Nelson regarding Direct Labor O&M and the total O&M Expenses for the test year.

18.9 Direct Testimony: Corix Exhibit 7.0 – Johan Grueso-Baron

Please see Corix Exhibit 7.0 Direct Testimony of Johan Grueso-Baron regarding how the O&M inputs have been included in the GRC Financial Model.

19 Support Services Cost Allocations

19.1 Corporate and Regional Support Services Allocations

The allocated support services costs included in total Admin O&M, previously mentioned in Section 18.6.1, are briefly discussed below in their respective cost categories. A more detailed description of the services provided for each support services cost category is included in Appendix B within the Regional Cost Allocation Methodology (CAM) Manual (see Corix Exhibit 2.5) and in Appendix B within the Corporate CAM Manual (see Corix Exhibit 2.6). The Regional CAM Manual and Corporate CAM Manual also includes a detailed description of the cost allocation methodology for the Regional Services and Corporate Services costs respectively.

Support Services Allocation Categories

1. **Regulatory Affairs** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) for utilities within Corix's parent company's DE West region that receive economic regulation. At a high level, this category captures the costs to ensure that UCDEU seeks and obtains all mandatory regulatory approvals and complies with all mandatory directives from the PSC.

2. **Health, Safety and Environment** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the health, safety and environment (HSE) program and compliance. At a high level, this category captures costs related to health, and safety programs, environmental compliance, incident management protocols and includes employee safety training and initiatives to maintain safe and sustainable operations.

3. **Financial Planning and Analysis (FP&A) and Accounting** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to FP&A and accounting. At a high level, this category captures costs associated with utility accounting and bookkeeping, budgeting, financial modeling and forecasting, and supporting various departments including but not limited to Regulatory Affairs for the preparation of rate applications, annual financial reports and other reports for the PSC.

4. **Business Operations and Accounts Payable** – This cost represents employee costs incurred on a shared basis at the regional level (Regional Service cost) related to procurement, accounts payable and general business operations. At a high level, this category captures costs associated with procurement process management, accounts payable, fleet management, asset management support and data analysis and internal reporting.

5. **Billing and Customer Care** – This cost represents employee costs incurred on a shared basis at the regional level (Regional Service cost) related to billing and customer care. Billing and customer care staff are often the first point of contact for utility customers. At a high level, this category captures costs associated with preparing customer bills, statements, and reports, processing rate changes in the billing system, responding to customer enquiries, and managing the accounts receivable processes.

6. **Operations Leadership and Strategy** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the oversight, guidance, leadership and direction of daily operations to ensure the safe, compliant and efficient operations of all utilities and all related engineering and project management activities in the region.

7. **Project Management Office** – This cost represents employee costs and third-party services costs incurred on a shared basis at the regional level (Regional Service cost) related to the management of the capital project program in the region. As these costs are typically capitalized to the respective projects, they have been forecast to be $0 each year. However, there may be residual actual costs for time spent

on general items, including but not limited to, providing support to the Regulatory Affairs team to respond to data requests.

8. **People and Culture** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) associated with human resource management, employee engagement, and organizational culture initiatives. At a high level, it includes policy and practice development, people programs and services administration, payroll processing, benefits and medical plan administration, pension plan administration, recruitment, training, employee development, and initiatives to foster a positive organizational culture.

9. **IT, OT and Cybersecurity** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) associated with the provision and maintenance of information technology (IT) and operational technology (OT) infrastructure, applications, cybersecurity programs, and related support services for the organization. At a high level, it includes network and cloud infrastructure management, IT hardware and standard application provisioning and implementation, an enterprise-wide help centre, OT systems and site implementation and management of uniform IT security and cybersecurity protocols.

10. **Communications** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for communications strategy development and execution, external and internal communications management, managing content on the external website and the intranet, management of the social media channels, and brand management.

11. **Legal and Risk Management** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for a comprehensive suite of risk management services, which includes enterprise risk management; technical safety and compliance leadership; HSE leadership; and legal services.

12. **Corporate Finance** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for corporate accounting, capital market engagement, corporate financial planning and analysis, insurance, taxation, and treasury services. Corporate Finance provides services that include, but is not limited to, securing debt and equity financing, managing liquidity, managing the preparation and consolidation of financial statements, and supervising the corporate income tax provision and compliance work.

13. **Executive Management** – This cost represents costs incurred on a shared basis at the corporate level (Corporate Service cost) for the executive management function responsible for all businesses within Corix's parent company's portfolio as well as rent and associated costs for the parent company headquarters, located in Vancouver, B.C.

19.2 Corporate Services Costs and Cost Allocation Methodology

Corporate services costs are shared costs incurred at the corporate level in order to provide a variety of necessary services to all affiliates. Of the cost categories listed in Section 19.1 above, corporate services and the associated costs include: people and culture; IT, OT and cybersecurity; communications; legal and risk management; corporate finance; and executive management. These costs are forecasted and incurred at the corporate level and then allocated to each business, including UCDEU, using the Corporate Cost Allocation Methodology (CAM). Corix Exhibit 2.6 of this Application includes the Corporate CAM Manual that sets out the process to allocate corporate services costs. The process outlined in Section 4 of the Corporate CAM Manual is consistent with that previously approved by the British Columbia Utilities Commission (BCUC) through Order G-349-20 with Reasons for Decision, issued December 24, 2020 following a public hearing review process specifically to review the CAM. The Corporate CAM relies on the use of a functional allocator or a composite allocator to allocate indirect costs to businesses. Functional allocators are used where the costs can be allocated

using an identified cost causation driver. Corporate services costs that do not have a direct correlation with any one particular cost causation driver are allocated using a composite allocator. The composite allocator is calculated using three equally weighted factors: (i) Gross Property, Plant & Equipment (Gross PPE); (ii) Gross Revenue; and (iii) Headcount. The composite allocator is used to represent the size, scope and complexity of each of the operating businesses. Table 23 below lists the corporate cost categories, and the corresponding allocator used.

TABLE 23 - CORPORATE SERVICES COST CATEGORIES AND ALLOCATORS

Item	Corporate Service Cost Category	Allocator Used
1	People and Culture	Headcount
2	IT, OT and Cybersecurity	Composite Allocator
3	Communications	Composite Allocator
4	Legal and Risk Management	Composite Allocator
5	Corporate Finance	Composite Allocator
6	Executive Management	Composite Allocator

For additional details, please refer to the Corporate CAM Manual included in Corix Exhibit 2.6 in this GRC Application which includes, among other things, a detailed description of the corporate cost allocation methodology, the scope of corporate services, a detailed description of each corporate service and a hypothetical example showing the application of the corporate cost allocation methodology.

19.3 Regional Services Costs and Cost Allocation Methodology

Regional services costs are shared costs incurred at the regional level in order to provide a variety of necessary services to relevant affiliates. Of the cost categories listed in Section 19.1 above, regional services and the associated costs include: regulatory affairs; health, safety and environment; FP&A and accounting; business operations, procurement and accounts payable; billing and customer care; operations leadership and strategy; and project management office. These costs are forecast and incurred at the regional level and then allocated to each relevant business, including UCDEU, using the Regional CAM. Corix Exhibit 2.5 in this GRC Application includes the Regional CAM Manual that sets out the process to allocate regional services costs. The process outlined in Section 4 of the Regional CAM Manual is consistent with the Corporate CAM and briefly described in Section 19.2 above. Table 24 below lists the regional cost categories, and the corresponding allocator used.

TABLE 24 - REGIONAL SERVICES COST CATEGORIES AND ALLOCATORS

Item	Regional Service Cost Category	Allocator Used
1	Regulatory Affairs	Composite Allocator
2	Health, Safety and Environment	Composite Allocator
3	FP&A and Accounting	Composite Allocator
4	Business Operations, Procurement and Accounts Payable	Composite Allocator
5	Billing and Customer Care	Bill Count
6	Operations Leadership and Strategy	Composite Allocator
7	Project Management Office	Composite Allocator

For additional details, please refer to the Regional CAM Manual included in Corix Exhibit 2.5 in this GRC Application which includes, among other things, a detailed description of the regional cost allocation methodology, the scope of regional services, a detailed description of each regional service and a hypothetical example showing the application of the regional cost allocation methodology.

19.4 Adjustments to O&M for Support Services

Corix forecasts the total Operations and Maintenance (O&M) costs to represent the full expense of operating the utility. However, for the purposes of rate-setting and managing deferral accounts, certain adjustments are applied. These adjustments ensure that only a reasonable and appropriate level of O&M cost recovery is included in the Delivery Revenue Requirement. The adjustments related to the Corporate Services Costs and the Regional Services Costs are explained below.

1) **Regional Services Adjustments for RDDA (Allowed Costs) –** Each Regional Services Cost is treated as a controllable expense. As a result, Corix does not propose to receive variance treatment for these types of costs under the RDDA. This means that any difference between forecast and actual amounts would be absorbed by Corix's shareholder. Corix forecasts an adjustment to reduce the proposed recovery of Regional Services costs from 2026 through to 2031. A declining reduction is applied during this time in an effort to ensure that utility customers are not burdened with the full recovery of Regional Services allocations during the early years of operations. From 2032 onwards, Corix includes the full Regional Service cost forecasts in the Delivery Revenue Requirement to be recovered from customers.

2) **Corporate Services Adjustments for RDDA (Allowed Costs) –** Each Corporate Services Cost is treated as a controllable expense. As a result, Corix does not propose to receive variance treatment for these types of costs under the RDDA. This means that any difference between forecast and actual amounts would be absorbed by Corix's shareholder. Corix forecasts an adjustment to: (i) remove Corporate Development from cost recovery for all years; (ii) remove long-term incentive plan costs from cost recovery for all years due to the current driver for the incentive plan; and (iii) to reduce the proposed recovery of Corporate Services costs from 2026 through to 2031 only. Corix removes items (i) and (ii) based on the understanding that these costs are not eligible for recovery from utility customers, despite being allocated to the utility. After the removal of items (i) and (ii), from 2026 through 2031 a declining reduction is applied in an effort to ensure that utility customers are not burdened with the full recovery of

eligible Corporate Services allocations during the early years of operations. From 2032 onwards, Corix includes the full eligible Corporate Service costs in the Delivery Revenue Requirement to be recovered from customers (i.e. items (i) and (ii) continue to be excluded).

For details on the Corporate Services and Regional Services cost allocation and adjustment amounts, please see Schedule 12 in Appendix A in Attachment 1.

19.5 See Direct Testimony of Errol South

This Section 19 has been prepared by Errol South. Please refer to his Direct Testimony in Corix Exhibit 2.0 - Errol South.

20 Cost of Capital

In Corix's pre-filed direct testimony the topic of 'Cost of Capital' is supported by three witnesses:

- Corix Exhibit 4.0 Direct Testimony of Maxwell Wang
    - Mr. Wang provides testimony from the perspective of Corix negotiating with Flagborough (the customer) with regards to cost of capital (capital structure, return on equity, and cost of debt). Mr. Wang also explains how the debt and equity for UCDEU is sourced.

- Corix Exhibit 5.0 Direct Testimony of Josh Figueroa
    - Mr. Figueroa is a Principal at The Brattle Group. Mr. Figueroa provides his expert testimony from the perspective of a market analysis of cost of capital (capital structure, return on equity, and cost of debt) that has been incorporated into the GRC Test Period.

- Corix Exhibit 7.0. Direct Testimony of Johan Grueso-Baron.
    - Mr. Grueson-Baron is responsible for the financial model to calculate the test year revenue requirement. He has used the cost of capital inputs in the financial model. Mr. Grueso-Baron's testimony resolves how the cost of capital inputs affect the revenue requirement in the test period.

20.1 Capital Structure and Cost of Capital

The test period revenue requirement includes a deemed capital structure composed of 50.0% debt and 50.0% equity, a return on equity (ROE) of 10.50%, and cost of debt at 7.49%.

The cost of capital for the test period is supported by Direct Testimonies in Corix Exhibit 4.0 (Maxwell Wang) and Corix Exhibit 5.0 (Josh Figueroa, The Brattle Group).

20.2 Deemed capital structure

Utah City Heating and Cooling has a deemed capital structure of 50.0% debt and 50.0% equity.

The Financial Schedules in Attachment 1, Appendix A, Schedule 11, lines 1 to 4 shows the test year's capital structure.

20.3 Cost of equity

In this GRC for the test period it includes the equity portion of the capital structure to be 50.0% with a ROE of 10.50%.

The Financial Schedules in Attachment 1, Appendix A, Schedule 11, lines 8 and 15 show the test year's ROE at 10.50% and the equity portion of rate base at $11,973,082, respectively. The resulting return on equity is $1,257,174 (line 20) for the test year.

20.4 Cost of Debt

In this GRC for the test period it includes the debt portion of the capital structure to be 50.0% with a cost of debt at 7.49%.

The Financial Schedules in Attachment 1, Appendix A, Schedule 11, lines 7 and 19 show the test year's debt interest rate at 7.49% and the debt portion of rate at $1,1973,082, respectively. The resulting interest on debt is $896,784 (line 19) for the test year.

20.5 Corix Exhibit 4.0, Direct Testimony of Maxwell Wang

Please see Corix Exhibit 4.0 regarding the Direct Testimony of Maxwell Wang. Corix Exhibit 4.0 explains how Corix negotiated the cost of capital in the Infrastructure Agreement that is also used in this GRC.

Mr. Wang discusses the negotiated cost of capital arising from the Infrastructure Agreement – Fee Framework, the capital structure, negotiated return on equity, cost of debt, equity funding, and debt funding. Included with Mr. Wang's testimony is the InterCompany Credit Agreement filed as Confidential Corix Exhibit 4.1.

20.6 Corix Exhibit 5.0, Direct Testimony of Josh Figueroa

Please see Corix Exhibit 5.0 Direct Testimony of Josh Figueroa of The Brattle Group. Exhibit 5.0 explains the reasonableness of the cost of capital (capital structure, ROE, and cost of debt) that is included in the test year of the GRC.

20.7 Corix Exhibit 7.0, Direct Testimony of Johan Grueso-Baron

Please see Corix Exhibit 7.0 Direct Testimony of Johan Grueso-Baron regarding how the cost of capital inputs have been included in the GRC Financial Model.

21 Taxes Other Than Income Tax

This section describes the taxes and assessments included in the Utility's cost of service other than federal and state income taxes. Taxes other than income taxes are generally expensed in the period incurred and are reflected in operating expenses to the extent they are attributable to the provision of regulated service. The items described below summarize the specific taxes and assessments applicable to UCDEU during the forecast period and the manner in which each item is treated for ratemaking purposes.

21.1 Property Tax

No property tax expense is included for UCDEU in the GRC Financial Model. Based on UCDEU's current circumstances and applicable tax treatment, the Utility does not incur property tax obligations on its Plant in Service during the forecast period. Accordingly, property tax expense is not reflected in operating expenses and is not included in the delivery revenue requirement.

21.2 Energy Use Tax

Energy-related sales taxes on natural gas and electricity are not included as delivery operating expenses. Instead, these taxes are included as part of energy supply costs and are recovered through the Energy Charge rather than the Delivery Charge. The relevant taxes reflected within energy supply costs include Utah State sales tax applied at a rate of 4.85% on natural gas and electricity purchases; and the Municipal Energy Sales and Use Tax ("MET") applied at a rate of 6.0%. This treatment aligns recovery of these taxes with the energy costs to which they are directly attributable.

21.3 Federal Labour Tax or Fee

Federal payroll taxes, including the employer portion of Social Security and Medicare taxes (FICA), are not presented as a separate "taxes other than income taxes" line item in this Application. Rather, these costs are embedded within the fully loaded labor cost for each full-time equivalent ("FTE") position included in the Utility's operating expenses. Accordingly, payroll tax costs are reflected in O&M labor expense and recovered through rates as part of overall labor costs.

21.4 Charges from the City

UCDEU does not currently include any charges from the City of Vineyard as tax or operating expenses. As of the test period, the Company has not been assessed, nor has it agreed to pay any municipal fee. Should any such charges be established and become effective during or after the test period, the Utility would seek appropriate regulatory treatment at that time.

21.5 Public Utilities Regulation Fee ("PURF")

The Public Utilities Regulation Fee ("PURF") is included as a tax other than income tax and represents the regulatory fee assessed to recover the Utah Public Service Commission's costs of regulating public utilities. The PURF is treated as a recurring tax other than income tax and is expensed in the period incurred. The PURF amount included in the revenue requirement is based on the Utility's forecasted PURF obligation for the test period as reflected in the GRC Financial Model (Highly Confidential Exhibit 7.1).

For further financial information regarding this section see Attachment 1, Appendix A, Schedule 2.

21.6 Direct Testimony: Corix Exhibit 7.0 – Johan Grueso-Baron

This Section 21 has been prepared by Johan Grueso-Baron. See the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

22 Income Tax

This section describes the income tax allowance reflected in the revenue requirement, including current federal and state income taxes payable, (ii) deferred income taxes arising from temporary differences consistent with the normalization principle, and (iii) permanent differences that affect taxable income but do not reverse. The current income tax payable computations are presented in Schedule 15 of the Financial Schedules (Appendix A). The bridge from regulatory book pre-tax income to taxable income is provided in Chapter X of the Direct Testimony of Johan Grueso-Baron (Exhibit 7.0)

22.1 Current Income Tax

22.1.1 Federal

UCDEU calculates current federal income tax payable using a standard corporate income tax approach. Regulatory book pre-tax income is adjusted for permanent and temporary differences to determine federal taxable income. Federal taxable income is then multiplied by the federal corporate income tax rate of 21 percent to determine current federal income tax payable for each forecast year. UCDEU forecasts that federal income tax payments will begin in 2036.

22.1.2 Utah State

The Utility calculates current Utah state income tax payable using a taxable income base that generally follows the federal structure, subject to Utah-specific conformity and state adjustments. The Utah corporate income tax rate of 4.5 percent is applied to Utah taxable income to determine the gross current state income tax liability for each forecast year.

22.1.3 Utah High Cost Infrastructure Tax Credit (HCITC)

The Utility incorporates the Utah High-Cost Infrastructure Tax Credit (“HCITC”) into its indicative year calculations, reflecting its application to the program. The forecasted credits that are anticipated to be utilized serve to reduce the amount of state payable income tax in the year when each credit is used. This approach ensures that the benefit of the HCITC is effectively passed through to customers in the same period that the Utility effectively receives the benefit, directly lowering the state income tax component included in the revenue requirement for that year.

22.2 Deferred Income Taxes and Normalization

In addition to current taxes payable, the Utility calculates deferred income taxes associated with temporary differences between regulatory book accounting and tax accounting. These temporary differences arise when revenues and expenses are recognized in different periods for book and tax purposes but reverse over time. The Utility’s treatment of deferred income taxes is consistent with the normalization principle, under which the revenue requirement reflects both current and deferred tax effects to match tax expense recognition with the timing of book cost recovery and plant depreciation.

The tax effects of temporary differences are recorded as Deferred Tax Assets ("DTAs") or Deferred Tax Liabilities ("DTLs") in the financial statements. A Deferred Tax Liability (DTL) arises when tax deductions are taken earlier than the corresponding book expense. In contrast, a Deferred Tax Asset (DTA) arises when book deductions precede tax deductions. The primary temporary differences reflected in the income tax allowance include Accelerated tax depreciation, the RDDA deferred revenues and the interest expense deductibility limitation.

22.2.1 Accelerated tax depreciation

For federal and state income tax purposes, the Utility applies accelerated tax depreciation under Modified Accelerated Cost Recovery System (MACRS) relative to straight-line book depreciation. Accelerated tax depreciation generally reduces current taxable income in early years and creates a deferred tax liability, which increases the overall tax allowance in the revenue requirement in those periods.

22.2.2 Deferred revenues associated with the Delivery Charge Levelization mechanism

Deferred revenues associated with the Capacity Charge Levelization mechanism and the RDDA are recognized as a regulatory asset on the regulatory balance sheet but are not recognized as taxable revenue until collected. The levelization mechanism creates a temporary difference in the revenue recognition for book versus tax, the Utility recognizes deferred income tax effects associated with those timing differences as temporary differences that reverse over time.

22.2.3 Net Operating Losses

Net Operating Losses (“NOLs”) arise when tax-deductible expenses exceed taxable revenues in a given period. Under federal tax law, those losses may be carried forward and used to offset taxable income in future years. As a result, NOLs defer the payment of federal income taxes to future periods rather than permanently eliminating them. When NOLs are generated, the UCDEU records a deferred tax asset reflecting future tax benefits associated with the carryforward of those losses. When the NOLs are later utilized to offset taxable income, that deferred tax asset is reversed.

22.2.4 Interest expense deductibility limitation (Internal Revenue Code §163(j))

To the extent the Utility’s interest expense is subject to timing differences in deductibility under §163(j), the resulting limitation creates a temporary difference between book interest expense and the amount deductible for tax purposes. The Utility reflects the deferred income tax effects of these timing differences consistent with normalization.

22.3 Tax Allowance Included in the Delivery Revenue Requirement

Table 25 summarizes the UCDEU’s Test Year and indicative years income tax allowance. As shown, current income tax is $100 for the Test Year. Income taxes driven by the accelerated tax depreciation, the RDDA revenue deferrals, the net operating losses, and the interest expense limitations are normalized. On a net basis, these current and deferred tax components result in a total tax allowance of $340,380, $79,267 in 2026 plus $261,104 in 2027, for inclusion in the revenue requirement. The 2027 partial year income tax included in the test year (From January to July 2027) is proportionally allocated to the test year ($447,607 / 12 x 7 months =$261,104).

TABLE 25 - SUMMARY TAX ALLOWANCE IN THE TEST YEAR

	Test Year
Current Federal income tax ($)	0
Current State income tax ($)	100
Def. Income tax due to MACRS ($)	1,319,412
Def. Income tax due to RDDA ($)	737,807
Def. Income tax due to NOL ($)	-1,528,615
Def. Income tax due to Int. expense ($)	-188,324
Deferred Tax allowance ($)	**340,380**

Table 26 summarizes the UCDEU's Test Year and indicative years income tax allowance.

TABLE 26 – SUMMARY TAX ALLOWANCE IN THE INDICATIVE YEARS

Tax allowance	2026	2027	2028	2029	2030
Current Federal income tax ($)	0	0	0	0	0
Current State income tax ($)	100	0	0	0	0
Def. Income tax due to MACRS ($)	670,664	1,254,741	1,102,701	1,750,570	3,570,330
Def. Income tax due to RDDA ($)	209,325	870,545	888,010	1,269,352	1,416,156
Def. Income tax due to NOL ($)	-757,354	-1,429,338	-1,135,316	-1,709,099	-2,884,779
Def. Income tax due to Int. expense ($)	-43,458	-248,342	-300,353	-395,108	-476,008
Total Tax Allowance ($)	**79,276**	**447,607**	**555,043**	**915,716**	**1,625,699**

22.4 Accumulated Deferred Income Taxes (ADIT) and rate base

Accumulated Deferred Income Taxes ("ADIT") represent the cumulative net balance of all deferred tax assets (DTA) and liabilities (DTL) recorded to date. The ADIT balance is treated as a reduction to rate base, consistent with standard utility regulatory practice. This treatment reflects the view that accumulated deferred tax balances represent a source of funds provided by customers in advance of the related tax payments, which reduces the utility's net capital investment requiring a return.

For further financial information regarding this section see Attachment 1, Appendix A, Schedule 15.

22.5 Direct Testimony: Corix Exhibit 7.0 – Johan Grueso-Baron

This Section 22 has been prepared by Johan Grueso-Baron. See the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

23 Delivery Deferral Account

Corix proposes the establishment of the following delivery deferral account to implement rate stabilization.

- Revenue Deficiency Deferral Account (RDDA)

The rationale for the Revenue Deficiency Deferral Account (RDDA) is explained in detail in Section 12.6.

The RDDA activity and balances can be found in Attachment 1, Appendix A, Schedule 9, lines 4 to15.

23.1 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 23 has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

24 Delivery Revenue Requirement

24.1 Delivery Revenue Requirement

The Delivery Revenue Requirement represents the annual revenue necessary to recover the UCDEU's non-energy-costs of providing regulated service. Under the cost-of-service model, the Utility calculates the Delivery Revenue Requirement as the sum of operating and maintenance expenses, depreciation and amortization expense, taxes other than income taxes, the income tax allowance, and the authorized return on rate base. The return on rate base is calculated using the Utility's approved capital structure, applying the cost of debt rate of 7.49 percent to the debt component and the authorized return on equity of 10.50 percent to the equity component.

24.1.1 O&M

Operating & Maintenance Expense includes direct labor, maintenance, insurance, allocations, and other O&M. The O&M included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedules 12 and 13. The methodology and assumptions used to calculate the O&M are explained in detail the section 18 above, the Direct Testimony in Corix Exhibit 6.0 – Derek Nelson, and in the Section VIII of the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.1.2 Depreciation

The Depreciation and Amortization expenses included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedules 4, 5, and 7. The assumptions and depreciation rates used to calculate the depreciation expense are explained in detail in Section 17, and in the section VI of the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.1.3 Taxes Other than Income Tax

The taxes other than income tax included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedule 2, line 13. The methodology and assumptions used to calculate the taxes other than income tax are explained in detail in Section 21 above, and Section X of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.1.4 Income Tax allowance

The income tax allowance included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedule 15. The methodology and assumptions used to calculate the income tax allowance are explained in detail in Section 22 above, and Section X of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.1.5 Debt Interest

The debt interest included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedule 11. The methodology and assumptions used to calculate the debt interest are explained in detail in Section 20 above, and Section IX of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.1.6 Return on equity

The return on equity included in the Test Year and the indicative years can be found in Attachment 1, Appendix A, Schedule 11. The methodology and assumptions used to calculate the debt interest are explained in detail in Section 20 above, and Section IX of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.2 Rate Base

The rate base represents the net investment in utility property that is used and useful in providing regulated service and upon which the Utility is authorized an opportunity to earn its approved return. UCDEU's rate base is comprised of the net book value of Plant in Service (gross Plant in Service less accumulated depreciation and net of Contributions in Aid of Construction), working capital allowance necessary to fund day-to-day utility operations, the RDDA balance as a regulatory asset included rate base, and accumulated deferred income taxes ("ADIT"), which reflects the net tax timing differences associated with utility plant and other temporary differences and is included as a component of rate base consistent with normalization.

24.2.1 Plant in Service Net Book Value Net of CIAC

The Plant in Service Net Book Value included in the rate base in the test year and the indicative years can be found in Attachment 1, Appendix A, Schedules 4 and 5. The methodology and assumptions used to calculate the Plant in service Net Book Value net of CIAC are explained in detail in Sections 15 to 17 above, and Section VI of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.2.2 Working Capital allowance

The Working Capital included in the rate base in the test year and the indicative years can be found in Attachment 1, Appendix A, Schedule 8. The methodology and assumptions used to calculate the Working capital allowance are explained in detail in Section VIII of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.2.3 Rate Base Deferrals

The RDDA is proposed to be included in the rate base. The RDDA included in the test year and the indicative years can be found in Attachment 1, Appendix A, Schedule 9. The methodology and assumptions used to calculate the RDDA are explained in Section 25 below, and in Section VII of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.2.4 ADIT

The ADIT included in the test year and the indicative years can be found in Attachment 1, Appendix A, Schedules 15 and 3, line 33. The methodology and assumptions used to calculate the ADIT balance are explained in Section 22 above, and in Section X of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

24.2.5 Calculation of rate base

In 2026, UCDEU uses a weighted average Rate Base to account for assets commissioned on August 1, capturing only the period each asset is in service. From 2027 onward, a mid-year rate base method is used.

The mid-year rate base included in the test year and the indicative years can be found in Attachment 1, Appendix A, Schedule 3. The rational around the rate base calculation is explained in Section VII of the the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

For further financial information regarding this section see Attachment 1, Appendix A, Schedule 2.

24.3 Direct Testimony: Corix Exhibit 7.1 – Johan Grueso-Baron

The GRC Financial Model is filed as Highly Confidential Corix Exhibit 7.1. The GRC Financial Model contains the Excel file that was used to calculate the delivery revenue requirement and the proposed Capacity Charge.

24.4 Direct Testimony: Corix Exhibit 7.0 – Johan Grueso-Baron

This Section 24 has been prepared by Johan Grueso-Baron. See the Direct Testimony in Corix Exhibit 7.0 – Johan Grueso-Baron.

25 Rate Stabilization with Revenue Deficiency Deferral Account (RDDA)

25.1 Rate Stabilization at UCDEU

Section 12.6 above explained the rationale of rate stabilization with a deferral account.

25.2 Implementing Rate Stabilization with a Deferral Account

To implement rate stabilization requires the following steps:

1. Calculate the cost of service and revenue requirement for the test period without rate stabilization.
2. Implement rate stabilization (levelized rates) by billing the customer a different amount than indicated by the calculated cost of service/revenue requirement.
    a. During preliminary years, including the Test Period, revenues billed to customers are less than the actual cost of service/revenue requirement, which will be quite high. The unbilled amounts are accounted for in the RDDA.
    b. When the peak RDDA is reached, billed revenues will equal the actual cost of service/revenue requirement.
    c. In later cost recovery years, billed revenues will be greater than the actual cost of service/revenue requirement. The surplus will be applied to reduce the RDDA balance.
3. The full repayment date is the day on which the RDDA is fully recovered. On the full repayment date, billed revenues will be higher than the actual cost of service/ revenue requirement. Rates will be brought down over an adjustment period until billed revenues are equal to the cost of service/revenue requirement.

25.3 Cost of service/revenue requirements

The test period's calculated revenue requirement is shown in Attachment 1, Appendix A, Schedule 1, line 3 for the test year (July 1, 2026 to June 30, 2027). It shows that if delivery rates were not levelized the non-levelized rates would collect $4,639,539 (line 3) in revenues within the test year.

25.4 Delivery Billed Revenues

After rate levelization, capacity billed revenues during the test period are shown in Attachment 1, Appendix A, Schedule 20, line 4 for the test year (July 1, 2026 to June 30, 2027). At proposed rates with rate levelization the capacity billed revenues for the test year are $1,126,019 (line 3). The utility also has Other charges of $100 (line 5) in the test period. The test period total delivery billed revenues is $1,126,119 (Schedule 1, line 4).

25.5 Revenue Deficiency/Revenue Surplus and Balances

The RDDA annual activity and year-end balances are shown in Schedule 9, lines 3 to 17.

After rate levelization, the billed revenues are less than the cost of service. For the test year (July 1, 2026 to June 30, 2027) the delivery revenue shortfall is $3,513,368 (Attachment 1, Schedule 1, line 5).

25.6 Target Year of RDDA full recovery

Corix has included indicative years following the test period to allow for a better understanding of the long-term rate stabilization implemented for UCDEU. Attachment 1, Appendix A, Schedule 9, line 15 shows the indicative RDDA year-end balances from 2026 to 2041. As can be seen in year 2041, the RDDA balance reaches nil and is fully recovered in rates.

25.7 Rate Levelization Assumptions

The rate levelization plan depends on the following assumptions:

- The forecast buildout schedule and peak load demand.
- The forecast capital additions to meet the buildout.
- The levelized annual growth rate of 2% (Schedule 17, line 7). Rates are changed annually.
- The target year of full RDDA recovery. The GRC anticipates full recovery by the end of 2041.

As the buildout development progresses there may be actual differences either favorable or favorable. In each subsequent GRC application the proposed rate may need to be further updated so the target year of full RDDA recovery is met.

25.8 RDDA is consistent with U.S. GAAP and regulatory rate-making

The Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) 980 provides accounting guidance for regulated operations. ASC 980-10-15-2 provides three criteria[14] that quality for a regulated operation. They are:

- The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.
- The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form.
- In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers.

ASC 980-10-20 Glossary states:[15]

[14] FASB ASC 980-10-15-2, https://asc.fasb.org/1943274/2147482086
[15] FASB ASC 980-10-20 Glossary, https://asc.fasb.org/1943274/2147482063

- Allowable Costs: “All costs for which revenue is intended to provide recovery. Those costs can be actual or estimated. In that context, allowable costs include interest cost and amounts provided for earnings on shareholders' investments.”
- Capitalize: “Capitalize is used to indicate that the cost would be recorded as the cost of an asset. That procedure is often referred to as deferring a cost, and the resulting asset is sometimes described as a deferred cost.”
- Incurred Cost: “A cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for.”

PwC in its Accounting Guide for Utilities and Power in Section 17.2.2.1 explains the Impact of alternative ratemaking.[16] With regards to Deferred recovery plans PwC states the following:

> “In some jurisdictions, regulators have adopted deferred recovery plans in response to significant increases in costs. These plans vary, but typically provide for rates to remain fixed or increase moderately with a tracking mechanism to capture costs in excess of the level allowed in current rates.”

ASC 980-340-25-1 states:

> “Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
>
> a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.
>
> A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.”[17]

25.8.1 RDDA is a Regulatory Asset

The RDDA once approved by the PSC is a regulatory asset and recognized in the utility’s financial statements. The RDDA is a long-term deferred recovery plan that is used to implement rate stabilization by capturing the difference between billed revenues and the cost of service/revenue requirements. As a regulatory asset the RDDA impacts the presentation of financial statements.

[16] PwC, US Utilities Guide, Section 17.2.2.1 Impact of alternative ratemaking, Deferred recovery plans, https://viewpoint.pwc.com/dt/us/en/pwc/accounting_guides/utilities_and_power_/utilities_and_power__US/chapter_17_regulated_US/172_scope_of_asc_980_US.html#pwc-topic.dita_1624041008178980
[17] FASB 980-340-25-1, https://asc.fasb.org/1943274/2147477711

The RDDA is very similar to the Energy Cost Reconciliation Account. The ECRA is also a regulatory asset if in a debit position or a regulatory liability if in a credit position. The ECRA is typically used as a short-term balancing account for pass through energy costs and also recognized in the financial statements.

25.9 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 25 has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

26 Proposed Capacity Charges for Test Period

26.1 Delivery Revenue Requirement Recovered by a Capacity Charge

Corix proposes to recover its Delivery Revenue Requirement through a Capacity Charge that has been designed with a rate stabilization plan via the use of a long-term deferral account named the Revenue Deficiency Deferral Account (RDDA).

Delivery costs form the Delivery Revenue Requirement, which was discussed in detail in Section 24 above, while the rate stabilization approach using the RDDA was discussed in detail in Section 25 above.

26.2 Delivery Revenue Requirements Summary

Schedule 2 in the Financial Schedules (Appendix A) provide the long-term annual Delivery Revenue Requirements from 2026 through to 2041 and shows that the Delivery Revenue Requirement for the 12-month Test Period from August 1, 2026 to July 31, 2027 is forecast to be $4.639 million. The Test Period forecast comprises:

- $1.366 million from August 1, 2026 to December 31, 2026; and
- $3.273 million from January 1, 2027 to July 31, 2027.

Table 27 below summarizes the annual Delivery Revenue Requirements for the first five years of operations on a calendar year basis.

TABLE 27 – SUMMARY OF TOTAL ANNUAL DELIVERY REVENUE REQUIREMENTS

	2026	2027	2028	2029	2030
Delivery Revenue Requirements ($ millions)	1.366	5.652	6.776	10.938	18.978

The forecasts from 2028 onwards are indicative only at this time for the purpose of supporting the contemplated rate stabilization plan. The forecasts from 2028 onwards will be updated with each subsequent general rate case filed with the PSC, based on updated information available at the time of each respective filing.

For details surrounding the calculation of the Delivery Revenue Requirement, please refer to the GRC Financial Model, submitted in Highly Confidential Corix Exhibit 7.1.

26.3 Peak Load

Schedule 16 in the Financial Schedules (Appendix A) provide the long-term forecast peak load from 2026 through to 2041. Table 28 below summarizes the total annual peak load (undiversified) for the first five years of operations.

TABLE 28 – SUMMARY OF TOTAL ANNUAL UNDIVERSIFIED PEAK LOAD

	2026	2027	2028	2029	2030
Heating (MW)	3.8	5.5	6.7	16.8	30.5
Cooling (MW)	2.8	4.6	6.4	20.4	39.7
Total (MW)	6.6	10.1	13.1	37.2	70.2

The medium-term peak load shown in the table above, as well as the long-term peak load included in Schedule 16 of the Financial Schedules are indicative only, since the peak load is driven by the buildout schedule of the property development. The forecasts from 2028 onwards will be updated with each subsequent general rate case filed with the PSC, based on updated information available at the time of each respective filing.

For details surrounding the calculation of the peak load, please refer to Schedule 16 in Appendix A, as well as the GRC Financial Model, submitted in Highly Confidential Corix Exhibit 7.1.

26.4 Proposed Delivery Charge for Test Period

Based on the Delivery Revenue Requirements, the undiversified peak load, the buildout schedule, the Capacity Charge rate stabilization plan with annual escalation, and a RDDA recovery period ending in 2041, Corix proposes to set the Capacity Charge to $15.85 per kW per month (Schedule 17, line 2).

The proposed Capacity Charge would remain in effect until the subsequent rate change to the Capacity Charge is approved through the next GRC Application.

26.5 Direct Testimony: Corix Exhibit 2.0 - Errol South

This Section 26 Proposed Capacity Charges for Test Period has been prepared by Errol South. Please refer to his Direct Testimony in Corix Exhibit 2.0 - Errol South.

27 Thermal Tariff (Terms, Conditions, and Rates)

The proposed Thermal Tariff for UCDEU is included in the GRC Application as Corix Exhibit 1.0.

27.1 Explanation of Thermal Tariff and Related Agreements

The thermal tariff includes the following sections:

A. Definitions
B. Terms and Conditions
C. Standard Fees and Charges Schedule
D. Energy Cost Reconciliation Account
E. Rate Schedule 1: General Service

While the tariff provides the terms and conditions of service and rates, there are two related agreements that a UCDEU customer will sign; a District Energy Services Agreement (DESA) and a Customer Agreement.

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section IV Related Agreements;
b. Direct Testimony in Corix Exhibit 8.1 – Hang Hockley, District Energy Services Agreement (DESA);
c. Direct Testimony in Corix Exhibit 8.2 – Hang Hockley, Customer Agreement

27.2 Fair Treatment of End-user Tenants

Corix meters thermal energy consumption at the building level using bulk energy meters and in turn, the utility bills are generated for the entire building. Our Customer Agreements are with the owner(s) of the building, and they are the parties which receive the utility bills. Although the tenants within the developments are not direct customers, we acknowledge and recognize that as the users of the thermal energy service, tenants are materially affected by the level of service as well as the rates, since the building owners will pass on the thermal energy costs. Included in the tariff are sections pertaining to the fair allocation of costs to tenants and resolution of tenant complaints.

27.2.1 Fair Allocation of Thermal Energy Costs and Sub-meters for Cost Allocation

If a customer of Corix intends to pass the thermal energy costs from the utility bill to end-users, it is their responsibility to allocate the costs. The thermal tariff states that when allocating the thermal energy costs to tenants, no mark-up or profit on the allocation is permitted and allocations must be fair, reasonable and transparent.

In certain circumstances, sub-meters may be installed to aid the customer with cost allocation, and the thermal tariff outlines the eligibility criteria. Outside of the eligibility criteria, the thermal tariff allows sub-metering on a case-by-case exemption approval by the PSC.

See the following:

d. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection A. Fair Allocation of Thermal Energy Costs;

e. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection B. Sub-meters for Cost Allocation;

f. Exhibit 1.0 - Thermal Tariff, Section B, subsection 3(a) Fair Allocation of Thermal Energy Costs;

g. Exhibit 1.0 – Thermal Tariff, Section B, subsection 7 Sub-meters for Cost Allocation.

27.2.2 End-user Tenant Complaints and Recourse

As indirect customers, end-user tenants will have the building manager/owner or property manager as the main contact for service and billing inquiries. The tariff states that the end-user tenant may also lodge a complaint with the utility regarding service or fair allocation, and Corix will investigate the issues accordingly.

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection F. Dispute Resolution;

b. Exhibit 1.0 - Thermal Tariff, Section B, subsection 30 Dispute Resolution.

27.3 Distribution Extensions

If there is an opportunity or a request to complete a distribution extension to connect one or more new potential customers, the tariff provides a high-level overview of the factors that would be considered when assessing the economic impact of the extension on existing customers of the utility.

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection C. Distribution Extensions;

b. Exhibit 1.0 - Thermal Tariff, Section B, subsection 10 Distribution Extensions.

27.4 Flexible Payment Plans

Corix proposes two flexible payment plans in the thermal tariff:

1. A Capacity Charge Deferred Payment Plan (CCDPP) is available during the first 12 months the Capacity Charge and is payable and applicable to the Capacity Charge only. It is intended to support the customer through the phase immediately following construction when tenancy levels are still ramping up and full allocation of the thermal energy bill may not be possible;
2. A Deferred Payment Agreement; available at any time and applicable to all charges and fees making up the account balance.

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection D. Capacity Charge Deferred Payment Plan (CCDPP);

b. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection E. Deferred Payment Agreement;

c. Exhibit 1.0 - Thermal Tariff, Section B, subsection 13 Capacity Charge Deferred Payment Plan (CCDPP);

d. Exhibit 1.0 – Thermal Tariff, Section B, subsection 14 Deferred Payment Agreement.

27.5 Dispute Resolution

Upon receipt of a complaint, Corix will attempt to resolve the issue by negotiation as permitted by the terms and conditions of the thermal tariff. The tariff also states that if resolution is not found by working directly with the utility, customers may submit a complaint to the Division of Public Utilities (DPU), which may be followed by a formal review by the Commission. Contact information and website links for the DPU are included in the tariff.

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection F. Dispute Resolution;

b. Exhibit 1.0 - Thermal Tariff, Section B, subsection Dispute Resolution.

27.6 Standard Fees and Charges

See the following:

a. Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section V, subsection G. Standard Fees and Charges Schedule;

b. Exhibit 1.0 - Thermal Tariff, Section C, Standard Fees and Charges Schedule.

27.7 Summary of Approvals Sought

Corix seeks approval of Exhibit 1.0 - Thermal Tariff which includes the following sections:

A. Definitions

B. Terms and Conditions

C. Standard Fees and Charges Schedule

D. Energy Cost Reconciliation Account

E. Rate Schedule 1: General Service

27.8 Direct Testimony: Corix Exhibit 8.0 – Hang Hockley

This Section 27 Thermal Tariff (Terms, Conditions, and Rates) has been prepared by Hang Hockley. See the Direct Testimony in Corix Exhibit 8.0 – Hang Hockley.

28 Other Matters – Service Quality Standards

28.1 Service Quality Standards

There are multiple service quality standards within the tariff itself, as well as other metrics tracked independently of the tariff.

See Direct Testimony in Corix Exhibit 8.0 – Hang Hockley, Section VI Service Quality Standards.

29 Other Matters – Thermal Uniform System of Accounts

29.1 Uniform System of Accounts for Other Public Utilities

The Federal Energy Regulatory Commission (FERC) has adopted Uniform System of Accounts (USoA) for electric and natural gas utilities but does not have a USoA for steam or thermal utilities. The National Association of Regulatory Utility Commissioners (NARUC) has a USoA for water utilities based on the FERC account approach with unique differences applicable to water service.

Corix understands that the Utah PSC has a Uniform System of Accounts requirement for its electric, gas, and water utilities based on the applicable national standard setter.

Corix not aware of any Uniform System of Accounts that is applicable for thermal service. Thermal service has elements of electric, gas, and water services so reporting for thermal service would resemble all three types of services. Thermal service is similar to natural gas and water since they all use pipes. However, thermal service is similar to electric service from the perspective that are many source resources to produce electricity as there are many different sources resources to produce thermal service.

Thermal service though similar to natural gas there are also differences. Natural gas companies have over the years consolidated into state-wide natural monopolies. In contrast, thermal service in North America is mostly a neighborhood system or a campus system in an academic institution or medical institution. There are some remaining legacy downtown district energy steam systems in North America which are not regulated or lightly rate-regulated. Modern non-steam thermal systems tend to be local or community systems since each system is sized and designed based on the needs and available resources of that local system. Given the bespoke nature of thermal energy, they have not evolved into regional or state-wide utilities in North America.

29.2 Development of a Thermal Uniform System of Accounts

Corix considers that a regulated Utah thermal utility should utilize a uniform system of accounts similar in manner to the other traditional energy and water utilities. Corix has also reviewed the New York Public Service Commission reporting requirements for the regulated Consolidated Edison (ConEd) steam utility where it utilizes an adapted reporting approach similar to FERC's electric and gas accounts. The legacy steam system is a form of thermal energy. However, Corix's district energy system does not utilize thermal steam but instead utilizes modern hot and cold water distribution to provide thermal heating and cooling service. It should be noted that ConEd Steam uses an adapted approach; its Steam Annual Report is not complete since many sections refer back to the Electric/Gas Annual Report for accounts that are not reported for Steam.

Corix considers developing an adapted Thermal Uniform System of Accounts that is based on a FERC Uniform System of Accounts would meet the PSC's requirement for thermal reporting. Corix has further looked into developing a Thermal Uniform System of Accounts by more closely reviewing the Electric and Natural Gas FERC accounts. Corix believes the most promising approach to developing a Thermal Uniform System of Accounts is it be based on the FERC Electric Uniform System of Accounts but include adaptions for thermal energy. The final form of the Thermal Uniform System of Accounts would have the following characteristics:

- Based on the FERC Electric Uniform System of Accounts with adaptations.
- Adaptations that include concepts of the FERC Natural Gas Uniform System of Accounts for piped energy.
- Adaptations that include thermal assets similar in approach and concept to how the NARUC Water Uniform System of Accounts have water assets incorporated rather than gas or electric assets.

- Adaptations to include a decoupling of pass-through costs for energy supply costs. When the Uniform System of Accounts were first developed it did fully appreciate the concept of pass-through costs that were separate and distinct from Operation and Maintenance costs since it considered a bundled approach to rate making.
- Adaptations to recognize that a small neighborhood utility incurs a relatively higher amount of allocated costs from its affiliates. The FERC Uniform System Accounts has a presumption that the utility is sufficiently large that most of its resources (particularly labor) is from its own employees. A small utility like UCDEU are not sufficiently large enough to hire its only utility personnel for all its functions. A small utility typically relies on support services from an affiliate. Where economically appropriate, a small utility may grow to sufficient size that it may be able to hire its own operators rather than rely on shared resources.

29.3 Proposal for working group to develop a Thermal Uniform System of Accounts

At this time Corix has not yet fully completed a draft of a Thermal Uniform System of Accounts. Corix proposes that the Commission in its decision for this GRC Application forms a working group and directs Corix to work with the DPU and OCS on developing a Thermal Uniform System of Accounts for the PSC to review and approve.

After formation of the working group, Corix would propose the initial draft to the parties for consideration. The parties would work collaboratively in the development of a new Thermal Uniform System of Accounts that reflect modern regulatory practices, thermal utility considerations, and small utility considerations. The parties would bring forward to the Commission a proposed Thermal Uniform System of Accounts for approval.

29.4 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 29 Other Matters – Thermal Uniform System of Accounts has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

30 Other Matters – Annual Reports

30.1 Annual Reports

Corix understands that the electrical, natural gas, and water corporations have prescribed annual reports which reply on their approved Uniform System of Accounts. Corix understands the annual reports are due on April 15th each year following the fiscal and calendar year ending December 31st.

Corix has its fiscal year ending December 31st and considers that the heat corporation's annual report would be due April 15th. However, at this time the PSC has not prescribed a filing requirement for a heat corporation and there is no thermal utility Uniform System of Accounts.

30.2 Proposal for working group to develop an Annual Report for a Heat Corporation

Corix proposes that the Commission in its decision for this GRC Application forms a working group and directs Corix to work with the DPU and OCS to develop an annual report template for a heat corporation for the PSC to review and approve.

After formation of the working group, Corix would work collaboratively with the DPU and OCS in the development of a suitable annual report for a heat corporation. The two working groups (Thermal Uniform System of Accounts and annual report) could occur concurrently. However, the annual report working group can only complete it work after the PSC has approved a Thermal Uniform System of Accounts since the accounts are a key input to the development of the annual reporting template.

30.3 Annual Report Requirement Reporting and Development

UCDEU is expecting to start utility service on or about August 1, 2026. Corix submits that if Corix were required to file an annual report for the period ended December 31, 2026, the Commission should consider requiring a streamlined annual report until a Thermal Uniform Systems of Accounts has been approved for use for a heating corporation. Corix submitting a streamlined annual report in the interim may be appropriate until requirements for an annual report is established for a heating corporation.

30.4 Direct Testimony: Corix Exhibit 3.0 - Douglas Chong

This Section 29 Other Matters – Annual Reports has been prepared by Douglas Chong. See the Direct Testimony in Corix Exhibit 3.0 - Douglas Chong.

31 Conclusion

Utah City District Energy System is first heat corporation in Utah offering both heating and cooling in a combined operation. Utah City is unique with its long-term build-out with buildings connections spanning from 2026 to 2044.

Corix submits that the Commission should approve the proposed Thermal Tarif in Corix Exhibit 1.0.

Corix also submits that the requests contained in this GRC Application has been supported by information contained in Attachment 1: Supplement to Application with Appendices; accompanying direct testimonies from seven individuals; and the various pre-filed exhibits.

Corix looks forward to connecting its first building to the district energy system and commencing utility operations in Utah.

Appendix A Financial Schedules

Schedule	Description
GRC Financial Model: Delivery Revenue Requirement	
Schedule 1	Revenue Requirement and RDDA Summary
Schedule 2	Revenue Requirements
Schedule 3	Rate Base
Schedule 4	Plant Continuity and Net Book Value
Schedule 5	Utility Plant in Service and CIAC
Schedule 6	Capital Expenditure and AFUDC
Schedule 7	Depreciation and Amortization Rates
Schedule 8	Working Capital
Schedule 9	Rate Base Deferrals
Schedule 10	Non-Rate Base Deferrals
Schedule 11	Cost of Capital and Return on Rate Base
Schedule 12	Operating and Maintenance Expenses
Schedule 13	Employee and Direct Labor Breakdown
Schedule 14	Energy Supply Costs
Schedule 15	Income Tax and Tax Depreciation
Schedule 16	Buildout, Peak Load and Energy Demand
Schedule 17	Customer Rates
Schedule 18	Estimated Typical Customer Building Bill Impact
Schedule 19	Estimated End-User Cost Impact
Schedule 20	Billed Revenue
ECRA Financial Model: Energy Supply Revenue Requirement	
Schedule A1	Energy Charge Proposed Rate
Schedule A2	ECRA Monthly Balances

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 1 - Revenue Requirement and RDDA Summary

Line No.	Revenue Requirements *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	Proposed Rates																					
3	Total Delivery Revenue Requirement	-	1,365,886	3,273,601	2,378,784	4,639,486	1,365,886	5,652,385	6,776,520	10,938,712	18,979,914	24,329,583	27,277,312	27,953,598	34,030,796	38,360,365	38,385,817	40,995,559	42,352,842	41,571,373	41,045,123	39,882,280
4	Delivery Revenue at Proposed Rates	-	369,100	757,019	749,912	1,126,119	369,100	1,506,931	2,547,899	4,894,177	12,236,316	18,391,920	24,077,366	27,280,193	31,907,645	38,844,458	41,806,204	43,998,104	45,809,418	47,231,414	48,953,328	50,043,592
5	Revenue Shortfall / (Surplus)	-	996,786	2,516,582	1,628,872	3,513,368	996,786	4,145,454	4,228,621	6,044,535	6,743,598	5,937,663	3,199,945	673,405	2,123,151	(484,093)	(3,420,387)	(3,002,545)	(3,456,575)	(5,660,041)	(7,908,205)	(10,161,312)
6	Cumulative Shortfall / (Surplus)	-	996,786	3,513,368	5,142,240	3,513,368	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312	(0)
7																						
8	RDDA Opening Balance	-	-	996,786	3,513,368	-	-	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312
9	RDDA Closing Balance	-	996,786	3,513,368	5,142,240	3,513,368	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312	(0)
10																						

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 2 - Revenue Requirements

Line No.	Revenue Requirements *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	Delivery Revenue Requirement																					
3	Total Operation and Maintenance Expenses	-	490,163	771,774	551,736	1,261,937	490,163	1,323,510	1,575,276	1,856,056	3,139,905	3,464,649	4,203,859	4,437,726	5,221,652	5,555,414	5,827,934	6,603,418	7,244,433	7,485,349	7,831,232	8,125,172
4																						
5	Depreciation	-	299,391	583,628	456,907	883,020	299,391	1,040,535	1,154,535	2,439,304	3,991,382	5,020,124	5,397,601	5,604,464	7,584,245	8,131,560	8,223,332	9,221,085	9,393,306	9,417,124	9,590,427	9,709,902
6	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Subtotal Depreciation & Amortization	-	299,391	583,628	456,907	883,020	299,391	1,040,535	1,154,535	2,439,304	3,991,382	5,020,124	5,397,601	5,604,464	7,584,245	8,131,560	8,223,332	9,221,085	9,393,306	9,417,124	9,590,427	9,709,902
8																						
9	Interest on Debt	-	206,945	689,838	492,741	896,783	206,945	1,182,579	1,430,254	2,336,847	4,194,770	5,376,413	5,997,871	6,077,248	7,199,417	8,370,588	8,254,759	8,537,139	8,721,552	8,365,545	8,009,678	7,473,332
10	Return on Equity	-	290,110	967,063	690,759	1,257,173	290,110	1,657,822	2,060,036	3,389,074	6,025,319	8,241,218	9,193,817	9,315,490	11,035,603	12,830,829	12,653,281	13,086,126	13,368,803	12,823,098	12,277,608	11,455,473
11	Subtotal Return on Rate Base	-	497,055	1,656,901	1,183,501	2,153,956	497,055	2,840,401	3,490,290	5,725,921	10,220,089	13,617,631	15,191,688	15,392,738	18,235,020	21,201,418	20,908,040	21,623,265	22,090,355	21,188,643	20,287,286	18,928,806
12																						
13	Taxes other than Income Tax	-	-	193	138	193	-	331	1,377	1,715	2,840	5,210	6,882	7,973	8,362	10,089	11,584	11,810	12,567	13,008	12,935	12,941
14																						
15	Income tax	-	79,276	261,104	186,503	340,380	79,276	447,607	555,043	915,716	1,625,699	2,221,969	2,477,281	2,510,696	2,981,517	3,461,885	3,414,927	3,535,980	3,612,181	3,467,249	3,323,243	3,105,459
16																						
17	**Total Delivery Revenue Requirement**	**-**	**1,365,886**	**3,273,601**	**2,378,784**	**4,639,486**	**1,365,886**	**5,652,385**	**6,776,520**	**10,938,712**	**18,979,914**	**24,329,583**	**27,277,312**	**27,953,598**	**34,030,796**	**38,360,365**	**38,385,817**	**40,995,559**	**42,352,842**	**41,571,373**	**41,045,123**	**39,882,280**
18																						
19	Energy Supply Revenue Requirement																					
20	**Total Energy Supply Revenue Requirement**	**-**	**88,674**	**179,544**	**213,050**	**268,218**	**88,674**	**392,594**	**749,530**	**1,525,683**	**3,883,377**	**5,874,797**	**7,715,448**	**8,744,520**	**10,246,904**	**12,478,485**	**13,445,924**	**14,155,828**	**14,736,955**	**15,197,668**	**15,750,478**	**16,101,731**
21																						
22	**Total Revenue Requirement**	**-**	**1,454,560**	**3,453,145**	**2,591,834**	**4,907,704**	**1,454,560**	**6,044,979**	**7,526,050**	**12,464,395**	**22,863,291**	**30,204,380**	**34,992,759**	**36,698,118**	**44,277,700**	**50,838,851**	**51,831,741**	**55,151,387**	**57,089,798**	**56,769,041**	**56,795,602**	**55,984,011**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 3 - Rate Base

Line No.	Rate Base *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	Gross Plant in Service																					
3	Opening Balance	-	-	25,779,345	31,789,958	-	-	25,779,345	32,972,866	35,553,483	78,010,569	131,177,044	161,369,101	172,514,567	177,532,334	253,294,308	265,478,889	273,027,442	312,319,134	315,248,538	325,624,904	332,740,187
4	Ending Balance	-	25,779,345	31,789,958	32,972,866	31,789,958	25,779,345	32,972,866	35,553,483	78,010,569	131,177,044	161,369,101	172,514,567	177,532,334	253,294,308	265,478,889	273,027,442	312,319,134	315,248,538	325,624,904	332,740,187	336,750,681
5	Mid-Year Plant in Service						5,370,697	29,376,105	34,263,174	56,782,026	104,593,807	146,273,073	166,941,834	175,023,451	215,413,321	259,386,598	269,253,166	292,673,288	313,783,836	320,436,721	329,182,545	334,745,434
6																						
7	Plant Accumulated Depreciation																					
8	Opening Balance	-	-	299,391	883,020	-	-	299,391	1,339,927	2,494,461	4,933,766	8,925,147	13,945,272	19,342,873	24,947,337	32,531,583	40,663,142	48,886,474	58,107,560	67,500,866	76,917,990	86,508,417
9	Ending Balance	-	299,391	883,020	1,339,927	883,020	299,391	1,339,927	2,494,461	4,933,766	8,925,147	13,945,272	19,342,873	24,947,337	32,531,583	40,663,142	48,886,474	58,107,560	67,500,866	76,917,990	86,508,417	96,218,319
10	Mid-Year Plant Accumulated Depreciation						62,373	819,659	1,917,194	3,714,113	6,929,456	11,435,209	16,644,072	22,145,105	28,739,460	36,597,362	44,774,808	53,497,017	62,804,213	72,209,428	81,713,203	91,363,368
11																						
12	Net Mid-Year Plant in Service						5,308,324	28,556,446	32,345,981	53,067,913	97,664,350	134,837,863	150,297,762	152,878,345	186,673,861	222,789,236	224,478,357	239,176,271	250,979,623	248,227,293	247,469,342	243,382,066
13																						
14																						
15	Gross Contributions in Aid of Construction (CIAC)																					
16	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Mid-Year CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19																						
20	CIAC Accumulated Amortization																					
21	Opening Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Mid-Year CIAC Accumulated Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																						
25	Net Mid-Year Contributions in Aid of Construction	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26																						
27																						
28	Rate Base																					
29	Mid-Year Plant in Service (Net of CIAC)						5,308,324	28,556,446	32,345,981	53,067,913	97,664,350	134,837,863	150,297,762	152,878,345	186,673,861	222,789,236	224,478,357	239,176,271	250,979,623	248,227,293	247,469,342	243,382,066
30	Mid-Year Rate Base Deferrals - RDDA						207,664	3,069,513	7,256,551	12,393,129	18,787,195	25,127,826	29,696,630	31,633,305	33,031,583	33,851,112	31,898,872	28,687,406	25,457,846	20,899,537	14,115,414	5,080,656
31	Mid-Year Rate Base Deferrals - Others						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Working Capital						15,074	143,434	252,557	356,659	650,314	1,022,671	1,328,672	1,568,847	1,790,675	2,093,903	2,331,735	2,502,069	2,671,290	2,791,525	2,891,545	2,988,038
33	Accum. Deferred Income Tax - ADIT[2]						(5,155)	(191,836)	(616,308)	(1,263,916)	(2,333,876)	(4,012,787)	(6,202,740)	(8,642,593)	(11,294,155)	(14,337,508)	(17,694,092)	(21,106,203)	(24,464,898)	(27,668,872)	(30,617,103)	(33,251,272)
34	Mid-Year Rate Base						5,525,907	31,577,557	39,238,781	64,553,784	114,767,984	156,975,573	175,120,324	177,437,905	210,201,964	244,396,744	241,014,873	249,259,544	254,643,861	244,249,484	233,859,199	218,199,489

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.
(2) Accumulated Deferred Income Tax (ADIT) represents the net cumulative balance of Deferred Tax Assets (DTAs) and Deferred Tax Liabilities (DTLs) arising from temporary timing differences between regulatory accounting and tax accounting. These differences are primarily driven by accelerated tax depreciation relative to regulatory depreciation. ADIT reflects taxes deferred or prepaid as a result of these timing differences and is recognized in accordance with standard utility tax normalization practices.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 4 - Plant Continuity and Net Book Value

Line No.	Plant Continuity	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
	All figures in $s																					
1																						
2	Gross Plant																					
3	Opening Balance	-	-	25,779,345	31,789,958	-	-	25,779,345	32,972,866	35,553,483	78,010,569	131,177,044	161,369,101	172,514,567	177,532,334	253,294,308	265,478,889	273,027,442	312,319,134	315,248,538	325,624,904	332,740,187
4	Additions	-	25,779,345	6,010,613	1,182,908	31,789,958	25,779,345	7,193,521	2,580,617	42,457,086	53,166,475	30,192,057	11,145,466	5,017,767	75,761,974	12,184,581	7,548,553	39,291,692	2,929,404	10,376,366	7,115,283	4,010,495
5	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Ending Balance	-	25,779,345	31,789,958	32,972,866	31,789,958	25,779,345	32,972,866	35,553,483	78,010,569	131,177,044	161,369,101	172,514,567	177,532,334	253,294,308	265,478,889	273,027,442	312,319,134	315,248,538	325,624,904	332,740,187	336,750,681
8																						
9	Accumulated Depreciation																					
10	Opening Balance	-	-	299,391	883,020	-	-	299,391	1,339,927	2,494,461	4,933,766	8,925,147	13,945,272	19,342,873	24,947,337	32,531,583	40,663,142	48,886,474	58,107,560	67,500,866	76,917,990	86,508,417
11	Depreciation Provision	-	299,391	583,628	456,907	883,020	299,391	1,040,535	1,154,535	2,439,304	3,991,382	5,020,124	5,397,601	5,604,464	7,584,245	8,131,560	8,223,332	9,221,085	9,393,306	9,417,124	9,590,427	9,709,902
12	Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Ending Balance	-	299,391	883,020	1,339,927	883,020	299,391	1,339,927	2,494,461	4,933,766	8,925,147	13,945,272	19,342,873	24,947,337	32,531,583	40,663,142	48,886,474	58,107,560	67,500,866	76,917,990	86,508,417	96,218,319
15																						
16	Net Book Value																					
17	Opening Balance	-	-	25,479,954	30,906,939	-	-	25,479,954	31,632,939	33,059,022	73,076,804	122,251,897	147,423,830	153,171,694	152,584,997	220,762,725	224,815,747	224,140,968	254,211,575	247,747,672	248,706,914	246,231,770
18	Ending Balance	-	25,479,954	30,906,939	31,632,939	30,906,939	25,479,954	31,632,939	33,059,022	73,076,804	122,251,897	147,423,830	153,171,694	152,584,997	220,762,725	224,815,747	224,140,968	254,211,575	247,747,672	248,706,914	246,231,770	240,532,363
19																						

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 5 - Utility Plant in Service and CIAC

Line No.	01/01/2026 - 07/31/2026 - Forecast	Gross Plant						Accum. Depreciation of Utility Plant / Accum. Amortization of CIAC					Net Book Value	
	Category	Opening Balance	Additions (New)	Additions (R&R)	Retirements	Adjustments	Ending Balance	Opening Balance	Depreciation Provision	Retirements	Adjustments	Ending Balance	Opening Balance	Ending Balance
1	**Utility Plant**													
2	**Production**													
3	Plant heating equipment structures	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Boiler plant equipment. Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Miscellaneous heating plant equipment - Device	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Plant cooling equipment structures	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Miscellaneous Cooling plant equipment - Device	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Plant thermal equipment structures	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Thermal plant equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Miscellaneous thermal plant equipment - Device	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Plant siteworks	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal - Production**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
14														
15	**Distribution**													
16	Energy Transfer Station	-	-	-	-	-	-	-	-	-	-	-	-	-
17	HEX Installations on customers' premises	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-
19	DPS	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal - Distribution**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21														
22	**General Plant**													
23	Office Furniture and Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Hardware & Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Computer - Software	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Miscellaneous equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Subtotal - General Plant**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
29														
30														
31	**Total Plant**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
32														
33	**Contribution In Aid of Construction (CIAC)**													
34	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Other CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39														
40	**Total Net Plant After CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 5 - Utility Plant in Service and CIAC

Line No.	08/01/2026 - 12/31/2026 - Forecast	Gross Plant						Accum. Depreciation of Utility Plant / Accum. Amortization of CIAC					Net Book Value	
	Category	**Opening Balance**	**Additions (New)**	**Additions (R&R)**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Depreciation Provision**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Ending Balance**
1	**Utility Plant**													
2	**Production**													
3	Plant heating equipment structures	-	1,129,089	-	-	-	1,129,089	-	7,527	-	-	7,527	-	1,121,562
4	Boiler plant equipment. Gas	-	1,173,677	-	-	-	1,173,677	-	15,649	-	-	15,649	-	1,158,028
5	Miscellaneous heating plant equipment - Device	-	75,861	-	-	-	75,861	-	2,529	-	-	2,529	-	73,332
6	Plant cooling equipment structures	-	3,169,823	-	-	-	3,169,823	-	21,132	-	-	21,132	-	3,148,691
7	Chillers	-	3,102,635	-	-	-	3,102,635	-	41,368	-	-	41,368	-	3,061,267
8	Miscellaneous Cooling plant equipment - Device	-	266,710	-	-	-	266,710	-	8,890	-	-	8,890	-	257,820
9	Plant thermal equipment structures	-	5,616,742	-	-	-	5,616,742	-	37,445	-	-	37,445	-	5,579,297
10	Thermal plant equipment	-	1,722,664	-	-	-	1,722,664	-	22,969	-	-	22,969	-	1,699,695
11	Miscellaneous thermal plant equipment - Device	-	1,517,121	-	-	-	1,517,121	-	50,571	-	-	50,571	-	1,466,551
12	Plant siteworks	-	1,203,629	-	-	-	1,203,629	-	40,121	-	-	40,121	-	1,163,508
13	**Subtotal - Production**	**-**	**18,977,952**	**-**	**-**	**-**	**18,977,952**	**-**	**248,201**	**-**	**-**	**248,201**	**-**	**18,729,750**
14														
15	**Distribution**													
16	Energy Transfer Station	-	514,746	-	-	-	514,746	-	3,002	-	-	3,002	-	511,744
17	HEX Installations on customers' premises	-	266,866	-	-	-	266,866	-	3,113	-	-	3,113	-	263,753
18	Meters	-	41,862	-	-	-	41,862	-	1,221	-	-	1,221	-	40,641
19	DPS	-	5,895,470	-	-	-	5,895,470	-	39,303	-	-	39,303	-	5,856,167
20	**Subtotal - Distribution**	**-**	**6,718,944**	**-**	**-**	**-**	**6,718,944**	**-**	**46,639**	**-**	**-**	**46,639**	**-**	**6,672,305**
21														
22	**General Plant**													
23	Office Furniture and Equip.	-	36,804	-	-	-	36,804	-	1,227	-	-	1,227	-	35,577
24	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Hardware & Communication Equipment	-	39,336	-	-	-	39,336	-	2,622	-	-	2,622	-	36,713
26	Computer - Software	-	6,310	-	-	-	6,310	-	701	-	-	701	-	5,609
27	Miscellaneous equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Subtotal - General Plant**	**-**	**82,449**	**-**	**-**	**-**	**82,449**	**-**	**4,550**	**-**	**-**	**4,550**	**-**	**77,899**
29														
30														
31	**Total Plant**	**-**	**25,779,345**	**-**	**-**	**-**	**25,779,345**	**-**	**299,391**	**-**	**-**	**299,391**	**-**	**25,479,954**
32														
33	**Contribution In Aid of Construction (CIAC)**													
34	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Other CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39														
40	**Total Net Plant After CIAC**	**-**	**25,779,345**	**-**	**-**	**-**	**25,779,345**	**-**	**299,391**	**-**	**-**	**299,391**	**-**	**25,479,954**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 5 - Utility Plant in Service and CIAC

Line No.	01/01/2027 - 07/31/2027 - Forecast	Gross Plant						Accum. Depreciation of Utility Plant / Accum. Amortization of CIAC					Net Book Value	
	Category	**Opening Balance**	**Additions (New)**	**Additions (R&R)**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Depreciation Provision**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Ending Balance**
1	**Utility Plant**													
2	**Production**													
3	Plant heating equipment structures	1,129,089	-	-	-	-	1,129,089	7,527	13,173	-	-	20,700	1,121,562	1,108,389
4	Boiler plant equipment. Gas	1,173,677	-	-	-	-	1,173,677	15,649	27,386	-	-	43,035	1,158,028	1,130,642
5	Miscellaneous heating plant equipment - Device	75,861	-	-	-	-	75,861	2,529	4,425	-	-	6,954	73,332	68,907
6	Plant cooling equipment structures	3,169,823	1,366,353	-	-	-	4,536,176	21,132	46,090	-	-	67,222	3,148,691	4,468,954
7	Chillers	3,102,635	1,338,597	-	-	-	4,441,232	41,368	90,243	-	-	131,611	3,061,267	4,309,621
8	Miscellaneous Cooling plant equipment - Device	266,710	115,070	-	-	-	381,780	8,890	19,394	-	-	28,284	257,820	353,496
9	Plant thermal equipment structures	5,616,742	-	-	-	-	5,616,742	37,445	65,529	-	-	102,974	5,579,297	5,513,768
10	Thermal plant equipment	1,722,664	-	-	-	-	1,722,664	22,969	40,195	-	-	63,164	1,699,695	1,659,499
11	Miscellaneous thermal plant equipment - Device	1,517,121	-	-	-	-	1,517,121	50,571	88,499	-	-	139,069	1,466,551	1,378,052
12	Plant siteworks	1,203,629	-	-	-	-	1,203,629	40,121	70,212	-	-	110,333	1,163,508	1,093,297
13	**Subtotal - Production**	**18,977,952**	**2,820,019**	**-**	**-**	**-**	**21,797,971**	**248,201**	**465,145**	**-**	**-**	**713,347**	**18,729,750**	**21,084,625**
14														
15	**Distribution**													
16	Energy Transfer Station	514,746	1,030,143	-	-	-	1,544,889	3,002	12,873	-	-	15,875	511,744	1,529,014
17	HEX Installations on customers' premises	266,866	534,117	-	-	-	800,984	3,113	13,348	-	-	16,462	263,753	784,522
18	Meters	41,862	83,783	-	-	-	125,645	1,221	5,235	-	-	6,456	40,641	119,189
19	DPS	5,895,470	1,542,550	-	-	-	7,438,020	39,303	79,064	-	-	118,367	5,856,167	7,319,653
20	**Subtotal - Distribution**	**6,718,944**	**3,190,594**	**-**	**-**	**-**	**9,909,538**	**46,639**	**110,520**	**-**	**-**	**157,160**	**6,672,305**	**9,752,378**
21														
22	**General Plant**													
23	Office Furniture and Equip.	36,804	-	-	-	-	36,804	1,227	2,147	-	-	3,374	35,577	33,430
24	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Hardware & Communication Equipment	39,336	-	-	-	-	39,336	2,622	4,589	-	-	7,212	36,713	32,124
26	Computer - Software	6,310	-	-	-	-	6,310	701	1,227	-	-	1,928	5,609	4,382
27	Miscellaneous equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Subtotal - General Plant**	**82,449**	**-**	**-**	**-**	**-**	**82,449**	**4,550**	**7,963**	**-**	**-**	**12,513**	**77,899**	**69,936**
29														
30														
31	**Total Plant**	**25,779,345**	**6,010,613**	**-**	**-**	**-**	**31,789,958**	**299,391**	**583,628**	**-**	**-**	**883,020**	**25,479,954**	**30,906,939**
32														
33	**Contribution In Aid of Construction (CIAC)**													
34	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Other CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39														
40	**Total Net Plant After CIAC**	**25,779,345**	**6,010,613**	**-**	**-**	**-**	**31,789,958**	**299,391**	**583,628**	**-**	**-**	**883,020**	**25,479,954**	**30,906,939**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 5 - Utility Plant in Service and CIAC

Line No.	08/01/2026 - 07/31/2027 Test Year - Forecast	Gross Plant						Accum. Depreciation of Utility Plant / Accum. Amortization of CIAC					Net Book Value	
	Category	**Opening Balance**	**Additions (New)**	**Additions (R&R)**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Depreciation Provision**	**Retirements**	**Adjustments**	**Ending Balance**	**Opening Balance**	**Ending Balance**
1	**Utility Plant**													
2	**Production**													
3	Plant heating equipment structures	-	1,129,089	-	-	-	1,129,089	-	20,700	-	-	20,700	-	1,108,389
4	Boiler plant equipment. Gas	-	1,173,677	-	-	-	1,173,677	-	43,035	-	-	43,035	-	1,130,642
5	Miscellaneous heating plant equipment - Device	-	75,861	-	-	-	75,861	-	6,954	-	-	6,954	-	68,907
6	Plant cooling equipment structures	-	4,536,176	-	-	-	4,536,176	-	67,222	-	-	67,222	-	4,468,954
7	Chillers	-	4,441,232	-	-	-	4,441,232	-	131,611	-	-	131,611	-	4,309,621
8	Miscellaneous Cooling plant equipment - Device	-	381,780	-	-	-	381,780	-	28,284	-	-	28,284	-	353,496
9	Plant thermal equipment structures	-	5,616,742	-	-	-	5,616,742	-	102,974	-	-	102,974	-	5,513,768
10	Thermal plant equipment	-	1,722,664	-	-	-	1,722,664	-	63,164	-	-	63,164	-	1,659,499
11	Miscellaneous thermal plant equipment - Device	-	1,517,121	-	-	-	1,517,121	-	139,069	-	-	139,069	-	1,378,052
12	Plant siteworks	-	1,203,629	-	-	-	1,203,629	-	110,333	-	-	110,333	-	1,093,297
13	**Subtotal - Production**	**-**	**21,797,971**	**-**	**-**	**-**	**21,797,971**	**-**	**713,347**	**-**	**-**	**713,347**	**-**	**21,084,625**
14														
15	**Distribution**													
16	Energy Transfer Station	-	1,544,889	-	-	-	1,544,889	-	15,875	-	-	15,875	-	1,529,014
17	HEX Installations on customers' premises	-	800,984	-	-	-	800,984	-	16,462	-	-	16,462	-	784,522
18	Meters	-	125,645	-	-	-	125,645	-	6,456	-	-	6,456	-	119,189
19	DPS	-	7,438,020	-	-	-	7,438,020	-	118,367	-	-	118,367	-	7,319,653
20	**Subtotal - Distribution**	**-**	**9,909,538**	**-**	**-**	**-**	**9,909,538**	**-**	**157,160**	**-**	**-**	**157,160**	**-**	**9,752,378**
21														
22	**General Plant**													
23	Office Furniture and Equip.	-	36,804	-	-	-	36,804	-	3,374	-	-	3,374	-	33,430
24	Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Hardware & Communication Equipment	-	39,336	-	-	-	39,336	-	7,212	-	-	7,212	-	32,124
26	Computer - Software	-	6,310	-	-	-	6,310	-	1,928	-	-	1,928	-	4,382
27	Miscellaneous equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Subtotal - General Plant**	**-**	**82,449**	**-**	**-**	**-**	**82,449**	**-**	**12,513**	**-**	**-**	**12,513**	**-**	**69,936**
29														
30														
31	**Total Plant**	**-**	**31,789,958**	**-**	**-**	**-**	**31,789,958**	**-**	**883,020**	**-**	**-**	**883,020**	**-**	**30,906,939**
32														
33	**Contribution In Aid of Construction (CIAC)**													
34	Developer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Customer Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Grants	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Other CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Total CIAC**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39														
40	**Total Net Plant After CIAC**	**-**	**31,789,958**	**-**	**-**	**-**	**31,789,958**	**-**	**883,020**	**-**	**-**	**883,020**	**-**	**30,906,939**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 6 - Capital Expenditure and AFUDC

01/01/2026 - 07/31/2026 - Forecast — **Contruction Work in Progress (CWIP)**

Line No.	Category	Opening Balance	Direct Costs	AFUDC - ROE	AFUDC - Interest	Capitalization	Ending Balance
1	**Utility Plant**						
2	**Production**						
3	Plant heating equipment structures	754,445	194,371	29,199	22,183	-	1,000,198
4	Boiler plant equipment. Gas	187,133	801,086	29,101	22,113	-	1,039,433
5	Miscellaneous heating plant equipment - Device	12,095	51,778	1,880	1,429	-	67,183
6	Plant cooling equipment structures	1,654,911	1,341,918	87,420	66,280	-	3,150,529
7	Chillers	495,268	2,441,698	83,208	63,091	-	3,083,265
8	Miscellaneous Cooling plant equipment - Device	42,574	209,893	7,155	5,423	-	265,045
9	Plant thermal equipment structures	4,916,494	(200,293)	147,686	112,187	-	4,976,074
10	Thermal plant equipment	274,664	1,175,794	42,713	32,455	-	1,525,627
11	Miscellaneous thermal plant equipment - Device	241,892	1,035,502	37,617	28,584	-	1,343,595
12	Plant siteworks	208,880	804,504	29,880	22,703	-	1,065,967
13	**Subtotal - Production**	**8,788,357**	**7,856,252**	**495,859**	**376,448**	**-**	**17,516,915**
14							
15	**Distribution**						
16	Energy Transfer Station	11,718	602,686	9,438	6,951	-	630,792
17	HEX Installations on customers' premises	0	318,570	4,866	3,583	-	327,019
18	Meters	-	49,972	763	563	-	51,298
19	DPS	2,196,602	3,418,491	115,696	85,597	-	5,816,385
20	**Subtotal - Distribution**	**2,208,320**	**4,389,718**	**130,762**	**96,693**	**-**	**6,825,494**
21							
22	**General Plant**						
23	Office Furniture and Equip.	-	24,351	107	78	-	24,536
24	Vehicles	-	-	-	-	-	-
25	Hardware & Communication Equipment	-	26,028	113	83	-	26,224
26	Computer - Software	-	4,174	19	13	-	4,206
27	Miscellaneous equipment	-	-	-	-	-	-
28	**Subtotal - General Plant**	**-**	**54,553**	**239**	**174**	**-**	**54,966**
29							
30							
31	**Total CWIP**	**10,996,677**	**12,300,524**	**626,860**	**473,315**	**-**	**24,397,375**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 6 - Capital Expenditure and AFUDC

08/01/2026 - 12/31/2026 - Forecast — **Contruction Work in Progress (CWIP)**

Line No.	Category	Opening Balance	Direct Costs	AFUDC - ROE	AFUDC - Interest	Capitalization	Ending Balance
1	**Utility Plant**						
2	**Production**						
3	Plant heating equipment structures	1,000,198	125,315	2,076	1,500	1,129,089	-
4	Boiler plant equipment. Gas	1,039,433	130,519	2,162	1,563	1,173,677	-
5	Miscellaneous heating plant equipment - Device	67,183	8,436	140	101	75,861	0
6	Plant cooling equipment structures	3,150,529	877,411	17,177	12,324	3,169,823	887,618
7	Chillers	3,083,265	859,884	16,834	12,077	3,102,635	869,425
8	Miscellaneous Cooling plant equipment - Device	265,045	73,917	1,447	1,039	266,710	74,738
9	Plant thermal equipment structures	4,976,074	622,895	10,317	7,457	5,616,742	-
10	Thermal plant equipment	1,525,627	191,570	3,173	2,294	1,722,664	-
11	Miscellaneous thermal plant equipment - Device	1,343,595	168,712	2,794	2,020	1,517,121	(0)
12	Plant siteworks	1,065,967	133,843	2,217	1,602	1,203,629	-
13	**Subtotal - Production**	**17,516,915**	**3,192,504**	**58,337**	**41,977**	**18,977,952**	**1,831,781**
14							
15	**Distribution**						
16	Energy Transfer Station	630,792	648,942	10,986	7,861	514,746	783,835
17	HEX Installations on customers' premises	327,019	336,478	5,696	4,075	266,866	406,402
18	Meters	51,298	52,781	893	640	41,862	63,750
19	DPS	5,816,385	1,112,035	26,644	19,136	5,895,470	1,078,730
20	**Subtotal - Distribution**	**6,825,494**	**2,150,236**	**44,219**	**31,712**	**6,718,944**	**2,332,717**
21							
22	**General Plant**						
23	Office Furniture and Equip.	24,536	12,176	53	39	36,804	-
24	Vehicles	-	-	-	-	-	-
25	Hardware & Communication Equipment	26,224	13,014	57	41	39,336	-
26	Computer - Software	4,206	2,087	9	7	6,310	-
27	Miscellaneous equipment	-	-	-	-	-	-
28	**Subtotal - General Plant**	54,966	**27,277**	**119**	**87**	**82,449**	**-**
29							
30							
31	**Total CWIP**	**24,397,375**	**5,370,016**	**102,675**	**73,776**	**25,779,345**	**4,164,497**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 6 - Capital Expenditure and AFUDC

01/01/2027 - 07/31/2027 - Forecast — **Contruction Work in Progress (CWIP)**

Line No.	Category	Opening Balance	Direct Costs	AFUDC - ROE	AFUDC - Interest	Capitalization	Ending Balance
1	**Utility Plant**						
2	**Production**						
3	Plant heating equipment structures	-	-	-	-	-	-
4	Boiler plant equipment. Gas	-	-	-	-	-	-
5	Miscellaneous heating plant equipment - Device	0	-	-	-	-	0
6	Plant cooling equipment structures	887,618	459,318	11,340	8,077	1,366,353	-
7	Chillers	869,425	450,143	11,113	7,916	1,338,597	-
8	Miscellaneous Cooling plant equipment - Device	74,738	38,695	956	680	115,070	(0)
9	Plant thermal equipment structures	-	-	-	-	-	-
10	Thermal plant equipment	-	-	-	-	-	-
11	Miscellaneous thermal plant equipment - Device	(0)	-	-	-	-	(0)
12	Plant siteworks	-	-	-	-	-	-
13	**Subtotal - Production**	**1,831,781**	**948,157**	**23,409**	**16,673**	**2,820,019**	**(0)**
14							
15	**Distribution**						
16	Energy Transfer Station	783,835	897,367	18,753	13,350	1,030,143	683,162
17	HEX Installations on customers' premises	406,402	465,287	9,724	6,923	534,117	354,219
18	Meters	63,750	72,986	1,525	1,086	83,783	55,564
19	DPS	1,078,730	723,647	16,948	12,071	1,542,550	288,846
20	**Subtotal - Distribution**	**2,332,717**	**2,159,287**	**46,950**	**33,430**	**3,190,594**	**1,381,790**
21							
22	**General Plant**						
23	Office Furniture and Equip.	-	-	-	-	-	-
24	Vehicles	-	-	-	-	-	-
25	Hardware & Communication Equipment	-	-	-	-	-	-
26	Computer - Software	-	-	-	-	-	-
27	Miscellaneous equipment	-	-	-	-	-	-
28	**Subtotal - General Plant**	-	-	-	-	-	-
29							
30							
31	**Total Plant**	**4,164,497**	**3,107,444**	**70,359**	**50,103**	**6,010,613**	**1,381,790**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 6 - Capital Expenditure and AFUDC

Test Year - Forecast — **Contruction Work in Progress (CWIP)**

Line No.	Category	Opening Balance	Direct Costs	AFUDC - ROE	AFUDC - Interest	Capitalization	Ending Balance
1	**Utility Plant**						
2	**Production**						
3	Plant heating equipment structures	1,000,198	125,315	2,076	1,500	1,129,089	-
4	Boiler plant equipment. Gas	1,039,433	130,519	2,162	1,563	1,173,677	-
5	Miscellaneous heating plant equipment - Device	67,183	8,436	140	101	75,861	0
6	Plant cooling equipment structures	3,150,529	1,336,729	28,517	20,401	4,536,176	-
7	Chillers	3,083,265	1,310,027	27,947	19,993	4,441,232	-
8	Miscellaneous Cooling plant equipment - Device	265,045	112,613	2,403	1,719	381,780	(0)
9	Plant thermal equipment structures	4,976,074	622,895	10,317	7,457	5,616,742	-
10	Thermal plant equipment	1,525,627	191,570	3,173	2,294	1,722,664	-
11	Miscellaneous thermal plant equipment - Device	1,343,595	168,712	2,794	2,020	1,517,121	(0)
12	Plant siteworks	1,065,967	133,843	2,217	1,602	1,203,629	-
13	**Subtotal - Production**	**17,516,915**	**4,140,660**	**81,746**	**58,650**	**21,797,971**	**-**
14		-					
15	**Distribution**	-					
16	Energy Transfer Station	630,792	1,546,309	29,739	21,211	1,544,889	683,162
17	HEX Installations on customers' premises	327,019	801,765	15,420	10,998	800,984	354,219
18	Meters	51,298	125,767	2,418	1,726	125,645	55,564
19	DPS	5,816,385	1,835,682	43,592	31,207	7,438,020	288,846
20	**Subtotal - Distribution**	**6,825,494**	**4,309,523**	**91,169**	**65,142**	**9,909,538**	**1,381,790**
21							
22	**General Plant**						
23	Office Furniture and Equip.	24,536	12,176	53	39	36,804	-
24	Vehicles	-	-	-	-	-	-
25	Hardware & Communication Equipment	26,224	13,014	57	41	39,336	-
26	Computer - Software	4,206	2,087	9	7	6,310	-
27	Miscellaneous equipment	-	-	-	-	-	-
28	**Subtotal - General Plant**	54,966	**27,277**	**119**	**87**	**82,449**	**-**
29							
30							
31	**Total Plant**	**24,397,375**	**8,477,460**	**173,034**	**123,879**	**31,789,958**	**1,381,790**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 7 - Depreciation and Amortization Rates

Line No.	Category	Rate	Life (Years)	Examples
1	**Utility Plant**			
2	**Production**			
3	Plant heating equipment structures	2.0%	50	NG Structure, boiler breeching, gas trains
4	Boiler plant equipment. Gas	4.0%	25	Industrial boilers
5	Miscellaneous heating plant equipment - Device	10.0%	10	HEX, boiler circulation pumps, boiler management system
6	Plant cooling equipment structures	2.0%	50	Plant cooling equipment structures
7	Chillers	4.0%	25	Chillers
8	Cooling towers	4.0%	25	Cooling towers
9	Miscellaneous Cooling plant equipment - Device	10.0%	10	Miscellaneous Cooling plant equipment - Device
10	Plant thermal equipment structures	2.0%	50	Building, building structures and improvements
11	Thermal plant equipment	4.0%	25	Plumbing & Ventilation System
12	Miscellaneous thermal plant equipment - Device	10.0%	10	Ventilation fans, flood sensor, Intake&Exhaust Louvers, AC Split Unit for MDX Room
13	Plant siteworks	10.0%	10	TEC SiteWorks
14				
15	**Distribution**			
16	Energy Transfer Station	2.0%	50	Energy Transfer Station (ETS) main structure
17	HEX Installations on customers' premises	4.0%	25	HEX, valves
18	Meters	10.0%	10	Meters
19	DPS	2.0%	50	
20				
21	**General Plant**			
22	Office Furniture and Equip.	10.0%	10	Office furniture and equipment
23	Vehicles	20.0%	5	Vehicles
24	Hardware & Communication Equipment	20.0%	5	Hardware & Communication Equipment
25	Computer - Software	33.3%	3	Supervisory Control and Data Acquisition (SCADA), computer licenses
26	Miscellaneous equipment	20.0%	5	Misc. Equipment, Tools, Shop and Garage Equipment
27				
28	**Contribution In Aid of Construction (CIAC)**			
29	Contributions	2.0%	50	
30	Grants	2.0%	50	
31	Other CIAC	2.0%	50	

Notes

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 8 - Working capital

Line No.	Rate Base *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	Energy Supply Costs	-	88,674	179,544	213,050	268,218	88,674	392,594	749,530	1,525,683	3,883,377	5,874,797	7,715,448	8,744,520	10,246,904	12,478,485	13,445,924	14,155,828	14,736,955	15,197,668	15,750,478	16,101,731
3	Operating & Maintenance Costs	-	490,163	771,774	551,736	1,261,937	490,163	1,323,510	1,575,276	1,856,056	3,139,905	3,464,649	4,203,859	4,437,726	5,221,652	5,555,414	5,827,934	6,603,418	7,244,433	7,485,349	7,831,232	8,125,172
4	Other Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Total for Working Capital**	**-**	**578,837**	**951,318**	**764,785**	**1,530,156**	**578,837**	**1,716,104**	**2,324,806**	**3,381,739**	**7,023,282**	**9,339,446**	**11,919,306**	**13,182,246**	**15,468,556**	**18,033,900**	**19,273,857**	**20,759,246**	**21,981,388**	**22,683,017**	**23,581,711**	**24,226,903**
6																						
7	Days Working Capital	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
8	%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%
9																						
10	Total Working Capital	-	72,355	214,513	214,513	155,280	72,355	214,513	290,601	422,717	877,910	1,167,431	1,489,913	1,647,781	1,933,569	2,254,237	2,409,232	2,594,906	2,747,674	2,835,377	2,947,714	3,028,363
11																						
12	**Mid-Year Working Capital**						**15,074**	**143,434**	**252,557**	**356,659**	**650,314**	**1,022,671**	**1,328,672**	**1,568,847**	**1,790,675**	**2,093,903**	**2,331,735**	**2,502,069**	**2,671,290**	**2,791,525**	**2,891,545**	**2,988,038**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 9 - Rate Base Deferrals

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2																						
3	**Revenue Deficiency Deferral Account (RDDA)**																					
4	Opening Balance	-	-	996,786	3,513,368	-	-	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312
5																						
6	Additions / (Reductions)																					
7	Delivery Revenue Requirement	-	1,365,886	3,273,601	2,378,784	4,639,486	1,365,886	5,652,385	6,776,520	10,938,712	18,979,914	24,329,583	27,277,312	27,953,598	34,030,796	38,360,365	38,385,817	40,995,559	42,352,842	41,571,373	41,045,123	39,882,280
8	Less Billed Revenue from Capacity Charg	-	(369,050)	(756,969)	(749,887)	(1,126,019)	(369,050)	(1,506,856)	(2,547,874)	(4,893,977)	(12,236,041)	(18,391,720)	(24,077,191)	(27,280,143)	(31,907,445)	(38,844,283)	(41,806,154)	(43,998,079)	(45,809,418)	(47,231,364)	(48,953,303)	(50,043,592)
9	Less Billed Revenue from Other charges	-	(50)	(50)	(25)	(100)	(50)	(75)	(25)	(200)	(275)	(200)	(175)	(50)	(200)	(175)	(50)	(25)	-	(50)	(25)	-
10	Revenue Shortfall / (Surplus)	-	996,786	2,516,582	1,628,872	3,513,368	996,786	4,145,454	4,228,621	6,044,535	6,743,598	5,937,663	3,199,945	673,405	2,123,151	(484,093)	(3,420,387)	(3,002,545)	(3,456,575)	(5,660,041)	(7,908,205)	(10,161,312)
11																						
12	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Net Change	-	996,786	2,516,582	1,628,872	3,513,368	996,786	4,145,454	4,228,621	6,044,535	6,743,598	5,937,663	3,199,945	673,405	2,123,151	(484,093)	(3,420,387)	(3,002,545)	(3,456,575)	(5,660,041)	(7,908,205)	(10,161,312)
14																						
15	Ending Balance	-	996,786	3,513,368	5,142,240	3,513,368	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312	(0)
16																						
17	**Mid-Year Balance - RDDA**						**207,664**	**3,069,513**	**7,256,551**	**12,393,129**	**18,787,195**	**25,127,826**	**29,696,630**	**31,633,305**	**33,031,583**	**33,851,112**	**31,898,872**	**28,687,406**	**25,457,846**	**20,899,537**	**14,115,414**	**5,080,656**
18																						
19	**All Accounts**																					
20	Balance at Jan 1st	-	-	996,786	3,513,368	-	-	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312
21																						
22	Additions	-	996,786	2,516,582	1,628,872	3,513,368	996,786	4,145,454	4,228,621	6,044,535	6,743,598	5,937,663	3,199,945	673,405	2,123,151	-	-	-	-	-	-	-
23	Reductions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(484,093)	(3,420,387)	(3,002,545)	(3,456,575)	(5,660,041)	(7,908,205)	(10,161,312)
24	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Net Additions	-	996,786	2,516,582	1,628,872	3,513,368	996,786	4,145,454	4,228,621	6,044,535	6,743,598	5,937,663	3,199,945	673,405	2,123,151	(484,093)	(3,420,387)	(3,002,545)	(3,456,575)	(5,660,041)	(7,908,205)	(10,161,312)
26																						
27	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Balance at Dec 31st	-	996,786	3,513,368	5,142,240	3,513,368	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312	(0)
29																						
30	**Mid-Year Balance - All Accounts**						**207,664**	**3,069,513**	**7,256,551**	**12,393,129**	**18,787,195**	**25,127,826**	**29,696,630**	**31,633,305**	**33,031,583**	**33,851,112**	**31,898,872**	**28,687,406**	**25,457,846**	**20,899,537**	**14,115,414**	**5,080,656**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 10 - Non-Rate Base Deferred Charges

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2																						
3	**Energy Cost Reconciliation Account (ECRA)**																					
4	Balance at Jan 1st	-	-	20,983	(34)	-	-	20,983	2,509	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
5																						
6	Energy Supply Costs ($)	-	88,674	179,544	213,050	268,218	88,674	392,594	749,530	1,525,683	3,883,377	5,874,797	7,715,448	8,744,520	10,246,904	12,478,485	13,445,924	14,155,828	14,736,955	15,197,668	15,750,478	16,101,731
7	Energy Charges	-	(67,861)	(200,802)	(210,583)	(268,663)	(67,861)	(411,385)	(752,039)	(1,525,683)	(3,883,377)	(5,874,797)	(7,715,448)	(8,744,520)	(10,246,904)	(12,478,485)	(13,445,924)	(14,155,828)	(14,736,955)	(15,197,668)	(15,750,478)	(16,101,731)
8	Financing Costs	-	170	241	76	411	170	318	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Adjustments	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Net Additions	-	20,983	(21,017)	2,543	(34)	20,983	(18,473)	(2,509)	-	-	-	-	-	-	-	-	-	-	0	-	-
11																						
12	Amortization	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Balance at Dec 31st	-	20,983	(34)	2,509	(34)	20,983	2,509	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
14																						
15	**Mid-Year Balance - ECRA**						**10,491**	**11,746**	**1,255**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 11 - Cost of Capital and Return on Rate Base

Line No.		Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1	Deemed Capital Structure																					
2	Debt Ratio (Debt %)	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
3	Equity Ratio (Equity %)	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
4	Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5																						
6	Cost of Capital - Rates																					
7	Debt Interest Rate	7.49%	7.49%	7.49%	7.49%	7.49%	7.49%	7.49%	7.29%	7.24%	7.31%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%	6.85%
8	Return on Equity (Allowed)	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%	10.50%
9																						
10	**Mid-Year Rate Base ($)[2]**	**-**	**5.525.907**	**31.577.557**	**31.577.557**	**23.946.148**	**5.525.907**	**31.577.557**	**39.238.781**	**64.553.784**	**114.767.984**	**156.975.573**	**175.120.324**	**177.437.905**	**210.201.964**	**244.396.744**	**241.014.873**	**249.259.544**	**254.643.861**	**244.249.484**	**233.859.199**	**218.199.489**
11																						
12	**Utah City District Energy Utility Cost of Capital**																					
13	Capital Financing																					
14	Debt ($)	-	2,762,953	15,788,778	15,788,778	11,973,074	2,762,953	15,788,778	19,619,390	32,276,892	57,383,992	78,487,786	87,560,162	88,718,952	105,100,982	122,198,372	120,507,436	124,629,772	127,321,930	122,124,742	116,929,600	109,099,745
15	Equity ($)	-	2,762,953	15,788,778	15,788,778	11,973,074	2,762,953	15,788,778	19,619,390	32,276,892	57,383,992	78,487,786	87,560,162	88,718,952	105,100,982	122,198,372	120,507,436	124,629,772	127,321,930	122,124,742	116,929,600	109,099,745
16	**Total Capital Financing**	**-**	**5,525,907**	**31,577,557**	**31,577,557**	**23,946,148**	**5,525,907**	**31,577,557**	**39,238,781**	**64,553,784**	**114,767,984**	**156,975,573**	**175,120,324**	**177,437,905**	**210,201,964**	**244,396,744**	**241,014,873**	**249,259,544**	**254,643,861**	**244,249,484**	**233,859,199**	**218,199,489**
17																						
18	Cost of Capital ($)																					
19	Interest on Debt ($)	-	206,945	689,838	492,741	896,783	206,945	1,182,579	1,430,254	2,336,847	4,194,770	5,376,413	5,997,871	6,077,248	7,199,417	8,370,588	8,254,759	8,537,139	8,721,552	8,365,545	8,009,678	7,473,332
20	Return on Equity ($)	-	290,110	967,063	690,759	1,257,173	290,110	1,657,822	2,060,036	3,389,074	6,025,319	8,241,218	9,193,817	9,315,490	11,035,603	12,830,829	12,653,281	13,086,126	13,368,803	12,823,098	12,277,608	11,455,473
21	**Total Cost of Capital on Rate Base**	**-**	**497,055**	**1,656,901**	**1,183,501**	**2,153,956**	**497,055**	**2,840,401**	**3,490,290**	**5,725,921**	**10,220,089**	**13,617,631**	**15,191,688**	**15,392,738**	**18,235,020**	**21,201,418**	**20,908,040**	**21,623,265**	**22,090,355**	**21,188,643**	**20,287,286**	**18,928,806**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.
2) Mid-Year Rate Base for the Test Year represents a weighted average of the rate base for 2026 and 2027, reflecting the August 1, 2026 to July 31, 2027 Test Year period.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 12 - Operation & Maintenance Expenses

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	**Operation & Maintenance Expenses**																					
3																						
4	**Thermal Production - Operation**																					
5	Operation Supervision & Labor	-	67,833	113,928	81,377	181,761	67,833	195,305	201,164	279,809	619,410	637,992	657,132	676,846	949,677	978,167	1,007,512	1,313,679	1,606,858	1,655,063	1,704,715	1,755,857
6	Supplies and expenses																					
7	Thermal Production Expenses																					
8	**Total Thermal Production - Operation (excluding Energy Supply Costs)**	**-**	**67,833**	**113,928**	**81,377**	**181,761**	**67,833**	**195,305**	**201,164**	**279,809**	**619,410**	**637,992**	**657,132**	**676,846**	**949,677**	**978,167**	**1,007,512**	**1,313,679**	**1,606,858**	**1,655,063**	**1,704,715**	**1,755,857**
9																						
10	**Thermal Production - Maintenance**																					
11	Maintenance Supervision & Labor	-	9,690	16,275	11,625	25,966	9,690	27,901	28,738	39,973	88,487	91,142	93,876	96,692	135,668	139,738	143,930	187,668	229,551	236,438	243,531	250,837
12	Maintenance of Structures and Improvements	-	-	6,889	4,920	6,889	-	11,809	11,809	11,809	28,398	55,805	67,614	67,614	67,614	115,025	142,433	144,512	189,433	189,433	223,893	241,481
13	Maintenance Heating	-	-	1,850	1,321	1,850	-	3,172	3,172	3,172	7,675	12,339	20,371	20,371	20,371	35,423	40,088	45,052	50,860	50,860	61,593	66,287
14	Maintenance Cooling	-	-	5,086	3,633	5,086	-	8,719	12,479	12,479	31,362	49,888	77,910	81,670	81,670	142,451	160,977	180,646	199,983	203,743	246,627	266,480
15	Maintenance of Other Production Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	**Total Production - Maintenance**	**-**	**9,690**	**30,100**	**21,500**	**39,791**	**9,690**	**51,600**	**56,197**	**67,432**	**155,922**	**209,175**	**259,771**	**266,347**	**305,323**	**432,638**	**487,428**	**557,877**	**669,827**	**680,474**	**775,643**	**825,084**
17																						
18	**Miscellaneous Production Expenses**																					
19	Production - Rents																					
20	Joint Expenses - Credit																					
21	**Total Miscellaneous Production Expenses**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																						
23	**Total Thermal Production Expenses**	**-**	**77,523**	**144,028**	**102,877**	**221,551**	**77,523**	**246,905**	**257,361**	**347,241**	**775,332**	**847,167**	**916,903**	**943,193**	**1,255,000**	**1,410,805**	**1,494,940**	**1,871,557**	**2,276,685**	**2,335,537**	**2,480,358**	**2,580,941**
24																						
25	**Distribution - Operation**																					
26	Operation Supervision & Labor	-	9,690	16,275	11,625	25,966	9,690	27,901	28,738	39,973	88,487	91,142	93,876	96,692	135,668	139,738	143,930	187,668	229,551	236,438	243,531	250,837
27	Mains & Services																					
28	Meter expenses.																					
29	Customer installations expenses.																					
30	Miscellaneous distribution expenses																					
31	Transportation																					
32	Distribution Operation - Rents																					
33	**Total Distribution - Operation**	**-**	**9,690**	**16,275**	**11,625**	**25,966**	**9,690**	**27,901**	**28,738**	**39,973**	**88,487**	**91,142**	**93,876**	**96,692**	**135,668**	**139,738**	**143,930**	**187,668**	**229,551**	**236,438**	**243,531**	**250,837**
34																						
35	**Distribution - Maintenance**																					
36	Maintenance Supervision & Labor	-	9,690	16,275	11,625	25,966	9,690	27,901	28,738	39,973	88,487	91,142	93,876	96,692	135,668	139,738	143,930	187,668	229,551	236,438	243,531	250,837
37	Maintenance of Structures and Improvements																					
38	Maintenance of Mains & Services	-	-	5,226	3,733	5,226	-	8,959	14,790	18,231	32,533	52,825	77,820	98,493	108,625	140,459	176,976	200,397	230,031	246,436	276,216	314,022
39	Maintenance of Meters and Accessory Equipment																					
40	Maintenance of other equipment																					
41	Maintenance Operation Rents																					
42	**Total Distribution Maintenance**	**-**	**9,690**	**21,501**	**15,358**	**31,192**	**9,690**	**36,859**	**43,528**	**58,204**	**121,020**	**143,967**	**171,696**	**195,185**	**244,293**	**280,197**	**320,906**	**388,066**	**459,582**	**482,874**	**519,747**	**564,859**
43																						
44	**Total Distribution Expenses**	**-**	**19,381**	**37,777**	**26,983**	**57,158**	**19,381**	**64,760**	**72,266**	**98,177**	**209,507**	**235,108**	**265,572**	**291,878**	**379,961**	**419,935**	**464,836**	**575,734**	**689,133**	**719,311**	**763,278**	**815,696**
45																						
46	**Customer Accounts Expenses Operation**																					
47	Supervision & Labor																					
48	Meter Reading Expenses																					
49	Customer Records and Collection Expense																					
50	Uncollectible Accounts																					
51	Miscellaneous Customer Accounts Expense																					
52	Customer Billing System	-	487	1,691	1,676	2,178	487	3,367	5,127	8,503	17,177	14,151	17,092	18,712	20,748	23,742	25,038	26,097	26,799	27,592	28,614	29,397
53	**Total Customer Accounts Expenses**	**-**	**487**	**1,691**	**1,676**	**2,178**	**487**	**3,367**	**5,127**	**8,503**	**17,177**	**14,151**	**17,092**	**18,712**	**20,748**	**23,742**	**25,038**	**26,097**	**26,799**	**27,592**	**28,614**	**29,397**
54																						
55	**Customer Service Expenses Operation**																					
56	Supervision & Labor																					
57	Information Advertising Expenses																					
58	Miscellaneous Customer Services Expenses																					
59	**Total Customer Service Expenses**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60																						
61	**Sales Expenses Operation**																					
62	Supervision & Labor																					
63	Demonstrating and Selling Expenses																					
64	Advertising Expenses																					
65	Miscellaneous Sales Expenses																					
66	**Total Sales Expenses**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67																						
68	**Administrative and General Expenses Operation**																					
69	Administrative and General Salaries (not included elsewhere)	-	36,163	65,183	46,559	101,346	36,163	111,742	115,095	118,547	122,104	125,767	129,540	133,426	137,429	141,552	145,798	150,172	154,677	159,318	164,097	169,020
70	Office Supplies and Expenses	-	20,833	30,625	21,875	51,458	20,833	52,500	55,125	57,881	59,039	60,220	61,424	62,653	63,906	65,184	66,487	67,817	69,173	70,557	71,968	73,407
71	Other Administrative Expenses																					
72	Outside Services																					
73	Insurance	-	66,692	62,446	44,604	129,138	66,692	107,051	130,064	237,252	383,868	486,307	524,683	546,708	800,767	852,919	887,892	1,058,064	1,087,745	1,143,945	1,202,253	1,241,684
74	Injuries and Damages																					
75	Employee Pensions and Benefits																					
76	Regulatory Commission Expenses																					
77	External Regulatory Costs	-	-	45,845	32,747	45,845	-	78,592	82,355	86,299	89,786	93,413	97,187	101,113	105,198	109,448	113,870	118,470	123,256	128,236	133,417	138,807
78	**Total Administrative and General Expenses Operation**	**-**	**123,688**	**204,099**	**145,785**	**327,787**	**123,688**	**349,885**	**382,639**	**499,980**	**654,797**	**765,707**	**812,834**	**843,900**	**1,107,300**	**1,169,102**	**1,214,047**	**1,394,523**	**1,434,853**	**1,502,055**	**1,571,735**	**1,622,918**
79																						
80	**Regional Operations Allocated Costs**																					
81	Regulatory Affairs	90,599	64,713	92,900	66,357	157,613	155,312	159,257	182,991	196,053	202,770	208,853	215,119	221,572	228,219	235,066	242,118	249,382	256,863	264,569	272,506	280,681
82	Health, Safety and Environment	10,952	7,823	10,310	7,365	18,133	18,775	17,675	18,313	18,883	19,496	43,662	44,972	46,321	73,479	75,683	77,954	80,292	82,701	85,182	87,738	90,370
83	Financing Planning & Analysis & Accounts Payable	91,712	65,508	121,027	86,448	186,535	157,220	207,474	238,705	246,262	254,578	275,578	283,845	320,714	330,335	340,245	350,453	360,966	371,795	382,949	394,438	406,271
84	Business Operations (split out customer service 90x)	40,325	28,803	37,782	26,987	66,585	69,128	64,769	66,867	69,122	71,527	109,045	112,316	153,212	157,808	162,542	167,419	172,441	177,614	182,943	188,431	194,084
85	Billing and Customer Care	3,646	2,605	3,578	2,555	6,182	6,251	6,133	6,344	6,567	6,805	35,307	46,081	64,976	90,116	92,820	117,474	149,156	153,631	158,239	162,987	167,876
86	Operations Leadership and Strategy	72,830	52,022	66,461	47,472	118,483	124,852	113,933	114,639	120,533	121,561	125,208	128,964	132,833	136,818	140,923	145,150	149,505	153,990	158,610	163,368	168,269
87	Project Management Office	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	**Total Regional Operations Allocated Costs**	**310,064**	**221,474**	**332,057**	**237,184**	**553,531**	**531,538**	**569,241**	**627,859**	**657,420**	**676,737**	**797,653**	**831,298**	**939,628**	**1,016,776**	**1,047,279**	**1,100,567**	**1,161,742**	**1,196,594**	**1,232,492**	**1,269,467**	**1,307,551**
89																						
90	**Corporate Allocated Costs**																					
91	People and Culture	29,860	21,329	24,112	17,223	45,441	51,188	41,335	53,137	56,056	60,807	62,631	64,510	66,446	68,439	70,492	72,607	74,785	77,029	79,340	81,720	84,171
92	IT, OT & Cybersecurity	88,221	63,015	95,920	68,514	158,935	151,236	164,434	247,929	254,875	300,400	309,412	318,694	328,255	338,103	348,246	358,693	369,454	380,537	391,954	403,712	415,824
93	Communications	30,703	21,930	31,929	22,806	53,859	52,633	54,735	95,955	103,291	123,797	127,511	131,337	135,277	139,335	143,515	147,821	152,255	156,823	161,528	166,373	171,365
94	Legal, Technical Safety & Compliance	49,378	35,270	53,892	38,494	89,162	84,648	92,386	141,365	152,012	181,981	187,440	193,063	198,855	204,821	210,965	217,294	223,813	230,528	237,444	244,567	251,904
95	Corporate Finance & Accounting	99,602	71,144	102,337	73,098	173,481	170,745	175,435	268,555	288,893	345,967	356,346	367,036	378,048	389,389	401,071	413,103	425,496	438,261	451,409	464,951	478,899
96	Executive Management	106,961	76,401	105,759	75,542	182,160	183,362	181,301	274,876	294,756	351,966	362,525	373,400	384,602	396,140	408,025	420,265	432,873	445,860	459,235	473,012	487,203
97	Corporate Development	31,090	22,207	37,436	26,740	59,643	53,298	64,176	98,597	106,137	127,211	131,028	134,959	139,007	143,178	147,473	151,897	156,454	161,148	165,982	170,962	176,090
98	**Total Corporate Allocated Costs**	**435,815**	**311,296**	**451,384**	**322,417**	**762,680**	**747,111**	**773,801**	**1,180,415**	**1,256,020**	**1,492,129**	**1,536,893**	**1,583,000**	**1,630,490**	**1,679,405**	**1,729,787**	**1,781,680**	**1,835,131**	**1,890,185**	**1,946,890**	**2,005,297**	**2,065,456**
99																						
100	Administrative Expenses Transfer - Credit																					
101	Duplicate Charges - Credit																					
102	General Advertising Expenses																					
103	Miscellaneous General Expenses																					
104	Rents	-	28,175	28,842	20,601	57,017	28,175	49,443	50,613	51,811	52,847	53,904	54,982	56,082	57,203	58,347	59,514	60,705	61,919	63,157	64,420	65,709
105																						
106	**Total Administrative and General Expenses**	**745,878**	**684,633**	**1,016,382**	**725,987**	**1,701,015**	**1,430,511**	**1,742,369**	**2,241,526**	**2,465,231**	**2,876,510**	**3,154,157**	**3,282,114**	**3,470,100**	**3,860,684**	**4,004,516**	**4,155,810**	**4,452,101**	**4,583,550**	**4,744,595**	**4,910,919**	**5,061,633**
107																						
108	**Total Operation**	**745,878**	**782,025**	**1,199,877**	**857,524**	**1,981,902**	**1,527,903**	**2,057,401**	**2,576,280**	**2,919,152**	**3,878,527**	**4,250,583**	**4,481,680**	**4,723,882**	**5,516,393**	**5,858,998**	**6,140,624**	**6,925,489**	**7,576,167**	**7,827,034**	**8,183,169**	**8,487,666**
109																						
110	**Maintenance**																					
111	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	**Total Maintenance**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113																						
114	**Adjustments for Delivery Revenue requirement Calculation**																					
115	Regional Services Adjustments for RDDA (Allowed Costs)	(310,064)	(110,737)	(166,029)	(118,592)	(276,766)	(420,801)	(284,621)	(313,930)	(328,710)	(169,184)	(199,413)	-	-	-	-	-	-	-	-	-	-
116	Corporate Services Adjustments for RDDA (Allowed Costs)	(435,815)	(181,124)	(262,074)	(187,196)	(443,199)	(616,939)	(449,271)	(687,074)	(734,386)	(569,438)	(586,521)	(277,822)	(286,156)	(294,741)	(303,583)	(312,691)	(322,071)	(331,734)	(341,686)	(351,936)	(362,494)
117	**Total Adjustments for Delivery Revenue requirement Calculation**	**(745,878)**	**(291,862)**	**(428,103)**	**(305,788)**	**(719,965)**	**(1,037,740)**	**(733,891)**	**(1,001,004)**	**(1,063,096)**	**(738,622)**	**(785,934)**	**(277,822)**	**(286,156)**	**(294,741)**	**(303,583)**	**(312,691)**	**(322,071)**	**(331,734)**	**(341,686)**	**(351,936)**	**(362,494)**

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 12 - Operation & Maintenance Expenses

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
118																						
119																						
120	**Total Operation and Maintenance Expenses**	**-**	**490,163**	**771,774**	**551,736**	**1,261,937**	**490,163**	**1,323,510**	**1,575,276**	**1,856,056**	**3,139,905**	**3,464,649**	**4,203,859**	**4,437,726**	**5,221,652**	**5,555,414**	**5,827,934**	**6,603,418**	**7,244,433**	**7,485,349**	**7,831,232**	**8,125,172**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.
(4) Total Direct Labor (Recoverable) reported in Schedule 13 is reconciled to this schedule as the sum of lines 5, 11, 26, 36, and 69.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 13 - Employee and Direct Labor Breakdown

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	**Employee Costs**																					
3	Salaries & Wages	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Overtime	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Pensions and Benefits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Incentive Plan: Short-Term	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Incentive Plan: Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Total Employee Costs**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Less Non-recoverable Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	**Total Employee Costs (Recoverable)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11																						
12	**Direct Labor**																					
13	Salaries & Wages	-	98,125	168,083	120,059	266,208	98,125	288,143	296,787	382,181	742,554	764,831	787,776	811,409	1,101,773	1,134,826	1,168,871	1,494,627	1,806,795	1,860,999	1,916,829	1,974,334
14	Overtime	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Pensions and Benefits	-	27,966	47,904	34,217	75,869	27,966	82,121	84,584	108,922	211,628	217,977	224,516	231,252	314,005	323,426	333,128	425,969	514,937	530,385	546,296	562,685
16	Incentive Plan: Short-Term	-	6,976	11,950	8,536	18,926	6,976	20,486	21,100	27,172	52,793	54,376	56,008	57,688	78,332	80,682	83,102	106,262	128,456	132,310	136,279	140,367
17	Incentive Plan: Long-Term	-	3,488	5,975	4,268	9,463	3,488	10,243	10,550	13,586	26,396	27,188	28,004	28,844	39,166	40,341	41,551	53,131	64,228	66,155	68,140	70,184
18	**Total Direct Labor**	-	136,555	233,912	167,080	370,467	136,555	400,992	413,022	531,860	1,033,371	1,064,373	1,096,304	1,129,193	1,533,276	1,579,275	1,626,653	2,079,988	2,514,416	2,589,849	2,667,544	2,747,571
19	Less Non-recoverable Portion	-	3,488	5,975	4,268	9,463	3,488	10,243	10,550	13,586	26,396	27,188	28,004	28,844	39,166	40,341	41,551	53,131	64,228	66,155	68,140	70,184
20	**Total Direct Labor (Recoverable)**	-	133,067	227,937	162,812	361,004	133,067	390,749	402,471	518,275	1,006,975	1,037,184	1,068,300	1,100,349	1,494,110	1,538,934	1,585,102	2,026,857	2,450,188	2,523,694	2,599,405	2,677,387
21																						
22																						

Notes

1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

(2) Employees represent staff hired by Corix Utah City Heating and Cooling LLC.

(3) Corix does not seek recovery of Long-Term Incentive Plan (LTIP) costs from regulated utilities, whether as operating expenses or capitalized costs.

(4) Total Direct Labor (Recoverable) reconciles to Schedule 12 as the sum of lines 5, 11, 26, 36, and 69.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 14 - Energy Supply Costs

Line No.	*All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1	**Energy Supply Costs**																					
2	Electricity	-	24,769	72,597	71,681	97,367	24,769	144,278	298,094	606,359	1,627,552	2,438,949	3,224,088	3,632,868	4,277,979	5,192,739	5,580,859	5,876,645	6,121,230	6,310,779	6,541,565	6,688,897
3	Natural Gas	-	58,368	86,462	123,867	144,830	58,368	210,329	373,634	764,038	1,837,017	2,814,738	3,671,728	4,193,227	4,883,274	5,974,580	6,459,351	6,795,898	7,070,711	7,294,605	7,558,633	7,725,220
4	Water	-	1,255	5,981	5,368	7,236	1,255	11,350	23,026	46,775	128,882	192,170	254,797	286,231	337,909	409,430	439,437	462,817	482,205	497,060	515,280	526,942
5	Sewer	-	2,406	9,200	8,064	11,606	2,406	17,265	35,026	71,152	196,047	292,317	387,583	435,398	514,008	622,801	668,446	704,011	733,502	756,098	783,814	801,554
6	Chemicals, Safety & Testing	-	1,877	5,302	4,070	7,179	1,877	9,372	19,750	37,359	93,879	136,624	177,250	196,795	233,734	278,934	297,831	316,457	329,308	339,127	351,187	359,119
7	**Total Energy Supply Costs ($)**	**-**	**88,674**	**179,544**	**213,050**	**268,218**	**88,674**	**392,594**	**749,530**	**1,525,683**	**3,883,377**	**5,874,797**	**7,715,448**	**8,744,520**	**10,246,904**	**12,478,485**	**13,445,924**	**14,155,828**	**14,736,955**	**15,197,668**	**15,750,478**	**16,101,731**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 15 - Income Tax and Tax Depreciation

Line No.	Utah City District Energy Utility *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1	**Earnings before tax**																					
2	Revenue, Energy charges	-	88,844	179,785	213,126	268,629	88,844	392,911	749,530	1,525,683	3,883,377	5,874,797	7,715,448	8,744,520	10,246,904	12,478,485	13,445,924	14,155,828	14,736,955	15,197,668	15,750,478	16,101,731
3	Revenue, Capacity charges	-	1,365,886	3,273,601	2,378,784	4,639,486	1,365,886	5,652,385	6,776,520	10,938,712	18,979,914	24,329,583	27,277,312	27,953,598	34,030,796	38,360,365	38,385,817	40,995,559	42,352,842	41,571,373	41,045,123	39,882,280
4	Total Revenues	-	1,454,729	3,453,386	2,591,910	4,908,116	1,454,729	6,045,296	7,526,050	12,464,395	22,863,291	30,204,380	34,992,759	36,698,118	44,277,700	50,838,851	51,831,741	55,151,387	57,089,798	56,769,041	56,795,602	55,984,011
5																						
6	Fuel and Electricity (consumables) costs	-	88,674	179,544	213,050	268,218	88,674	392,594	749,530	1,525,683	3,883,377	5,874,797	7,715,448	8,744,520	10,246,904	12,478,485	13,445,924	14,155,828	14,736,955	15,197,668	15,750,478	16,101,731
7	Operating Costs	745,878	782,025	1,200,071	857,662	1,982,095	1,527,903	2,057,732	2,577,657	2,920,867	3,881,367	4,255,792	4,488,563	4,731,856	5,524,755	5,869,087	6,152,209	6,937,299	7,588,733	7,840,043	8,196,104	8,500,608
8	Total Operating Costs	745,878	870,699	1,379,615	1,070,712	2,250,314	1,616,577	2,450,326	3,327,187	4,446,549	7,764,744	10,130,590	12,204,010	13,476,375	15,771,659	18,347,572	19,598,132	21,093,128	22,325,689	23,037,711	23,946,582	24,602,339
9																						
10	EBITDA	(745,878)	584,030	2,073,772	1,521,199	2,657,802	(161,848)	3,594,970	4,198,863	8,017,845	15,098,548	20,073,790	22,788,749	23,221,743	28,506,041	32,491,279	32,233,608	34,058,259	34,764,109	33,731,330	32,849,019	31,381,672
11																						
12	Depreciation	-	(299,391)	(583,628)	(456,907)	(883,020)	(299,391)	(1,040,535)	(1,154,535)	(2,439,304)	(3,991,382)	(5,020,124)	(5,397,601)	(5,604,464)	(7,584,245)	(8,131,560)	(8,223,332)	(9,221,085)	(9,393,306)	(9,417,124)	(9,590,427)	(9,709,902)
13	(+) CIAC Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	AFUDC Equity	626,860	102,675	70,359	73,492	173,034	729,535	143,851	777,319	1,190,554	800,868	256,218	294,928	1,568,988	387,908	193,606	870,294	166,548	161,306	183,687	135,169	53,639
15	AFUDC Interest Income	473,315	73,776	50,103	51,900	123,879	547,091	102,003	537,680	821,072	558,073	167,151	192,404	1,023,575	253,059	126,308	567,771	108,653	105,231	119,839	88,184	34,991
16	Interest	(473,315)	(280,721)	(739,941)	(544,641)	(1,020,662)	(754,036)	(1,284,582)	(1,967,934)	(3,157,919)	(4,752,843)	(5,543,564)	(6,190,275)	(7,100,823)	(7,452,476)	(8,496,896)	(8,822,530)	(8,645,792)	(8,826,783)	(8,485,384)	(8,097,862)	(7,508,323)
17																						
18	**Earnings before tax**	**(119,019)**	**180,369**	**870,664**	**645,042**	**1,051,033**	**61,351**	**1,515,706**	**2,391,394**	**4,432,248**	**7,713,264**	**9,933,470**	**11,688,204**	**13,109,018**	**14,110,287**	**16,182,736**	**16,625,811**	**16,466,583**	**16,810,556**	**16,132,348**	**15,384,083**	**14,252,077**
19																						
20																						
21	**Current Federal income tax payable**																					
22	Earnings before tax	(119,019)	180,369	870,664	645,042	1,051,033	61,351	1,515,706	2,391,394	4,432,248	7,713,264	9,933,470	11,688,204	13,109,018	14,110,287	16,182,736	16,625,811	16,466,583	16,810,556	16,132,348	15,384,083	14,252,077
23	**Deduct:** Deferral revenue	-	(996,786)	(2,516,582)	(1,628,872)	(3,513,368)	(996,786)	(4,145,454)	(4,228,621)	(6,044,535)	(6,743,598)	(5,937,663)	(3,199,945)	(673,405)	(2,123,151)	484,093	3,420,387	3,002,545	3,456,575	5,660,041	7,908,205	10,161,312
24	**Addback:** Unrecovered Expenses	745,878	291,862	428,103	305,788	719,965	1,037,740	733,891	1,001,004	1,063,096	738,622	785,934	277,822	286,156	294,741	303,583	312,691	322,071	331,734	341,686	351,936	362,494
25	**Addback:** Depreciation - AFUDC Equity	-	7,572	14,525	11,191	22,097	7,572	25,716	27,982	55,762	90,406	117,616	125,479	129,511	180,579	192,451	193,349	215,894	219,879	220,363	224,115	226,969
26	**Addback:** Depreciation - Non-AFUDC Equity	-	291,819	569,104	445,716	860,922	291,819	1,014,820	1,126,553	2,383,543	3,900,976	4,902,508	5,272,123	5,474,954	7,403,667	7,939,108	8,029,983	9,005,191	9,173,427	9,196,761	9,366,312	9,482,933
27	**Addback:** CIAC Amortization (negative)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Addback:** Interest Expense	473,315	280,721	739,941	544,641	1,020,662	754,036	1,284,582	1,967,934	3,157,919	4,752,843	5,543,564	6,190,275	7,100,823	7,452,476	8,496,896	8,822,530	8,645,792	8,826,783	8,485,384	8,097,862	7,508,323
29	**Deduct:** State income tax	-	(100)	-	-	(100)	(100)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	**Deduct:** AFUDC Equity Income	(626,860)	(102,675)	(70,359)	(73,492)	(173,034)	(729,535)	(143,851)	(777,319)	(1,190,554)	(800,868)	(256,218)	(294,928)	(1,568,988)	(387,908)	(193,606)	(870,294)	(166,548)	(161,306)	(183,687)	(135,169)	(53,639)
31	**Deduct:** AFUDC Interest Income	(473,315)	(73,776)	(50,103)	(51,900)	(123,879)	(547,091)	(102,003)	(537,680)	(821,072)	(558,073)	(167,151)	(192,404)	(1,023,575)	(253,059)	(126,308)	(567,771)	(108,653)	(105,231)	(119,839)	(88,184)	(34,991)
32	**Deduct:** Tax Depreciation	-	(3,485,455)	(3,657,961)	(3,331,816)	(7,143,416)	(3,485,455)	(6,989,777)	(6,377,510)	(10,719,593)	(20,902,550)	(27,202,053)	(26,017,936)	(20,677,729)	(26,254,503)	(33,125,161)	(27,696,369)	(25,130,743)	(22,084,788)	(18,536,326)	(17,476,394)	(12,973,317)
33	**Deduct:** Tax Interest Expense	-	-	-	-	-	-	-	-	(455,379)	(1,928,065)	(3,262,183)	(4,520,493)	(5,203,462)	(6,088,359)	(7,609,701)	(8,227,845)	(8,552,493)	(8,820,158)	(9,090,316)	(9,405,513)	(9,586,843)
34	Taxable Income before LCF	(0)	(3,606,448)	(3,672,669)	(3,133,702)	(7,279,117)	(3,606,448)	(6,806,371)	(5,406,265)	(8,138,566)	(13,737,044)	(15,542,175)	(10,671,803)	(3,046,698)	(5,665,231)	(7,455,908)	42,472	3,699,640	7,647,472	12,106,415	14,227,253	19,345,319
35	Tax Loss Carryforward (Utilized)	-	3,606,448	3,672,669	3,133,702	7,279,117	3,606,448	6,806,371	5,406,265	8,138,566	13,737,044	15,542,175	10,671,803	3,046,698	5,665,231	7,455,908	(33,977)	(2,959,712)	(6,117,978)	(9,685,132)	(11,381,802)	(15,476,256)
36	Taxable income after LCF	(0)	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	8,494	739,928	1,529,494	2,421,283	2,845,451	3,869,064
37	Tax Rate	0.0%	0.0%	0.0%	0.0%	0.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
38	**Current Federal income tax payable**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(0)**	**-**	**-**	**1,784**	**155,385**	**321,194**	**508,469**	**597,545**	**812,503**
39																						
40	**Federal Tax Loss Carryforward (LCF)**																					
41	Opening Balance	-	-	3,606,448	7,279,117	-	-	3,606,448	10,412,819	15,819,083	23,957,649	37,694,693	53,236,868	63,908,671	66,955,369	72,620,601	80,076,508	80,042,531	77,082,819	70,964,841	61,279,709	49,897,907
42	Additions	-	3,606,448	3,672,669	3,133,702	7,279,117	3,606,448	6,806,371	5,406,265	8,138,566	13,737,044	15,542,175	10,671,803	3,046,698	5,665,231	7,455,908	-	-	-	-	-	-
43	Losses Utilized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33,977)	(2,959,712)	(6,117,978)	(9,685,132)	(11,381,802)	(15,476,256)
44	**Closing Balance**	**-**	**3,606,448**	**7,279,117**	**10,412,819**	**7,279,117**	**3,606,448**	**10,412,819**	**15,819,083**	**23,957,649**	**37,694,693**	**53,236,868**	**63,908,671**	**66,955,369**	**72,620,601**	**80,076,508**	**80,042,531**	**77,082,819**	**70,964,841**	**61,279,709**	**49,897,907**	**34,421,651**
45																						
46	**Tax Pools**																					
47	Opening Balance																					
48	5-Year MACRS	-	-	36,358	27,874	-	-	36,358	21,815	13,089	52,655	29,499	50,923	42,048	22,649	140,813	95,044	95,197	169,540	108,010	190,730	140,697
49	7-Year MACRS	-	-	20,499,556	22,795,763	-	-	20,499,556	20,679,572	16,933,069	46,243,310	77,577,263	79,941,433	65,055,927	49,494,697	97,138,140	76,167,564	56,027,842	69,348,821	50,348,397	42,052,039	31,744,741
50	10-Year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	15-Year MACRS	-	-	1,112,956	1,048,033	-	-	1,112,956	1,001,660	901,494	2,385,081	2,146,515	1,931,887	1,735,206	1,551,281	1,378,836	1,211,975	1,044,996	877,969	710,991	543,963	376,985
52	20-year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53																						
54	Subtotal Opening Balance	-	-	21,648,869	23,871,670	-	-	21,648,869	21,703,047	17,847,652	48,681,047	79,753,276	81,924,243	66,833,181	51,068,626	98,657,788	77,474,583	57,168,036	70,396,330	51,167,398	42,786,733	32,262,422
55																						
56	Additions																					
57	5-Yr MACRS	-	45,447	-	-	45,447	45,447	-	-	56,002	-	43,492	14,369	-	161,449	15,701	50,420	141,147	17,157	165,284	36,406	77,197
58	7-Yr MACRS	-	23,917,344	5,880,762	1,163,192	29,798,107	23,917,344	7,043,955	2,522,116	39,840,358	51,974,779	29,329,526	10,912,506	4,913,175	73,682,216	11,926,255	7,339,401	38,217,890	2,838,698	9,990,377	6,915,678	3,824,993
59	10-Yr MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	15-Yr MACRS	-	1,171,532	-	-	1,171,532	1,171,532	-	-	1,656,627	-	-	-	-	-	-	-	-	-	-	-	-
61	20-Yr MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62																						
63	Subtotal Additions	-	25,134,324	5,880,762	1,163,192	31,015,086	25,134,324	7,043,955	2,522,116	41,552,987	51,974,779	29,373,019	10,926,875	4,913,175	73,843,665	11,941,956	7,389,821	38,359,037	2,855,855	10,155,661	6,952,084	3,902,191
64																						
65	Tax Deductions																					
66	5-Year MACRS	-	(9,089)	(8,484)	(6,060)	(17,573)	(9,089)	(14,543)	(8,726)	(16,436)	(23,156)	(22,069)	(23,243)	(19,400)	(43,285)	(61,469)	(50,267)	(66,805)	(78,687)	(82,564)	(86,439)	(79,965)
67	7-Year MACRS	-	(3,417,789)	(3,584,555)	(3,279,383)	(7,002,344)	(3,417,789)	(6,863,939)	(6,268,618)	(10,530,117)	(20,640,827)	(26,965,356)	(25,798,012)	(20,474,405)	(26,038,773)	(32,896,830)	(27,479,124)	(24,896,911)	(21,839,123)	(18,286,735)	(17,222,976)	(12,760,885)
68	10-Year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69	15-Year MACRS	-	(58,577)	(64,922)	(46,373)	(123,499)	(58,577)	(111,296)	(100,166)	(173,039)	(238,567)	(214,628)	(196,681)	(183,925)	(172,445)	(166,861)	(166,979)	(167,027)	(166,979)	(167,027)	(166,979)	(132,467)
70	20-year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71																						
72	Subtotal Tax Deductions	-	(3,485,455)	(3,657,961)	(3,331,816)	(7,143,416)	(3,485,455)	(6,989,777)	(6,377,510)	(10,719,593)	(20,902,550)	(27,202,053)	(26,017,936)	(20,677,729)	(26,254,503)	(33,125,161)	(27,696,369)	(25,130,743)	(22,084,788)	(18,536,326)	(17,476,394)	(12,973,317)
73																						
74	Tax Balance																					
75	5-Year MACRS	-	36,358	27,874	21,815	27,874	36,358	21,815	13,089	52,655	29,499	50,923	42,048	22,649	140,813	95,044	95,197	169,540	108,010	190,730	140,697	137,929
76	7-Year MACRS	-	20,499,556	22,795,763	20,679,572	22,795,763	20,499,556	20,679,572	16,933,069	46,243,310	77,577,263	79,941,433	65,055,927	49,494,697	97,138,140	76,167,564	56,027,842	69,348,821	50,348,397	42,052,039	31,744,741	22,808,849
77	10-Year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	15-Year MACRS	-	1,112,956	1,048,033	1,001,660	1,048,033	1,112,956	1,001,660	901,494	2,385,081	2,146,515	1,931,887	1,735,206	1,551,281	1,378,836	1,211,975	1,044,996	877,969	710,991	543,963	376,985	244,518
79	20-year MACRS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80																						
81	Subtotal Tax Balance	-	21,648,869	23,871,670	21,703,047	23,871,670	21,648,869	21,703,047	17,847,652	48,681,047	79,753,276	81,924,243	66,833,181	51,068,626	98,657,788	77,474,583	57,168,036	70,396,330	51,167,398	42,786,733	32,262,422	23,191,296
82																						

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 15 - Income Tax and Tax Depreciation

Line No.	Utah City District Energy Utility *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
83	**State Income Tax**																					
84	Federal taxable Income before NOL	(0)	(3,606,448)	(3,672,669)	(3,133,702)	(7,279,117)	(3,606,448)	(6,806,371)	(5,406,265)	(8,138,566)	(13,737,044)	(15,542,175)	(10,671,803)	(3,046,698)	(5,665,231)	(7,455,908)	42,472	3,699,640	7,647,472	12,106,415	14,227,253	19,345,319
85	**Addback:** Interest from state/territory bonds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	**Addback:** State, foreign, and Puerto Rico taxes deducted fec	-	100	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	**Addback:** Safe harbor lease adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	Taxable Income before LCF	(0)	(3,606,348)	(3,672,669)	(3,133,702)	(7,279,017)	(3,606,348)	(6,806,371)	(5,406,265)	(8,138,566)	(13,737,044)	(15,542,175)	(10,671,803)	(3,046,698)	(5,665,231)	(7,455,908)	42,472	3,699,640	7,647,472	12,106,415	14,227,253	19,345,319
89	Tax Loss Carryforward (Utilized)	-	-	-	-	-	3,606,348	6,806,371	5,406,265	8,138,566	13,737,044	15,542,175	10,671,803	3,046,698	5,665,231	7,455,908	(42,472)	(3,699,640)	(7,647,472)	(12,106,415)	(14,227,253)	(19,345,319)
90	Taxable income after LCF	(0)	(3,606,348)	(3,672,669)	(3,133,702)	(7,279,017)	-	-	-	-	-	-	-	(0)	-	-	(0)	0	-	0	-	-
91	Tax Rate	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
92	Current State income tax payable	-	100	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
93	Utah State HCITC	-	-	-	100	-	-	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
94	**Current State income tax payable**	**-**	**100**	**-**	**-**	**100**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
95																						
96	**Federal Tax Loss Carryforward (LCF)**																					
97	Opening Balance	-	-	3,606,448	7,279,117	-	-	3,606,448	10,412,819	15,819,083	23,957,649	37,694,693	53,236,868	63,908,671	66,955,369	72,620,601	80,076,508	80,042,531	77,082,819	70,964,841	61,279,709	49,897,907
98	Additions	-	3,606,348	3,672,669	3,133,702	7,279,017	3,606,348	6,806,371	5,406,265	8,138,566	13,737,044	15,542,175	10,671,803	3,046,698	5,665,231	7,455,908	-	-	-	-	-	-
99	Losses Utilized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33,977)	(2,959,712)	(6,117,978)	(9,685,132)	(11,381,802)	(15,476,256)
100	**Closing Balance**	**-**	**3,606,348**	**7,279,117**	**10,412,819**	**7,279,017**	**3,606,348**	**10,412,819**	**15,819,083**	**23,957,649**	**37,694,693**	**53,236,868**	**63,908,671**	**66,955,369**	**72,620,601**	**80,076,508**	**80,042,531**	**77,082,819**	**70,964,841**	**61,279,709**	**49,897,907**	**34,421,651**
101																						
102	**Deferred income tax**																					
103	Net Plant in Service Temporary diff.																					
104	Total Tax Basis - Net Plant in Service	-	21,648,869	23,871,670	21,703,047	23,871,670	21,648,869	21,703,047	17,847,652	48,681,047	79,753,276	81,924,243	66,833,181	51,068,626	98,657,788	77,474,583	57,168,036	70,396,330	51,167,398	42,786,733	32,262,422	23,191,296
105	Total Accounting Basis - Net Plant in Service	-	24,842,505	30,154,164	30,871,640	30,154,164	24,842,505	30,871,640	32,267,204	71,436,648	119,510,451	143,980,962	149,635,714	149,073,935	215,513,933	219,516,781	218,876,620	248,230,466	241,912,894	242,871,794	240,457,565	234,876,823
106	Tax/Accounting Basis Difference - Net Plant in Service	-	(3,193,636)	(6,282,494)	(9,168,594)	(6,282,494)	(3,193,636)	(9,168,594)	(14,419,551)	(22,755,601)	(39,757,175)	(62,056,720)	(82,802,533)	(98,005,309)	(116,856,145)	(142,042,198)	(161,708,584)	(177,834,136)	(190,745,497)	(200,085,061)	(208,195,143)	(211,685,526)
107	Deferred Tax Liability - Net Plant in Service	-	670,664	1,319,324	1,925,405	1,319,324	670,664	1,925,405	3,028,106	4,778,676	8,349,007	13,031,911	17,388,532	20,581,115	24,539,790	29,828,862	33,958,803	37,345,169	40,056,554	42,017,863	43,720,980	44,453,961
108																						
109	Deferral Revenue Temporary diff.																					
110	Accounting Basis - Deferral Revenue	-	996,786	3,513,368	5,142,240	3,513,368	996,786	5,142,240	9,370,861	15,415,396	22,158,994	28,096,657	31,296,602	31,970,008	34,093,158	33,609,066	30,188,679	27,186,133	23,729,558	18,069,517	10,161,312	(0)
111	Tax Basis - Deferral Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Tax/Accounting Basis Difference - Deferral Revenue	-	(996,786)	(3,513,368)	(5,142,240)	(3,513,368)	(996,786)	(5,142,240)	(9,370,861)	(15,415,396)	(22,158,994)	(28,096,657)	(31,296,602)	(31,970,008)	(34,093,158)	(33,609,066)	(30,188,679)	(27,186,133)	(23,729,558)	(18,069,517)	(10,161,312)	0
113	Deferred Tax Liability - Deferral Revenue	-	209,325	737,807	1,079,870	737,807	209,325	1,079,870	1,967,881	3,237,233	4,653,389	5,900,298	6,572,286	6,713,702	7,159,563	7,057,904	6,339,623	5,709,088	4,983,207	3,794,599	2,133,875	(0)
114																						
115	Net Operating Losses Temporary diff.																					
116	Deferred Income Tax Asset - NOL	-	3,606,448	7,279,117	10,412,819	7,279,117	3,606,448	10,412,819	15,819,083	23,957,649	37,694,693	53,236,868	63,908,671	66,955,369	72,620,601	80,076,508	80,042,531	77,082,819	70,964,841	61,279,709	49,897,907	34,421,651
117	Accounting Basis - NOL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
118	Tax Basis - NOL	-	3,606,448	7,279,117	10,412,819	7,279,117	3,606,448	10,412,819	15,819,083	23,957,649	37,694,693	53,236,868	63,908,671	66,955,369	72,620,601	80,076,508	80,042,531	77,082,819	70,964,841	61,279,709	49,897,907	34,421,651
119	Deferred Tax Asset - NOL	-	(757,354)	(1,528,615)	(2,186,692)	(1,528,615)	(757,354)	(2,186,692)	(3,322,008)	(5,031,106)	(7,915,886)	(11,179,742)	(13,420,821)	(14,060,628)	(15,250,326)	(16,816,067)	(16,808,931)	(16,187,392)	(14,902,617)	(12,868,739)	(10,478,560)	(7,228,547)
120																						
121	Interest Expense Temporary diff.																					
122	Total Tax Basis - Interest Expense	-	206,945	896,783	1,389,525	896,783	206,945	1,389,525	2,819,778	4,701,246	6,967,950	9,082,181	10,559,558	11,433,344	12,544,402	13,305,290	13,332,204	13,316,850	13,218,244	12,493,473	11,097,637	8,984,127
123	Total Accounting Basis - Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
124	Total Tax Basis - Interest Expense	-	206,945	896,783	1,389,525	896,783	206,945	1,389,525	2,819,778	4,701,246	6,967,950	9,082,181	10,559,558	11,433,344	12,544,402	13,305,290	13,332,204	13,316,850	13,218,244	12,493,473	11,097,637	8,984,127
125	Deferred Tax Asset - Interest Expense Closing Balance	-	(43,458)	(188,324)	(291,800)	(188,324)	(43,458)	(291,800)	(592,153)	(987,262)	(1,463,270)	(1,907,258)	(2,217,507)	(2,401,002)	(2,634,324)	(2,794,111)	(2,799,763)	(2,796,538)	(2,775,831)	(2,623,629)	(2,330,504)	(1,886,667)
126																						
127	Deferred Tax allowance	-	79,176	261,104	186,503	340,280	79,176	447,607	555,043	915,716	1,625,699	2,221,969	2,477,281	2,510,696	2,981,517	3,461,885	3,413,143	3,380,595	3,290,987	2,958,780	2,725,698	2,292,956
128																						
129	Total Income tax allowance	-	79,276	261,104	186,503	340,380	79,276	447,607	555,043	915,716	1,625,699	2,221,969	2,477,281	2,510,696	2,981,517	3,461,885	3,414,927	3,535,980	3,612,181	3,467,249	3,323,243	3,105,459

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 16 - Build-out, Peak Load and Energy Demand Summary

Line No.		Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2	**Number of Connections**	-	2	5	5	5	2	5	6	14	25	33	40	42	50	57	59	60	60	62	63	63
3																						
4	**Floor Area**																					
5	General Service																					
6	Residential (ft^2)	-	416,776	698,674	698,674	698,674	416,776	698,674	970,864	3,101,560	6,008,560	8,258,560	10,150,560	10,687,560	12,854,560	14,805,560	15,210,560	15,740,560	15,740,560	16,192,560	16,192,560	16,192,560
7	Grocery (ft^2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60,000	60,000
8	Pool (ft^2)	-	-	26,896	26,896	26,896	-	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896	26,896
9	Retail (ft^2)	-	8,224	11,796	11,796	11,796	8,224	11,796	11,796	38,396	95,916	196,336	211,876	211,876	242,456	287,296	290,796	366,876	366,876	366,876	366,876	366,876
10	Large Office (ft^2)	-	-	-	-	-	-	-	-	-	-	250,000	375,000	375,000	700,000	1,075,000	1,075,000	1,075,000	1,075,000	1,075,000	1,075,000	1,075,000
11	Hotel/Hospitality (ft^2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	General Service (ft^2)	-	425,000	737,366	737,366	737,366	425,000	737,366	1,009,556	3,166,852	6,131,372	8,731,792	10,764,332	11,301,332	13,823,912	16,194,752	16,603,252	17,209,332	17,209,332	17,661,332	17,721,332	17,721,232
13																						
14	**Total Floor Area (ft^2)**	**-**	**425,000**	**737,366**	**737,366**	**737,366**	**425,000**	**737,366**	**1,009,556**	**3,166,852**	**6,131,372**	**8,731,792**	**10,764,332**	**11,301,332**	**13,823,912**	**16,194,752**	**16,603,252**	**17,209,332**	**17,209,332**	**17,661,332**	**17,721,332**	**17,721,232**
15																						
16	**Peak Load - Heating (Space Heating and DHW)**																					
17	Peak Load - Heating: General Service (MW)																					
18	Cumulative Peak Load - Heating: Residential (MW)	-	3.8	3.8	5.1	3.8	3.8	5.1	6.4	16.3	29.8	40.2	49.0	51.5	61.6	70.6	72.5	75.0	75.0	77.1	77.1	77.1
19	Cumulative Peak Load - Heating: Grocery (MW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3
20	Cumulative Peak Load - Heating: Pool (MW)	-	-	0.3	0.3	0.3	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
21	Cumulative Peak Load - Heating: Retail (MW)	-	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.2	0.4	0.9	1.0	1.0	1.1	1.3	1.4	1.7	1.7	1.7	1.7	1.7
22	Cumulative Peak Load - Heating: Large Office (MW)	-	-	-	-	-	-	-	-	-	-	1.2	1.7	1.7	3.3	5.0	5.0	5.0	5.0	5.0	5.0	5.0
23	Cumulative Peak Load - Heating: Hotel/Hospitality (MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Cumulative Peak Load - Heating: General Service (MW)	-	3.8	4.2	5.5	4.2	3.8	5.5	6.7	16.8	30.5	42.6	52.1	54.5	66.3	77.3	79.2	82.0	82.0	84.1	84.4	84.4
25																						
26	Cumulative Peak Load - Heating: Total (MW)	-	3.8	4.2	5.5	4.2	3.8	5.5	6.7	16.8	30.5	42.6	52.1	54.5	66.3	77.3	79.2	82.0	82.0	84.1	84.4	84.4
27																						
28	Diversification Factor	NA	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
29	**Diversified Cumulative Peak Load - Heating (MW)**	**-**	**2.7**	**2.9**	**3.8**	**2.9**	**2.7**	**3.8**	**4.7**	**11.7**	**21.4**	**29.8**	**36.4**	**38.2**	**46.4**	**54.1**	**55.4**	**57.4**	**57.4**	**58.9**	**59.1**	**59.1**
30	**Heating Installed Capacity (MW)**	**-**	**5.3**	**5.3**	**5.3**	**5.3**	**5.3**	**5.3**	**5.3**	**16.4**	**27.1**	**37.7**	**37.7**	**37.7**	**59.1**	**59.1**	**59.1**	**64.0**	**64.0**	**64.0**	**64.0**	**64.0**
31																						
32	**Peak Load - Cooling (Space Cooling)**																					
33	Peak Load - Cooling: Residential (MW)																					
34	Cumulative Peak Load - Cooling: Residential (MW)	-	2.7	2.7	4.5	2.7	2.7	4.5	6.3	20.2	39.1	53.7	66.0	69.5	83.6	96.3	98.9	102.4	102.4	105.3	105.3	105.3
35	Cumulative Peak Load - Cooling: Grocery (MW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4
36	Cumulative Peak Load - Cooling: Pool (MW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Cumulative Peak Load - Cooling: Retail (MW)	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.6	1.3	1.4	1.4	1.6	1.9	1.9	2.4	2.4	2.4	2.4	2.4
38	Cumulative Peak Load - Cooling: Large Office (MW)	-	-	-	-	-	-	-	-	-	-	1.6	2.4	2.4	4.6	7.0	7.0	7.0	7.0	7.0	7.0	7.0
39	Cumulative Peak Load - Cooling: Hotel/Hospitality (MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Cumulative Peak Load - Cooling: General Service (MW)	-	2.8	2.8	4.6	2.8	2.8	4.6	6.4	20.4	39.7	56.6	69.8	73.3	89.7	105.1	107.8	111.7	111.7	114.7	115.1	115.1
41		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Cumulative Peak Load - Cooling: Total (MW)	-	2.8	2.8	4.6	2.8	2.8	4.6	6.4	20.4	39.7	56.6	69.8	73.3	89.7	105.1	107.8	111.7	111.7	114.7	115.1	115.1
43																						
44	Diversification Factor	NA	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
45	**Diversified Cumulative Peak Load - Cooling (MW)**	**-**	**1.9**	**1.9**	**3.2**	**1.9**	**1.9**	**3.2**	**4.5**	**14.3**	**27.8**	**39.6**	**48.9**	**51.3**	**62.8**	**73.6**	**75.5**	**78.2**	**78.2**	**80.3**	**80.5**	**80.5**
46	**Cooling Installed Capacity (MW)**	**-**	**4.9**	**7.4**	**7.4**	**7.4**	**4.9**	**7.4**	**7.4**	**23.0**	**37.9**	**52.8**	**52.8**	**52.8**	**82.7**	**82.7**	**82.7**	**89.6**	**89.6**	**89.6**	**89.6**	**89.6**
47																						
48	**Energy Demand - Heating**																					
49	Heating General Service																					
50	Heating delivered annually: Residential (kWh)	-	1,185,625	2,463,482	2,885,146	3,649,107	1,185,625	5,348,628	10,051,779	21,428,516	52,305,198	77,248,051	98,086,781	109,888,830	124,009,132	145,975,678	154,886,806	159,887,167	162,968,886	165,020,456	167,648,640	167,648,640
51	Heating delivered annually: Grocery (kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	252,674	621,206
52	Heating delivered annually: Pool (kWh)	-	-	443,027	655,653	443,027	-	1,098,680	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865	1,494,865
53	Heating delivered annually: Retail (kWh)	-	30,506	47,801	52,388	78,308	30,506	100,189	122,129	242,921	807,761	1,607,508	2,171,146	2,193,645	2,371,901	2,802,475	2,990,395	3,356,221	3,798,427	3,798,427	3,798,427	3,798,427
54	Heating delivered annually: Large Office (kWh)	-	-	-	-	-	-	-	-	-	-	1,680,839	3,155,991	3,882,539	6,231,302	10,587,028	11,129,944	11,129,944	11,129,944	11,129,944	11,129,944	11,129,944
55	Heating delivered annually: Hotel/Hospitality (kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Heating delivered annually: General Service(kWh)	-	1,216,131	2,954,310	3,593,187	4,170,441	1,216,131	6,547,497	11,668,773	23,166,303	54,607,824	82,031,264	104,908,783	117,459,879	134,107,200	160,860,047	170,502,010	175,868,198	179,392,123	181,443,693	184,324,551	184,693,083
57																						
58	Heating delivered annually: Total (kWh)	-	1,216,131	2,954,310	3,593,187	4,170,441	1,216,131	6,547,497	11,668,773	23,166,303	54,607,824	82,031,264	104,908,783	117,459,879	134,107,200	160,860,047	170,502,010	175,868,198	179,392,123	181,443,693	184,324,551	184,693,083
59																						
60	**Energy Demand - Cooling**																					
61	Cooling General Service																					
62	Cooling delivered annually: Residential (kWh)	-	398,634	1,826,899	1,429,705	2,225,533	398,634	3,256,604	6,658,749	13,113,907	36,548,222	51,709,029	66,930,063	73,226,299	83,845,247	97,127,447	102,311,487	105,757,271	107,957,894	109,181,214	111,057,972	111,057,972
63	Cooling delivered annually: Grocery (kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81,245	411,515
64	Cooling delivered annually: Pool (kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cooling delivered annually: Retail (kWh)	-	12,606	34,182	27,060	46,788	12,606	61,242	80,904	152,783	617,930	1,075,257	1,451,103	1,453,169	1,617,354	1,865,748	1,979,901	2,200,034	2,516,248	2,516,248	2,516,248	2,516,248
66	Cooling delivered annually: Large Office (kWh)	-	-	-	-	-	-	-	-	-	-	1,178,490	2,052,425	2,571,968	4,254,883	7,323,137	7,372,974	7,372,974	7,372,974	7,372,974	7,372,974	7,372,974
67	Cooling delivered annually: Hotel/Hospitality (kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Cooling delivered annually: General Service(kWh)	-	411,239	1,861,081	1,456,765	2,272,320	411,239	3,317,845	6,739,652	13,266,690	37,166,152	53,962,776	70,433,590	77,251,436	89,717,485	106,316,332	111,664,361	115,330,278	117,847,116	119,070,437	121,028,440	121,358,710
69																						
70	Cooling delivered annually: Total (kWh)	-	411,239	1,861,081	1,456,765	2,272,320	411,239	3,317,845	6,739,652	13,266,690	37,166,152	53,962,776	70,433,590	77,251,436	89,717,485	106,316,332	111,664,361	115,330,278	117,847,116	119,070,437	121,028,440	121,358,710
71																						
72	Total delivered annually: Total (kWh)	-	1,627,371	4,815,391	5,049,952	6,442,762	1,627,371	9,865,343	18,408,426	36,432,993	91,773,976	135,994,040	175,342,373	194,711,314	223,824,685	267,176,379	282,166,371	291,198,476	297,239,240	300,514,130	305,352,991	306,051,792

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 17 - Rates

Line No.		Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1	**Thermal Rates - General Service**																					
2	Capacity Charge ($/kW per month)	15.85	15.85	15.85	15.85	15.85	15.85	15.85	16.17	16.49	16.82	17.16	17.50	17.85	18.20	18.57	18.94	19.32	19.70	20.10	20.50	20.91
3																						
4	Energy Charge ($/kWh)	0.0417	0.0417	0.0417	0.0417	0.0417	0.0417	0.0417	0.0409	0.0419	0.0423	0.0432	0.0440	0.0449	0.0458	0.0467	0.0477	0.0486	0.0496	0.0506	0.0516	0.0526
5																						
6	**Annual Change in Thermal Rates - General Service**																					
7	Capacity Charge ($/kW per month)						NA	–	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
8																						
9	Energy Charge ($/kWh)						NA	–	(2.0%)	2.5%	1.0%	2.1%	1.9%	2.1%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
10																						

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 18 - Estimated Typical Customer Building Bill Impact

Line No.	Residential Building	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1	Residential Building Size sq. ft	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500	23,500
	Residential Building Size sq. mt	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183	2,183
2																	
3	**Thermal Service**																
4	Peak Demand Intensity (W/m^2)	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
5	EUI (kWh/m^2)	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
6	Peak Demand (kW)	2,820.00	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820	2,820
7	Annual Energy Consumption (kWh)	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812	4,353,812
8																	
9	Amount for Capacity Charge ($)	536,364	536,364	547,084	558,018	569,171	580,546	592,149	603,984	616,056	628,368	640,927	653,737	666,803	680,130	693,723	707,588
10	Amount for Energy Charge ($)	181,554	181,554	177,866	182,322	184,230	188,080	191,577	195,530	199,322	203,345	207,470	211,649	215,860	220,182	224,575	229,059
11	**Total for Thermal Charges - Annual ($)**	**717,918**	**717,918**	**724,950**	**740,340**	**753,401**	**768,627**	**783,727**	**799,515**	**815,377**	**831,713**	**848,397**	**865,386**	**882,662**	**900,312**	**918,298**	**936,647**
12	Total for Thermal Charges - Monthly ($)	59,826	59,826	60,413	61,695	62,783	64,052	65,311	66,626	67,948	69,309	70,700	72,115	73,555	75,026	76,525	78,054
13																	
14	**Total Estimated Annual Bill for Res. Building ($)**	**717,918**	**717,918**	**724,950**	**740,340**	**753,401**	**768,627**	**783,727**	**799,515**	**815,377**	**831,713**	**848,397**	**865,386**	**882,662**	**900,312**	**918,298**	**936,647**
15	Total Estimated Monthly Bill for Res. Building (Average) ($)	59,826	59,826	60,413	61,695	62,783	64,052	65,311	66,626	67,948	69,309	70,700	72,115	73,555	75,026	76,525	78,054
16																	
17	Annual Change Analysis																
18	% Change in Thermal Capacity Charge Amount		–	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
19	% Change in Thermal Energy Charge Amount		–	(2.0%)	2.5%	1.0%	2.1%	1.9%	2.1%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
20	% Change in Total Thermal Service Amount		–	1.0%	2.1%	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
21																	
22	**% Change in Total Est. Annual Bill for Residential Building**		**–**	**1.0%**	**2.1%**	**1.8%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 19 - Estimated End-User Bill Impact

Line No.	Typical Residential Apartment	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
	Typical Residential Apartment Size: 950 sq. ft. (approx. 88 m2)	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
1	Typical Residential Apartment Size: 88 m2 (approx. 950 sq. ft.)	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
2																	
3	**Thermal Service**																
4	Thermal Peak Demand (W/m^2)	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
5	Thermal EUI (kWh/m^2)	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
6	Thermal Peak Demand (kW)	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59	10.59
7	Annual Heating Energy Consumption (kWh)	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352	16,352
8																	
9	Amount for Capacity Charge ($)	2,014	2,014	2,055	2,096	2,138	2,180	2,224	2,268	2,314	2,360	2,407	2,455	2,504	2,554	2,605	2,658
10	Amount for Energy Charge ($)	682	682	668	685	692	706	720	734	749	764	779	795	811	827	843	860
11	**Total for Thermal Charges - Annual ($)**	**2,696**	**2,696**	**2,723**	**2,781**	**2,830**	**2,887**	**2,943**	**3,003**	**3,062**	**3,124**	**3,186**	**3,250**	**3,315**	**3,381**	**3,449**	**3,518**
12	Total for Thermal Charges - Monthly ($)	225	225	227	232	236	241	245	250	255	260	266	271	276	282	287	293
13																	
14	**Total Estimated Annual Bill for Res. End-User ($)**	**2,696**	**2,696**	**2,723**	**2,781**	**2,830**	**2,887**	**2,943**	**3,003**	**3,062**	**3,124**	**3,186**	**3,250**	**3,315**	**3,381**	**3,449**	**3,518**
15	Total Estimated Monthly Bill for Res. End-User ($)	225	225	227	232	236	241	245	250	255	260	266	271	276	282	287	293
16																	
17	Annual Change Analysis																
18	% Change in Thermal Capacity Charge Amount		–	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
19	% Change in Thermal Energy Charge Amount		–	(2.0%)	2.5%	1.0%	2.1%	1.9%	2.1%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
20	% Change in Total Thermal Service Amount		–	1.0%	2.1%	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
21																	
22	**% Change in Total Est. Annual Bill for Typical Residential Apartment**		**–**	**1.0%**	**2.1%**	**1.8%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**2.0%**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

Utah City District Energy Utility
2026 - 2027 Revenue Requirements and Rates Application
Schedule 20 - Billed Revenue

Line No.	Billed Revenue *All figures in $s*	Forecast 01/01/2026 - 07/31/2026	Forecast 08/01/2026 - 12/31/2026	Forecast 01/01/2027 - 07/31/2027	Forecast 08/01/2027 - 12/31/2027	Test Year 08/01/2026 - 07/31/2027	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036	Forecast 2037	Forecast 2038	Forecast 2039	Forecast 2040	Forecast 2041
1																						
2																						
3	From Capacity Charges	-	369,050	756,969	749,887	1,126,019	369,050	1,506,856	2,547,874	4,893,977	12,236,041	18,391,720	24,077,191	27,280,143	31,907,445	38,844,283	41,806,154	43,998,079	45,809,418	47,231,364	48,953,303	50,043,592
4	From Energy Charges	-	67,861	200,802	210,583	268,663	67,861	411,385	752,039	1,525,683	3,883,377	5,874,797	7,715,448	8,744,520	10,246,904	12,478,485	13,445,924	14,155,828	14,736,955	15,197,668	15,750,478	16,101,731
5	Other charges	-	50	50	25	100	50	75	25	200	275	200	175	50	200	175	50	25	-	50	25	-
6	**Total Billed Revenue**	**-**	**436,961**	**957,820**	**960,495**	**1,394,782**	**436,961**	**1,918,315**	**3,299,938**	**6,419,860**	**16,119,693**	**24,266,717**	**31,792,814**	**36,024,713**	**42,154,549**	**51,322,943**	**55,252,128**	**58,153,933**	**60,546,373**	**62,429,082**	**64,703,806**	**66,145,323**

Notes
1) The Test Year covers the period from August 1, 2026 through July 31, 2027.

UTAH CITY DISTRICT ENERGY UTILITY (UCDEU)
ENERGY COST RECONCILIATION ACCOUNT (ECRA) MODEL
Schedule A1 - Proposed rates
For the period: **August 1, 2026 to July 31, 2027**

Line No.	(1) Details	(2) Pre-Tax	(3) Percentage	(4) Forecast Energy (kWh)	(5) Unit Rate ($ / kWh)
1	ECRA Balance at August 1, 2026	$ -			
2	Forecast Incurred Energy Costs - August 1, 2026 to July 31, 2027	$ 268,218			
3	Forecast Incurred Carrying Costs - August 1, 2026 to July 31, 2027	$ 411			
4	Forecast Recovery of Energy Costs based on existing Energy Charge (August 1, 2026 - July 31, 2027)	$ -			
5					
6	ECRA Ratio = Forecast recovery of Energy Cost *(Line 4)*	= $ -	= 0.00%		
7	Projected ECRA Balance (Line 1) + Forecast Incurred Energy Costs *(Line 2)* + Forecast Incurred Carrying Costs (Line 3)	$ 268,629			
8					
9					
10	Existing Energy Charge				$ -
11					
12	Forecast Demand - August 1, 2026 to July 31, 2027			6,442,762	
13					
14	ECRA Balance at August 1, 2026	$ -			
15	Forecast ECRA Activities - August 1, 2026 to July 31, 2027	$ 268,629			
16	Under / (Over) Recovery at Existing Rate(s)	$ 268,629			
17					
18	**Rate Change Required to address Under / (Over) Recovery based on Forecast Demand**	**$ 268,629**		**6,442,762**	**$ 0.0417**
19					
20				Tested Rate $ per kWh	**$ 0.0417**
21					
22					
23				**Tested Rate effective:**	**01-Aug-26**
24				**Tested Rate $ per kWh**	**$ 0.0417**
25				**Tested rate increase/(decrease) relative to existing rate**	**N/A**
26					

UTAH CITY DISTRICT ENERGY UTILITY (UCDEU)
ENERGY COST RECONCILIATION ACCOUNT (ECRA) MODEL
Schedule A2 - Monthly Balances

	Forecast Jan-26	Forecast Feb-26	Forecast Mar-26	Forecast Apr-26	Forecast May-26	Forecast Jun-26	Forecast Jul-26	Forecast Aug-26	Forecast Sep-26	Forecast Oct-26	Forecast Nov-26	Forecast Dec-26	Aug-26 to Dec-26
ECRA - Beginning	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,935	$ 4,526	$ 9,752	$ 15,097	$ -
Electricity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,757	$ 5,762	$ 5,650	$ 3,832	$ 2,768	$ 24,769
Natural Gas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,680	$ 3,144	$ 7,555	$ 18,446	$ 27,543	$ 58,368
Water & Sewer cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 958	$ 696	$ 490	$ 678	$ 839	$ 3,660
Chemicals & Testings cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 517	$ 420	$ 326	$ 312	$ 302	$ 1,877
Total Energy Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,912	$ 10,022	$ 14,020	$ 23,269	$ 31,452	$ 88,674
Total Sales (kWh)	-	-	-	-	-	-	-	191,395	178,502	211,597	431,016	614,861	1,627,371
Variable Charge ($ per kWh)	-	-	-	-	-	-	-	0.0417	0.0417	0.0417	0.0417	0.0417	0.0417
Revenue from Approved Variable Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,981)	$ (7,444)	$ (8,824)	$ (17,973)	$ (25,640)	$ (67,861)
Adjustments/(Refunds)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carrying Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4	$ 13	$ 29	$ 50	$ 73	$ 170
ECRA - Ending	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,935**	**$ 4,526**	**$ 9,752**	**$ 15,097**	**$ 20,983**	**$ 20,983**

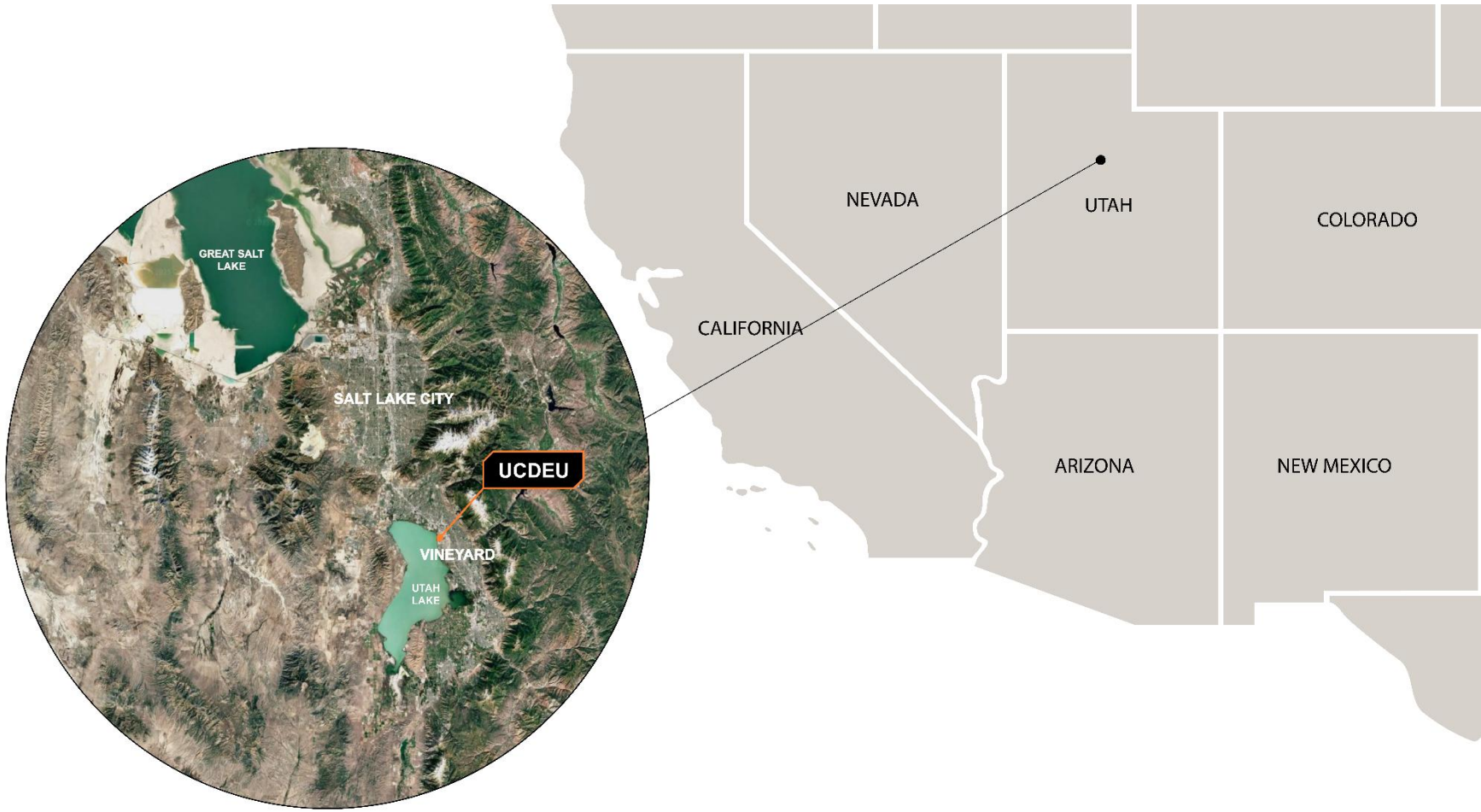
	Forecast Jan-27	Forecast Feb-27	Forecast Mar-27	Forecast Apr-27	Forecast May-27	Forecast Jun-27	Forecast Jul-27	Forecast Aug-27	Forecast Sep-27	Forecast Oct-27	Forecast Nov-27	Forecast Dec-27	Jan-27 to Dec-27
ECRA - Beginning	$ 20,983	$ 15,856	$ 11,892	$ 7,419	$ 6,084	$ 4,574	$ 3,188	$ (34)	$ (959)	$ 1,787	$ 9,151	$ 7,580	$ 20,983
Electricity Cost	$ 2,681	$ 3,549	$ 5,870	$ 8,552	$ 11,110	$ 17,501	$ 23,336	$ 20,477	$ 20,296	$ 17,860	$ 7,443	$ 5,606	$ 144,278
Natural Gas Cost	$ 16,637	$ 16,091	$ 19,483	$ 13,654	$ 10,152	$ 5,668	$ 4,776	$ 6,483	$ 12,411	$ 25,069	$ 34,512	$ 45,391	$ 210,329
Water & Sewer cost	$ 896	$ 869	$ 1,213	$ 1,502	$ 2,196	$ 3,428	$ 5,078	$ 4,240	$ 3,319	$ 2,152	$ 1,749	$ 1,973	$ 28,615
Chemicals & Testings cost	$ 323	$ 321	$ 386	$ 547	$ 796	$ 1,209	$ 1,718	$ 1,460	$ 1,118	$ 657	$ 439	$ 395	$ 9,372
Total Energy Costs	$ 20,538	$ 20,831	$ 26,952	$ 24,255	$ 24,253	$ 27,806	$ 34,908	$ 32,659	$ 37,144	$ 45,738	$ 44,143	$ 53,365	$ 392,594
Total Sales (kWh)	617,229	595,969	754,544	614,338	618,349	700,429	914,533	805,331	824,946	920,752	1,097,097	1,401,826	9,865,343
Variable Charge ($ per kWh)	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	$ 0.0417	0.0417
Revenue from Approved Variable Charge	$ (25,738)	$ (24,852)	$ (31,464)	$ (25,618)	$ (25,785)	$ (29,208)	$ (38,136)	$ (33,582)	$ (34,400)	$ (38,395)	$ (45,749)	$ (58,456)	$ (411,385)
Adjustments/(Refunds)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Carrying Charge	$ 75	$ 56	$ 39	$ 27	$ 22	$ 16	$ 6	$ (2)	$ 2	$ 22	$ 34	$ 20	$ 318
ECRA - Ending	**$ 15,856**	**$ 11,892**	**$ 7,419**	**$ 6,084**	**$ 4,574**	**$ 3,188**	**$ (34)**	**$ (959)**	**$ 1,787**	**$ 9,151**	**$ 7,580**	**$ 2,509**	**$ 2,509**

Appendix B State Map – Utility Location

Corix Utah City Heating and Cooling LLC

Utah City District Energy Utility

Utility Location Map in the State of Utah



Appendix C UCDEU Service Area

Corix Utah City Heating and Cooling LLC

Utah City District Energy Utility

Service Area

Appendix D Pre-filed Direct Testimony List

GRC Application, Attachment 1, Appendix D
Pre-filed Direct Testimony List

Line	Corix Exhibit No.	Exhibit Name	Position	Topic & GRC Application, Attachment 1, Section number
1	**2.0**	Direct Testimony of Errol South		Test Period (Section 2)
2				Relief Sought (Section 3)
3				Proposed Energy Charges for Test Period (Section 9)
4				Overview of Corporate Structure, Organizational Structure, and Utility Resourcing (Section 13)
5				Support Services Cost Allocations (Section 19)
6				Proposed Capacity Charges for Test Period (Section 26)
7				Conclusion (Section 31)
8				
9	**3.0**	Direct Testimony of Douglas Chong		Background and Overview (Section 1)
10				Rate Design (Section 4)
11				Regulatory Framework for Thermal Energy Supply Costs and Cost Recovery (Section 10)
12				Calculation of Carrying Charge (Section 11)
13				Regulatory Framework for Thermal Delivery Costs and Cost Recovery (Section 12)
14				Delivery Deferral Account (Section 23)
15				Rate Stabilization with Revenue Deficiency Deferal Account (RDDA) (Section 25)
16				Other Matters - Thermal Uniform System of Accounts (Section 29)
17				Other Matters - Annual Reports (Section 30)
18				
19	**4.0**	Redacted/Confidential Direct Testimony of Maxwell Wang	Chief Financial Officer	Cost of Capital (Section 20.5)
20				
21	**5.0**	Redacted/Confidential Direct Testimony of Josh Figueroa	Principal, The Brattle Group	Cost of Capital (Section 20.6)
22				
23	**6.0**	Direct Testimony of Derek Nelson		Project Development Progress and Operations (Section 5)
24				Customer Letter of Support (Section 6)
25				Capital Expenditures and Asset Life (Section 14)
26				O&M (Section 18)
27				
28	**7.0**	Direct Testimony of Johan Grueso-Baron		Forecast Customers, Peak Load, and Energy Demand (Section 7)
29				Energy Supply Costs and Energy Supply Revenue Requirement (Section 8)
30				Capital Additions (Section 15)
31				Contributions in Aid of Construction (Section 16)
32				Depreciation and Amortization (Section 17)
33				O&M (inputs in financial model) (Section 18)
34				Cost of Capital (cost of capital inputs in financial model) (Section 20)
35				Taxes Other Than Income Tax (Section 21)
36				Income Tax (Section 22)
37				Delivery Revenue Requirement (Section 24)
38				
39	**8.0**	Direct Testimony of Hang Hockley		Thermal Tariff (Terms, Conditions, and Rates) (Section 27)
40				Other Matters - Service Quality Standards (Section 28)
41				

Appendix E List of GRC Pre-filed Exhibits

Corix GRC Application, Attachment 1, Appendix E
List of GRC Pre-filed Exhibits

Line	Exhibit No.	Exhibit Name	Reference
1	1.0	Thermal Tariff	Attachment 1, Section 27
2			
3	2.0	Direct Testimony of Errol South	See Attachment 1, Appendix D for various topics addressed in direct testimony.
4	2.1	Index pertaining to GRC Filing Requirements for UCDEU	Attachment 1, Section 2.7
5	2.2	Simplified Ownership Chart	Attachment 1, Section 13.1
6	2.3	Simplified Ownership Chart with affiliates	Attachment 1, Section 13.1
7	2.4	Support Services Diagram	Attachment 1, Section 13.2
8	2.5	Regional Cost Allocation Methodology Manual	Attachment 1, Section 19
9	2.6	Corporate Cost Allocation Methodology Manual	Attachment 1, Section 19
10	2.7	Highly Confidential - Corporate CAM Model	Attachment 1, Section 19
11	2.8	Highly Confidential - Regional CAM Model	Attachment 1, Section 19
12	2.9	Affiliate Services - US to UCDEU	Corix Exhibit 2.0
13	2.10	Affiliate Services - Canada to UCDEU	Corix Exhibit 2.0
14			
15	3.0	Direct Testimony of Douglas Chong	See Attachment 1, Appendix D for various topics addressed in direct testimony.
16	3.1	Redacted - Infrastructure Agreement	Attachment 1, Section 1.7.2
17	3.1	Highly Confidential - Infrastructure Agreement	Attachment 1, Section 1.5.2
18	3.2	Carrying Charge Calculation	Attachment 1, Section 11.1
19	3.3	Levelized and Non-Levelized Capacity Rates	Attachment 1, Section 12.4.1
20	3.4	RDDA Balance Relative to NBV	Attachment 1, Section 12.6.3.5
21			
22	4.0	Redacted - Direct Testimony of Maxwell Wang	See Attachment 1, Appendix D for various topics addressed in direct testimony.
23	4.0	Confidential - Direct Testimony of Maxwell Wang	See Attachment 1, Appendix D for various topics addressed in direct testimony.
24	4.1	Confidential - Intercompany Credit Agreement	Attachment 1, Section 20.5
25			
26	5.0	Confidential - Direct Testimony of Josh Figueroa	See Attachment 1, Appendix D for various topics addressed in direct testimony.
27	5.0	Redacted - Direct Testimony of Josh Figueroa	See Attachment 1, Appendix D for various topics addressed in direct testimony.
28	5.1	Curriculum vitae	Corix Exhibit 5.0
29	5.2	Technical Appendix	Corix Exhibit 5.0
30	5.3	Cost of Capital	Corix Exhibit 5.0
31	5.4	Confidential - Cost of Capital Model	Corix Exhibit 5.0
32	5.5	Confidential - Implied Risk Premium Model – Natural Gas	Corix Exhibit 5.0
33	5.6	Confidential - Implied Risk Premium Model - Water	Corix Exhibit 5.0
34	5.7	Confidential - Bond Yields & MRP	Corix Exhibit 5.0
35	5.8	Confidential - FERC MRP	Corix Exhibit 5.0
36	5.9	Confidential - Business Risk	Corix Exhibit 5.0
37	5.10	Confidential - Capital Structure	Corix Exhibit 5.0
38			
39	6.0	Direct Testimony of Derek Nelson	See Attachment 1, Appendix D for various topics addressed in direct testimony.
40	6.1	Customer Letter of Support	Attachment 1, Section 6
41	6.2	Ramboll Technical Memo	Attachment 1, Section 14
42	6.3	Capital Expenditures by CWIP Projects and Phases	Attachment 1, Section 14
43	6.4	Assets useful life	Attachment 1, Section 14
44			
45	7.0	Direct Testimony of Johan Grueso-Baron	See Attachment 1, Appendix D for various topics addressed in direct testimony.
46	7.1	Highly Confidential - UCDEU GRC Financial Model - Excel	Attachment 1, Section 8.5
47	7.2	Highly Confidential - UCDEU ECRA Financial Model - Excel	Attachment 1, Section 24.3
48	7.3	UCDEU ECRA Financial Model - Public - Excel	Attachment 1, Section 8.1
49	7.4	Highly Confidential - Detailed Build-out Schedule	Attachment 1, Section 15.6.1
50	7.5	WP - Maintenance cost estimates %	Attachment 1, Section 18
51	7.6	Corix Bad Debts Policy	Attachment 1, Section 18
52	7.7	Highly Confidential Short Term Incentive Plan	Attachment 1, Section 18.3
53			
54	8.0	Direct Testimony of Hang Hockley	See Attachment 1, Appendix D for various topics addressed in direct testimony.
55	8.1	District Energy Services Agreement (DESA)	Attachment 1, Section 27
56	8.2	Customer Agreement	Attachment 1, Section 27

Appendix F UCDEU General Rate Case Filing Requirements

UCDEU General Rate Case Filing Requirements

Applicable Utah City District Energy Utility General Rate Case (GRC) Filing Requirements approved by Order dated March 26, 2026. This Order applies only to Corix for its GRC filing in Docket No. 26-2666-01.

R746-700-60. Information For a General Rate Case Application for a Heating Corporation.

An applicant submitting a general rate case application shall provide the following information with the application, for the operating utility and on a Utah jurisdictional basis using the allocation methods used in the public utility's last general rate case proceeding or any allocation method subsequently approved by the Commission. An applicant will provide an index which identifies where in the application, testimony, exhibits, documents, information, data, etc. filed with the application the applicant has responded to and complied with these R746-700-60 rule requirements. The index may be presented in testimony, as a table embedded in testimony, as an exhibit to testimony, or in any other manner so long as it is clearly identified.

A. **Historical results of operations information:**

1. actual, unadjusted results of operations, including all regulated costs and revenues, for a historical 12-month period as contained in its last periodic reported results of operations filing submitted to the Commission.

2. adjusted results of operations for the same period.

3. a description of any significant changes in accounting policies, procedures or practices since the previous general rate case application and, if a forecasted test period is used, any future significant changes accounted for in a future test period. Significant changes for this purpose are anything referenced or that would be referenced in footnotes of financial statements or auditor's reports.

B. **Cost of Service and Rate Design.** An applicant shall file the following Cost of Service and Rate Design information with any general rate case application.

1. Utah Class Cost of Service Study.

a. If the applicant has more than one customer class it shall either provide a Utah Class Cost of Service Study based on the test period with supporting documentation including the development of allocation factors, or explain why no class cost of service study is included.

b. If a new customer class is proposed, the applicant shall either include class cost of service studies; one which uses only existing customer classes and another with the newly proposed class included, or explain why no class cost of service study including the new customer class is included and how the new customer class is to be treated in setting rates in the case.

2. If the applicant proposes a cost or revenue shift between rate classes, its proposal for spreading any Utah revenue requirement change among the rate schedules. This will include the dollar and percentage revenue requirement change for each rate schedule.

3. Its proposed rates for each rate component of each rate schedule and the billing determinants for the test period for all rate components used to calculate revenues necessary to recover the proposed revenue requirement.

4. Its proposed tariff sheets for all tariff provisions for which it proposes changes.

a. An applicant need not include proposed tariff sheets for changes to tariff pages showing rates, charges, or fees if these proposed price changes are provided in a readily identifiable form elsewhere in the application.

R746-700-61. Information for a General Rate Case Application Using a Fully or Partially Forecasted Test Period Filed by a Heat Corporation.

An applicant shall file with the Commission the following information or documents when filing a general rate case application which uses a forecasted test period not previously approved by the Commission. An applicant will provide an index which identifies where in the application, testimony, exhibits, documents, information, data, etc. filed with the application the applicant has responded to and complied with these R746-700-61 rule requirements. The index may be presented in testimony, as a table embedded in testimony, as an exhibit to testimony, or in any other manner so long as it is clearly identified. Contemporaneously with the filing of an application, a heat corporation shall provide the following information and documents to the parties specified in R746-700-1.E.3, unless the information or document is already included in or with the application.

A. Definitions. As used herein, the following terms shall have the indicated meanings:

1. Time Periods. Definitions of time periods for which information is to be provided in compliance with this rule are as follows:

a. Year: A 12-month period designated as "12 months ending Month Date, Year".

b. Base Year (BY): The 12-month historical period ending on the ending date for the most recent periodic reported results of operations filing submitted for the public utility, or if it does not file periodic results of operations, the base period upon which the test period used in the application is developed.

c. Test Period (TP): The 12-month period used as the test period for the general rate case application.

d. Historical Year(s) (HY): Year(s) immediately preceding the Base Year.

e. To Date: Up to the most recent date for which information is reasonably available to the public utility in preparing its general rate case application.

f. Workpapers: Documents and spreadsheets containing data and calculations used to develop the inputs to

the general rate case filing will be provided, if not already included in the Model(s). The type, nature, level of detail, format, etc. of the information compilation, schedule, document, etc. shall be reasonably comparable to that provided to parties in the public utility's prior general rate cases.

2. Provide, Describe, etc. The terms "provide" or "describe," or terms with similar meaning, shall mean to deliver available electronic copies and/or paper copies of designated data and documents to interested persons; provided that, when necessary and appropriate, prompt arrangements may be made for review of designated data and documents at a utility location in Utah or at another mutually agreeable place. Models and spreadsheets are to be provided in "live" electronic format (not PDF), with formulas intact and input data available.

3. Materiality. Materiality is defined as a change in requested Utah jurisdictional revenue requirement equal to or greater than 0.1 % of total state revenue requirement or $50,000, whichever is less.

4. Model(s). The term Model(s) shall mean the major analytical software tools and spreadsheets used by the utility to develop its general rate case application. Smaller analytical tools, such as special purpose electronic spreadsheets, are not included in the definition of the term Model(s) for purposes of this rule.

B. **Revenue Requirement Information.**

1. Forecasted test period data. A comparison of the Test Period data Results of Operations (RO) to the Base Year actual, unadjusted RO and adjusted RO. This is to be made available in a side-by-side comparison on a consistent basis.

2. Operating and Capital Budgets. A comparison of the utility's operating budget and capital budget to the actual results for the Base Year, the prior Historical Year, and To Date. This comparison is to be made at a reasonable level of detail level and explanation for material variances should be provided.

3. Operating Costs Forecast.

a. Provide forecasted costs to an appropriate level of detail, with information on escalators or drivers including details of the base costs and the key drivers that impact the forecasted amount. If forecasted costs are not based on historical levels that have been inflated or escalated, the applicant shall provide a detailed explanation and supporting documents, if available.

b. The information will identify the index or rate of inflation applied to accounts, budget items or specific cost components that result in the costs in the forecasted test period. If applicable, source documents supporting the index or rate of inflation applied will be identified and will be provided or made available.

4. Labor Costs. Labor Costs shall be identified separately within Operating Costs. The applicant will provide:

a. A comparison of budgeted labor costs and number of full-time equivalents to the actual labor costs and full-time equivalents by year for the Base Year and the prior test period. The information shall provide available explanations for material variances.

b. The actual most recent number of full-time equivalent employees and, separately, the forecasted number of full-time equivalent employees for the forecasted period.

c. The associated costs related to the full-time equivalent labor and contract labor levels. Direct employees, contract employees, union and nonunion employees, where applicable, will each be provided separately. These shall show separately, to the degree available, the direct labor costs, premiums, incentives, benefits and overhead costs. These shall show contract labor costs separately from direct labor cost.

d. Any assumed salary and wage increases included in the projected labor costs will be identified.

5. Workpapers. In addition to the information defined by Workpapers above, the information shall provide the forecast workpapers (including assumptions, spreadsheets and tests).

6. Forecasted Data - Revenue Requirement.

a. Support and explanations for forecasted values, including Base Year starting values, adjustments made to the Base Year values and key drivers that impact the forecasts, together with supporting documents, if any.

b. Indices, inflation rates and escalation factors used in preparing forecasts, including supporting source documents, if any.

7. Models. Workable versions of Models utilized in determining or projecting rate case values, with formulae intact and source data included. The model will include regulatory financial schedules that include the summary revenue requirement and summary rate base for the test period plus supporting schedules. Supporting schedules will include capital expenditures, capital additions, plant account balances with depreciation continuity, deferral accounts, capital structure, cost of capital, OMAG, depreciation/amortization, and taxes. Models may be submitted confidentially.

C. Cost of Service Information. The applicant will provide for the operating utility:

1. Forecasted Data - Class Cost of Service. Class cost of service data for the Base Year and Test Period.

2. Forecasted Data - Rate Design. Test Period rate design data.

D. Miscellaneous Information

1. Accounting - Write-offs. A description of Material write-offs of assets and/or liabilities that took place since the previous rate case, including the amount of write-off and the accounts charged, as well as the supporting explanation for the write-off.

2. Ownership - Organizational Charts. A simplified ownership chart for the operating utility including parent companies, divisions, subsidiaries and relevant affiliates. The regulatory status of each entity shown must be disclosed.

3. Affiliates. A description of corporate restructurings and changes in relevant affiliate relationships that are pertinent to the operating utility, which occurred since the filing of the prior general rate case.

4. Affiliates. A copy of Material new or Materially modified contracts or agreements entered into since the filing of the prior general rate case, including attachments thereto, if relevant to the costs the utility seeks to recover from Utah ratepayers through Utah regulatory operations or costs allocated or directly charged to Utah regulated operations included in the general rate case application, between the utility and/or its parent company and affiliated companies for services and/or goods rendered between or among them. This is to include a list of active contracts unless already provided in the most recent Affiliate Interest

Report.

5. Affiliates. A copy of cost allocation manuals and/or policies and procedures that set forth the detailed cost allocation methodology and/or pricing methodology used to charge costs between affiliates that have changed since the filing of the prior general rate case.

6. Audit - Financial. A copy of management letters received from the operating utility's independent auditors, if any.

7. Audits - Internal. A listing of internal audits conducted by or for the utility or its parent company for the Base Year, the prior Historical Year and To Date if relevant to the costs the utility seeks to recover from Utah ratepayers through Utah regulatory operations or the costs allocated or directly charged to Utah regulated operations included in the general rate case application. Notice of Internal Audit reports completed during the pendency of the case will be provided upon completion to all parties participating in the case.

8. Cost of Capital - Debt Expense. The financing costs for the Historical Years, the Base Year and forecasted for the next three years including any deemed debt expense.

9. Cost of Capital. Copies of the most recent bond rating agencies reports on the Company, if applicable.

10. Employee Costs – Wages and Salaries. The actual percentage of increases in salaries and wages for exempt, non-exempt and union employees for the Base Year, the Prior Historical Year, Test Period, and To Date.

11. Employee Costs – Incentive Plans. Complete copies of bonus programs or incentive award programs in effect for the utility for the Base Year, the prior Historical Year, the Test Period and To Date. Identify incentive and bonus program expenses incurred in the Base Year, the prior Historical Year, the Test Period and To Date and identify the amounts included in the Test Period. Identify the accounts charged. Identify incentive and bonus program expenses charged or allocated to the utility from affiliates or the parent company in the Base Year, the prior Historical Year, the Test Period and To Date.

12. Employee Costs – Pensions. The two most recent pension actuarial reports prepared for the utility.

13. Employee Costs - Post Retirement Benefits Other Than Pensions (PBOP). The two most recent PBOP actuarial reports prepared for the utility.

14. Operation, Maintenance, Administrative and General (OMAG) Expenses - Other - Contributions. For the Base Year and the Test Period, a list of contributions for charitable and political purposes, if any, included in accounts other than below the line. Indicate the amount of the expenditure, the recipient of the contribution, and the specific account in which the expense is included in the filing. Also identify for the Base Year and the Test Period the amounts of contributions for charitable and political purposes charged to the utility from affiliates in accounts other than below the line accounts.

15. OMAG Expenses - Advertising. For the Base Year, the prior Historical Year and the Test Period the amount of advertising expense, by account, by type of advertising (i.e., informational, instructional, promotional).

16. OMAG Expenses - Dues, Industry Associations. The Material amounts included in the Base Year, the prior Historical Year and the Test Period for above-the-line payments to industry associations. Identify the organization/association name and amounts, along with the account in which the costs are included in the filing. If any of the dues or other amounts paid to the organizations/associations go toward lobbying and public relations efforts and are recorded in above-the-line accounts, provide the associated amounts included in the above-the-line accounts whether Material in magnitude or not.

17. OMAG Expenses - Outside Services Expense. An itemization of Material outside services expenses for the Base Year, the prior Historical Year and the Test Period.

18. OMAG Expense - Insurance. The amount of insurance expense, by insurance type (i.e., property insurance, liability insurance, workers compensation, directors and officers liability insurance, etc.) for the Base Year, the prior Historical Year and the Test Period and identify the accounts the associated costs are included in.

19. OMAG Expense - Insurance. For insurance coverage for which the utility is self-insured, a description of that self insurance, a description of how it is accounted for in the utility's books and records and a description of activity for the Base Year, the prior Historical Year and the Test Period.

20. OMAG Expense - Legal Settlements. A list of Material amounts included in the Base Year and the Test Period (on a direct charge basis, affiliate billing, or allocation) that are the result of the settlement of lawsuits or other legal action that impact the operating utility.

21. OMAG - Uncollectibles - Bad Debt Reserve. In addition to the information defined as Workpapers above, the following information will be provided if included for recovery in the rate application. For the Base Year, the prior Historical Year and the Test Period the beginning bad debt reserve balance, the amount written off, the recoveries, the reserve adjustment, other charges or credits, and the ending reserve balance. For the same periods, provide the total amount of retail revenue from retail sales and total retail bad debt expense.

22. OMAG - Uncollectibles. In addition to the Workpapers defined above, the following information shall be provided if included for recovery in the rate application. A detailed description of changes in the utility's collection policies or write-off policies since the filing of the prior general rate case.

23. Penalties and Fines. For the operating utility, a list of penalties and fines in the Base Year and the Test Period and indicate in which accounts the associated amounts are included.

24. Capital Expenditures or additions. The applicant will provide capital expenditures detail, and changes affecting rate base, including:

a. The detail for the changes, beginning with the start of the historic period results of operation through the test period. The detail will include dollar amounts and information on when the asset was placed into service.
b. The detailed calculation of depreciation expense for the test period.
c. Interdependencies of capital expenditures, if any, to operation and maintenance items will be identified or explained.
d. A list will be provided of all major capital additions to rate base individually exceeding $100,000 of total company net plant in service, whichever is greater for each year. Projects under $100,000 shall be grouped in

aggregate. A brief description will be provided for each major capital addition in the list.

e. Detailed calculation of plant retirements.

25. Regulatory Adjustments. The applicant will provide details of all the regulatory adjustments required in the filing:

a. Information for recurring regulatory adjustments, such as amortizations, indicating compliance with past Commission orders for any item included in the filing.

b. Separately, a reversing adjustment and the reasons for non-inclusion or departure from a Commission ordered practice or adjustments if the applicant does not wish to have them apply to the application.

c. Unless already included in unadjusted results, regulatory adjustment information will include disallowances from prior orders, implementation of accounting orders approved by the Commission, or other adjustments necessary to make the forecasted test period data acceptable for ratemaking in Utah. Each of the regulatory adjustments will be supported by prefiled testimony or a detailed description contained within the schedules.

26. Rate Base - Working Capital. A complete copy of the lead/lag study, with supporting documents, used to compute cash working capital for the utility's application, or an explanation of the calculation of working capital if a study is not available.

27. Rate Base - Deferral Accounts.

a. Any proposed deferral accounts are to include the purpose, rationale, and approach.

28. Non-Rate Base - Deferral Accounts.

a. Any proposed deferral accounts are to include the purpose, rationale, and approach.

29. Rate stabilization with deferral account.

a. If the heating corporation proposes a rate stabilization method pursuant to Utah Code Section 54-4-4.1, the applicant shall include the rationale, the rate stabilization period, and supporting information for the rate stabilization. The applicant will explain any associated deferral account that is used in conjunction with the rate stabilization.

b. If the heating corporation has an approved rate stabilization method, the applicant will report on the progress of the rate stabilization until it is discontinued.

30. Other Rate Base. Details of other rate base accounts shall be provided by the applicant. For other items of rate base, such as deferred debits, accumulated deferred income taxes, materials and supplies, miscellaneous rate base, customer advances, deferred credits, etc., the applicant shall provide information showing the 12-month period of the historical results of operations, and any changes, to those amounts through the test period resulting in the projected amount included in the filing.

31. Reserve Accounts. Information on whether or not the utility maintains reserve accounts (e.g., an injuries and damages reserve account). If so, provide the historical and forecast balances in reserve accounts.

32. Revenues. Provide regulated billed revenue, by customer class, along with supporting information such as:

a. Customer Count, by customer class

b. Revenue drivers (billing determinants) by customer class, including but not limited to, number of customers, floor area, design peak demand, energy sales

c. Assumptions used in the development of the revenue forecasts

d. Charges, fees, and rates used in the forecast development

e. Contract changes or other specific changes anticipated in the forecast.

33. Revenues - Other. Provide the amount of other nonregulated-retail-sales revenues by revenue type, if any.

34. Sales of Property. For the Base Year, the prior Historical Year, and the Test Period provided any sales of property that had been or are included in Utah rates while in service.

35. Taxes. Forecasting methods, calculations and key assumptions in the test period will be provided on a tax item basis (i.e., income, FICA, property taxes, etc.).

36. Taxes: Income. A list of and provide copies or make available for review, subject to R746-1-601 through 605, an appropriate protective order, confidentiality agreement, or other confidentiality protective arrangement, depending on specific content, revenue ruling requests, IRS responses, and correspondence between the utility and the IRS since the filing of the prior rate case.

37. Taxes: Income. Provide copies or make available for review, subject to R746-1-601 through 605, an appropriate protective order, confidentiality agreement, or other confidentiality protective arrangement, copies of the most recent State and Federal income tax returns in which the utility participated.

38. Taxes: Income. Provide a copy of the current tax sharing agreement in which the utility participates.

Appendix G List of Acronyms and Glossary

Acronym / Glossary	Description
Application	This GRC Application
Applicant	Corix Utah Heating and Cooling LLC
BCI	British Columbia Investment Management Corporation; ultimate sole owner of Corix
Building	Building means the structure within a lot.
Capacity	The maximum amount of heat/cooling that the system can produce to warm/cool. For UCDEU this is measured in MW (megawatt) or equivalently kW (kilowatt).
Capacity Charge	A fixed monthly basic charge based on capacity billed in kW.
Capital structure	The mix of debt and equity to fund rate base.
CEP	Central energy plant
COP	Coefficient of performance
Corix	Corix Utah City Heating and Cooling LLC; the regulated thermal utility and the Applicant.
CPCN	Certificate of Public Convenience and Necessity
CPCN Application	CPCN Application with PSC Docket No. 25-26666-01 submitted on July 31, 2025 and later by Order conditionally approved on February 2, 2026.
Customer Agreement	Customer Agreement is the application for service form executed by the customer to create an account with Corix Utah City Heating and Cooling LLC
DES	District energy system
DESA	District Energy Service Agreement between Utah City District Energy Utility and the developer of a lot/parcel contains prerequisites and terms and conditions for connecting the building on that lot to the utility.
Development Project	The master planned community project owned by the Developer encompassing 350 acres, west of the Frontrunner Commuter Rail tracks.
Developer	Flagborough L.L.C.
Developer Customer	In this Application all the buildings/lots will be owned by a common entity, Flagborough L.L.C. or its affiliates. Collectively Flagborough L.L.C. and its affiliates are the Developer Customer.
District Energy	A system that centrally generates and distributes thermal energy (heating and/or cooling) to multiple buildings through a network of pipes, instead of individual systems in each building.

Acronym / Glossary	Description
DPS	Distribution piping system
Enbridge	Enbridge Gas Utah, the local natural gas utility.
Energy Charge	A variable charge for energy supply costs billed for consumption measured in kWh.
Equipment Lease	Lease Agreement with the Developer and Corix in the absence of rate regulation. It spells out contractually the rates and terms of thermal service in the absence of rate regulation.
ETS	Energy Transfer Station
EUI	Energy Use Intensity
Fee Framework	The negotiated fee framework between Corix and Flagborough if the district energy system was not regulated by the Commission.
Flagborough	Flagborough L.L.C., the Customer
GAAP	United States Generally Accepted Accounting Principles
GFA	Gross floor area
GRC	General Rate Case
GRC Application	This general rate case application to establish the revenue requirement and rates of UCDEU.
Heat corporation	A regulated public utility under Utah Code Ann. § 54-2-1
HVAC	Heating, ventilation, and air conditioning
IEC	Interim Energy Center
kW	Kilowatt; one thousand watts
kWh	Kilowatt-hour
MW	Megawatt; one million watts
MWh	Megawatt-hour
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturer
PPE	Property, plant and equipment
PSC	Public Service Commission of Utah
PSC Rules	The PSC's established rules and procedures for regulating public utilities.
Rate Application	Also known as the General Rate Case Application

Acronym / Glossary	Description
Rate Base	The invested capital of the utility to which the delivery cost-based rates are set.
Revenue Deficiency Deferral Account	Revenue Deficiency Deferral Account abbreviated as RDDA. The RDDA is sometimes known as the Rate Balancing Account (RSA).
Revenue Requirement	The total annual cost of service used to set rates. The annual revenue requirement can be segmented into a delivery revenue requirement and an energy supply revenue requirement when there is an unbundled rate structure.
RMP	Rocky Mountain Power, the local electric utility.
Services	Thermal (heating and cooling) energy service offered by the utility.
Service Area	The utility service area by Order on February 2, 2026 conditonally approved in Docket No. 25-2666-25 for the CPCN Application by UCDEU. The area is 350 acres with 64 buildings/lots that is north of the Vineyard Connector Road and west of the FrontRunner Commuter Rail tracks in Vineyard, Utah.
System extension	A system extension is the extension of the utility network beyond the initial service area.
UCDEU	Utah City District Energy Utility
Utah City District Energy Utility	The thermal system in Vineyard, Utah owned and operated by Corix Utah City Heating and Cooling LLC.
Utah Code Title 54	Utah Code Title 54 Public Utilities. The legislation regarding public utilities in the State of Utah.
Utah City	The 350-acre master-planned development focusing on sustainability and walkability in Vineyard, Utah.
Vineyard, Utah	The city in Utah where the utility is located.