Washington City
Where Dixie Begins

WASHINGTON CITY POWER

Impact Fee Facility Plan

May 2024

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SECTION I GENERAL

Introduction

Intermountain Consumer Professional Engineers, Inc. (“ICPE”) performed studies and analyses for Washington City Power (“WCP”) to update their 2019 Electrical Power Capital Facilities Plan and Impact Fee Facilities Plan.

ICPE utilized load predictions in the studies that were developed using recent load data provided by WCP and load trends observed in Washington City over the past several years. The future loads used in the studies are predictions and do not reflect actual values which prevents ICPE from guaranteeing or assuring that the recommendations reflect actual events that will occur in the future. However, it is believed that all predictions and observations used in the study are reasonable and appropriate for the purpose of the Capital Facilities Plan and Impact Fee Facilities Plan.

Impact Fees - General

Impact fees are generally used by cities to fund infrastructure projects necessary to provide services to new developments within the city’s boundary. The new development should bear the additional or incremental capital cost for the services, existing residents who do not benefit from the new development should not bear the costs for services to the new development. Impact fees are not intended for operating expenses or for corrections to existing deficiencies in the services presently being provided by a city. Impact fees are based on anticipated new load increase to the electrical system due to the new developments. The improvements outlined in the plans are required to maintain the present level of service to both new and existing customers.

Impact Fees - Utah

In Utah, impact fees are governed by state statute, specifically U.C.A. 1953 § 11-36a-102. The Statute requires that each governmental agency that imposes an impact fee shall (1) prepare an Impact Fee Facilities Plan (§ 11-36a-301), (2) perform an Impact Fee Analysis (§ 11-36a-303), (3) calculate the Impact Fee(s) (§ 11-36a-305) and (4) certify the Impact Fee Facilities Plan (§ 11-36a-306).

As stated in the Statute, the “Impact Fee Facilities Plan (“IFFP”) shall identify (a) demands placed upon existing public facilities by new development activity; and (b) the proposed means by which the political subdivision will meet those demands.” The IFFP shall also consider all revenue sources, including impact fees, used to finance impacts on system improvements. This report incorporates the most recent WCP Capital Facilities Plan ("CFP"), dated April 2024. In general, the CFP outlines all projects necessary to maintain electrical service to existing customers and the IFFP outlines fees for the improvements necessary to provide service to new developments and customers. Projects identified in the CFP may be due to the correction of an existing deficiency or improvement necessary to maintain reliability and are not included in the IFFP.

The Utah Statute requires the governmental agency that imposes an impact fee to perform an analysis of the impact fee and document the results. The agency is also required to provide a summary document of the analysis that can be understood by a layman. The estimated impacts on the existing electrical system due to the new development are to be included in the Impact Fee Analysis (IFA) along with the costs associated with addressing the impacts. The IFA is also required to include the costs of existing capacity that will be recouped.

Impact Fee calculations may include the following:

(a) The construction cost.
(b) The cost of acquiring land and material.
(c) The cost for planning, surveying, and engineering fees for services provided to design the construction.
(d) Debt service charges, if the impact fees are used to pay the principal and interest on bonds or other obligations to finance the costs of the construction.

Impact Fee calculations are to be based on local industry standard material and labor estimates. The assumptions used to develop the estimates are to be included in the IFA. The IFFP and the IFA area to be certified by the person or entity that prepared the documents.

Washington City

According to the US Census, Washington City is located in Washington County, Utah. The land area is 32.86 square miles and the estimated population in 2023 was about 33,877 persons. The median resident age is 36.3 years, the average household size is 2.99 persons and the median household income is about $94,655.

Washington City Power was formed in 1987 to serve electricity to Washington City. The service area is north of the Virgin River and within the Washington City limits. The CFP and IFFA plans do not include the south side of the Virgin River which is served by Dixie Power.

Electricity Supply

General

Figure 1 illustrates the three basic components of an electrical system, an electric generator that creates the electricity, a transmission system that carries the electricity to the distribution system; and the distribution system that delivers the electricity to the customer.

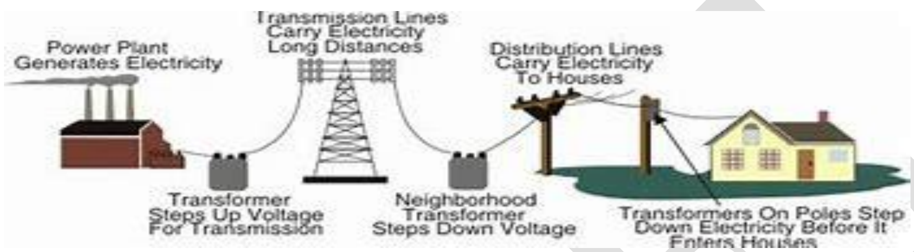

Figure 1

Illustration of a Typical Power Delivery System

Electricity Generation

Electricity is produced by a generator that is powered by a fuel source. The generator can be a steam, hydro, turbine, diesel engine, wind, solar or geothermal. The generated electricity is provided to a utility through purchased power agreements, which can be a firm power agreement (long-term and short-term); unit power (a portion of a specific generating unit) and non-firm (usually short-term). The type and amount of each generating resource that is used by a utility to meet the electrical demand depends on the amount and duration of the demand, the availability of the generating units and the cost of the electricity from the generating units. To meet the hourly demand for electricity, each available generating resource is evaluated according to its availability, capacity and operating cost and then dispatched accordingly to meet the demand for electricity in each hour of the day.

The utility's peak demand is the highest demand for electricity in any one hour. It is during these peak hours that a utility will use multiple generating resources including its own generating resources.

Electricity Transmission

The electricity leaving the generator is stepped up to a higher voltage by a transformer and delivered to the transmission system. The transmission system consists of transmission power poles or towers, conductors, substations and other equipment necessary to deliver electricity from the generators to the utility.

Transmission of electricity to Washington City Power is through the Utah Associated Municipal Power Systems (UAMPS) transmission system. UAMPS receives electricity through Rocky Mountain Power's transmission system.

Electricity Distribution

Electricity distribution is the final stage in the delivery of electricity to customers. An electricity distribution system receives electricity from the transmission system and delivers it to consumers. A typical electric distribution system includes medium-voltage (69 kV & 12.47 kV) power lines, substations, transformers, service drops and metering. The distribution system begins where the voltage is stepped down through transformer(s) and ends at the secondary service point at the customer's meter. Distribution circuits begin at the low-voltage side of the transformer located in the City's substation. Conductors for the distribution delivery system are either located overhead on utility poles or buried underground.

Most electric customers are connected to a pole mounted or pad mounted transformer that reduces the distribution voltage to the low voltage used by customers. Each customer has an electrical service connection and a meter.

SECTION II CAPITAL FACILITIES PLAN AND IMPACT FEE FACILITIES PLAN

General

The Impact Fee Facilities Plan identifies the additional electrical load placed on an existing electrical system by new developments, identifies additions or modifications to the existing electrical system necessary to meet the increased load and provides costs for the system additions or modifications. The Plan will enable the utility to determine how they will fund the projects necessary to meet the load increase to the system.

The following summarizes the results of the Capital Facilities Plan Update that was completed in April 2024 where load increases were identified, projects were proposed to meet the load increase and costs were provided for the proposed projects.

Historical Population and Load Growth

According to the U.S. Census Bureau, the Washington City's population in 2020 was approximately 27,993. The population grew to 33,877 by 2023 for an approximate 20% increase in population over three years. The following table is a summary of the population growth since 1960.

Table 2-1
Washington City Historical Population

Historical population		
Census	**Pop.**	**%±**
1960	445	2.3%
1970	750	68.5%
1980	3,092	312.3%
1990	4,198	35.8%
2000	8,186	95.0%
2010	18,761	129.2%
2020	27,993	49.2%
Est. 2023	33,877	21.0%

Washington City experienced a high growth rate between 1980 and 1990 and between 1990 and 2010. However the electrical load during these periods did not increase as significantly as the population. The annual historical load growth since 1987 is shown in Table 2-2.

Table 2-2
Washington City
Electrical Load History

	PEAK kW			
Year	**Summer Peak**	**% Growth (Summer)**	**Winter Peak**	**% Growth (Winter)**
1987	3,639		6,498	
1988	3,840	5.52%	6,146	-5.42%
1989	4,360	13.54%	6,851	11.47%
1990	4,514	3.53%	6,520	-4.83%
1991	4,433	-1.79%	6,500	-0.31%
1992	5,121	15.52%	5,616	-13.60%
1993	5,615	9.65%	6,083	8.32%
1994	6,514	16.01%	6,268	3.04%
1995	6,984	7.22%	6,376	1.72%
1996	8,112	16.15%	6,436	0.94%
1997	8,590	5.89%	6,665	3.56%
1998	9,883	15.05%	6,410	-3.83%
1999	10,646	7.72%	7,154	11.61%
2000	11,956	12.31%	6,976	-2.49%
2001	14,490	21.19%	8,144	16.74%
2002	15,638	7.92%	8,930	9.65%
2003	17,782	13.71%	8,714	-2.42%
2004	19,840	11.57%	9,716	11.50%
2005	23,971	20.82%	11,302	16.32%
2006	25,093	4.68%	12,966	14.72%
2007	28,542	13.74%	14,854	14.56%
2008	27,852	-2.42%	15,216	2.44%
2009	28,176	1.16%	14,374	-5.53%
2010	29,005	2.94%	14,731	2.48%
2011	29,035	0.10%	14,332	-2.71%
2012	31,518	8.55%	15,332	6.98%
2013	32,117	1.90%	16,614	8.36%
2014	31,714	-1.25%	15,377	-7.45%
2015	34,025	7.29%	14,893	-3.15%
2016	36,134	6.20%	14,945	0.35%
2017	37,943	5.01%	14,906	-0.26%
2018	38,494	1.45%	16,183	8.57%
2019	40,414	4.99%	16,777	3.67%
2020	45,665	12.99%	17,890	6.68%
2021	51,708	13.23%	18,440	3.07%
2022	51,028	-1.32%	18,990	2.98%
2023	52,511	2.91%		

Electric Infrastructure and Future Needs

Transmission

It is proposed to install Grapevine substation by approximately 2025. Significant load is expected to occur in the area surrounding I-15 Exit 13 and in the Solente area lands. The new substation will be required to serve this load. A new 69 kV transmission line will be required to feed Grapevine substation. It is also proposed to install a new 69 kV tie line from the intersection at Main St. and Parkway that feeds the Parkway Substation to the new line feeding Grapevine substation. This will create a 69 kV loop so that both substations can be fed from more than one location in the event of a line outage or for system maintenance. This versatility will enhance the City's ability to operate the electrical system and will improve service reliability to City customers.

Substation & Distribution

Approximately 32 MW of new load is projected over the next ten years in Washington City. Main Street circuits will be heavily impacted since the area currently served by Main Street is projected to grow by 12.3 MW. A significant load for Main Street circuits is expected to occur in the area surrounding I-15 Exit 13 and in the Solente area lands. Additionally, Sienna Hills circuits will need to feed several projects for apartment buildings and hotels that are currently in the planning and construction stages. Without upgrades, the Main Street circuit 202 and Main Street transformer T2 will become overloaded. It is proposed to add a new Grapevine Substation. Three new circuits for the Grapevine substation are proposed. It is proposed to add a third circuit to the Parkway substation to help feed some of the Solente Area.

Approximately 12.9 MW of load is projected for the Solente area lands. A new Grapevine substation, as described above, will help serve this load. Additionally, Parkway circuits will also help serve the new load in this area. Several new distribution lines will be required in the Solente area lands. Three new lines are proposed to be built by Washington City to tie the Solente area lands into existing circuits. The rest of the new lines in the Solente area are proposed to be built by developers as the area is developed.

Level of Service Standards

Consistent with current practice and level of service, Washington City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions remain below their base rating.
- The system is capable of adequately serving load under single contingency (N-1) situations, where "N" is a power system elements such as a transformer or line.
- The system switching required under an N-1 contingency is simplified to ensure that switching orders not become unnecessarily complex.
- Distribution circuit loading remains below 90% of its maximum current rating.
- Primary circuit voltage is kept between 95% and 105% of its nominal value.
- Distribution circuit mains are able to serve additional load under N-1 contingencies.

The above criteria was used to determine Washington City's future facility needs based on the amount of new load placed on the existing electrical system over the study period.

Demands Placed on Existing Facilities

Electrical demand loads on a system are measured in kilowatts (kW) or kilovolt-amperes (kVA) and are indicated as either coincident-peak ("CP") demand or non-coincident peak ("NCP") demand. The system CP demand is the maximum demand for the entire system measured at a point in time where the sum of all demands on the system is the highest for the system as a whole. The NCP demand is the sum of the maximum demands of individual customers or customer classes such as residential, commercial, industrial, measured for a period of time. The CP demand represents the combined loads across all customer classes measured at the system level where the NCP demand represents the total demand the system would be subject to if all customer classes peaked at the same time. The CP demand is usually lower than the NCP demand. For Impact Fees, CP represents the demand placed on the existing system as a whole, while NCP reflects the maximum demand placed on local facilities by individual customer classes. The CP demand is normally the demand that a utility plans for when sizing facilities that will be used to meet future growth on the system. However, each individual piece of equipment must be able to support its own individual peak demand even if that demand does not occur at the same time as the system's CP.

Washington City's projected CP demand between 2023 and 2032 are shown in Table 2-3. The System CP Demands for the planning period (2023 – 2032) were developed by ICPE.

Table 2-3
Summary of CP Demands
For the Period 2023 through 2033

Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total System CP Demands (kW)	52,511	54,882	58,449	62,230	66,073	69,996	73,921	77,355	80,345	83,279

System Modeling for the CFP/IFFP

The recently CFP completed contains results of load flow analysis of the Washington City electrical system. The system load flows provide insight on substation transformer loading, distribution circuit loading, and system voltage drop. The study includes analyzing N-1 outage conditions. An N-1 outage condition is the loss of a major system component such as loss of a substation transformer or loss of a main line section. The existing substations that were studied include Staheli, Main Street, Coral Canyon, Buena Vista, Sienna Hills, and Parkway. Seventeen existing 12.47 kV circuits were studied. The CFP proposes changes to circuit boundaries, the addition of one new substation and the addition of four new circuits.

To perform load flow analysis a system computer model was developed. System model development and analysis were performed on Paladin DesignBase 4.0 software. System modeling data was developed from data provided by Washington City. System load was modeled based on 2022 peak values since they were available at the time. The actual 2023 peak value is close to the projected 2023 peak value. Circuit models are based on the assumption that provided circuit maps and data (conductor sizes, circuit configurations, line lengths, etc.) are reflective of actual field conditions.

Model Results

The following System Improvement Summary from the CFP details the anticipated projects and estimated expenditures necessary to sustain the projected growth rate for Washington City's electrical system for the next 10 years. There is greater confidence in projecting requirements for 2 to 3 years than there is for a 10-year or longer outlook. However it is necessary to forecast future projects due to the magnitude (and cost) of the modifications necessary. Also substation and transmission line projects can take significant time from start to finish due to material lead times and permitting requirements. Substation, distribution, and transmission line requirements need to be addressed to meet future needs of the City in a timely fashion.

The proposed projects will provide a method for Washington City to plan and budget for the facilities necessary to serve the anticipated electrical load growth. Existing electrical facilities as well as new facilities will be used to meet projected load levels. Table 2-4 is a summary of the recommended projects, timing and costs. Detailed cost estimates for the various projects can be found in the appendix of the CFP. Costs shown are based on present 2024 project material and labor pricing.

Table 2-4
Summary of CFP Improvement Projects
For the Period 2024 through 2032*

Project ID	Description	Project Estimated Cost ($) **	Estimated Timeframe	Impact Fee %	Impact Fee Amount ($)	Revenue Funds %	Revenue Funds Amount ($)
25-PR-03	New Circuit 801	350,000.00	2024-2026	100.00%	350,000.00	0.00%	0.00
23-PR-01***	1100 E to 300 E Underbuild Upgrade	231,250.00	2024-2025	40.00%	92,500.00	60.00%	138,750.00
25-PR-01	New Grapevine Substation	6,239,000.00	2024-2025	100.00%	6,239,000.00	0.00%	0.00
24-PR-02	69kV Line Extension to Grapevine with Circuit 802 Underbuild	1,724,000.00	2024-2025	100.00%	1,724,000.00	0.00%	0.00
25-PR-02	69 kV Line Extension to Grapevine	887,000.00	2024-2025	100.00%	887,000.00	0.00%	0.00
23-PR-02	New Circuit 803	669,000.00	2029-2030	100.00%	669,000.00	0.00%	0.00
	Circuit 601/803 to Circuit 402 750 Tie	200,000.00	2024-2025	100.00%	200,000.00	0.00%	0.00
21-PR-06	Circuit 102 to Circuit 603 Tie	478,000.00	2026-2027	100.00%	478,000.00	0.00%	0.00
23-PR-03	Circuit 302 to Circuit 303 Tie	760,000.00	2031-2032	100.00%	760,000.00	0.00%	0.00
	TOTALS	11,538,250.00			11,399,500.00		138,750.00

* Note: Project timing will vary based on actual load growth amount and location.
** Values have been rounded.
*** Project identified in previous CFP and is 75% completed.

IFFP Capital Projects and Costs

As previously mentioned, the costs for the above projects are estimated in 2024 dollars. As with most capital facilities plans, the majority of these projects are scheduled to occur in the earlier planning windows. However, growth in demand on the system generally happens in "groups" or "lumps" according to actual commercial and residential development. Actual load growth may be sooner or later than shown based on current economic and development levels. Projects shown in the IFFP may be delayed or accelerated based on actual load growth locations and timing.

Certification of the IFFP

I certify that the attached Impact Fee Facilities Plan:

1. includes only the costs of public facilities that are:
    a. allowed under the Impact Fees Act; and
    b. actually incurred; or
    c. projected to be incurred or encumbered within six years after the day on which each impact fee is paid;
2. does not include:
    a. costs of operation and maintenance of public facilities;
    b. costs for qualifying public facilities that will raise the level of service for facilities, through impact fees, above the level of service that is supported by existing residents;
    c. an expense for overhead, unless the expense is calculated pursuant to a methodology that is consistent with generally accepted cost accounting practices and the methodological standards set forth by the federal Office of Management and Budget for federal grant reimbursement;

CERTIFIED BY:

Signature: Mac Fillingim

Name: Mac Fillingim

Title: ICPE, Senior Engineer

Date: May, 2024

Washington City Power Department

Electric Impact Fee Analysis

Mark Beauchamp, President
Utility Financial Solutions, LLC

Presentation Objectives

- Define what an impact fee is and why it is needed
- Describe how impact fees are determined
- Review results and modifications to impact fee structure

Impact Fees – Growth Pays for Growth

The Impact Fee Study aims to identify:

- Impacts caused by new customers
  - Growth causes additional capacity investments
  - The investments tend to occur intermittently
- Value new customers provide
  - New customers generate contribution margins in the rates to fund fixed infrastructure costs
  - Cost of service study identifies the fixed and variable cost components used to determine a customer's value

Projected Impact Fee Related Projects

2024 - 2032

Washington City CIP	Estimated Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	Impact Fee %	Impact Related Cost
New Circuit 801	$ 350,000	$ 116,667	$ 116,667	$ 116,667	$ -	$ -	$ -	$ -	$ -	$ -	100%	$ 350,000
1100 E to 300 E Underbuild Upgrade	$ 103,680	51,840	51,840	-	-	-	-	-	-	-	40%	$ 41,472
New Grapvine Substation	$ 4,619,397	2,309,699	2,309,699	-	-	-	-	-	-	-	100%	$ 4,619,397
69kV Line Extension to Grapvine with circuit 802	$ 1,663,355	831,678	831,678	-	-	-	-	-	-	-	100%	$ 1,663,355
69 kV Line Extension to Grapvine	$ 865,058	432,529	432,529	-	-	-	-	-	-	-	100%	$ 865,058
New Circuit 803	$ 434,064	-	-	-	-	-	217,032	217,032	-	-	100%	$ 434,064
Circuit 601/803 to Circuit 402 750 Tie	$ 200,000	100,000	100,000	-	-	-	-	-	-	-	100%	$ 200,000
Circuit 102 to Circuit 603 Tie	$ 478,000	-	-	239,000	239,000	-	-	-	-	-	100%	$ 478,000
Circuit 302 to Circuit 303 Tie	$ 760,000	-	-	-	-	-	-	-	380,000	380,000	100%	$ 760,000

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Impact Fees by Service Level

- Residential base installation is 100 AMP 120/240V, 1 phase service
- Small Commercial/Special Services is based on 120/240V, 1 phase
- Large Commercial/varies between 208/120V, 3 phase or 480/277V, 3 phase
- The calculated impact fee is proportioned based on the amperage and voltage level of service

Proposed Impact Fee Schedule
* Residential

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Residential (120/240 V, 1 phase)			
100 Amp (min. size)	$ 1,387	$ 1,517	9%
125 Amp	1,733	1,897	9%
150 Amp	2,080	2,276	9%
200 Amp	2,773	3,035	9%
225 Amp	3,120	3,414	9%
400 Amp	5,546	6,070	9%
600 Amp	8,320	9,105	9%
800 Amp	11,093	12,139	9%
Residential (208/120 V, 3 phase Apartments)			
100 Amp (min. size)	$ 2,081	$ 2,278	9%
125 Amp	2,602	2,847	9%
150 Amp	3,122	3,417	9%
200 Amp	4,163	4,556	9%
225 Amp	4,683	5,125	9%
400 Amp	8,326	9,111	9%
600 Amp	12,488	13,667	9%
800 Amp	16,651	18,222	9%
1000 Amp	20,814	22,778	9%
1200 Amp	24,977	27,333	9%
1600 Amp	33,302	36,444	9%

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment.
Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

Proposed Impact Fee Schedule
* Small Commercial & Special Services

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (120/240 V, 1 phase)			
100 Amp (min. size)	$ 2,219	$ 2,425	9%
125 Amp	2,774	3,031	9%
150 Amp	3,329	3,638	9%
200 Amp	4,439	4,850	9%
225 Amp	4,993	5,456	9%
400 Amp	8,877	9,700	9%
600 Amp	13,316	14,550	9%
Special Services (120/240 V, 1 phase) *			
60 Amp	$ 666	$ 728	9%

* By special approval (includes sprinkler controllers; gate openers; and fiber optic communication boosters, etc.with limited load requirements).

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment. Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

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Proposed Impact Fee Schedule

* Large Commercial

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (208/120 V, 3 phase)			
100 Amp (min. size)	$ 3,331	$ 4,001	20%
125 Amp	4,164	5,002	20%
150 Amp	4,997	6,002	20%
200 Amp	6,663	8,003	20%
225 Amp	7,496	9,003	20%
300 Amp	9,994	12,004	20%
400 Amp	13,325	16,005	20%
600 Amp	19,988	24,008	20%
800 Amp	26,651	32,010	20%
1200 Amp	39,976	48,015	20%
1600 Amp	53,301	64,020	20%
2000 Amp	66,627	80,025	20%
2500 Amp	83,283	100,032	20%
3000 Amp	99,940	120,038	20%
4000 Amp	133,253	160,050	20%

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment. Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (480/277 V, 3 phase)			
200 Amp (min. size)	$ 15,458	$ 18,467	19%
225 Amp	17,390	20,776	19%
400 Amp	30,916	36,935	19%
800 Amp	61,833	73,869	19%
1200 Amp	92,749	110,804	19%
1400 Amp	108,207	129,272	19%
2000 Amp	154,582	184,674	19%

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment. Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

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Residential vs. Commercial

9% Residential vs. 20% Large Commercial

Usage patterns of large commercial customers changed between the 2020 cost of service study and the 2024 study. This resulted in greater customer impacts occurring with new customers within this class.

Washington City
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Washington City Power Department

Electric Impact Fee Analysis

January 2025

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Submitted Respectfully by:
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President, Utility Financial Solutions, LLC
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UTILITY FINANCIAL SOLUTIONS, LLC

January 2025

Rick Hansen, Power Department Director
Washington City Power Department
111 North 100 East
Washington City, UT 84780

Dear Mr. Hansen:

We are pleased to present a report for the Impact Fee Analysis for Washington City Power Department (Washington City). This report was prepared to provide Washington City with a comprehensive examination of its existing impact fee structure by an outside party. It is compliant with Utah Statute U.C.A. 1953 §11-36a-102.

The specific purposes of this rate study are:

- Identify the fixed cost contributions to plant a new customer provides through electric rate tariffs
- Identify gross investment in plant necessary to service new growth at various sizes and voltages
- Determine impact fees by subtracting the present value of the fixed cost contributions from the impacts on plant

This report utilizes results of the electric cost of service study and financial projections performed in 2024 and Washington City's capital improvement plan.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
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TABLE OF CONTENTS

LIST OF TABLES

Introduction

This report identifies the impact fees Washington City should charge to new customers by identifying the cost of expansion of the system for new customers and subtracting customers contributions toward system expansion through rates charged to the new customers (Contribution Margin).

The purpose of this analysis is to help ensure:

- New customers are not subsidizing existing customers
- Existing customers are not subsidizing new customers

This analysis helps ensure growth will benefit all customers in the system and not be adversely impacted by rate increases due to growth of the system. Growth causes additional capacity investments that often occur intermittently, and funds generated through impact fees are used to fund the expansions.

As new customers are added to the system, Washington City receives contribution margins through rates to fund a portion of the fixed infrastructure costs. When electric rates are set by the governing body, they include a recovery component for the replacement cost of current assets that new customers will contribute toward funding through the rates charged. This is often referred to as net revenue, which can be allocated to offset a certain amount of the system expansions.

However, when the system expansion exceeds the net revenues generated from customers it results in impact charges for new customers, as detailed in this report.

Steps to Complete the Analysis

The following steps were taken to complete the impact fee analysis:

1) Identify the contribution margins (Net Revenues) generated by rate tariffs and used to fund replacement cost of existing infrastructure.
2) The contribution margins are valued over an appropriate period to determine the present value of the new customers contribution margins.
3) Review and classification of plant investments into investment to serve future growth and other investments used to either replace infrastructure or does not increase capacity in the system.
4) Total system cost impacts based on new plant investments divided by residential equivalent factors are then reduced by the value of the contribution margins.
5) The residential equivalent factors are converted to amperage and proposed to each amperage based on potential capacity needs of each customer.

Step One – Determination of Contribution Margin

Contribution margins were calculated for each class by subtracting variable costs typically power supply costs from revenues to identify the contribution margins generated by each class.

Revenue minus variable cost equals contribution margin

Table 1 identifies the total revenue requirements for each class and subtracts the variable costs to identify the fixed cost recoveries for each class of customers. Expense used in the analysis is from the cost of service study completed in 2024. Variable costs are primarily driven by power supply and transmission costs, and most of the distribution system is classified as fixed cost recovery. This includes distribution and sub-transmission cost recovery used to fund operation, maintenance, replacement, and expansion of the distribution and sub-transmission system.

Table 1 below identifies the total recovery of distribution operations for each class. The residential class generates $5.67M, Small Commercial $423k, Large Commercial $963k, and Steel Structures $10k.

Table 1 – Contribution Margin by Class

Expense Description	Expense Classification	Residential	Small Commercial	Large Commercial	Steel Structures
Power Supply Expenses:					
Summer Demand	Variable	$ 2,979,687	$ 229,306	$ 679,517	$ 5,998
Summer Energy	Variable	3,707,231	286,034	975,892	7,781
Winter Demand	Variable	147,930	22,930	63,618	782
Winter Energy	Variable	1,664,749	201,402	604,721	7,190
Inter 2 Demand	Variable	390,326	28,469	82,981	835
Inter 2 Energy	Variable	2,660,801	235,126	794,684	6,057
Inter 4 Demand	Variable	288,456	36,986	108,276	1,000
Inter 4 Energy	Variable	1,576,785	205,844	666,912	6,647
Distribution Expenses:					
Distribution	Fixed	1,305,149	96,615	286,304	3,061
Transmission	Fixed	783,611	67,759	198,409	2,010
Transformer	Fixed	17,876	1,323	3,921	-
Substation	Fixed	1,649,245	122,086	361,786	3,867
Customer Related Expenses:					
Distribution Customer Costs	Fixed	1,277,857	90,533	75,444	888
Transformer Customer Costs	Fixed	127,746	9,051	7,542	-
Substation Customer Costs	Fixed	210,648	14,924	12,437	146
Meter O&M	Included in Customer Investment	16,415	2,139	1,733	15
Meter Reading	Variable	126,696	29,920	7,480	63
Billing	Variable	290,040	20,549	17,124	201
Services	Included in Customer Investment	61,120	4,341	4,131	40
Customer Service	Fixed	290,040	20,549	17,124	201
Total		$ 19,572,408	$ 1,725,884	$ 4,970,037	$ 46,783
Total Fixed		**$ 5,662,172**	**$ 422,839**	**$ 962,967**	**$ 10,173**

Step Two - Contribution Margin Unit Conversion

The contribution to margin (Net Revenue) is present valued over a specified time period to determine the maximum value a new customer will generate over an appropriate recovery period. Table 2 shows the average net revenue generated by each customer type on a per kWh or kW basis. For example, for each kWh sold to the residential class, $0.0529 cents of fixed cost recovery is used to fund the distribution system. For the remaining classes the contribution margins are expressed in dollars per kW of demand charged to the customers.

Table 2 – Determination of Present Value of Contribution Margins

Customer Class	Recovery Period (Years)		1	2	3	4
Residential	4	per kWh	$ 0.0529	$ 0.0529	$ 0.0529	$ 0.0529
Small Commercial	2	per kW	12.39	12.39	-	-
Large Commercial	2	per kW	9.77	9.77	-	-
Steel Structures	2	per kW	7.99	7.99	-	-

Table 3 details the value of the contribution margins by customer class. The value of the fixed cost recovery for a typical residential customer is $1,947. Due to variations in customer usages within the small and large commercial classes and steel structures, the utility investment is best expressed on a per kW basis multiplied by the projected annual kW sales for that customer. For example, to determine the value of a new small commercial customer, $22.71 kW is multiplied by the annual kW sales to the new customer.

Table 3 – Average Contribution Margin per Billing Basis

Customer Class	COS Revenue Requirement	Fixed Costs Contribution	Recovery Period (Years)	Utility Investment		Maximum Utility Investment per Customer
Residential	$ 19,572,408	$ 5,662,172	4	$ 0.1833	per kWh	$ 1,947
Small Commercial	1,725,884	422,839	2	22.71	per kW	1,629
Large Commercial	4,970,037	962,967	2	17.91	per kW	14,836
Steel Structures	46,783	10,173	2	14.65	per kW	18,652

Step Three - Infrastructure Cost Analysis

The determination of impact fees depends on the additional capacity needed to service new load and is expressed by amperage and voltage requirements.

The infrastructure costs are broken down into the following components:

- Distribution Local – Investments made to service customers peak demands
- Distribution Substation – Investments made to service peaks of customers located in specific areas

Washington City provided a capacity plan for the total system with a breakout of the amount attributed to expansion due to growth. The table below outlines the projected Washington City investments in plant, the additional capacity provided by the investments, and the expansion costs on a per kW basis.

Table 4 is used to identify the cost impacts associated with each type of cost component.

Table 4 – Cost of Additional Investment in Plant

	Distribution Local	Distribution Sub
Gross Investment in Plant	$ 2,263,536	$ 7,147,810
Additional Capacity	12,000	12,000
Cost per kW	$ 188.63	$ 595.65

Customer Demand – Peaks created by customers
NCP – Area or Class Peak Demands
CP – System Peak Demands

Step Four – Determine Cost Impact by Class

The cost of service study provided information on each class's demand impacts on various portions of the electric system and the capacity needs for a new customer within each class.

Residential Class Example

The average residential customer creates a peak demand of 4.02 kW on local infrastructure and substations. The expansion cost per kW is then multiplied by the peak demand kW.

For residential, the average cost impact of $3,464.24 is reduced by the maximum contribution margin value of $1,946.82 to identify an average impact of $1,517.42.

Table 5 – Calculation of Impact Fees by Class

Description	Residential Service	Small Commercial	Large Commercial	Steel Structures
A. Rate per kW				
Distribution Local	$ 316.81	$ 316.81	$ 316.81	$ 316.81
Distribution Sub	$ 544.94	$ 544.94	$ 544.94	$ 544.94
B. Average Impacts				
Distribution Local (NCP)	4.02	6.30	74.68	101.70
Distribution Substation (NCP)	4.02	6.30	74.68	101.70
Cost Impact by Component (A x B)				
Distribution Local	$ 1,273.58	$ 1,995.90	$ 23,659.37	$ 32,219.58
Distribution Sub	$ 2,190.66	$ 3,433.12	$ 40,696.12	$ 55,420.40
Total Impact Cost	$ 3,464.24	$ 5,429.02	$ 64,355.49	$ 87,639.98
Less: Maximum Utility Contribution	$ 1,946.82	$ 1,628.63	$ 14,836.11	$ 18,651.53
Impact Fees to be Recovered	$ 1,517.42	$ 3,800.39	$ 49,519.38	$ 68,988.45
Rate per kW installed Transformer Capacity	$ 377.47	$ 603.24	$ 663.09	$ 678.35

Step Five – Conversion to Amperage

Table 6 expresses the results by Amperage and Voltage level using a typical 100 AMP residential service voltage (120/240V) as the base.

Table 6 – Impact Fees by Amperage and Voltage Level (Residential)

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Residential (120/240 V, 1 phase)			
100 Amp (min. size)	$ 1,387	$ 1,517	9%
125 Amp	1,733	1,897	9%
150 Amp	2,080	2,276	9%
200 Amp	2,773	3,035	9%
225 Amp	3,120	3,414	9%
400 Amp	5,546	6,070	9%
600 Amp	8,320	9,105	9%
800 Amp	11,093	12,139	9%
Residential (208/120 V, 3 phase Apartments)			
100 Amp (min. size)	$ 2,081	$ 2,278	9%
125 Amp	2,602	2,847	9%
150 Amp	3,122	3,417	9%
200 Amp	4,163	4,556	9%
225 Amp	4,683	5,125	9%
400 Amp	8,326	9,111	9%
600 Amp	12,488	13,667	9%
800 Amp	16,651	18,222	9%
1000 Amp	20,814	22,778	9%
1200 Amp	24,977	27,333	9%
1600 Amp	33,302	36,444	9%

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment.
Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

Table 7 expresses the results by Amperage and Voltage level using a typical small commercial service or special services voltage (120/240V, 1 phase) as the base.

Table 7 – Impact Fees by Amperage and Voltage Level (Small Commercial & Special Services)

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (120/240 V, 1 phase)			
100 Amp (min. size)	$ 2,219	$ 2,425	9%
125 Amp	2,774	3,031	9%
150 Amp	3,329	3,638	9%
200 Amp	4,439	4,850	9%
225 Amp	4,993	5,456	9%
400 Amp	8,877	9,700	9%
600 Amp	13,316	14,550	9%
Special Services (120/240 V, 1 phase) *			
60 Amp	$ 666	$ 728	9%

* By special approval (includes sprinkler controllers; gate openers; and fiber optic communication boosters, etc.with limited load requirements).

** For Panel Sizes not listed Impact Fees will be calculated by the Power Deparment. Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

Table 8 expresses the results by Amperage and Voltage level using a typical large commercial service voltage (208/120V, 3 phase or 480/277V, 3 phase) as the base.

Table 8 – Impact Fees by Amperage and Voltage Level (Large Commercial)

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (208/120 V, 3 phase)			
100 Amp (min. size)	$ 3,331	$ 4,001	20%
125 Amp	4,164	5,002	20%
150 Amp	4,997	6,002	20%
200 Amp	6,663	8,003	20%
225 Amp	7,496	9,003	20%
300 Amp	9,994	12,004	20%
400 Amp	13,325	16,005	20%
600 Amp	19,988	24,008	20%
800 Amp	26,651	32,010	20%
1200 Amp	39,976	48,015	20%
1600 Amp	53,301	64,020	20%
2000 Amp	66,627	80,025	20%
2500 Amp	83,283	100,032	20%
3000 Amp	99,940	120,038	20%
4000 Amp	133,253	160,050	20%
Commercial (480/277 V, 3 phase)			
200 Amp (min. size)	$ 15,458	$ 18,467	19%
225 Amp	17,390	20,776	19%
400 Amp	30,916	36,935	19%
800 Amp	61,833	73,869	19%
1200 Amp	92,749	110,804	19%
1400 Amp	108,207	129,272	19%
2000 Amp	154,582	184,674	19%

** For Panel Sizes not listed Impact Fees will be calculated by the Power Depardment. Calculations to be based on the formulas provided in the Impact Fee Study.

Amounts are rounded to the nearest dollar.

Significant Assumptions

The following assumptions are made in the creation of this report:

1) **Discount Rate** – 6.0%
2) **Recovery Period:**
   All Residential Services – 4 year recovery
   Commercial – 2 year recovery

Statistical Information

Table 9 – Class Load Data and Statistics

Description	Residential Service	Small Commercial	Large Commercial	Steel Structures
Number of Customers	10,078	476	119	1
Energy at Meter	107,013,328	11,054,190	35,755,795	352,545
NCP Meter	40,510	2,999	8,887	102
NCP Primary	42,317	3,133	9,283	102
NCP Input	44,187	3,271	9,693	104
Group LF	30%	42%	46%	40%
Class Peak Factor	100%	100%	100%	100%
Grouping of Classes	Res	MC	LC	Ind
Transmission Impacts				
Average NCP (kw)	4.02	6.30	74.68	101.70
Average NCP (kw) Impact	$ 8,766.89	$ 13,740.26	$ 162,869.52	$ 221,807.70
Average kWh per kW of NCP	2,642	3,686	4,024	3,467
Average kWh per kW of NCP Impact	657.18	585.11	53.88	34.09
Substation Impacts				
Average NCP (kw)	4.02	6.30	74.68	101.70
Average NCP (kw) Impact	$ 4,920.07	$ 7,711.18	$ 91,404.08	$ 124,480.80
Average kWh per kW of NCP	2,642	3,686	4,024	3,467
Average kWh per kW of NCP Impact	657.18	585.11	53.88	34.09
Group Diversity Factor Impact	$ 2,190.48	$ 3,433.11	$ 40,694.23	$ 55,420.40
Transformer Impacts				
Average NCP (kw)	4.02	6.30	74.68	101.70
Average kWh per kW of NCP	2,642	3,686	4,024	3,467
Average kWh per kW of NCP Impact	657.18	585.11	53.88	34.09
Group Diversity Factor Impact	$ 1,273.47	$ 1,995.90	$ 23,658.27	$ 32,219.58
Feeder Impacts				
Average kWh per kW of NCP	2,642	3,686	4,024	3,467
Average kWh per kW of NCP Impact	0.23	0.17	0.15	0.18
Group Diversity Factor Impact	$ 51.00	$ 45.90	$ 45.90	$ 45.90
Impacts on Distribution Substations				
Total Class NCP (kw)	40,510.16	2,998.79	8,886.51	101.70
Average Customer NCP (kw)	4.02	6.30	74.68	101.70
Impacts on System Substations and Sub-Transmission Facilities				
Total System CP (kw)	40,510.16	2,998.79	8,886.51	101.70
Average kW - System (kw)	4.02	6.30	74.68	101.70

Considerations

Currently, new customers are not contributing enough to cover the cost of capacity upgrades to the system. Table 10 and Table 11 compare the current and proposed impact fees for all classes.

Table 10 – Proposed Impact Fees for Residential Services

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Residential (120/240 V, 1 phase)			
100 Amp (min. size)	$ 1,387	$ 1,517	9%
125 Amp	1,733	1,897	9%
150 Amp	2,080	2,276	9%
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Table 11 – Proposed Impact Fees for Commercial/Special Services

Description / Panel Rating	2021 Impact Fee **	2024 Proposed	Percent Change
Impact Fee Charge for Applicable Panel Size			
Commercial (120/240 V, 1 phase)			
100 Amp (min. size)	$ 2,219	$ 2,425	9%
125 Amp	2,774	3,031	9%
150 Amp	3,329	3,638	9%
200 Amp	4,439	4,850	9%
225 Amp	4,993	5,456	9%
400 Amp	8,877	9,700	9%
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Commercial (208/120 V, 3 phase)			
100 Amp (min. size)	$ 3,331	$ 4,001	20%
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225 Amp	17,390	20,776	19%
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UAMPS

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

December 2024

Project Meeting Overview Report

CARBON FREE POWER PROJECT (CFPP)

1. **Philo Shelton was elected Project Chair.**
2. Discussed in Executive Session:
    a. Project wind down status, timeline and DOE engagement.

CENTRAL-ST. GEORGE PROJECT

1. **Gary Hall was re-elected Project Chair.**
2. **Approved the Washington County 69kV-138kV Transformer upgrade Plan #3, as discussed.**
3. Discussed the Operations Report including substation reports for the month of November.

COLORADO RIVER STORAGE PROJECT (CRSP)

1. **Darren Hess was elected Project Chair.**
2. Discussed the Operations Report including output for each resource for the month of November.

CRAIG MONA PROJECT

1. **Cory Daniels was re-elected Project Chair.**
2. Discussed the Operations Report including production line usage for the month of November.

FIRM POWER SUPPLY PROJECT

1. **Mark Montgomery was elected Project Chair.**
2. Discussed the Operations Report including output and scheduling from each resource for the month of November.

GOVERNMENT AND PUBLIC AFFAIRS PROJECT (GPA)

1. **Les Williams was elected Project Chair.**
2. Discussed Federal & State Legislation including Executive Branch and Congressional Updates:
   a. The White House including EPA, Interior and DOE.
   b. The Senate including EPA, Interior and DOE.
   c. The House including voting, new House members and committee assignments.
   d. State matters including Operation Gigawatt, legislature and lobbyists.
   e. 2025 General Session and the topics of focus including energy-related issues.
3. **Legislative Reception at the Utah State Capitol is scheduled for February 20, 2024.**
4. **Reminder to RSVP for the 2024 APPA Legislative Rally.**

HORSE BUTTE PROJECT (HBW)

1. **Bruce Rigby was elected Project Chair.**
2. Discussed plant operations including generator repair and site mowing activity.
3. Discussed software upgrade including current status and next steps.
4. Discussed the Operations Report including production output for the month of November.

HUNTER PROJECT

1. **Jason Norlen was elected Project Chair.**
2. Discussed the Operations Report including plant scheduled output for the month of November.

INTERMOUNTAIN POWER PROJECT (IPP)

1. **Nick Tatton was re-elected Project Chair.**
2. Discussed IPP Callback including current status, timeline, project updates, IPP UAMPS forecast and IPP compared to market.
3. Discussed a plant update including plant visits, investigating connecting to the switch yard and coal usage planning.
4. Discussed the Operations Report including scheduled output for the month of November.

MEMBER SERVICES PROJECT

1. **Josey Parsons was re-elected Project Chair.**
2. Discussed AMI including current status and next steps.

MILLARD COUNTY PROJECT

1. **Joel Eves was elected Project Chair.**
2. **Approved a resolution relating to the Millard County Power Project; declaring the Effective Date and finalizing the terms of the Power Sales Contracts; authorizing UAMPS to proceed with the development of the Project under the direction of the Project Management Committee; and related matters with the discussed changes.**
3. Discussed in Executive Session:
   a. Project update including development parameters, land options and next steps.
   b. Development milestones and timeline.

NATURAL GAS PROJECT

1. **Jason Norlen was elected Project Chair.**
2. Discussed the Operations Report including the MMBtu scheduled for the month of November.

NEBO PROJECT

1. **Shawn Black was re-elected Project Chair.**
2. Discussed plant operation including November statistics, operational item highlights, plant maintenance/safety highlights, outage follow-up items and plant water update.
3. Discussed the Operations Report for the month of November including Nebo energy breakdown and Nebo sales margins.

POOL PROJECT

1. **Jeremy Franklin was re-elected Project Chair.**
2. Discussed in Executive Session:
   a. Scheduling coordinator including investigating options, criteria details, overall scoring and UAMPS recommendations.
3. **Approved moving forward with negotiation agreement for Scheduling Coordinator services, as recommended and discussed.**
4. Discussed the PX & Scheduling Report including UAMPS yearly peak, energy and member internal generation.
5. Discussed the Forecast Load and Resources.
6. Discussed Mercuria Swap & RECs including optimizing PCC2 REC sales, value optimization and next steps.
7. Discussed the Operations Report for the month of November including load peak and energy.

RESOUCE PROJECT

1. **Allen Johnson was re-elected Project Chair.**
2. **Approved the formation of the Millard County Natural Gas Project as a standalone project and moved it out from under the umbrella of the Resource Project.**
3. Discussed in Executive Session:
   a. Horse Butte 2 Study Project including current status, budget and next steps.
   b. Rodatherm & Cove Fort 2 Study Project including current status, timeline and next steps.
   c. Uinta Wind Study Project including term sheet update and next steps.

   d. Power County Natural Gas including current status and next steps.

4. **Approved Horse Butte 2 Study Project & Budget Amendment #12 of $110,000, as presented.**
5. **Approved Uinta Wind Study Project Term Sheet as presented and discussed.**

SAN JUAN PROJECT

1. **Isaac Jones was re-elected Project Chair.**

VEYO HEAT RECOVERY PROJECT

1. **Kent Kummer was elected Project Chair**
2. Discussed past and future project REC sales including REC comparisons,
3. **Approved selling all RECs produced by the Veyo Project in 2024 at the best available price and move the sale of 2025 RECs to budget discussions.**
4. Discussed the 2024 plant outage projects and future planned maintenance.
5. Discussed the Operations Report including scheduling Veyo for the month of November with peak output and tripped/restricted hours.

ANNUAL MEMBER MEETING

1. **Elected Project Directors.**

BOARD OF DIRECTORS MEETING

1. **Elected UAMPS Officers:**
   a. Rick Hansen was elected Chair.
   b. Shane Ward was elected Vice Chair.
   c. Greg Bellon was elected Secretary.
   d. Shawn Black was elected Treasurer.
2. Discussed the Operations Report:
   a. Natural Gas including regional storage and gas consumption for electricity generation.

b. Seasonal outlook including December forecast and 2025 Q1 forecast.

c. Industry news including EDAM filing, Western Market development and WECC 2024 assessment of Resource Adequacy Report.

d. Transmission update including challenges building new transmission, the approval process, and other state and federal transmission related policies and initiatives.

3. Discussed the Budget Committee including members and the upcoming meeting schedule.
4. **Approved resolution relating to the Millard County Power Project; declaring the Effective Date and finalizing the terms of the Power Sales Contracts; authorizing UAMPS to proceed with the development of the Project under the direction of the Project Management Committee; and related matters.**
5. Discussed in Executive Session:

   a. Compensation Survey

   b. CEO Contract Negotiations

6. **Approved the Compensation Survey.**
7. Approved all action items for the Project Meetings.