Washington City
Where Dixie Begins

WASHINGTON CITY POWER

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

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Section 1 - Background

1.1 Introduction

Washington City Power ("the City," "Washington" or "WCP") 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 2013 Impact Fee Study"), the results of which will be implemented upon city council approval

The 2013 Impact Fee Study was issued to update the previous study which was performed in 2007 by ICPE. This study was similar in scope to the current study and a similar methodology was used to create the updated study.

In conducting the subject study, certain publicly available information, data supplied by WCP 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 by 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 of commercial square feet. 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:

Residential	=	$2,000,000 x .50 / 5,000 = $200 per dwelling unit
Commercial	=	$2,000,000 x .50 / 1,000,000 = $1.00 per sq. foot.

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 Washington 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 the system WCP Capital Facilities Plan (CFP) 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 WCP 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 Washington City and WCP

Washington City is located in southwest Utah in Washington County, approximately 120 miles northeast of Las Vegas, NV. The estimated population in 2011 was about 18,800 persons, nearly a 130 percent increase since 2000. The median resident age is 31 years and the median household income is about $47,000. The land area is 31.5 square miles and the population density is 597 people per square mile. The average household size is 3.1 persons.[1]

[1] Source: city-data.com.

WCP was formed in 1987 to serve as the public power provider to Washington City, Utah and certain contiguous areas thereto. At present WCP serves over 6,000 electric accounts through 5 substations (with 6 transformers), 35 miles of transmission, and 120 miles of distribution lines, both overhead and underground. WCP serves the area north of the Virgin River and within the Washington limits. The north side of the I-15 Freeway corridor is also served by WCP. The Tortoise Habitat area provides the northern and western boundaries to this portion of the service area. The plan does not provide any information or evaluation for the loads on the south side of the Virgin River which is served by Dixie Power.

1.5 Washington County

According to the 2010 U.S. Census, the County's population was 138,115. Its county seat, as well as the largest city, is St. George having a population of nearly 73,000. The county has a total area of 2,430 square miles, of which 2,427 square miles is land and 3 square miles is water. The population density is about 37 people per square mile. Trade, transportation and utilities make up the largest sector of employment with the largest area employers being Intermountain Health Care, Dixie Regional Medical Center and Washington County School District. The annual per capital income is about $26,000.[2]

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.

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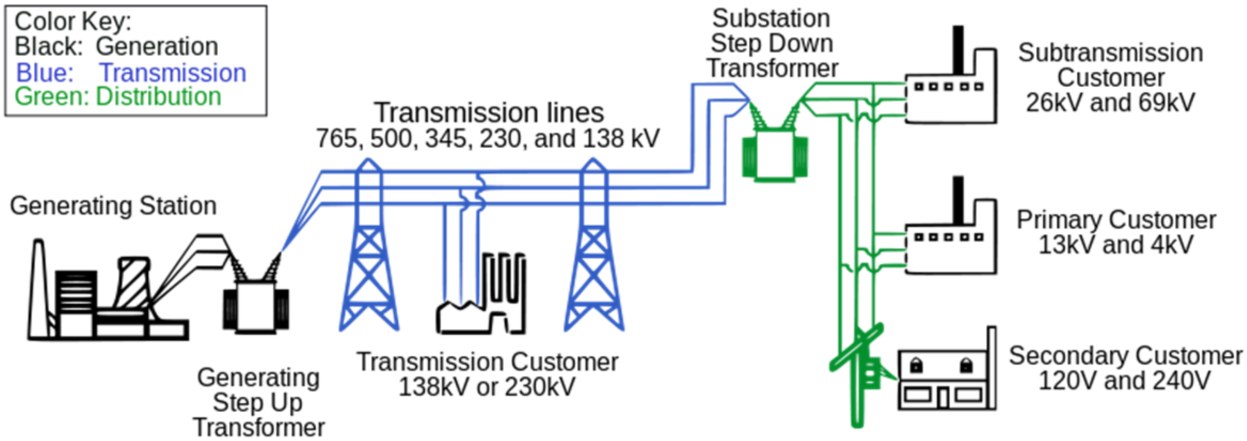
[2] Sources: Wikipedia.com and Washington County Economic Development Commission website: *www.dixiebusinessalliance.com/wcedc/*

Figure 1-1

Illustration of a Typical Power Delivery System



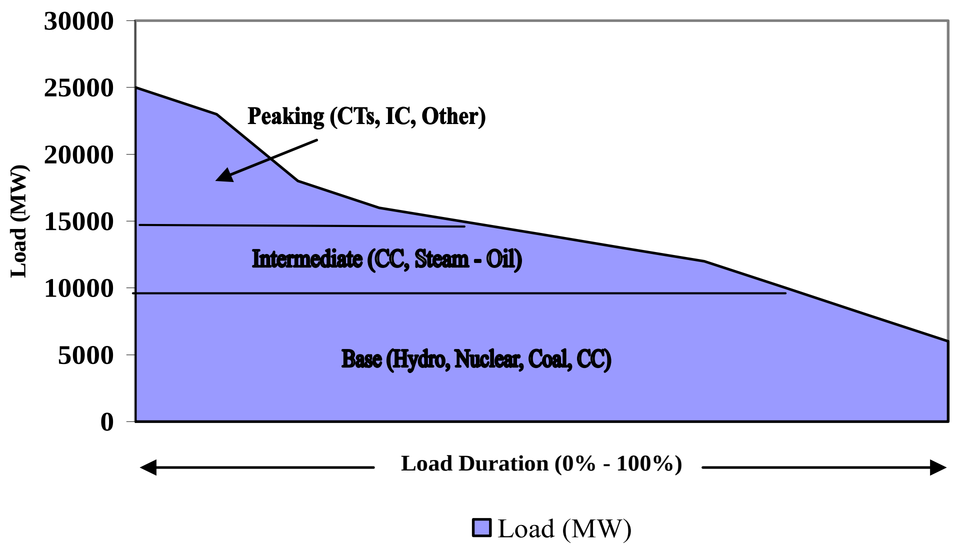
Source: en.Wikepedia.org

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) 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., 12.46 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., 69 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 June 2013, 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 20,900 in 2012. As depicted in the following table, the current population is primarily the result of tremendous growth that occurred during the last decade (2000 – 2010).

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%
Est. 2011	19,249	2.6%
Est. 2012	20,888	8.5%

The City consistently experienced a high rate of growth from 1992 until 2007, with an overall average annual growth rate of over 12% for the fifteen year period. However, load levels on the City's system remained relatively flat for the 2007 to 2011 period, with only 0.4% average growth per year for the four year period. This is most likely due to both the economic downturn and relatively mild summer temperatures experienced for the past several years. The annual historical load growth since 1987 is presented in the following 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%		

2.3 Existing Electric Infrastructure and Future Needs

2.3.1 Generation

Washington City currently owns (3) 2 MW generation units. They are presently physically located in the Hurricane City and Santa Clara City generation facilities. It order to provide local voltage and other system support these generation units should be moved and connected to the Washington City system. A new generation facility adjacent to the Coral Canyon substation will be constructed to allow for these units to be relocated and feed directly to the Washington system.

2.3.2 Transmission

The primary or normal source for Washington City is served from a 69 kV transmission line originating in the UAMPS River Substation. UAMPS owns the 138 kV transmission line feeding the River Substation and the 69 kV portion of the line running from the River Substation to the Millcreek Substation. UAMPS meters the Washington City Power system at Millcreek Substation. (Meters are also located on the 12.5 kV bus at each distribution substation.) The UAMPS 69 kV line (River to Millcreek) is constructed with 1272 ACSR conductor but the capacity is limited due to short sections of 795 ACSR at each end of the line and is able to provide a total of 80 MVA of power to the entities it serves. This UAMPS line also serves the electrical needs of Hurricane City and a portion of the St. George load (Millcreek distribution Substation). It should be noted that the system is configured to provide backup service to the Rocky Mountain Power (RMP) system in the Hurricane area if capacity is available.

Washington owns the 69 kV lines that connect the Millcreek Substation to the Staheli, Main Street, Coral Canyon, Sienna Hills and Buena Vista Substations. The City owns these five substations. Washington City also owns the 69 kV line from the Purgatory tap to the Coral Canyon Substation and then along Telegraph Road to approximately 1100 East.

With the exception of the Telegraph Road section of line described below, the City's 69 kV transmission lines use 795 ACSR conductor and are able to provide up to 80 MVA of electrical power to the City system before approaching a thermal overload condition. The section of line from 1100 East along Telegraph to the Purgatory tap is constructed with 1272 ACSR conductor. This section is a double circuit line, with RMP being the owner of the second circuit conductors. While the 1272 conductor has a larger capacity it is limited by the 795 sections on both ends of the line.

Limited capacity is available from the Purgatory Tap 69kV line until the proposed Hurricane West 138/69 kV Substation is constructed. The Hurricane West substation is planned to be constructed (see below) as a 138 to 69 kV substation initially, with long term plans for 345 kV to 138 kV transformation to be installed. The most recent joint plan recommends that Hurricane West be in service for 2014, however firm construction plans and agreements are not in place at this time. When constructed the Hurricane West substation will provide an alternate source to Washington City that would be able to support the City's load for many years based on present load projections.

A third 69 kV transmission source is available through the Red Cliffs meter point located on the west side of the City near the Wal-Mart commercial area. This line is fed from the St. George Energy Service (SGES) system and is constructed with 795 ACSR conductor. Available capacity on this line depends on the SGES load level on this line.

Washington and UAMPS participate in the countywide planning efforts that are done on an ongoing basis. This effort is coordinated through the South West Utah Technical Task Force (SWTTF). The SWTTF identifies the potential for joint projects with the seven utilities in the county in an effort to minimize the number of lines and facilities that are constructed and to keep the overall transmission costs as low as possible. Any UAMPS or countywide plans to upgrade the transmission system is critical for power system planning and should be considered before the City makes major construction commitments.

2.3.3 Substations

The existing Staheli, Main Street, Coral Canyon, Buena Vista and Sienna Hills Substations are used to supply electrical energy within the Washington City Power service area boundaries. These substations are well placed to supply power in the areas around them for many years. As the City continues to expand into undeveloped areas, additional substations, transmission lines, and distribution feeder lines will be required. The new electrical facilities will be connected to the system in such a way that they can provide backup support to adjacent circuits and substations. The existing substations should be maintained and expanded as necessary to handle future load growth within the service areas they serve. The Staheli Substation presently serves the general area between the substation and the Virgin River, a small portion of the downtown area and to provide backup to the Wal-Mart/Home Depot commercial area. The Coral Canyon Substation provides electrical service to the Coral Canyon Development Area. The Main Street Substation is located to serve existing commercial businesses and new developments along I-15 as well as the loads south along Main St. to Telegraph Road and the City's wells located north of the City. The Buena Vista Substation has been built to deliver power to the Buena Vista/Green Springs residential area and also serves the commercial area on the west side of Washington City. The Sienna Hills substation serves the new Washington Parkway area and the east portion of the historic City area.

The Staheli substation transformer will need to be replaced with a larger unit or have an additional unit installed to sustain the rate of growth within the service area. The Coral Canyon substation has been constructed to serve the growth in the Coral Canyon Development area. The area surrounding the I-15 exit to State Road #9 (to Hurricane) is expected to fill in with commercial loads, light industrial loads, as well as a significant amount of residential housing. This substation will provide electrical power for these customers.

The area around the Mile Post 13 (Washington Parkway) interchange has opened additional lands for development. This development includes the construction of the Washington Parkway Boulevard between Telegraph Road and I-15. Residential, community commercial as well as regional commercial are planned for this area. The general plan for the area north of and west of the Washington Parkway interchange includes residential and community commercial. The Sienna Hills Substation will initially serve customers between the freeway and Telegraph Road and between the Sod Farm and Coral Canyon Development Area. This substation will also serve the loads that develop on the south side of Telegraph Road.

Due to the high growth potential for the areas around the Washington Parkway interchange, at least one new substation and possibly two substations (Parkway North and Parkway East) will be required to serve this area. The load levels experienced in this area should be closely monitored as actual development takes place.

The rapid growth in the Buena Vista area prompted the building of the Buena Vista Substation to alleviate loading stress on existing electrical facilities Buena Vista Substation will also provide capacity for expected development along the north side of the I-15 corridor and for the area west of the Main Street Substation. Due to the continued load growth in this area another new substation (Green Springs) is proposed to support the northern end of the Buena Vista area growth. It will provide for the northward growth of the Buena Vista area and the undeveloped area north of I-15 presently owned by SITLA. It will also provide interconnection points with the Main Street and Buena Vista Substations for maintenance and reliability purposes.

With the recent construction of substations, overall the City has adequate substation capacity for the near future. However the need for the replacement and upgrade of older equipment in the Staheli substation is needed to serve the needs of both existing and future customers. It is also noted that the ability to provide the needed backup capabilities to adjacent substations is dependent on the distribution system capacity as described in the next section.

2.3.4 Distribution

General guidelines for main feeder distribution line construction are included in the distribution section. The guidelines emphasize construction of power lines with capacity to handle current and expected future load, provide backup capacity, maintain reliability, and minimize losses.

The long-range planning map included with the capital facilities plan shows prospective routes for new main feeder distribution lines. The lines typically run along existing and future road right-of-ways, as shown on the Washington City General Plan.

The distribution routes on the long-range map are intended as a general guide to aid in planning new distribution facilities. Line routing will vary from the plan depending on when and where development occurs as well as the actual alignment of the roads at the time of construction.

The present 12 kV distribution system has adequate capacity to handle existing load, under normal conditions, with limited backup capacity for some contingency situations. As the load continues to grow it will require changes to the distribution system to maximize the use of the existing installed substation capacity, including new and upgraded main feeders between substations to allow for load transfers and proper backup capabilities. Other modifications and additions will be projected through the term of the study. New distribution feeders to serve growth areas should be engineered to provide for overall distribution feeder system reliability improvement. Ongoing engineering evaluation of the distribution system is recommended to prevent low voltage and overloaded facilities, provide for power factor correction, maintain over-current coordination, and provide backup capacity to maintain reliability. Mapping of facilities serving newly developed areas will be increasingly critical as electrical facilities expand and more complex service configurations are installed.

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 base 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 not become unnecessarily complex
- Distribution circuit loading criteria must remain below 90% of its maximum current rating;
- Primary circuit voltage must remain between 95% and 105% 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 Washington's future facility needs based on the amount of load (i.e., demand) placed on the existing system over a pre-determined CFP/IFFP planning horizon (e.g., one, three, six, ten and twenty years).

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 one, three, six, ten, and twenty year plans through 2032, 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 2013 through 2032

Description	2013 1 Year	2015 3 Year	2018 6 Year	2022 10 Year	2032 20 Year
Total System CP Demands (kW)	31,470	34,441	37,634	42,358	55,636
Total System NCP Demands (kW)	35,586	38,545	42,984	48,903	63,700

The System CP Demands for the 10-year planning period (2013 – 2022) were developed by ICPE and reviewed by the Consultant. The Consultant extended the planning period forecast to 2032 for purposes of the IFA. From the Load Forecast in Exhibit 1, the Estimated NCP Demands (measured at the meter) shown on lines 24-27 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 200 new connections per year and was correlated to the anticipated population growth. Approximately 25 customers are assumed to be added to the Commercial class each year while no growth was assumed for the Industrial class.
- Growth in Average Annual Usage per Customer (lines 36-38) for residential, commercial and other customer classes was assumed to be nil due to increases in appliance efficiencies and demand side management programs. Industrial customers were predicted to show growth in relation to GDP.

- Estimated NCP Load Factors (lines 39-41) were assumed to be: Residential – 30%; Commercial – 35%; and Industrial – 65%.
- The System Load Factor (line 3) was assumed to average approximately 40% over the forecast period and approximates recent historical loading patterns for the system and was determined by historical loading.

As discussed later in Section 3, it is the estimated change (i.e., increase) in the Total System CP Demand from 2012 to 2022 that is used as the starting point for calculation of the Impact Fees. Based on FY 2012 metering data the system CP was 29,255 kW and the total system load was 102,343 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 40.0%.

2.6 System Modeling for the CFP/IFFP

Modeling for the CFP/IFFP was accomplished using the City's General Plan information which was provided in GIS (Geographic Information System) format. The GIS information was used to develop a build-out estimate for each functional aspect of the utility. The General Plan outlines the current plans for the various areas of the city, identifying residential areas and densities as well as commercial and industrial areas. It should be noted that both existing City and declared boundaries were used to develop the build-out estimates. The build-out load level indicated estimates the possible future load level if *all* of the land within the City's boundaries were to be fully developed based on the current general plan of the City. Detailed information for the build-out estimate for the WCP service area can be found in the Appendix of the CFP.

Maps were created based on the general plans provided. The first map created was the Estimated Percent Developed map, this was developed based on aerial images obtained from Utah AGRC (2011 NAIP 1 meter Orthophotography). The second map created was the Future Load Growth per Area and was based on land use type. These maps were created to visually predict where future load growth could be expected and to assist in the placement of substations and line routes.

The model that was developed to generate the individual load data maps was correlated to current demand levels and customer counts. Average customer loads were developed for each customer type and are based on historical values and estimations. Using the estimated percent developed with the density and class usage, the current units and load levels were approximated and compared to the provided values. This was done to evaluate the method used and to check for erroneous results. Based on the General Plan land usage type, the model was then used to calculate the load growth for the complete development of the general plan in the City. Values shown on the maps in the CFP are the additional future loads for each area if it was fully built out. A total build-out load estimate for the Washington City area is approximately 135 MW.

2.7 Model Results

The following System Improvement Summary details the anticipated projects and expenditures necessary to sustain the projected growth rate for Washington City's electrical system for the next 5 years. Some long term projects in the 5-10 year timeframe have been previously mentioned. There is greater confidence in projecting requirements for 2 to 3 years than there is for a 5-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.

The projects were developed based on the following parameters:

1. Existing WCP Substations would be served at 69 kV with new lines constructed as needed. Where possible, additional loops to the existing 69 kV system should be formed. The installation of switches at each substation tap point will allow line segments within the loop to be de-energized for maintenance and repair. This arrangement also provides a significant improvement over the radial 69kV system currently in operation.

2. To minimize expenditures and the capital procurement of new equipment existing substation transformers and equipment would be utilized as long as possible.

3. Backup capacity would have to be built into the distribution system for load transfers between substations in order to defer purchasing additional substation transformers, which would only be required for N–1 contingency.

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 2013 project material and labor pricing.

Table 2-4
Summary of CFP Improvement Projects
For the Period 2013 through 2022 *

ID	Project Description	Estimated Cost
	2013	
D1	Buena Vista Blvd Upgrade	$200,940.00
D4	100 South Rebuild	214,395.60
G1	Generation Facility	2,492,139.00
	2013 Subtotal	$2,907,474.60
	2014	
D2	Overhead Freeway Crossing	$43,581.90
D6	Main St. to Buena Vista Tie	40,290.00
D7	Graham Manor to Underbuild Tie	33,100.00
S1	Rebuild Staheli Substation	2,370,734.52
	2014 Subtotal	$2,487,706.42
	2015	
D3	Telegraph St. Underbuild Upgrade	$102,761.70
T1	Main St. to Green Springs 69 kV Line	$1,635,085.97
	2015 Subtotal	$1,737,847.67
	2017	
S2	New Green Springs Substation	$2,242,409.40
	2017 Subtotal	$2,242,409.40
	2018	
D5	Green Springs Dr. - New Feeder	$319,360.00
	2018 Subtotal	$319,360.00
	TOTAL ALL PROJECTS	$9,694,798.09

* Note: Project timing will vary based on actual load growth amount and location.

2.8 IFFP Capital Projects and Costs

As previously mentioned, the costs for the above projects are estimated in 2013 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. Because residential developments are generally in subdivision form and commercial developments are generally grouped around a single location, many of the sub-areas in the IFFP area may not realize the growth modeled; therefore, some of the projects could, in reality, be delayed until required by localized growth. In contrast, it is possible that projects may need to be accelerated if growth in an area occurs faster than anticipated.

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: Ricky L. Hansen

Name: Rick Hansen

Title: ICPE, Senior Engineer

Date: October 23, 2013

Section 3 - Impact Fee Analysis

3.1 General

As discussed in Section 1, the IFA portion of the Statue 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 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 Impact Fee Cost Analysis

The Impact Fee Cost Analysis is shown in the attached Exhibit 2. Page 2, Column (a) of this exhibit shows the costs (in 2013 dollars) of the projects identified in the CFP 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. Column (c) shows the percentage of costs to be allocated for recovery through the proposed Impact Fees. As shown on line 8, only the only project to be partially allocated for recovery through Impact Fees (at 20 percent) is the Rebuild of Staheli Substation in 2014. All other projects have been determined to be 100 percent related to new development on the WCP system and therefore recoverable through Impact Fees. Columns (d), (e) and (f) of Exhibit 2 present the Impact Fee related project costs at three different recovery levels 100 percent, 75 percent and 50 percent. The various recovery levels are designed to allow the City Council to consider the appropriate Impact Fee it wishes to implement. Exhibit 2, page 3 shows the calculation of financing costs to be recovered through Impact Fees at the three project cost recovery levels. The addition of financing costs results in the Total Impact Fee Costs to be Recovered through Impact Fees, as summarized in Exhibit 2, page 1 and the following Table 3-1.

Table 3-1
Total Project Costs to be Recovered through Impact Fees

Line No.	Description of System Improvements	Impact Fee Project Costs at Various Recovery Levels		
		100%	75%	50%
		(c)	(d)	(e)
1	Net Impact Fee Project Costs to be Recovered	$ 8,175,725	$ 6,131,793	$ 4,087,862
	Add:			
2	Project Financing Costs	1,107,963	830,972	553,982
3	Total Impact Fee Project Costs to be Reovered	$ 9,283,688	$ 6,962,766	$ 4,641,844

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 Impact Fee by customer class (i.e., Residential, Commercial and Industrial) and for the total system. The first step was to determine the increase in the CP demand over the 10-year Recovery Period (2013 – 2022) which, for the total system, is 13,103.0 kW (see lines 1-3). The increase in CP demand was then converted to NCP demand by applying an Estimated System Coincidence Factor of 0.80; resulting in an increase in NCP demand at the input to the distribution system of 16,378.8 kW (line 5). Lines 6-11 of show the increase in customers over the 10-year planning horizon 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.

3.2.3 Calculation of the Impact Fee

The Base Impact Fee Calculation is shown in the following Table 3-3 (and Exhibit 4) and is simply determined as the Total Impact Fee Project Costs to be Recovered divided by the Demand Placed on the Existing System.

Table 3-3
Base Impact Fee Calculation

Line No.	Description		Base Impact Fee at Various Recovery Levels 100%	75%	50%
			(a)	(b)	(c)
1	Net Impact Fee Project Costs to be Recovered	$	9,283,688	6,962,766	4,641,844
2	Future Demand Placed on Existing System	kW	16,378.8	16,378.8	16,378.8
3	Base Impact Fee (Line 1 / Line 2)	$/kW	566.81	425.11	283.41

3.3 Impact Fee Charges – Present and Proposed

A summary of Impact Fee charges for the Residential and Commercial 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:

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

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:

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

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% - Residential; 20% - 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 calculated using a base fee of $560.00 per kW (based on the 2007 Impact Fee Study). Charges calculated based on the Proposed Impact Fee under each of the assumed recovery levels is shown in columns (b) through (d) 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 Robert E. Pender

Name: Robert E. Pender, ASA

Title: President

Company: R. E. Pender, Inc.

Date: October 23, 2013

Exhibits

Exhibit 1
Forecasted Customers, Energy and Demands
2013 - 2032

Washington City
Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2013 - 2032

Line No.	Description		Actual FY 2012	Forecast Period (Fiscal Year) 1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
1	System Coincident Peak Demand [1]	kW	29,255	31,470.0	33,437.0	34,441.0	35,474.0	36,538.0	37,634.0	38,763.0	39,926.0	41,124.0	42,358.0
2	Total System Energy (Input to Distribution System) [2]	MWh	102,342,592	108,198,245	112,764,095	117,329,945	121,895,796	126,461,646	131,027,496	135,593,346	140,159,197	144,725,047	149,290,897
3	System Load Factor	%	39.93%	39.00%	38.00%	39.00%	39.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	Energy Sales at Meter [3]												
4	Residential	kWh	55,437,019	58,252,553	60,268,910	62,285,267	64,301,624	66,317,981	68,334,338	70,350,695	72,367,052	74,383,409	76,399,766
5	Commercial	kWh	36,564,326	40,976,065	43,160,291	45,344,516	47,528,741	49,712,966	51,897,192	54,081,417	56,265,642	58,449,867	60,634,092
6	Industrial	kWh	322,484	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767
7	Total	kWh	92,323,829	99,542,385	103,742,968	107,943,550	112,144,132	116,344,714	120,545,296	124,745,879	128,946,461	133,147,043	137,347,625
8	System Energy Loss Factor [4]	%	9.79%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
	Number of Customers [5]												
	Average												
9	Residential	#	5,578	5,778	5,978	6,178	6,378	6,578	6,778	6,978	7,178	7,378	7,578
10	Commercial	#	444	469	494	519	544	569	594	619	644	669	694
11	Industrial	#	1	1	1	1	1	1	1	1	1	1	1
12	Total	#	6,023	6,248	6,473	6,698	6,923	7,148	7,373	7,598	7,823	8,048	8,273
	Average Annual Usage Per Customer [6]												
13	Residential	kWh/Cust.	9,938.5	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8
14	Commercial	kWh/Cust.	82,352.1	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0
15	Industrial	kWh/Cust.	322,484.0	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7
	Coincident Peak Demand Allocation [7]												
16	Residential	kW	18,657.2	19,601.5	20,688.1	21,176.5	21,685.1	22,214.5	22,764.8	23,336.2	23,928.9	24,543.2	25,179.3
17	Commercial	kW	10,547.7	11,818.4	12,698.8	13,214.4	13,738.8	14,273.4	14,819.1	15,376.7	15,947.0	16,530.7	17,128.6
18	Industrial	kW	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1
19	Total	kW	29,255.0	31,470.0	33,437.0	34,441.0	35,474.0	36,538.0	37,634.0	38,763.0	39,926.0	41,124.0	42,358.0
	Average CP Demand Per Customer												
20	Residential	kW	3.34	3.39	3.46	3.43	3.40	3.38	3.36	3.34	3.33	3.33	3.32
21	Commercial	kW	23.76	25.20	25.71	25.46	25.26	25.09	24.95	24.84	24.76	24.71	24.68
22	Industrial	kW	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09
23	Total	kW	4.86	5.04	5.17	5.14	5.12	5.11	5.10	5.10	5.10	5.11	5.12
	Estimated NCP Demand at Meter [8]												
24	Residential	kW	21,094.8	22,166.1	22,933.4	23,700.6	24,467.9	25,235.2	26,002.4	26,769.7	27,536.9	28,304.2	29,071.4
25	Commercial	kW	11,925.7	13,364.7	14,077.1	14,789.5	15,501.9	16,214.3	16,926.7	17,639.1	18,351.5	19,063.9	19,776.3
26	Industrial	kW	56.6	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
27	Total	kW	33,077.1	35,585.9	37,065.5	38,545.2	40,024.9	41,504.5	42,984.2	44,463.9	45,943.5	47,423.2	48,902.8
28	System Coincidence Factor [9]	%	79.8%	81.4%	83.0%	82.2%	81.5%	81.0%	80.5%	80.2%	80.0%	79.8%	79.7%

Washington City
Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2013 - 2032

Line No.	Description		Actual FY 2012	Forecast Period (Fiscal Year) 1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022
	Average NCP Per Customer												
29	Residential	kW/Cust.	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
30	Commercial	kW/Cust.	26.9	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
31	Industrial	kW/Cust.	56.6	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1
32	Total	kW/Cust.	5.5	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9	5.9	5.9
	Avg. Number of Customers Added Per Year [10]												
33	Residential			200	200	200	200	200	200	200	200	200	200
34	Commercial			25	25	25	25	25	25	25	25	25	25
35	Industrial			-	-	-	-	-	-	-	-	-	-
	Estimated Increase in Average Usage Per Customer [11]												
36	Residential			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Commercial			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38	Industrial			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Estimated Class NCP Load Factor [12]												
39	Residential		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
40	Commercial		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
41	Industrial		65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%

Footnotes shown on page 5.

Washington City
Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2013 - 2032

Line No.	Description		Forecast Period 11 2023	12 2024	13 2025	14 2026	15 2027	16 2028	17 2029	18 2030	19 2031	20 2032	Annual Growth Rate
1	System Coincident Peak Demand [1]	kW	43,628.0	45,211.9	46,515.0	47,818.0	49,121.0	50,424.1	51,727.1	53,030.2	54,333.2	55,636.2	3.04%
2	Total System Energy (Input to Distribution System) [2]	MWh	153,856,747	158,422,598	162,988,448	167,554,298	172,120,148	176,685,999	181,251,849	185,817,699	190,383,549	194,949,399	3.15%
3	System Load Factor	%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	
	Energy Sales at Meter [3]												
4	Residential	kWh	78,416,123	80,432,480	82,448,837	84,465,194	86,481,551	88,497,908	90,514,265	92,530,622	94,546,979	96,563,336	2.70%
5	Commercial	kWh	62,818,318	65,002,543	67,186,768	69,370,993	71,555,219	73,739,444	75,923,669	78,107,894	80,292,120	82,476,345	3.75%
6	Industrial	kWh	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767	313,767	0.00%
7	Total	kWh	141,548,208	145,748,790	149,949,372	154,149,954	158,350,536	162,551,119	166,751,701	170,952,283	175,152,865	179,353,447	3.15%
8	System Energy Loss Factor [4]	%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	
	Number of Customers [5]												
	Average												
9	Residential	#	7,778	7,978	8,178	8,378	8,578	8,778	8,978	9,178	9,378	9,578	2.70%
10	Commercial	#	719	744	769	794	819	844	869	894	919	944	3.75%
11	Industrial	#	1	1	1	1	1	1	1	1	1	1	0.00%
12	Total	#	8,498	8,723	8,948	9,173	9,398	9,623	9,848	10,073	10,298	10,523	2.78%
	Average Annual Usage Per Customer [6]												
13	Residential	kWh/Cust.	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	10,081.8	0.00%
14	Commercial	kWh/Cust.	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	87,369.0	0.00%
15	Industrial	kWh/Cust.	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	313,766.7	0.00%
	Coincident Peak Demand Allocation [7]												
16	Residential	kW	25,837.0	26,680.2	27,356.8	28,033.3	28,709.8	29,386.3	30,062.7	30,739.1	31,415.5	32,091.8	2.63%
17	Commercial	kW	17,740.9	18,481.7	19,108.1	19,734.6	20,361.1	20,987.7	21,614.3	22,241.0	22,867.7	23,494.4	3.68%
18	Industrial	kW	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	0.00%
19	Total	kW	43,628.0	45,211.9	46,515.0	47,818.0	49,121.0	50,424.1	51,727.1	53,030.2	54,333.2	55,636.2	3.04%
	Average CP Demand Per Customer												
20	Residential	kW	3.32	3.34	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	
21	Commercial	kW	24.67	24.84	24.85	24.85	24.86	24.87	24.87	24.88	24.88	24.89	
22	Industrial	kW	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	50.09	
23	Total	kW	5.13	5.18	5.20	5.21	5.23	5.24	5.25	5.26	5.28	5.29	
	Estimated NCP Demand at Meter [8]												
24	Residential	kW	29,838.7	30,606.0	31,373.2	32,140.5	32,907.7	33,675.0	34,442.3	35,209.5	35,976.8	36,744.0	2.70%
25	Commercial	kW	20,488.7	21,201.1	21,913.5	22,625.9	23,338.3	24,050.7	24,763.1	25,475.5	26,187.9	26,900.3	3.75%
26	Industrial	kW	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	0.00%
27	Total	kW	50,382.5	51,862.2	53,341.8	54,821.5	56,301.1	57,780.8	59,260.5	60,740.1	62,219.8	63,699.5	3.11%
28	System Coincidence Factor [9]	%	79.7%	80.2%	80.2%	80.2%	80.3%	80.3%	80.3%	80.3%	80.3%	80.4%	

Washington City
Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2013 - 2032

Line No.	Description		Forecast Period 11 2023	12 2024	13 2025	14 2026	15 2027	16 2028	17 2029	18 2030	19 2031	20 2032	Annual Growth Rate
	Average NCP Per Customer												
29	Residential	kW/Cust.	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	0.00%
30	Commercial	kW/Cust.	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	0.00%
31	Industrial	kW/Cust.	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	55.1	0.00%
32	Total	kW/Cust.	5.9	5.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.1	0.32%
	Avg. Number of Customers Added Per Year [10]												
33	Residential		200	200	200	200	200	200	200	200	200	200	
34	Commercial		25	25	25	25	25	25	25	25	25	25	
35	Industrial		-	-	-	-	-	-	-	-	-	-	
	Estimated Increase in Average Usage Per Customer [11]												
36	Residential		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	Commercial		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	Industrial		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Estimated Class NCP Load Factor [12]												
39	Residential		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	
40	Commercial		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	
41	Industrial		65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	

Footnotes shown on page 5.

Washington City
2013 Impact Fee Analysis

Forecasted Customers, Energy and Demands
For Years 2013 - 2032

[1] 2013 - 2023 per the Capital Facilities Plan, June 2013. 2024 - 2032 is calculated based on Total System Energy (line 2) and an assumed System Load Factor of 40.0%.
[2] Calculated based on Total Sales at Meter (line 7) and the assumed System Loss Factor (line 8).
[3] Calculated based on average number of customers and usage per customer.
[4] Based on the historical average of years 2009 - 2012.
[5] Equals prior year number plus current year additions (lines 33 - 35).
[6] Based on historical average plus assumed growth in usage (lines 36-38).
[7] Allocated to various customer classes based on NCP calculations (lines 24 - 26).
[8] Annual NCP Demand based on kWh sales at meter, assumed NCP load factor and indicated loss factor.
[9] Line 1 / Line 27 after adjustment for losses.
[10] Estimated number of customers added per year.
[11] Assumes there will be no increase in average usage per customer.
[12] Based on a review of industry literature/data.

Exhibit 2

Impact Fee Projects / Costs

Washington City
Impact Fee Analysis

Impact Fee Projects / Costs Summary

Line No.	Description of System Improvements	Impact Fee Project Costs at Various Recovery Levels 100%	75%	50%
		(c)	(d)	(e)
1	Net Impact Fee Project Costs to be Recovered	$ 8,175,725	$ 6,131,793	$ 4,087,862
	Add:			
2	Project Financing Costs	1,107,963	830,972	553,982
3	Total Impact Fee Project Costs to be Reovered	$ 9,283,688	$ 6,962,766	$ 4,641,844

Washington City
Impact Fee Analysis

Impact Fee Projects / Costs

Line No.	Description of System Improvements		Estimated Total Project Costs Current $ [1]	Future $ [2]	Portion to be Recovered through Impact Fee	Impact Fee Project Costs at Various Recovery Levels 100%	75%	50%
			(a)	(b)	(c)	(d)	(e)	(f)
	2013							
1	Buena Vista Blvd. Upgrade	$	200,940	200,940	100.00%	200,940	150,705	100,470
2	100 South Rebuild	$	214,396	214,396	100.00%	214,396	160,797	107,198
3	Generation Facility	$	2,492,139	2,492,139	100.00%	2,492,139	1,869,104	1,246,070
4	Sub-total 2013	$	2,907,475	2,907,475		2,907,475	2,180,606	1,453,737
	2014							
5	Overhead Freeway Crossing	$	43,582	44,671	100.00%	44,671	33,504	22,336
6	Main St. to Buena Vista Tie	$	40,290	41,297	100.00%	41,297	30,973	20,649
7	Graham Manor to Underbuild Tie	$	33,100	33,928	100.00%	33,928	25,446	16,964
8	Rebuild Staheli Substation	$	2,370,735	2,430,003	20.00%	486,001	364,500	243,000
9	Sub-total 2014	$	2,487,706	2,549,899		605,897	454,423	302,948
	2015							
10	Telegraph St. Underbuild Upgrade	$	102,762	107,964	100.00%	107,964	80,973	53,982
11	Main St. to Green Springs 69 kV Line	$	1,635,086	1,717,862	100.00%	1,717,862	1,288,397	858,931
12	Sub-total 2015	$	1,737,848	1,825,826		1,825,826	1,369,370	912,913
	2017							
13	New Green Springs Substation	$	2,242,409	2,475,200	100.00%	2,475,200	1,856,400	1,237,600
	2018							
14	Green Springs Dr. - New Feeder	$	319,360	361,327	100.00%	361,327	270,995	180,663
15	Total All Projects to be Recovered through Impact Fees	$	9,694,798	10,119,727		8,175,725	6,131,793	4,087,862
16	Less: Net Revenue (Deficit) Balance of Impact Fee Fund	$	-	-	100.00%	-	-	-
17	Net Impact Fee Project Costs	$	9,694,798	10,119,727		8,175,725	6,131,793	4,087,862

[1] Per the City's Updated Capital Facilities Plan, June 2013.
[2] Column (a) amounts inflated to year of construction at an est. annual rate of --> 2.50%

Washington City
Impact Fee Analysis

Impact Fee Projects / Costs
Estimated Debt Service Requirements

100% Recovery

1	Total Project Costs	$ 8,175,725									
2	Recovery Level	100%									
4	Total Debt Issue	$ 8,175,725									
4	Principal	$ 8,176,000									
5	Term	10									
6	Interest Rate	2.38%									
			1	2	3	4	5	6	7	8	9	10
	Debt Service											
7	Interest Payment	$ 1,107,963	$ 194,589	$ 177,124	$ 159,244	$ 140,938	$ 122,197	$ 103,009	$ 83,365	$ 63,253	$ 42,663	$ 21,582
8	Principal Payment	8,176,000	733,808	751,272	769,152	787,458	806,200	825,387	845,032	865,143	885,734	906,814
9	Total	$ 9,283,963	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396	$ 928,396

75% Recovery

1	Total Project Costs	$ 8,175,725										
2	Recovery Level	75%										
4	Total Debt Issue	$ 6,131,793										
4	Principal	$ 6,132,000										
5	Term	10										
6	Interest Rate	2.38%										
			1	2	3	4	5	6	7	8	9	10
	Debt Service											
7	Interest Payment	$ 830,972	$ 145,942	$ 132,843	$ 119,433	$ 105,704	$ 91,647	$ 77,257	$ 62,524	$ 47,440	$ 31,997	$ 16,187
8	Principal Payment	6,132,000	550,356	563,454	576,864	590,594	604,650	619,040	633,774	648,857	664,300	680,111
9	Total	$ 6,962,972	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297	$ 696,297

50% Recovery

1	Total Project Costs	$ 8,175,725										
2	Recovery Level	50%										
4	Total Debt Issue	$ 4,087,862										
4	Principal	$ 4,088,000										
5	Term	10										
6	Interest Rate	2.38%										
			1	2	3	4	5	6	7	8	9	10
	Debt Service											
7	Interest Payment	$ 553,982	$ 97,294	$ 88,562	$ 79,622	$ 70,469	$ 61,098	$ 51,505	$ 41,682	$ 31,627	$ 21,331	$ 10,791
8	Principal Payment	4,088,000	366,904	375,636	384,576	393,729	403,100	412,694	422,516	432,572	442,867	453,407
9	Total	$ 4,641,982	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198	$ 464,198

Exhibit 3

Impact Fee Demand Analysis

Washington City
Impact Fee Analysis

<u>Impact Fee Demand Analysis</u>

Line No.	Description		Residential	Commercial	Industrial	Total System
			(a)	(b)	(c)	(d)
	Calculation of Demand Placed on Existing System [1]					
1	2022 Coincident Peak Demand (Last Year of Recovery Period)	kW	25,179.3	17,128.6	50.1	42,358.0
2	2012 Coincident Peak Demand	kW	18,657.2	10,547.7	50.1	29,255.0
3	Increase in System Coincident Peak Demand	kW	6,522.1	6,580.9	0.0	13,103.0
4	Average System Coincidence Factor [1]		0.80	0.80	0.80	0.80
5	Increase in System Non-Coincident Peak Demand	kW	8,152.6	8,226.1	0.0	16,378.8
	Increase in Average Number of Customers [1]					
6	2022 Average Number of Customers (Last Year of Recovery Period)	#	7,578	694	1	8,273
7	2012 Average Number of Customers	#	5,578	444	1	6,023
8	Increase in Average Number of Customers	#	2,000	250	-	2,250
9	Average CP Demand per Customer Added	kW	3.26	26.3	N/A	5.8
10	Average System Coincidence Factor		0.80	0.80	0.80	0.80
11	Average NCP Demand per Customer Added	kW	4.1	32.9	N/A	7.3

[1] Per the Impact Fee Forecast of Customers, Energy and Demands, 2013 - 2022.

Exhibit 4
Base Impact Fee Calculation

Washington City
Impact Fee Analysis

Base Impact Fee Calculation

Line No.	Description		Base Impact Fee at Various Recovery Levels 100%	75%	50%
			(a)	(b)	(c)
1	Net Impact Fee Project Costs to be Recovered	$	9,283,688	6,962,766	4,641,844
2	Future Demand Placed on Existing System	kW	16,378.8	16,378.8	16,378.8
3	Base Impact Fee (Line 1 / Line 2)	$/kW	566.81	425.11	283.41

Exhibit 5
Summary of Charges
Present & Proposed Impact Fees

Washington City
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 Fee at Various Recovery Levels		
			100%	75%	50%
		(a)	(b)	(c)	(d)
1	***Base Impact Fee ($ per kW)***	$ 560.00	$ 566.81	$ 425.11	$ 283.41
	Assumed Panel Utilization				
2	Residential		10%	10%	10%
3	Commercial		20%	20%	20%
	Assumed Power Factor				
4	Residential		90%	90%	90%
5	Commercial		85%	85%	85%
	Impact Fee Charge for Applicable Panel Size				
	Residential (120/240, 1 phase)				
6	100 Amp	2,181	1,224	918	612
7	200 Amp	2,695	2,449	1,836	1,224
8	400 Amp	4,618	4,897	3,673	2,449
9	600 Amp	8,729	7,346	5,509	3,673
10	800 Amp	13,572	9,795	7,346	4,897
	Commercial (120/240, 1 phase)				
11	100 Amp	4,368	2,313	1,734	1,156
12	200 Amp	8,736	4,625	3,469	2,313
13	400 Amp	17,472	9,250	6,938	4,625
14	600 Amp	26,208	13,876	10,407	6,938
	Commercial (120/208, 3 phase)				
15	100 Amp	6,557	3,471	2,604	1,736
16	200 Amp	13,113	6,943	5,207	3,471
17	400 Amp	26,227	13,885	10,414	6,943
18	600 Amp	39,341	20,828	15,621	10,414
	Commercial (277/480, 3 phase)				
19	200 Amp	30,262	16,022	12,016	8,011
20	400 Amp	60,523	32,043	24,033	16,022
21	800 Amp	121,046	64,087	48,065	32,043
22	1200 Amp	181,569	96,130	72,098	48,065
	Special Services (120/240, 1 phase) *				
23	60 Amp	N/A	735	551	367

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

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.

CREDIT(S)

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

Current through 2011 Third Special Session.

END OF DOCUMENT

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.

CREDIT(S)

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

Current through 2011 Third Special Session.

END OF DOCUMENT

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-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.

CREDIT(S)

U.C.A. 1953 § 11-36a-302, UT ST § 11-36a-302

Current through 2011 Third Special Session.

END OF DOCUMENT

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-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.

CREDIT(S)

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

Current through 2011 Third Special Session.

END OF DOCUMENT

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-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.

CREDIT(S)

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

Current through 2011 Third Special Session.

END OF DOCUMENT

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-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.

CREDIT(S)

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

Current through 2011 Third Special Session.

END OF DOCUMENT

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-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.

END OF DOCUMENT