

SALEM CITY POWER

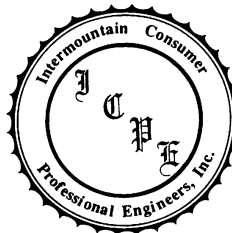


Capital Facility Plan, Impact Fee Facility Plan and Impact Fee Study

August 2019

PRELIMINARY – SUBJECT TO CHANGE / MODIFICATION

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Table of Contents

SECTION 1 - Background	1
1.1 Introduction	1
1.2 Impact Fees - General	1
1.3 Impact Fees - Utah	3
1.4 Salem City and SCP	4
1.5 Washington County	5
1.6 Electricity Supply & Demand	5
1.6.1 General	5
1.6.2 Electricity Supply	6
1.6.3 Transmission of Electricity	7
1.6.4 Distribution of Electricity	8
SECTION 2 - Capital Facilities Plan and Impact Fee Facilities Plan	10
2.1 General	10
2.2 Historical Population and Load Growth	10
2.3 Existing Electric Infrastructure and Future Needs	11
2.3.1 Transmission	11
2.3.2 Substation	12
2.3.3 Distribution	13
2.4 Level of Service Standards	14
2.5 Demands Placed on Existing Facilities	15
2.6 System Modeling for the CFP/IFFP	17
2.7 Model Results	17
2.8 IFFP Capital Projects and Costs	21
2.9 Certification of the IFFP	22
SECTION 3 - Impact Fee Analysis	23
3.1 General	23
3.2 Impact Fee Analysis	23
3.2.1 Identification of Impact Fee Projects/Costs	23
3.2.2 Impact Fee Demand Analysis	24
3.2.3 Calculation of the Impact Fee	25
3.3 Impact Fee Charges – Present and Proposed	25
3.4 Certification of the IFA	27

EXHIBITS

Exhibit 1 – Forecasted Customers, Energy and Demands, 2018 - 2037

Exhibit 2 – Impact Fee Projects / Costs

Exhibit 3 – Impact Fee Demand Analysis

Exhibit 4 – Base Impact Fee Calculation

Exhibit 5 – Summary of Charges – Present & Proposed Impact Fees

APPENDICES

Appendix A – Utah Statute U.C.A. 1953 § 11-36a-102

Section 1 - Background

1.1 Introduction

Salem City Power (“the City,” “Salem” or “SCP”) engaged the services of Intermountain Consumer Professional Engineers, Inc. (“ICPE”) who teamed with R. E. Pender Inc. (“Consultant”) to conduct certain studies and analyses related to the development of an updated Electrical Power Capital Facilities Plan, Impact Fee Facilities Plan Update, and Impact Fee Analysis (collectively, “the 2019 Impact Fee Study”), the results of which will be implemented upon city council approval.

The 2019 Impact Fee Study was undertaken to update the City’s current power impact fees as determined from a prior study performed in 2012 by Comlink Land Services, LLC.

In conducting the subject study, certain publicly available information, data supplied by SCP and electronic spreadsheets developed specifically for this engagement were utilized. In reaching the conclusions and recommendations discussed herein certain assumptions and considerations were made regarding future events and circumstances that may affect the ultimate outcome of the results. No assurances or guarantees are made as to the actual outcome of any assumption or consideration made in the development of these studies. However, it is believed that all assumptions and considerations made herein are appropriate and reasonable for purposes of the Impact Fee Study. In addition, certain information was obtained by the Consultant from other sources, all of which are believed to be reliable and reasonable for the purpose of this undertaking.

1.2 Impact Fees - General

Generally speaking, impact fees are used by government agencies (e.g., city and county governments) to fund certain capital-related expenditures (e.g., new infrastructure) incurred in providing governmental services to “new” development as mandated by law or ordinance. The basic philosophy behind the implementation of impact fees is that “new” development should bear the additional or “incremental” capital cost incurred in order to provide services to the “new” development. This establishes a cost causation or “nexus” requirement between the cost incurred in providing the service and those who benefit from the service. To be clear however, impact fees are not intended to recover annual operating expenses (e.g., utility costs) or to pay for capital expenditures related to the correction of an existing deficiency in the service provided.

There are two generally recognized methods for calculating impact fees: the *inductive* method and the *deductive* method.

Under the *inductive* method, the cost and capacity of a particular facility is identified and used as the generic model for all future facilities. Take for example the cost of a new electrical substation having a construction cost of \$2,000,000 and sized to serve approximately 5,000 residential dwelling units and 1,000,000 square feet of commercial space. In this very simple example, assuming the capital cost is recovered evenly (50% each) between residential and commercial loads, the impact fee would be determined as follows:

$$\begin{array}{lll} \text{Residential} & = & \$2,000,000 \times .50 / 5,000 = \$200 \text{ per dwelling unit} \\ \text{Commercial} & = & \$2,000,000 \times .50 / 1,000,000 = \$1.00 \text{ per sq. foot.} \end{array}$$

An advantage to this method is that it is fairly straightforward and easy to implement. It also is not affected by changes to capital improvement plans or population estimates. The monies needed for the future capital requirement (like the electrical substation in the above example) will be available as soon as actual growth reaches the design levels, which may be any number of years down the road. A disadvantage of the inductive method is that the impact fee calculation is based on a generic model approach and, therefore, may not address the special needs of the community. It also may fail to capture all of the capital requirements associated with the project, including, for example the additional facilities that will be needed to support the primary project (e.g., required increases to the capacity of administrative support offices).

The *deductive* approach involves calculating the impact fee based on the anticipated additional demand (e.g., number of new residential dwelling units) on a facility or infrastructure used in providing services. Normally, the entity implementing the impact fee usually will have an established level of service (“LOS”) standard for the particular service (e.g., 1 community park per 5,000 population) or alternatively, the current LOS (1 community park serving an existing population of 4,000) is used as the basis to determine the capital requirements underlying the impact fee calculation. In either case, once the LOS standard is known, it is a matter of applying that standard to future growth projections in population and/or commercial space as reflected in a master plan and/or capital improvement plan to determine the new capital requirements.

An advantage of using the deductive method is that it will address the specific needs of the community when determining the future capital requirements. The downside is that this method requires much more detailed information to perform the calculations and must be updated periodically as changes in population projections, master plans, etc. occur.

The inductive and deductive methods are both valid and the use of one or the other will depend largely upon the information available and the specific circumstances of the community. In calculating the subject electrical impact fees for the City, we have employed only the deductive approach.

1.3 Impact Fees - Utah

Almost all states have some form of impact fees and 26 of those states have statutes authorizing the use of impact fees. In Utah, impact fees are governed by state statute, specifically U.C.A. 1953 § 11-36a-102 (the “Statute”). A copy of the Statute is attached hereto as Appendix A.

Very generally, the Statute requires that each political subdivision imposing an impact fee shall, with some exceptions, (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).

According to 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 generally consider all revenue sources, including impact fees, used to finance impacts on system improvements. This report incorporates SCP Capital Facilities Plan (CFP), published June 2019, by reference but noting that the primary difference between the IFFP and the CFP is that the IFFP considers only those projects that are brought about by future growth on the SCP system. That is, certain projects identified in the CFP may be due to the correction of an existing deficiency and are therefore are not considered in the IFFP.

The Impact Fee Analysis (“IFA”) portion of the Statute states that (1) “each local political subdivision or private entity intending to impose an impact fee shall prepare a written analysis of each impact fee:” and (2) “shall also prepare a summary of the impact fee analysis designed to be understood by a lay person.” The requirements of the IFA include identifying the estimated impacts on existing capacity and system improvements caused by the anticipated development activity. The political subdivision must also estimate the proportionate share of (i) the costs of existing capacity that will be recouped and

(ii) the costs of the impacts on system improvements that are reasonably related to the new development activity.

The calculation of the Impact Fee may include the following:

- (a) The construction contract price;
- (b) The cost of acquiring land, improvements, materials, and fixtures;
- (c) The cost for planning, surveying, and engineering fees for services provided for and directly related to the construction of the system improvements; and
- (d) For a political subdivision, debt service charges, if the political subdivision might use impact fees as a revenue stream to pay the principal and interest on bonds, notes or other obligations issued to finance the costs of the system improvements.

Also, the calculation of the Impact Fee must be based on realistic estimates and the assumptions underlying such estimates must be disclosed in the IFA.

Finally, a written certification shall be included in the IFFP and the IFA by the person or entity that prepared those requirements.

1.4 Salem City and SCP



Salem City is located in north central Utah in Utah County, approximately 60 miles south of Salt Lake City. According to U.S. Census data, the estimated population as of July 1, 2017 was 8,210 persons, a 27.8 percent increase since 2010.¹ The median resident age is 28.6 years and the median household income in 2016 was about \$85,807. The land area is 10.2 square miles and the population density is 805 people per square mile.²

SCP provides electric power, transmission and distribution services to its customers located within the corporate limits of the City. Power department operations and planning are overseen by the City Council. For the year 2018, SCP served about 2,650 electric accounts with energy sales of 37.3 megawatt-hours (“MWh”). The system peak demand was 11.3 megawatts (“MW”). SCP’s power

¹ www.census.gov/quickfacts/Salemcityutah

² Source: <https://en.wikipedia.org>

supply needs are mostly met through its membership in the Utah Municipal Power Agency (“UMPA”). Electric systems located contiguously to SCP include Spanish Fork City, Payson City, SESD and Rocky Mountain Power.

1.5 Utah County



According to the 2010 U.S. Census, the County’s population was 516,564. The estimated population in 2017 was 606,425, reflecting an increase over 2010 of 17.4 percent. Its county seat, as well as the largest city, is Provo having a population of nearly 117,335 as of 2017. The county has a total area of 2,144 square miles, of which 2,003 square miles is land and 141 square miles is water. The population density is about 303 people per square mile. Education, health care and technology make up the largest sector of employment with the largest area employers being Brigham Young University, Utah Valley University, Utah Valley Hospital, and Vivint, Incorporated. The annual per capita income is about \$23,207.³

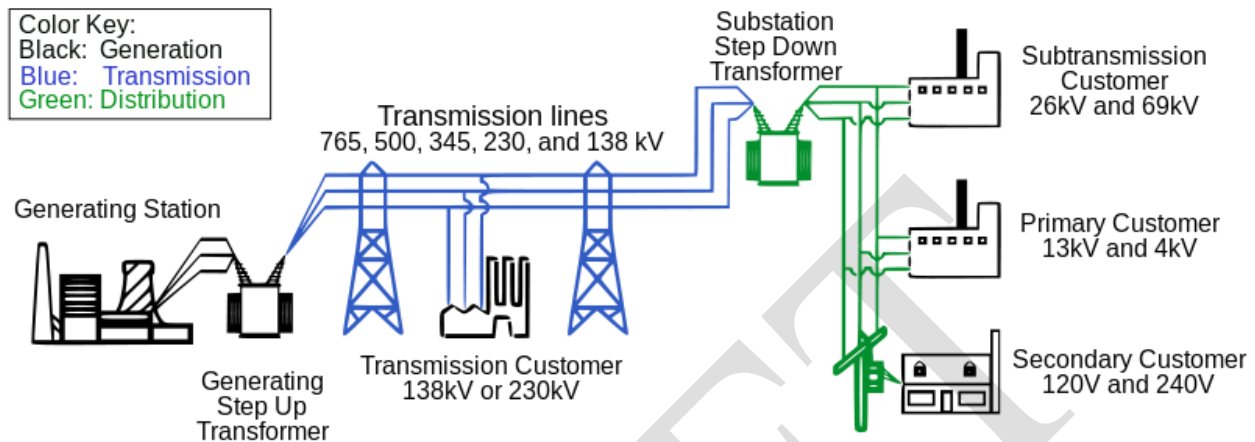
1.6 Electricity Supply & Demand

1.6.1 General

As illustrated in Figure 1-1 below, an electrical power delivery system is made up of three basic components or functions: electric generators that produce the power; a transmission system to deliver the power to the distribution system; and the distribution system which delivers the power to the end-user.

³ Per capita income in past 12 months (in 2017 dollars), 2013-2017; source: <https://www.census.gov/quickfacts/utahcountyutah>

Figure 1-1
Illustration of a Typical Power Delivery System

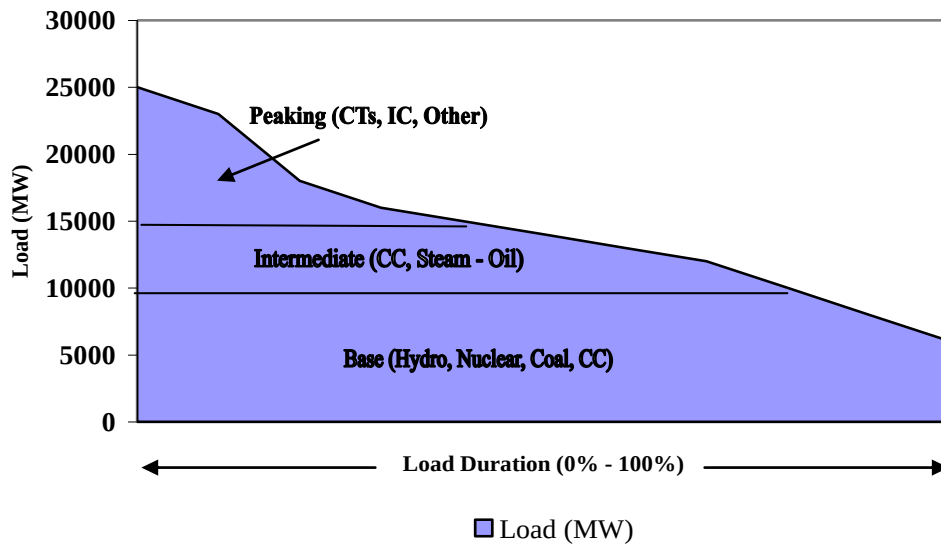


Source: <https://en.Wikipedia.org>

1.6.2 Electricity Supply

In any electrical system, electricity (measured in kilowatt-hours) is produced by a number of generation technologies, powered by a diversity of fuel resources. These generators may include steam (nuclear, coal and oil); hydroelectric (run-of-river and pumped storage); combined-cycle (natural gas and fuel oil); simple-cycle (natural gas and fuel oil); renewables (wind and solar) and internal combustion (diesel). The utility may also utilize generation supplied by others in the form of purchased power agreements, which can include firm power (long-term, interim and short-term); unit power (a purchase out of a specific generating unit) and non-firm (usually short-term). The type and amount of each generating resource that is utilized by the utility in meeting its hourly demand (measured in megawatts) for electricity at any point in time will depend primarily on the amount and duration of the demand, the availability of the generating units and the variable operating cost of the generating unit(s). Very simply, in meeting the daily demand for electricity, each available generating resource is stacked according to its operating cost (lowest to highest) and subsequently dispatched to meet the demand for electricity in each hour of the day. This so-called “merit” stacking/dispatch procedure can be illustrated as follows:

Figure 1-2
Illustration of a Load Duration Curve with Unit Stacking



The utility's peak demand is the highest demand for electricity (measured in megawatts) recorded in any one hour (based on a 15, 30 or 60 minute interval) and occurring within a specified time period (day, week, month, year or seasonal (summer, winter)). It is during these peak periods that a utility will utilize its entire portfolio of generating resources including its peaking generating resources such as combustion turbines. However, because of their relatively high operating costs, combustion turbines are usually called upon for only a very short period of time – when the utility's peak demands are at the highest levels.

1.6.3 Transmission of Electricity

Immediately after leaving the generator, electricity is transformed (i.e., stepped up to a higher voltage) for delivery to the utility's high-voltage ("H-V") transmission system. Generally, the H-V transmission system consists of the towers, conductor, substations and other equipment necessary to deliver power from the various generating stations to the utility's distribution system or to other utilities interconnected with the H-V transmission system. H-V transmission system voltages typically range from 115 kilovolts to 500 kilovolts. A power transmission system is sometimes referred to colloquially as a "grid." Redundant paths and lines are provided so that power can be routed from any power plant to

any load center, through a variety of routes, based on the economics and physical characteristics of the transmission path and the cost of power. Much analysis is done by transmission system owners to determine the maximum reliable capacity of each line, which, due to system stability considerations, may be less than the physical or thermal limit of the line. The H-V transmission system is continually monitored for potential “over-loading” conditions and utilities will sometimes be called upon to reduce/increase output at certain generating plants in order to relieve the condition. The location of generating plants in relation to the electricity load on the H-V transmission system is a very important consideration in utility planning. Needless-to-say, because of aesthetic, environmental, political, regulatory and other factors, generating plants and the transmission lines making up the “grid” can rarely be placed in the optimum location allowing for the for most efficient utilization of electric system. Transmission bottlenecks or “constraints” as they are typically referred to are sometimes created because the transmission grid is not configured or sized correctly to allow for the uninterrupted flow of power from the generating plant to the load centers experiencing the highest demand. Moreover, the level and duration of the constraint can vary depending on amount of load on the system, unit outages, and events affecting the flow of power.

1.6.4 Distribution of Electricity

Electricity distribution is the final stage in the delivery of electricity to end-users. A distribution system's network carries electricity from the transmission system and delivers it to consumers. Generally, a typical electric distribution system would include medium-voltage (e.g., 12.47 kV - 46 kV) power lines, substations, switches, poles, transformers, service drops and metering. The distribution system begins as the voltage is stepped down (e.g., 46 kV / 12.47 kV), via the substation transformer(s) and ends as the secondary service enters the customer's meter socket. Distribution circuits begin at the low-voltage side of the transformer located in the substation.

Conductors for the distribution delivery system are either located overhead on utility poles, or buried underground in the case of urban, downtown areas or new developments. Urban and suburban distribution is normally three-phase in order to serve all types of customers; residential, commercial, and industrial.

Most electric customers are connected to a transformer (pole mounted or ground level protective enclosure), which reduces the distribution voltage to the relatively low voltage used by lighting

and interior wiring systems. Each customer has an "electrical service" or "service drop" connection and a meter for billing.

Section 2 - Capital Facilities Plan and Impact Fee Facilities Plan

2.1 General

As discussed above, the Impact Fee Facilities Plan (“IFFP”) shall, in accordance with the Statute, identify (a) demands placed on existing public utilities by new development activity; and (b) the proposed means by which the local subdivision will meet those demands. In addition, each local political subdivision shall generally consider the revenue sources that will be used to finance the impacts on system improvements.

The IFFP, as discussed herein, is based largely on the Capital Facilities Plan Update, dated July 2018, prepared by ICPE. Certain parts of that report, which is incorporated herein by reference, are summarized in the following discussion of the CFP/IFFP.

2.2 Historical Population and Load Growth

According to the U.S. Census Bureau, the City had a population of approximately 8,210 in 2017. As depicted in the following table, the current population is the result of tremendous growth that occurred during the last two decades (1990 – 2010).

Table 2-1
Salem City Historical Population

Historical population		
Census	Pop.	%±
1960	920	
1970	1,081	17.5%
1980	2,233	106.6%
1990	2,284	2.3%
2000	4,372	91.4%
2010	6,423	46.9%
Est. 2017	8,210	27.8%

As depicted in the above table, the City almost doubled in size from 1990 through 2000 and then slowed somewhat during the period 2000 – 2010 primarily due to the economic downturn beginning in 2008. The population growth during the period 2010 through 2017 averaged about 3.6 percent per year.

Examination of the past seven years shows relatively moderate population growth, but the last two years have seen a renewed interest in development in the area. However, due to a stalled economic recovery

growth is projected to be approximately 3.5% annually for the next five years or more. Because of Salem City's location, continued interest of developers, favorable interest rates for investment, and the availability of manpower resources, it is expected that a high growth rate will return in coming years and should be closely monitored over the next five years. If growth accelerates above projections system improvements must also be accelerated. The annual historical load growth since 2002 is presented in the following Table 2-2.

**Table 2-2
Salem City
Electrical Load History**

Year	Summer Peak (kW Demand)
2002	5,210
2003	5,660
2004	5,734
2005	6,517
2006	6,940
2007	7,801
2008	8,150
2009	7,760
2010	8,630
2011	8,990
2012	9,068
2013	9,930
2014	9,523
2015	10,400
2016	10,240
2017	10,695
2018	11,330

2.3 Existing Electric Infrastructure and Future Needs

2.3.1 Transmission

Salem City Power does not currently have its own 46 kV transmission system. The 46 kV lines that feed Salem City Power's two substations are owned by ("SUVPS"). The SUVPS lines that feed Salem City Power are part of a looped system so that each substation can be fed from two directions.

One 46 kV transmission line project is necessary. Arrowhead Springs planned community will add 7.5 MW (350 amps) of additional load to Salem City Power and will require that a new Arrowhead Springs

substation be built. Approximately 1700 feet of new 46 kV line will be required to tie the substation into the existing SUVPS line that is in the area.

2.3.2 Substation

Evaluation of substations are performed to determine existing loading conditions, ability for future load addition, ability to backup adjacent substations, and to determine the need for new substations.

Substation loading forecasts are based on an evaluation of the following criteria and assumptions:

- Equipment loading per the Level of Service criteria
- Salem City's General Plan Land Use Map and Zoning
- Historical data on the area being developed per year; number residential lots, etc. per unit of developable area.
- All known new developments, loads, etc. within Salem City Power incorporate city limits.

Salem City Power currently has two substations which are Arrowhead Substation and Loafer Substation. Salem City Power substations have shared ownership with South Utah Valley Electric Service District ("SESD"). Loafer Substation contains two transformers. Loafer Transformer T1 feeds Salem City Power and Loafer Transformer T2 feeds SESD. Arrowhead Substation has one transformer that is shared between Salem City Power and SESD loads. A second transformer at Arrowhead is part way through a multi-year process to get installed. Once it is installed Salem City Power and SESD load will be on separate transformers. The project to finish adding the second transformer includes rebuilding the 46 kV portion of the substation to include one new 46 kV breaker that will be used to protect the new transformer. New protective relays used to protect the transformer and substation bus will be purchased and installed. A control building that is needed for the protective relaying will be purchased and installed.

Arrowhead Springs planned community is in the planning stages as of 2019 and is planned to contain 1500 new homes at buildout. Initial homes constructed in the new community will be placed on Arrowhead substation circuits. At 5 kW per home Arrowhead Springs planned community will add 7.5

MW (350 amps) of additional load. Arrowhead transformer and Arrowhead circuits do not have the capacity to serve the entire Arrowhead Springs planned community. By 2023 Arrowhead Transformer T2 will be nearing base loading which shouldn't be exceeded during normal loading to allow for backup capacity. Arrowhead circuits that can be used to feed Arrowhead Springs also do not have the needed capacity. As the Arrowhead Springs planned community continues to grow a new substation will be required.

Distribution

Lines

Within the scope of this study distribution feeders between substations were considered. Salem City Power presently maintains strong distribution circuits between substations. Strong distribution circuits between substations allows for load transfers, at distribution levels, from substation to substation. Load transfers are necessary in the event of substation component failure, loss of transmission path, or for maintenance purpose.

Arrowhead North circuit does not have a tie back into the rest of the system. Loss of the line feeding Arrowhead North would result in the inability to feed that circuit. Arrowhead North load is currently small, but will increase over time. It is recommended that a tie line from Arrowhead North Circuit to Arrowhead East Circuit be constructed.

Arrowhead East and West circuits are run on the same poles from Arrowhead Substation to about 400 North. Any problems resulting in the loss of one circuit would probably result in the loss of the other circuit as well. By 2023 it is recommended that a new switch be installed at approximately 600 South 500 East in order be able to pick up both circuits. Loafer West circuit can pick up Arrowhead West circuit. The new switch would allow the proposed Loafer East circuit to pick up the East part of Loafer North circuit. Loafer North circuit could then pick up the Arrowhead East circuit.

The lower portion of Loafer North circuit does not have a tie back into the rest of the system. Loss of the line feeding this area would result in the inability to feed that area. It is recommended that a tie line be constructed that will allow the area to be back fed from a different direction during a loss of the main feed.

It is recommended that a new Loafer East circuit be installed by 2023. This is due to voltage/overcurrent problems that would exist when trying to pick up Loafer North circuit after the main line has had a

problem. The new circuit would solve the voltage/overloading problems. The new circuit will require that a new underground 12.47 kV 1100 kcmil line be installed from approximately 200 East along High Line Canal to 300 East along High Line Canal. Loafer East circuit should be used to feed all the houses below 850 South.

Several new housing developments are occurring in the city. Main distribution feeder lines need extended when a new development occurs. Several sections of distribution underground lines are listed as projects. The line locations have been chosen based on areas of the city that are expected to have new housing developments occur in the next five years. The lines will be necessary to provide power to those areas as they develop.

Power Factor

Salem City power factor is currently 0.95. It is recommended that Salem City power factor be improved to at least 0.98. This will help support voltage during power system peak loading and during outage conditions. The need for power factor correction becomes more important as transformer and line loading levels increase. Improving power factor also reduces system losses. Improved power factor helps both the Salem City distribution system as well as the SUVPS transmission system.

The only circuit below 0.98 power factor is Arrowhead East. Its power factor is currently 0.93. A large percentage of Salem total load is on Arrowhead East circuit. The low power factor on this circuit has a large impact on the overall city power factor. It is recommended that three 300 kvar capacitor banks be added to Arrowhead East Circuit. This will improve city power factor to 0.98.

2.4 Level of Service Standards

The City plans, designs and operates its system based on the following criteria:

- Transformer ratings under varying load levels and loading conditions must remain below their ONAN/ONFA/ONFA 65 degree rating;
- The system must be able to adequately serve 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 should remain as simplified as possible to ensure that switching orders do not become unnecessarily complex
- Distribution circuit loading during a N-1 scenario is 90% or less of its maximum current rating;
- Distribution circuit voltage must remain between 97% and 105% (at loads) of its nominal value; and
- Distribution circuit mains must be able to serve additional load under N-1 contingencies.

The above criteria were used to determine Salem City Power's future facility needs based on the amount of load (i.e., demand) placed on the existing system over a pre-determined CFP/IFFP five year planning horizon.

2.5 Demands Placed on Existing Facilities

The demand placed on an electric system is typically measured in kilowatts (kW) or kilovolt-amperes (kVA) and stated as either coincident-peak ("CP") demand or non-coincident peak ("NCP") demand. The system CP demand is typically the maximum hourly demand for the entire system measured over some time period (e.g. week, month, year); i.e., the point in time where the sum of all demands placed on the system are the highest for the system as a whole. The NCP demand represents the sum of the maximum demands of individual customers or customer classes (e.g., residential, commercial, industrial) measured or estimated for a time period. 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 by definition will always be lower than the NCP demand. For purposes of determining 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 (e.g., residential and commercial). 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. Therefore, it is the NCP demand that is used to determine the Base Impact Fees discussed later in Section 3.

The analysis of the City's projected demands for the CFP/IFFP five- and 10-year planning periods, is shown in Exhibit 1 attached hereto and summarized hereunder in Table 2-3.

**Table 2-3
Summary of CP and NCP Demands
For the Period 2018 through 2028**

Description	2018	2023	5-Year Increase	2028	10-Year Increase
Total System CP Demands (kW)	11,330.0	15,100.0	3,770.0	20,124.4	8,794.4
Total System NCP Demands (kW)	13,750.4	18,492.3	4,741.9	23,097.2	9,346.8

The System CP Demands for the five-year planning period (2019 – 2023) were developed by ICPE and reviewed by the Consultant. CP Demands for the period beyond 2023 were developed by the Consultant by applying the same growth rates forecasted for the five-year planning period. From the Load Forecast presented in Exhibit 1, the Estimated NCP Demands (measured at the meter) shown on lines 29-33 were computed based on the Projected Energy Sales (shown on lines 4-8) and the following assumptions and considerations:

- Residential customer growth will average approximately 165 new connections per year and was correlated to the anticipated population growth. Approximately 12 customers are assumed to be added to the Commercial class each year while no growth was assumed for the Industrial and Other (primarily City accounts) classes.
- Growth in Average Annual Usage per Customer (lines 15-18) for Residential and Other customer classes was assumed to be nil. Commercial and Industrial are expected to grow by 2 percent per year based on the current long-term GDP forecast.
- Estimated NCP Load Factors (lines 48-51) were assumed to be: Residential – 25%; Commercial – 50%; Industrial – 58%; and Other – 50%.
- The System Load Factor (line 3) is forecast to average about 40% over the planning horizon and approximates recent historical loading patterns for the system.

As discussed later in Section 3, it is the estimated change (i.e., increase) in the Total System CP Demand from 2019 to 2028 that is used as the starting point for calculation of the Impact Fees. Based on FY 2018 metering data the system CP was 11.3 MW and the total system load was 37.3 MWh. By dividing the system load by the number of hours in the year (8,760 hrs.) and dividing that number by the system CP we get an average system load factor of 41.0%.

2.6. System Modeling for the CFP/IFFP

The CFP/IFFP study considers the electrical load growth within the Salem City Power service area. To evaluate system performance under existing and projected peak load conditions, a computer model of Salem City's power system was developed using power system modelling software and load flow simulations performed. Studies show that near term and future growth, without system improvements, will have an adverse effect on the current level of service. From the simulations, and system evaluation, projects that are necessary to accommodate load growth in the next five years were identified. These projects are required to maintain the proper level of service as the load in the SCP system increases.

Projects that are proposed in the Plan are listed in the following section with the recommended completion date and the estimated cost of the project in 2018 dollars. Actual timing of these projects may vary depending on the actual load growth of the electrical system.

The load forecast identified expected loads for existing substations, as well as the addition of an additional substation. Load transfers between substations were studied on the basis of maximizing the utilization of existing substation transformers. Capacity additions are only scheduled when the transfer of load to adjacent substations would result in overloading those facilities due to new growth. Maximizing the utilization of existing and future resources produces the least cost option. Backup capacity for substation transformers/equipment and provisions for improvement are also issues addressed in the CFP study.

Under current city boundaries, Salem City has substantial area for growth and will be able to support growth for the next five years with proposed projects. Growth is expected to be occur on all distribution feeders.

2.7 Model Results

The following Project Summary lists the anticipated projects through the planning period. Table 2-4 indicates expected project timing and associated expenditures necessary to sustain the projected growth rate for Salem City's electrical system for the next 5 years.

There is greater confidence in projecting requirements for 2 to 3 years than there is for a 5-year outlook. However it is necessary to forecast future projects due to the magnitude (and cost) of the modifications

necessary should the annual rate of growth exceeds projections. Substation, distribution, and transmission line requirements need to be addressed to meet future needs of the City in a timely fashion.

The proposed projects in Table 2-4, will provide a method for Salem City to plan and budget for the facilities necessary to serve the anticipated electrical load growth while maintaining the current level of service.

**TABLE 2-4
Salem City
CFP and IFFP**

Substation, Transmission, and Distribution Projects

The following is a listing of projects necessary to maintain the current level of service to Salem City Power customers. Projects include conceptual cost estimates in 2018 dollars. A brief description and explanation of each improvement are given.

Proposed System Improvements by 2023		
Proposed Improvement	Reason/Explanation	Estimated Cost
1. Install three 300 kVAR pole mount capacitor banks on Arrowhead East Circuit.	Recently completed SUVPS report indicated that Salem power factor needed to be improved to 0.98. It is currently 0.95.	\$42,500
2. Install underground 12.47 kV 1100 kcmil line from approximately 820 South 750 East to 950 South 750 East. Approximate line length is 0.13 miles (1000 feet).	A portion of Loafer North circuit that feeds housing below 850 South does not have an alternate source that can be used during outages of the main feed.	\$70,000
3. Install new 12.47 kV pad mount switch at approximately 820 South 750 East (near Salem Canal).	Required in conjunction with the new line #2 above.	\$21,500
4. Install underground 12.47 kV 1100 kcmil line from approximately Salem Park Circle Mill Road to 750 North State Road 198. Approximate line length is 1.15 miles (6100 feet).	Required when Arrowhead main circuit lines feeding West and East circuits are damaged and taken out of service. Allows East part of Arrowhead East circuit to be fed by North Circuit. Also allows Arrowhead East circuit to be an alternate feed for Arrowhead North circuit.	\$582,325
5. Install new 12.47 kV overhead switch at approximately 750 North State Road 198.	Required in conjunction with the new line #4 above.	\$17,000
6. Install one 46 kV breaker in Arrowhead substation	Required in order to put the Salem City load fed from Arrowhead Substation on the Salem City Arrowhead transformer.	\$300,000

Proposed System Improvements by 2023		
Proposed Improvement	Reason/Explanation	Estimated Cost
7. Install a new control building in Arrowhead Substation.	Required in order to put the Salem City load fed from Arrowhead Substation on the Salem City Arrowhead transformer.	\$200,000
8. Install protective relays for Arrowhead transformers.	Required in order to put the Salem City load fed from Arrowhead Substation on the Salem City Arrowhead transformer.	\$100,000
9. Install underground 12.47 kV 1100 kcmil line from approximately 200 East along High Line Canal to 300 East along High Line Canal. Approximate line length is 0.23 miles (1240 feet).	This will be part of a new Loafer East circuit. It is needed to help pick up Loafer North circuit load when Loafer North main line is damaged and taken out of service. Under normal operation Loafer East circuit will feed housing below 850 South	\$121,868
10. Install new 12.47 kV overhead switch at approximately 600 South 500 East.	Required when Arrowhead main circuit lines feeding East and West circuits are damaged and taken out of service. Allows new Loafer East circuit to pick up the east part of Loafer North circuit which would allow Loafer North circuit to pick up Arrowhead East circuit.	\$17,000
11. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.24 miles (1295 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$125,739
12. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.51 miles (2700 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$260,769

Proposed System Improvements by 2023		
Proposed Improvement	Reason/Explanation	Estimated Cost
13. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.25 miles (1345 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$130,734
Proposed System Improvements by 2023		
Proposed Improvement	Reason/Explanation	Estimated Cost
12. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.51 miles (2700 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$260,769
13. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.25 miles (1345 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$130,734
14. Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.06 miles (330 feet).	Required for future expansion of main feeder into new areas due to load growth.	\$35,112
15. Install new Arrowhead Springs substation with 12/16/20 MVA transformer.	Required to feed Arrowhead Springs planned community which will contain approximately 1500 new homes.	\$2,338,123
16. Install 46 kV line to feed the new substation. Approximate length is 0.32 miles (1700 feet).	Required to feed new substation from existing SUVPS line.	\$178,271
2023 Total Cost		\$4,540,941

2.8 Projects and Costs

The costs for the above projects are estimated in 2018 dollars. The projects are scheduled to commence in the early planning window. Growth in demand on the system generally happens in “groups” or “lumps” according to actual commercial and residential development. Because residential developments are generally in subdivision form and commercial developments are generally grouped around a single location, sub-areas in the IFFP area may not realize the growth modeled; therefore, some of the projects could, in reality, be advanced or delayed until required by localized growth.

2.9 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: _____

Name: Craig Michaelis, P.E.

Title: ICPE, Lead Engineer

Date: August 13, 2019

Section 3 - Impact Fee Analysis

3.1 General

As discussed in Section 1, the IFA portion of the Statute requires that each local political subdivision intending to impose an impact fee prepare a written analysis of each impact fee. It also requires that IFA include a summary designed to be understood by a lay person. Additional requirements include identifying the estimated impacts on existing capacity and system improvements caused by the anticipated development activity. The political subdivision must also estimate the proportionate share of (i) the costs of existing capacity that will be recouped and (ii) the costs of the impacts on system improvements that are reasonably related to the new development activity.

3.2 Impact Fee Analysis

The Impact Fee Analysis for SCP involved three (3) basic steps or sub-analyses: (1) an Impact Fee Cost Analysis; (2) an Impact Fee Demand Analysis; and (3) the Calculation of the Impact Fee.

3.2.1 Identification of Impact Fee Projects/Costs

The Impact Fee Cost Analysis for current and future projects is shown in the attached Exhibit 2. Page 1, Column (a) of this exhibit shows the costs (in 2018 dollars) of the projects identified in the IFFP above (see Table 2-4) while column (b) is a restatement of project costs in the year of the expenditure, assuming an inflation rate of 2.5 percent per annum and a mid-point construction period of 2.5 years. This time adjustment is necessary to help ensure that the actual “future” construction costs of these projects will be fully recovered. Column (c) shows the percentage of costs to be allocated for recovery through the proposed Impact Fees. As shown in column (c), all of the projects identified in the CFP are determined to be 100 percent related to new development on the SCP system and therefore recoverable through Impact Fees. Column (d) is simply the product of columns (b) and (c). We have assumed that all of the Impact Fee projects will be funded directly through Impact Fees; that is, none of the projects will be funded from future bond financings; the total cost of which (principal and interest) would be recovered through Impact Fees over the life of the applicable bond issue. Therefore, approximately \$4.8 million will be recovered directly from impact fees (line 17).

3.2.2 Impact Fee Demand Analysis

The Impact Fee Demand Analysis is presented in Exhibit 3. This analysis calculates the Demand Placed on the Existing System to be used as the denominator in determining the Base Impact Fee. The first step was to determine the increase in the CP demand over two distinct recovery periods: a 5-year Recovery Period (2019 – 2023) and a 10-year Recovery Period (2019 – 2028). The 5-Year Recovery Period applies to projects that will be recovered directly through impact fees over a five-year period and includes all projects except those related to the new Arrowhead Springs Substation (see line items 15 and 16 on Exhibit 2). The new Arrowhead Springs substation, which will primarily serve the Arrowhead Springs subdivision, will be recovered over a 10-year period. The increase in CP Demand is shown on line 3 of Exhibit 3 which, for the total system, is 3,770.0 kW for the 5-year Recovery Period and 8,794.4 for the 10-year Recovery Period. The corresponding increase in total system NCP demand at the meter (line 8) is 4,741.9 kW for the 5-year Recovery Period and 9,346.8 kW for the 10-year Recovery Period. Lines 9-13 of show the increase in customers over the two planning horizons and the estimated average CP demand and NCP demand placed on the system per customer added. The NCP demand per customer provides the basis for determining the customer panel utilization percentages used in the Proposed Impact Fee for each customer classification, discussed below. You will notice that for the Industrial and Other customer classes, it has been assumed there will be no increase in the number of customers over the entire 10-year forecast period. The Impact Fee Demand Analysis is summarized in Table 3-2 below.

Table 3-2
Impact Fee Demand Analysis
By Customer Class and Total System

Description	5-Year Recovery Period	10-Year Recovery Period
NCP Demand at Meter (kW)		
Residential	3,750.2	7,500.3
Commercial	966.9	2,106.5
Industrial	24.9	52.4
Other	0.0	0.0
Total System NCP Demands (kW)	4,741.9	9,346.8

3.2.3 Calculation of the Impact Fee

The calculation of the Base Impact Fee is presented in Exhibit 4 and summarized below in Table 3-3. Lines 1-4 of Exhibit 4 reflect the total Impact Fee project costs to be recovered for Future and Current Projects over the two recovery periods. An additional adjustment (line 2) was made for Unrecovered Historical Growth-related Projects (\$727,954) in order to determine the Net Project Costs to be Recovered Through Impact Fees (line 3). For this study, we have assumed that 100 percent of the Net Project Costs will be recovered through impact fees.

The increase in NCP demand measured at the meter for Residential and Commercial is shown on lines 5 through 7; the total of which is used as the denominator for calculating the Base Impact Fee. The Base Impact Fee is presented on line 8 and is simply determined as the total impact fee project costs to be recovered (line 4) divided by the increase in total system NCP demand (line 7). Following is a summary of the calculation of the Base Impact Fee at various recovery levels.

**Table 3-3
Summary of the
Base Impact Fee Calculation**

Description	5-Year Recovery Period	10-Year Recovery Period	Total
Total Project Costs to be Recovered 100%	\$2,881,418	\$2,676,630	\$5,558,047
Total System NCP Demands (kW)	4,717.0	9,606.8	
Base Impact Fee (\$/kW)	\$610.85	\$278.62	\$889.47

3.3 Impact Fee Charges – Present and Proposed

A summary of Impact Fee charges for the Residential and Commercial / Industrial customer classes is provided in the attached Exhibit 5. The estimated charges, by selected electric panel size, have been calculated under each of the proposed Impact Fees as compared to the current Impact Fee. The calculation of the Impact Fee charge is based on the following:

Equation 1 – Single Phase Service:

$$\text{Impact Fee Charge} = IF_b \times PUF \times \left(PS \times \left(\frac{V}{1,000} \right) \times PF \right)$$

Where: IF_b = Base Impact Fee

PUF = Average Panel Utilization Factor

PS = Panel Size (amperage)

V = Line-to-line Voltage

PF = Estimated Power Factor

Equation 2 – Three Phase Service:

$$\text{Impact Fee Charge} = IF_b \times PUF \times \left(\sqrt{3} \times PS \times \left(\frac{V}{1,000} \right) \times PF \right)$$

Where: IF_b = Base Impact Fee

PUF = Average Panel Utilization Factor

PS = Panel Size (amperage)

V = Line-to-line Voltage

$\sqrt{3} = 1.732$

PF = Estimated Power Factor

The Panel Utilization Factor (10.0% - Residential; 20.0% - Commercial) shown on lines 2 and 3 of Exhibit 5 are based on the estimated per-customer NCP demand calculated on Exhibit 1. The Power Factor (90% - Residential; 85% - Commercial) was determined from research of available industry literature.

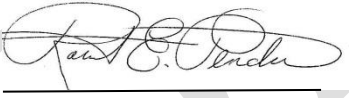
Charges under the currently effective Impact Fee schedules, shown under column (a) of Exhibit 5, are based on the data and information provided by SCP. Charges calculated based on the Proposed Base Impact Fee and the applicable formula shown above are shown in column b, lines 6 through 21 of Exhibit 5.

3.4 Certification of the IFA

I certify that the attached Impact Fee Analysis:

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; and
3. offsets costs with grants or other alternate sources of payment; and
4. complies in each and every relevant respect with the Impact Fees Act.

CERTIFIED BY:

Signature 

Name: Robert E. Pender, ASA

Title: President

Company: R. E. Pender, Inc.

Date: August 13, 2019

APPENDIX A

UTAH STATUTE U.C.A. 1953 § 11-36A-102



West's Utah Code Annotated [Currentness](#)

Title 11. Cities, Counties, and Local Taxing Units

▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 1](#). General Provisions

→→ **§ 11-36a-102. Definitions**

As used in this chapter:

(1)(a) “Affected entity” means each county, municipality, local district under Title 17B, Limited Purpose Local Government Entities--Local Districts, special service district under Title 17D, Chapter 1, Special Service District Act, school district, interlocal cooperation entity established under Chapter 13, Interlocal Cooperation Act, and specified public utility:

(i) whose services or facilities are likely to require expansion or significant modification because of the facilities proposed in the proposed impact fee facilities plan; or

(ii) that has filed with the local political subdivision or private entity a copy of the general or long-range plan of the county, municipality, local district, special service district, school district, interlocal cooperation entity, or specified public utility.

(b) “Affected entity” does not include the local political subdivision or private entity that is required under [Section 11-36a-501](#) to provide notice.

(2) “Charter school” includes:

(a) an operating charter school;

(b) an applicant for a charter school whose application has been approved by a chartering entity as provided in Title 53A, Chapter 1a, Part 5, The Utah Charter Schools Act; and

(c) an entity that is working on behalf of a charter school or approved charter applicant to develop or construct a charter school building.

(3) “Development activity” means any construction or expansion of a building, structure, or use, any change in use of a building or structure, or any changes in the use of land that creates additional demand and need for pub-

lic facilities.

(4) “Development approval” means:

(a) except as provided in Subsection (4)(b), any written authorization from a local political subdivision that authorizes the commencement of development activity;

(b) development activity, for a public entity that may develop without written authorization from a local political subdivision;

(c) a written authorization from a public water supplier, as defined in [Section 73-1-4](#), or a private water company:

(i) to reserve or provide:

(A) a water right;

(B) a system capacity; or

(C) a distribution facility; or

(ii) to deliver for a development activity:

(A) culinary water; or

(B) irrigation water; or

(d) a written authorization from a sanitary sewer authority, as defined in [Section 10-9a-103](#):

(i) to reserve or provide:

(A) sewer collection capacity; or

(B) treatment capacity; or

(ii) to provide sewer service for a development activity.

(5) “Enactment” means:

- (a) a municipal ordinance, for a municipality;
- (b) a county ordinance, for a county; and
- (c) a governing board resolution, for a local district, special service district, or private entity.

(6) “Encumber” means:

- (a) a pledge to retire a debt; or
- (b) an allocation to a current purchase order or contract.

(7) “Hookup fee” means a fee for the installation and inspection of any pipe, line, meter, or appurtenance to connect to a gas, water, sewer, storm water, power, or other utility system of a municipality, county, local district, special service district, or private entity.

(8)(a) “Impact fee” means a payment of money imposed upon new development activity as a condition of development approval to mitigate the impact of the new development on public infrastructure.

(b) “Impact fee” does not mean a tax, a special assessment, a building permit fee, a hookup fee, a fee for project improvements, or other reasonable permit or application fee.

(9) “Impact fee analysis” means the written analysis of each impact fee required by [Section 11-36a-303](#).

(10) “Impact fee facilities plan” means the plan required by [Section 11-36a-301](#).

(11)(a) “Local political subdivision” means a county, a municipality, a local district under Title 17B, Limited Purpose Local Government Entities--Local Districts, or a special service district under Title 17D, Chapter 1, Special Service District Act.

(b) “Local political subdivision” does not mean a school district, whose impact fee activity is governed by Section 53A-20-100. 5.

(12) “Private entity” means an entity with private ownership that provides culinary water that is required to be used as a condition of development.

(13)(a) “Project improvements” means site improvements and facilities that are:

- (i) planned and designed to provide service for development resulting from a development activity;
- (ii) necessary for the use and convenience of the occupants or users of development resulting from a development activity; and
- (iii) not identified or reimbursed as a system improvement.

(b) “Project improvements” does not mean system improvements.

(14) “Proportionate share” means the cost of public facility improvements that are roughly proportionate and reasonably related to the service demands and needs of any development activity.

(15) “Public facilities” means only the following impact fee facilities that have a life expectancy of 10 or more years and are owned or operated by or on behalf of a local political subdivision or private entity:

- (a) water rights and water supply, treatment, and distribution facilities;
- (b) wastewater collection and treatment facilities;
- (c) storm water, drainage, and flood control facilities;
- (d) municipal power facilities;
- (e) roadway facilities;
- (f) parks, recreation facilities, open space, and trails;
- (g) public safety facilities; or
- (h) environmental mitigation as provided in [Section 11-36a-205](#).

(16)(a) “Public safety facility” means:

- (i) a building constructed or leased to house police, fire, or other public safety entities; or

(ii) a fire suppression vehicle costing in excess of \$500,000.

(b) “Public safety facility” does not mean a jail, prison, or other place of involuntary incarceration.

(17)(a) “Roadway facilities” means a street or road that has been designated on an officially adopted subdivision plat, roadway plan, or general plan of a political subdivision, together with all necessary appurtenances.

(b) “Roadway facilities” includes associated improvements to a federal or state roadway only when the associated improvements:

(i) are necessitated by the new development; and

(ii) are not funded by the state or federal government.

(c) “Roadway facilities” does not mean federal or state roadways.

(18)(a) “Service area” means a geographic area designated by a local political subdivision on the basis of sound planning or engineering principles in which a defined set of public facilities provides service within the area.

(b) “Service area” may include the entire local political subdivision.

(19) “Specified public agency” means:

(a) the state;

(b) a school district; or

(c) a charter school.

(20)(a) “System improvements” means:

(i) existing public facilities that are:

(A) identified in the impact fee analysis under [Section 11-36a-304](#); and

(B) designed to provide services to service areas within the community at large; and

(ii) future public facilities identified in the impact fee analysis under [Section 11-36a-304](#) that are intended to provide services to service areas within the community at large.

(b) “System improvements” does not mean project improvements.

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U.C.A. 1953 § 11-36a-102, UT ST § 11-36a-102

Current through 2011 Third Special Session.

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West's Utah Code Annotated [Currentness](#)

Title 11. Cities, Counties, and Local Taxing Units

▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-301. Impact fee facilities plan**

(1) Before imposing an impact fee, each local political subdivision or private entity shall, except as provided in Subsection (3), prepare an impact fee facilities plan to determine the public facilities required to serve development resulting from new development activity.

(2) A municipality or county need not prepare a separate impact fee facilities plan if the general plan required by [Section 10-9a-401](#) or [17-27a-401](#), respectively, contains the elements required by [Section 11-36a-302](#).

(3)(a) A local political subdivision with a population, or serving a population, of less than 5,000 as of the last federal census need not comply with the impact fee facilities plan requirements of this part, but shall ensure that:

(i) the impact fees that the local political subdivision imposes are based upon a reasonable plan; and

(ii) each applicable notice required by this chapter is given.

(b) Subsection (3)(a) does not apply to a private entity.

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U.C.A. 1953 § 11-36a-301, UT ST § 11-36a-301

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▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-302. Impact fee facilities plan requirements--Limitations--School district or charter school**

(1) An impact fee facilities plan shall identify:

(a) demands placed upon existing public facilities by new development activity; and

(b) the proposed means by which the local political subdivision will meet those demands.

(2) In preparing an impact fee facilities plan, each local political subdivision shall generally consider all revenue sources, including impact fees and anticipated dedication of system improvements, to finance the impacts on system improvements.

(3) A local political subdivision or private entity may only impose impact fees on development activities when the local political subdivision's or private entity's plan for financing system improvements establishes that impact fees are necessary to achieve an equitable allocation to the costs borne in the past and to be borne in the future, in comparison to the benefits already received and yet to be received.

(4)(a) Subject to Subsection (4)(c), the impact fee facilities plan shall include a public facility for which an impact fee may be charged or required for a school district or charter school if the local political subdivision is aware of the planned location of the school district facility or charter school:

(i) through the planning process; or

(ii) after receiving a written request from a school district or charter school that the public facility be included in the impact fee facilities plan.

(b) If necessary, a local political subdivision or private entity shall amend the impact fee facilities plan to reflect a public facility described in Subsection (4)(a).

(c)(i) In accordance with Subsections 10-9a-305(4) and 17-27a-305(4), a local political subdivision may not

require a school district or charter school to participate in the cost of any roadway or sidewalk.

(ii) Notwithstanding Subsection (4)(c)(i), if a school district or charter school agrees to build a roadway or sidewalk, the roadway or sidewalk shall be included in the impact fee facilities plan if the local jurisdiction has an impact fee facilities plan for roads and sidewalks.

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Title 11. Cities, Counties, and Local Taxing Units

▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-303. Impact fee analysis**

(1) Subject to the notice requirements of [Section 11-36a-504](#), each local political subdivision or private entity intending to impose an impact fee shall prepare a written analysis of each impact fee.

(2) Each local political subdivision or private entity that prepares an impact fee analysis under Subsection (1) shall also prepare a summary of the impact fee analysis designed to be understood by a lay person.

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U.C.A. 1953 § 11-36a-303, UT ST § 11-36a-303

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Title 11. Cities, Counties, and Local Taxing Units

▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-304. Impact fee analysis requirements**

(1) An impact fee analysis shall:

(a) identify the anticipated impact on or consumption of any existing capacity of a public facility by the anticipated development activity;

(b) identify the anticipated impact on system improvements required by the anticipated development activity to maintain the established level of service for each public facility;

(c) subject to Subsection (2), demonstrate how the anticipated impacts described in Subsections (1)(a) and (b) are reasonably related to the anticipated development activity;

(d) estimate the proportionate share of:

(i) the costs for existing capacity that will be recouped; and

(ii) the costs of impacts on system improvements that are reasonably related to the new development activity; and

(e) based on the requirements of this chapter, identify how the impact fee was calculated.

(2) In analyzing whether or not the proportionate share of the costs of public facilities are reasonably related to the new development activity, the local political subdivision or private entity, as the case may be, shall identify, if applicable:

(a) the cost of each existing public facility that has excess capacity to serve the anticipated development resulting from the new development activity;

(b) the cost of system improvements for each public facility;

(c) other than impact fees, the manner of financing for each public facility, such as user charges, special assessments, bonded indebtedness, general taxes, or federal grants;

(d) the relative extent to which development activity will contribute to financing the excess capacity of and system improvements for each existing public facility, by such means as user charges, special assessments, or payment from the proceeds of general taxes;

(e) the relative extent to which development activity will contribute to the cost of existing public facilities and system improvements in the future;

(f) the extent to which the development activity is entitled to a credit against impact fees because the development activity will dedicate system improvements or public facilities that will offset the demand for system improvements, inside or outside the proposed development;

(g) extraordinary costs, if any, in servicing the newly developed properties; and

(h) the time-price differential inherent in fair comparisons of amounts paid at different times.

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U.C.A. 1953 § 11-36a-304, UT ST § 11-36a-304

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▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-305. Calculating impact fees**

(1) In calculating an impact fee, a local political subdivision or private entity may include:

(a) the construction contract price;

(b) the cost of acquiring land, improvements, materials, and fixtures;

(c) the cost for planning, surveying, and engineering fees for services provided for and directly related to the construction of the system improvements; and

(d) for a political subdivision, debt service charges, if the political subdivision might use impact fees as a revenue stream to pay the principal and interest on bonds, notes, or other obligations issued to finance the costs of the system improvements.

(2) In calculating an impact fee, each local political subdivision or private entity shall base amounts calculated under Subsection (1) on realistic estimates, and the assumptions underlying those estimates shall be disclosed in the impact fee analysis.

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U.C.A. 1953 § 11-36a-305, UT ST § 11-36a-305

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▢ [Chapter 36A](#). Impact Fees Act

▢ [Part 3](#). Establishing an Impact Fee

→→ **§ 11-36a-306. Certification of impact fee analysis**

(1) An impact fee facilities plan shall include a written certification from the person or entity that prepares the impact fee facilities plan that states the following:

“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 the 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; and

3. complies in each and every relevant respect with the Impact Fees Act.”

(2) An impact fee analysis shall include a written certification from the person or entity that prepares the impact fee analysis which states as follows:

“I certify that the attached impact fee analysis:

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 the 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;
3. offsets costs with grants or other alternate sources of payment; and
4. complies in each and every relevant respect with the Impact Fees Act.”

CREDIT(S)

U.C.A. 1953 § 11-36a-306, UT ST § 11-36a-306

Current through 2011 Third Special Session.

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END OF DOCUMENT

EXHIBITS

EXHIBIT 1

FORECAST OF CUSTOMERS,
ENERGY AND DEMANDS

Salem City
2019 Electric Impact Fee Analysis
Forecasted Customers, Energy and Demands
For Years 2019 - 2028

Line No.	Description		Actual 2018	Forecast Period (Fiscal Year)										Annual Growth Rate
				1 2019	2 2020	3 2021	4 2022	5 2023	6 2024	7 2025	8 2026	9 2027	10 2028	
1	System Coincident Peak Demand [1]	kW	11,330	11,999.9	12,709.5	13,461.0	14,257.0	15,100.0	15,992.9	16,938.5	17,940.1	19,000.9	20,124.4	5.91%
2	Total System Energy (Input to Distribution System) [2]	kWh	40,702,775	43,170,972	45,872,866	48,605,518	51,369,794	54,166,579	56,996,781	59,861,333	62,761,192	65,697,337	68,670,774	5.37%
3	System Load Factor	%	41.01%	41.00%	41.00%	41.00%	41.00%	41.00%	41.00%	40.00%	40.00%	39.00%	39.00%	
<u>Energy Sales at Meter [3]</u>														
4	Residential	kWh	23,135,340	24,777,909	26,420,479	28,063,048	29,705,617	31,348,187	32,990,756	34,633,325	36,275,895	37,918,464	39,561,033	5.51%
5	Commercial	kWh	11,540,506	12,331,855	13,150,242	13,996,431	14,871,208	15,775,378	16,709,765	17,675,218	18,672,606	19,702,819	20,766,771	6.05%
6	Industrial	kWh	1,215,000	1,239,300	1,264,086	1,289,368	1,315,155	1,341,458	1,368,287	1,395,653	1,423,566	1,452,037	1,481,078	2.00%
7	Other (City Accounts)	kWh	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	1,368,230	0.00%
8	Total	kWh	37,259,076	39,717,294	42,203,036	44,717,077	47,260,210	49,833,252	52,437,039	55,072,427	57,740,296	60,441,550	63,177,112	5.42%
9	System Energy Loss Factor [4]	%	8.46%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	
<u>Number of Customers [5]</u>														
Average														
10	Residential	#	2,324	2,489	2,654	2,819	2,984	3,149	3,314	3,479	3,644	3,809	3,974	5.51%
11	Commercial	#	252	264	276	288	300	312	324	336	348	360	372	3.97%
12	Industrial	#	1	1	1	1	1	1	1	1	1	1	1	0.00%
13	Other (City Accounts)	#	22	22	22	22	22	22	22	22	22	22	22	0.00%
14	Total	#	2,599	2,776	2,953	3,130	3,307	3,484	3,661	3,838	4,015	4,192	4,369	5.33%
<u>Average Annual Usage Per Customer [6]</u>														
15	Residential	kWh/Cust.	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	9,955.0	0.00%
16	Commercial	kWh/Cust.	45,795.7	46,711.6	47,645.8	48,598.7	49,570.7	50,562.1	51,573.3	52,604.8	53,656.9	54,730.1	55,824.7	2.00%
17	Industrial	kWh/Cust.	1,215,000.0	1,239,300.0	1,264,086.0	1,289,367.7	1,315,155.1	1,341,458.2	1,368,287.3	1,395,653.1	1,423,566.1	1,452,037.5	1,481,078.2	2.00%
18	Other (City Accounts)	kWh/Cust.	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	63,638.6	0.00%
<u>Coincident Peak Demand Allocation [7]</u>														
19	Residential	kW	8,704.5	9,241.8	9,806.6	10,400.8	11,026.3	11,684.9	12,378.7	13,109.5	13,879.7	14,691.2	15,546.5	5.97%
20	Commercial	kW	2,171.0	2,299.8	2,440.5	2,593.7	2,760.0	2,940.1	3,134.9	3,345.2	3,572.2	3,816.8	4,080.4	6.51%
21	Industrial	kW	197.0	201.0	205.0	209.1	213.3	217.5	221.9	226.3	230.9	235.5	240.2	2.00%
22	Other (City Accounts)	kW	257.4	257.4	257.4	257.4	257.4	257.4	257.4	257.4	257.4	257.4	257.4	0.00%
23	Total	kW	11,330.0	11,999.9	12,709.5	13,461.0	14,257.0	15,100.0	15,992.9	16,938.5	17,940.1	19,000.9	20,124.4	5.91%
<u>Average CP Demand Per Customer</u>														
24	Residential	kW	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.9	3.9	
25	Commercial	kW	8.6	8.7	8.8	9.0	9.2	9.4	9.7	10.0	10.3	10.6	11.0	
26	Industrial	kW	197.0	201.0	205.0	209.1	213.3	217.5	221.9	226.3	230.9	235.5	240.2	
27	Other (City Accounts)	kW	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	
28	Total	kW	4.4	4.3	4.3	4.3	4.3	4.3	4.4	4.4	4.5	4.5	4.6	
<u>Estimated NCP Demand at Meter [8]</u>														
29	Residential	kW	10,564.1	11,314.1	12,064.1	12,814.2	13,564.2	14,314.2	15,064.3	15,814.3	16,564.3	17,314.4	18,064.4	5.51%
30	Commercial	kW	2,634.8	2,815.5	3,002.3	3,195.5	3,395.3	3,601.7	3,815.0	4,035.4	4,263.2	4,498.4	4,741.3	6.05%
31	Industrial	kW	239.1	243.9	248.8	253.8	258.8	264.0	269.3	274.7	280.2	285.8	291.5	2.00%
32	Other (City Accounts)	kW	312.4	312.4	312.4	312.4	312.4	312.4	312.4	312.4	312.4	312.4	312.4	0.00%
33	Total	kW	13,750.4	14,685.9	15,627.7	16,575.9	17,530.7	18,492.3	19,461.0	20,436.8	21,420.1	22,410.9	23,409.6	5.46%
34	System Coincidence Factor [9]	%	75.4%	75.2%	74.8%	74.7%	74.8%	75.1%	75.6%	76.3%	77.1%	78.0%	79.1%	76.1%

Salem City
2019 Electric Impact Fee Analysis
Forecasted Customers, Energy and Demands
For Years 2019 - 2028

Line No.	Description	Actual 2018	Forecast Period (Fiscal Year)										Annual Growth Rate
			1 2019	2 2020	3 2021	4 2022	5 2023	6 2024	7 2025	8 2026	9 2027	10 2028	
	<u>Average NCP Per Customer</u>												
35	Residential kW/Cust.	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	0.00%
36	Commercial kW/Cust.	10.5	10.7	10.9	11.1	11.3	11.5	11.8	12.0	12.3	12.5	12.7	2.00%
37	Industrial kW/Cust.	239.1	243.9	248.8	253.8	258.8	264.0	269.3	274.7	280.2	285.8	291.5	2.00%
38	Other (City Accounts) kW/Cust.	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	0.00%
39	Total kW/Cust.	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.4	0.13%
	<u>Avg. Number of Customers Added Per Year [10]</u>												
40	Residential		165	165	165	165	165	165	165	165	165	165	
41	Commercial		12	12	12	12	12	12	12	12	12	12	
42	Industrial		-	-	-	-	-	-	-	-	-	-	
43	Other (City Accounts)		-	-	-	-	-	-	-	-	-	-	
	<u>Estimated Increase in Average Usage Per Customer [11]</u>												
44	Residential		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Commercial		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
46	Industrial		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
47	Other (City Accounts)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	<u>Estimated Class NCP Load Factor [12]</u>												
48	Residential	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	
49	Commercial	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	
50	Industrial	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	58.00%	
51	Other (City Accounts)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	

Footnotes shown on page 5.

Salem City
2019 Electric Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2019 - 2028

- [1] 2019 - 2023 per the June 2019 Capital Facilities Plan. 2024 - 2028 assumes the same growth rate during the first 5 years -- 5.9%.
- [2] Calculated based on Total Sales at Meter (line 8) and the assumed System Loss Factor (line 9).
- [3] Calculated based on average number of customers and usage per customer.
- [4] Based on the actual loss factor for 2018 rounded to the nearest whole percent.
- [5] Equals prior year number plus current year additions (lines 40 - 43).
- [6] Based on historical average plus assumed growth in usage (lines 44-47).
- [7] Allocated to various customer classes based on NCP calculations (lines 29 - 33).
- [8] Annual NCP Demand based on kWh sales at meter, assumed NCP load factor and indicated loss factor.
- [9] Line 1 / Line 33 after adjustment for losses.
- [10] Estimated number of customers added per year.
- [11] Assumed increase in usage per customer. Commercial and Industrial based on the long-term GDP forecast.
- [12] Residential load factor is estimated; commercial load factor is based on an analysis of data provided by the City.

EXHIBIT 2

IMPACT FEE PROJECTS / COSTS

Salem City
2019 Electric Impact Fee Analysis
Future Impact Fee Projects / Costs

Line No.	Description of System Improvements	Estimated Total Project Costs		Portion Related to New Development	Total Impact Fee Eligible Costs
		Current \$ [1]	Future \$ [2]		
		(a)	(b)	(c)	(d)
1	Install three (3) 300 kVAR pole mount capacitor banks on Arrowhead East Circuit	\$ 42,500	\$ 45,206	100.00%	\$ 45,206
2	Install underground 12.47 kV 1100 kcmil line from approximately 820 South 750 East to 950 South 750 East. Approximate line length is 0.13 miles (1000 feet).	70,000	74,457	100.00%	74,457
3	Install new 12.47 kV pad mount switch at approximately 820 South 750 East (near Salem Canal).	21,500	22,869	100.00%	22,869
4	Install underground 12.47 kV, 1100 kcmil line from approximately Salem Park Circle Mill Road to 750 North State Road 198. Approximate line length is 1.15 miles. (6,100 feet).	582,325	619,406	100.00%	619,406
5	Install new 12.47 kV overhead switch at approximately 750 North State Road 198	17,000	18,083	100.00%	18,083
6	Install one 46 kV breaker in Arrowhead Substation.	300,000	319,103	100.00%	319,103
7	Install a new control building in Arrowhead Substation	200,000	212,735	100.00%	212,735
8	Install protective relays for Arrowhead transformers	100,000	106,368	100.00%	106,368
9	Install underground 12.47 kV 1100 kcmil line from approximately 200 East along High Line Canal to 300 East along High Line Canal. Approximate line length is 0.23 miles (1240 feet).	121,868	129,628	100.00%	129,628
10	Install new 12.47 kV overhead switch at approximately 600 South 500 East.	17,000	18,083	100.00%	18,083
11	Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.24 miles (1295 feet).	125,739	133,746	100.00%	133,746
12	Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.51 miles (2700 feet).	260,769	277,374	100.00%	277,374
13	Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.25 miles (1345 feet).	130,734	139,059	100.00%	139,059
14	Install new 600 Amp main feeder with (1) 6" PVC conduit with (3) 1100 kcmil AL cables. Approximate length is 0.06 miles (1345 feet).	35,112	37,348	100.00%	37,348
15	Install new Arrowhead Springs substation with 12/16/20 MVA transformer.	2,338,123	2,487,007	100.00%	2,487,007
16	Install 46 kV line to feed the new substation. Approximate length is 0.32 miles (1700 ft.).	178,271	189,623	100.00%	189,623
17	Total All Projects	\$ 4,540,941	\$ 4,830,093		\$ 4,830,093

[1] Per the City's Capital Facilities Plan, June 2019.

[2] Column (a) amounts inflated to year of mid-point of construction period (2.5 years) at an est. annual rate of --> 2.50%

EXHIBIT 3

IMPACT FEE DEMAND ANALYSIS

Salem City
2019 Electric Impact Fee Analysis

Impact Fee Demand Analysis

Line No.	Description	5-Year Recovery Period					10-Year Recovery Period				
		Residential	Commercial	Industrial	Other	Total System	Residential	Commercial	Industrial	Other	Total System
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Calculation of Demand Placed on Existing System [1]										
2	CP Demand - Last Year of Recovery Period kW	11,684.9	2,940.1	217.5	257.4	15,100.0	15,546.5	4,080.4	240.2	257.4	20,124.4
	CP Demand - 2018 Actual kW	8,704.5	2,171.0	197.0	257.4	11,330.0	8,704.5	2,171.0	197.0	257.4	11,330.0
3	Increase in CP Demand at System Input kW	2,980.4	769.1	20.5	-	3,770.0	6,841.9	1,909.4	43.2	-	8,794.4
4	Average System Loss Factor %	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
5	Estimated Increase in CP Demand at Meter kW	2,742.0	707.6	18.9	-	3,468.4	6,294.6	1,756.6	39.7	-	8,090.9
6	NCP Demand - Last Year of Recovery Period at Meter [1] kW	14,314.2	3,601.7	264.0	312.4	18,492.3	18,064.4	4,741.27	291.5	312.4	23,097.2
7	Estimated NCP Demand - 2018 at Meter [1]	10,564.1	2,634.8	239.1	312.4	13,750.4	10,564.1	2,634.8	239.1	312.4	13,750.4
8	Estimated Increase in NCP Demand at Meter kW	3,750.2	966.9	24.9	-	4,741.9	7,500.3	2,106.5	52.4	-	9,346.8
9	Increase in Average Number of Customers [1]										
10	Avg. Number of Customers - Last Year of Recovery Perio #	3,149	312	1	22	3,484	3,974	372	1	22	4,369
	Avg. Number of Customers - 2018 Actual #	2,324	252	1	22	2,599	2,324	252	1	22	2,599
11	Increase in Average Number of Customers #	825	60	-	-	885	1,650	120	-	-	1,770
12	Average Increase in CP Demand per Customer Added kW	3.3	11.8	N/A	N/A	3.9	3.8	14.6	N/A	N/A	4.6
13	Average Increase in NCP Demand per Customer Added kW	4.5	16.1	N/A	N/A	5.4	4.5	17.6	N/A	N/A	5.3

[1] Per the Impact Fee Forecast of Customers, Energy and Demands, 2019 - 2028.

EXHIBIT 4
IMPACT FEE COST ANALYSIS

Salem City
2019 Electric Impact Fee Analysis

Impact Fee Cost Analysis

Line No.	Description		5-year Recovery Period 2019-2023 (a)	10-Year Recovery Period 2019-2028 (b)	Totals (c)
1	Total Growth-related Future Projects [1]	\$	2,153,464	2,676,630	4,830,093
2	Add: Unrecovered Historical Growth-related Projects [2]	\$	727,954	-	727,954
3	Net Project Costs to be Recovered Through Impact Fees	\$	2,881,418	2,676,630	5,558,047
4	Assumed Impact Fee Recovery Level 100%	\$	2,881,418	2,676,630	5,558,047
5	Increase in NCP Demand at Meter [3] Residential	kW	3,750.2	7,500.3	
6	Commercial	kW	966.9	2,106.5	
7	Total	kW	4,717.0	9,606.8	
8	Base Impact Fee	\$/kW	610.85	278.62	889.47

- [1] Based on City's Capital Improvement Plan, June 2019, see Exhibit 2.
 [2] Based on the current data provided by the City.
 [3] See Exhibit 3 - Impact Fee Demand Analysis.

EXHIBIT 5
SUMMARY OF CHARGES
PRESENT AND PROPOSED IMPACT FEES

Salem City
2019 Electric Impact Fee Analysis

Summary of Charges For Residential & Commercial Customers
Current and Proposed Impact Fees

Line No.	Description / Panel Rating	Current Impact Fee	Proposed Impact Fees
		(a)	(b)
1	Base Impact Fee (\$ per kW)		\$ 889.47
2	Assumed Panel Utilization		
3	Residential		10.0%
3	Commercial		20.0%
4	Assumed Power Factor		
4	Residential		90%
5	Commercial		85%
	Impact Fee Charge for Applicable Panel Size		
	<u>Residential (120/240, 1 phase)</u>		
6	100 Amp	427	1,921
7	150 Amp	853	2,882
8	200 Amp	1,067	3,843
9	400 Amp	2,133	7,685
10	600 Amp	N/A	11,528
11	800 Amp	N/A	15,370
	<u>Commercial (120/240, 1 phase)</u>		
12	200 Amp	2,560	7,258
13	400 Amp	3,627	14,516
14	600 Amp	N/A	21,774
	<u>Commercial (120/208, 3 phase)</u>		
15	200 Amp	5,760	10,895
16	400 Amp	11,947	21,790
17	600 Amp	17,920	32,685
	<u>Commercial (277/480, 3 phase)</u>		
18	200 Amp	13,867	25,142
19	400 Amp	27,734	50,284
20	800 Amp	55,681	100,568
21	1200 Amp	83,627	150,853