Final High Density Load Staff Report

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Executive Summary

District staff proposes a High Density Load (HDL) customer rate classification and associated rate applicable to server farms and similar high density technological operations as a means to mitigate operational and financial costs associated with serving these energy intensive loads. Consistent with Board guidance, staff has designed its recommended HDL rate as a cost-based rate to recover through the HDL rate the full costs of serving HDL customers. The HDL rate includes monthly customer, delivery and supply charges, which is the same rate structure as is used in the District's commercial and industrial rates. Because of limited information on the cost characteristics of HDL customers, the customer, delivery, and supply charges are based on the cost to serve the District's commercial and industrial customers. The HDL rate also includes an upfront charge to address the District's cost of increased expense for capital distribution assets associated with HDL customers and risk of stranded assets. The upfront capital charge would be due prior to connection of service. Staff's recommendation is the product of lengthy fact finding by staff, several public presentations by staff to the Board, and public input including from HDL customers.

Staff's rate recommendation has its genesis in December 2014 when, in response to a dramatic increase in inquiries for new service for loads with dramatically higher energy usage per square foot of customer space, the Board imposed a moratorium on accepting applications for new or increased loads greater than one average megawatt. The Board modified the moratorium in July 2015 to include applications for load using a large amount of energy per square foot. In December 2015, the Board modified the moratorium to apply only to applications from potential HDL customers, using a definition of "HDL" substantially the same as staff's recommended class definition in this report. In early 2016, the Board held public informational meetings on the proposed HDL rate and commenced the rate hearing. In March, the Board directed staff to prepare a rate proposal. This report provides staff's recommendation. Section 1 describes the cost characteristics of HDL as customers of the District and the need for rate action. Section 2 summarizes the legal criteria applicable to this classification and rate setting action. Section 3 describes the procedural history related to the rate recommendation. Section 4 explains staff's recommended definition of the HDL class. Section 5 provides the cost analysis and rate design in support of staff's rate recommendation.

Summary of Staff's Recommendation

Staff's Recommended High Density Load Class Definition:

The HDL rate schedule would apply to server farms and similar technological operations with an energy use intensity (EUI) of 250 kWh/ft^2/year or more and with average electrical loads up to and including 5 annual aMWs at a single Point of Delivery, where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District.
- "Server farm" means an entity whose Energy use serves mostly one or more computer server machines and any ancillary loads including HVAC, UPS, power systems, and lighting.

When calculating an EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this rate schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft^2/year.

Staff's Recommended High Density Load Rate:

Staff's Recommended Monthly HDL Rate			
Size of Service	Basic Charge (per Meter)	Demand Charge (per kW of Maximum Demand)	Energy Charge (per kWh)
up to 300 kW	$130	$5.50	2.7¢
300 kW to < 1 MW	$560	$5.50	2.7¢
1 MW to ≤ 5 aMW	$860	$5.50	2.7¢

Staff's Recommended HDL Upfront Capital Charge
Upfront Capital Charge (per kW of new or expanded HDL service)
$190

A draft HDL rate schedule containing staff's recommendations is attached as Appendix A.

Section 1 – High Density Load (HDL) Customers

Overview

In 2014, the District began experiencing inquiries for new service that far exceeded the typical volume of such requests. Most of the inquiries came from a common type of operation: small server farms, generally devoted to data processing for cryptocurrencies. These operations moved into old laundromats, old warehouses or even free standing cargo containers, anywhere they found access to power. As these small server farms came online, the District learned that this new type of load was of a different character than loads typically seen by the District in several ways. The small server farm operators often sought to use continuously the maximum amount of power possible at a given location. The server farm operators sometimes placed large, energy intensive load on the system that stressed the District's delivery system and overloaded transformers and secondary service wires.

Compounding the effects, the load of these small server farms often proved to be unusually mobile. Generally, large server farms invest substantial amounts in infrastructure, which ties them to a particular site. However, that has not been the experience of the District with the smaller server farms to which the proposed HDL rate applies. Many of the small server farms locating in the District's service area undertook minimal infrastructure investment by leasing existing low-cost commercial spaces, freeing the operators to simply truck their servers from one location to another. Large amounts of server farm loads have relocated within or in and out of the District's service area. These relocations result in unpredictable electrical use fluctuations in the affected areas, causing stress to the distribution system designed to handle traditional, predictable residential and commercial loads. In sum, these new loads have the potential to drastically change the configuration of the District's distribution infrastructure.

Electricity prices are an important factor in the profitability of a cryptocurrency mining operation.[1] The small server farms are apparently attracted by the District's electricity retail rates which are some of the lowest retail electric rates in the country.[2]

The District received inquiries for service from server farms at such a high rate that, by early 2015, if all such requests were served, the added load would have doubled the District's current total retail load. The District recognized that serving this rapidly growing type of customer load under existing rate schedules, which were not designed with high density server farm loads in mind and are below the cost of serving such loads, was unreasonable and unsustainable from an operational and financial perspective. The District is currently well positioned to serve the forecasted needs of its historical customers and new customers with similar characteristics. However, despite the currently good finances of the District, it cannot reasonably ignore the potential magnitude of HDL load and the cost of serving such loads. The reasonable long-term solution for serving HDL customers is to develop a new rate designed to recover the costs of serving such loads.

Over the course of a lengthy fact finding by staff, numerous presentations to the Board, and discussion with the public, including HDL customers, the Board directed staff to recommend a new rate class and

[1]The two major cost inputs for a basic digital currency mining operation are the cost of the computer hardware and the cost of the electricity to run the computers. For example, see the bitcoin profitability calculator at http://www.bitcoinx.com/profit/. *See also* Malachi Salcido, President, The Salcido Connection (December 7, 2015) (written comment stating electricity is "our major operating cost").

[2] Low rent, a favorable climate, and access to fiber telecommunications may also contribute to the growth of server farms in the area.

rate for small server farms, or as the District refers to them, “high density load” (HDL). This section summarizes the reasons underlying staff’s recommendations in this report.

Key Characteristics of HDL Load

The loads to which the HDL rate is intended to apply have two key characteristics that distinguish them from the historical loads for which the District’s existing delivery system was designed to support and for which its current rates were designed. First, HDL customers use large amounts of energy in small spaces, and they operate at close to their maximum demand most of the time. This usage pattern places higher stresses on local sections of the District’s delivery system than the system was designed to accommodate. Second, HDL customers are relatively mobile because their electricity consuming equipment (computer servers) are easy to move to new locations. Some server farms are even contained in portable shipping containers with attached portable HVAC systems to facilitate this mobility. Thus, HDL customers have the ability (and the interest) to add load to the District’s system in large quantities and nearly instantaneously. Appendix B provides case studies of HDL customers that exemplify these characteristics. Both the local intensity of the HDL loads and their mobility made the District’s existing rate schedules inadequate to recover the costs incurred by the District to serve the loads.

Energy Use Intensity (EUI)

The first key characteristic is measured by “energy use intensity”. Energy use intensity (EUI) is an energy industry term used to refer to the ratio of the energy usage at a given facility to the size of the building within which the load is housed.[3] Staff calculates EUI as the kilowatt hours of energy used in a year divided by the operating square footage. Server farm operators often seek to maximize computation capability in a given space, which creates very high EUI numbers. The following table shows the estimated average EUIs of certain types of customers made in a 2015 conservation potential assessment performed for the District by EES:

Chelan 2015 Conservation Potential Assessment Model		
Segment	**Chelan MWh**	**Chelan (EUI) kWh/FT^2/Year**
K-12 Schools	32,231	**9.2**
Warehouse	67,026	**9.1**
Small Box Retail	42,068	**13**
University	7,721	**16.9**
Assembly Hall	15,224	**11.9**
Small Office	76,635	**13.2**
High End Retail		**14.6**
Medium Office	6,299	**23.8**
Lodging	37,502	**15.1**
Large Office		**16.6**
Other Health Facilities	17,234	**14.9**
Hospital	30,467	**26.6**

[3] EUI is commonly used in the context of energy conservation. A comparison of the EUIs from buildings housing similar operations (e.g., mini marts) can identify buildings with high EUIs, which may have potential for energy conservation measures (e.g., insulation).

Big Box Retail	16,828	**13.9**
Supermarket	21,580	**43.5**
Restaurant	24,904	**55.7**
Mini Mart	5,185	**81.1**

The highest known EUI value of a non-HDL retail customer served by the District is less than 200. For comparison, computer data processing sites generally have EUI ratings well in excess of 500 kWh/ft^2/year, far exceeding the EUIs of the District's typical customers.[4] Locating high EUI loads in areas of the electrical distribution system originally designed for loads with more typical profiles stresses the District's system. Utilizing existing building space or portable spaces connected at existing service drops to operate small server farms increases the localized electrical needs by orders of magnitude over what the District originally designed the service line and distribution system to accommodate.

Load Factor and Diversity Factor

The load factor and diversity factor of HDL customers also differentiate them from the District's historical customers. Load factor means, for a specified time period, average load divided by peak load. HDL customers exhibit very high load factors, which means they operate at nearly full power nearly all the time. For digital currency servers in particular, computer processing effort relates directly to revenue. Most of the District's historical loads have a more cyclical profile as electricity usage changes throughout the day and week. Consequently, the District has historically designed its system to serve its typical cyclical load.

System engineers use diversity factor as a planning metric to reflect the probability that individual loads will operate coincidentally (*i.e.*, at the same time). Because individual loads each turn on and off at different times, the maximum system load is less than the sum of maximum individual loads. Diversity factor measures, for each portion of the system, the ratio of the sum of maximum demand of individual loads to the maximum demand on that portion of the system. For example, assume a given substation serves 100 homes each with a maximum demand of 15 kW. The sum of the maximum demands is 1500 kW (100 homes times 15 kW each). The maximum demand measured at any given time at the substation may be only 500 kW. This happens because not all the homes run at peak demand at the same time. One home turns on its dryer as another home's water heater turns off and so on. The diversity factor in the above example would be 3 (1500 kW / 500 kW).

HDL customers are different than the historically typical customers of the District. They run their computers continuously. Such continuous (or very high load factor) loads tend to be coincident with the local peak load on the system whenever that peak may occur. Very high load factor customers have a coincidence factor of very close to one. They lower the diversity factor of the system as a whole, and they can lower the diversity factor in their local area substantially. Re-running the above example, but replacing all the homes with 15 kW HDL customers, the sum of the individual maximum demands would still be 1500 kW. But the maximum demand at the local substation would be 1500 kW as well, so the diversity factor on that substation would be 1. The substation would need to have three times more capacity to serve the HDL customers than to serve the homes even if the peak loads of the homes and HDL customers were the same. A lower diversity factor means the District needs more infrastructure to serve the same individual maximum demands.

[4] According to one potential HDL customer, cryptocurrency servers "operate at significantly higher density than traditional data space servers". Malachi Salcido, President, The Salcido Connection (December 7, 2015) (written comment).

HDL loads can show up in all areas of our system, including rural or remote areas, even though the distribution system was designed and built for the diversity factor originally expected for such areas. Adding HDL loads in built up portions of the distribution system changes the diversity factors for that portion of the system and may make the local system inadequate to serve the loads.

Mobility

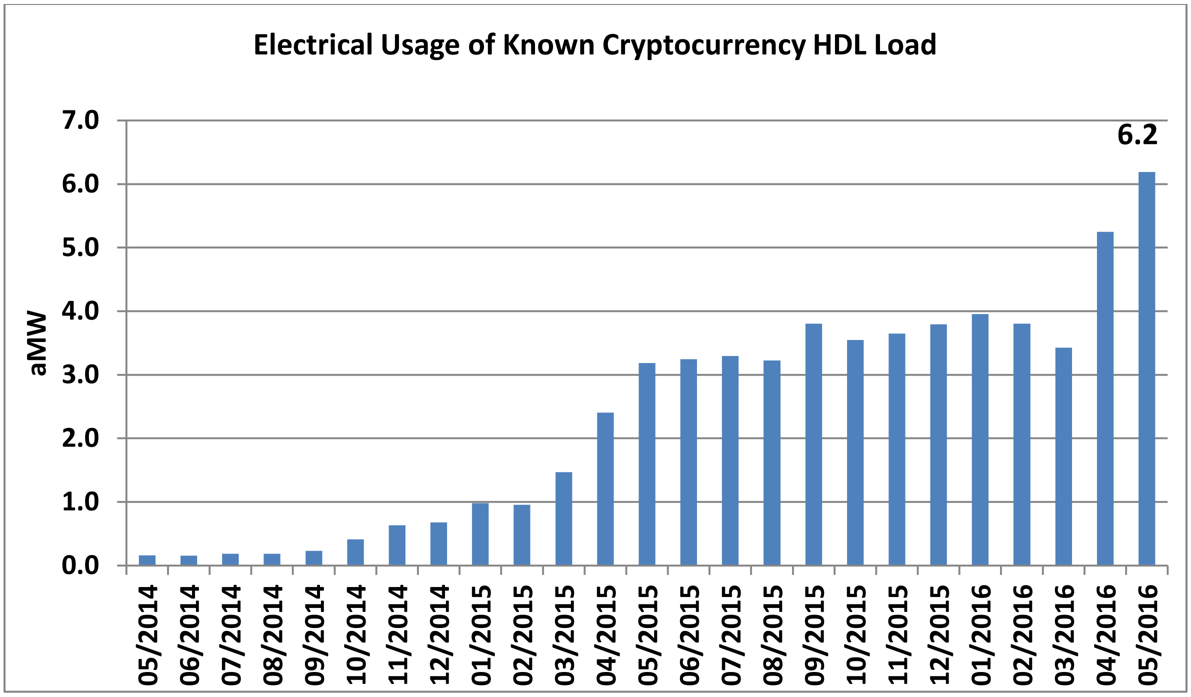
HDL customers typically have the ability to move a large number of servers, which equates to large amounts of load, in and out of or within the District's system with relative ease and very quickly as compared to the ability of historical loads to move. Some HDL customers park cargo containers converted to house 250 kW of computer servers at leased parking lots with electrical access, and plug into the District's system. As easily as HDL customers appear on the District's system, they move within or out of the system. They locate in the back of other businesses, in apartments, and in parking lots. At least one HDL location has no onsite personnel. In contrast, historical District nonresidential customers typically undertake significant capital investment and long-term planning when adding load to the District's system. Even though historical District loads can and do come and go, they do not demonstrate the same propensity for mobility and load shifting as do HDL customers. The mobility of HDL customers presents unique challenges for the District because the District needs to know the approximate loads throughout its system when conducting system maintenance and long-term planning.

Unpredictable Load Swings

Unlike the District's historical customers, HDL customers can turn large amounts of load on or off unpredictably without warning.

Magnitude of Load

Early in 2014, staff noticed a significant increase in load requests ranging from 1-20 MW each. The District received over 30 inquiries by July 2014, with 5 active applicants for 5-7 MW total. These load requests individually and in aggregate were well in excess of the typical 1-3 MW growth per year for which the District plans and staffs. The following graph shows the monthly total average load of cryptocurrency HDL customers (that the District is aware of) served by the District since May 2014.



The graph shows that known cryptocurrency HDL load has grown from less than 0.25 aMW to over 6 aMW in two years. Growth would likely have been significantly higher if the District had not implemented a moratorium on certain applications for service since December 2014.

Cost and Risk Characteristics

The District incurs operational, safety, reliability, and financial risks and costs because of the above described characteristics of HDL load. This significant increase in loads with atypical characteristics stresses the District's equipment and creates system safety and reliability issues described below. Such loads also challenge the ability of the existing system to accommodate growth of its more typical loads. The District's electric distribution system is designed to support a predictable level of residential and commercial growth. The influx of HDL loads has the potential to use up the capacity planned and installed for growth of these groups. Rapid growth also impacts the District's ability to respond to customer needs in a timely and quality manner. In short, HDL customers impose unique costs on the District that are not reflected in the District's existing rate charges.

Safety and Reliability Risks

Safety and reliability are two of the District's highest priorities. In order to maintain the District's standards for safety, staff must devote special attention to monitoring and policing HDL loads.

As load growth pushes the distribution system toward its capacity limits, safety and reliability are reduced. The District's feeders and substations are designed for historical load profiles. Adding the comparatively large HDL loads – with their significantly higher EUI and load factor, and lower diversification factor than historical loads – in existing vacant buildings can overload the electrical distribution equipment in the local area. This can lead to premature equipment failure and potentially unplanned outages interrupting service to many customers. Several safety and reliability issues due to such loads have already arisen.

District staff have repeatedly dealt with service connections made unsafe by HDL customers seeking to maximize electricity consumption. In one example, the customer overloaded the utility transformer and melted the insulation off of the overhead secondary service conductor creating a fire hazard. Staff have also had to find ways to maintain safety after discovering that electricity demand in an apartment had increased by a factor of approximately 10 because of computer servers packed into the apartment.

The mobility and large fluctuations in HDL loads compound these problems because an unexpected increase can push a circuit beyond its safety and reliability margins. The District must monitor high density loads much more closely than other loads, or it must operate and build the system with a much higher margin of excess capacity than it has historically needed.

Additionally, load volatility, especially loads turning on and off unexpectedly, pose significant risk to reliability. The District has experienced equipment failures and at least one outage as a result of new and increased HDL loads that the District was unaware of. As mentioned, distribution capacity to accommodate load growth requires construction of that capacity in advance of need. If a customer ramps up its load before the District has adequate capacity for the load, it can lead to outages and equipment damage. On the other hand, if the District expands its distribution capacity to meet customer requests and the customer does not increase load as planned, then the District will likely not recover the full cost of the underused assets it had installed on behalf of the customer. There are also times a customer changes out equipment or otherwise curtails load unannounced, causing an unexpected drop-off in power needs and subsequent unexpected increase when the equipment is back on-line. With significant amounts of power, this can also cause problems with balancing power resources for local load and system protection. All of these problems are more severe for large, low diversity factor HDL loads than they are for the type of loads the District has historically served. Not acting to address these risks would create unacceptable safety and reliability problems.[5]

Accelerated Capital Investment

Preparing to serve the potential volume of HDL loads the District reasonably expects in light of the inquiries it has received would require the District to expend substantial capital on new infrastructure at a greatly accelerated pace. The District attempts to forecast and anticipate load growth to ensure sufficient capacity is available and the District is prepared to serve the load when customers request service. With the lead times required to build new substations and site transmission lines, adding capacity is not something the District can do overnight, particularly when public processes are involved. Multiple years of planning, public outreach, design, and construction are required in advance of the need. This lag makes load forecasting and system evaluations crucial to ensuring that this investment in the system can occur at the most efficient and economical time. Historically, the District's planning process began when forecasts showed substations at or near 90% capacity so that construction could be scheduled so that the station is on-line just in time of need. The typical minimum timeline for the process, planning through energizing, is three years. These construction practices minimize the risk of building too much capacity too soon, for which costs are borne by customers. Considering historical growth rates of 1% - 3% annually, this "just in time" practice has served the District well. Significant and unexpected growth such as HDL compromises those past practices as one new HDL load can move a substation loading from well below 90% to over 100% in a very short period of time (10% of a substation load is approximately 2.8 MW) [6]. Accelerating substation construction pulls resources from other system projects (creating risks elsewhere in the system) and increases costs.

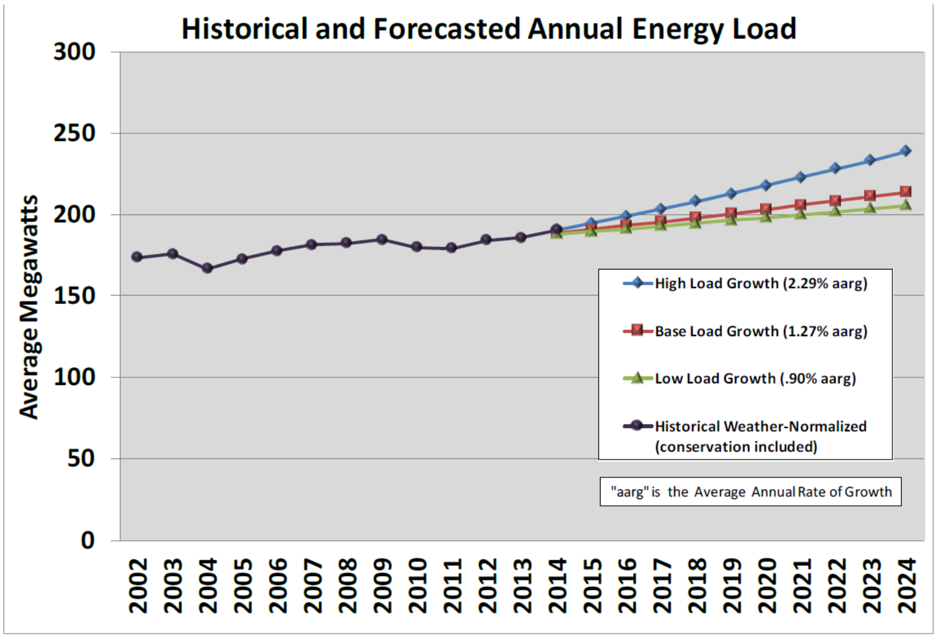
The District's electrical system serves mainly residential customers, some commercial customers and far fewer industrial loads. Current system conditions and the historical load growth (shown below) are used

[5] The District had to make changes to policy and practice in 2015 in part to address issues created by HDL customers, as discussed in Section 3.

[6] The District's standard substation is built with a 28 MVA transformer.

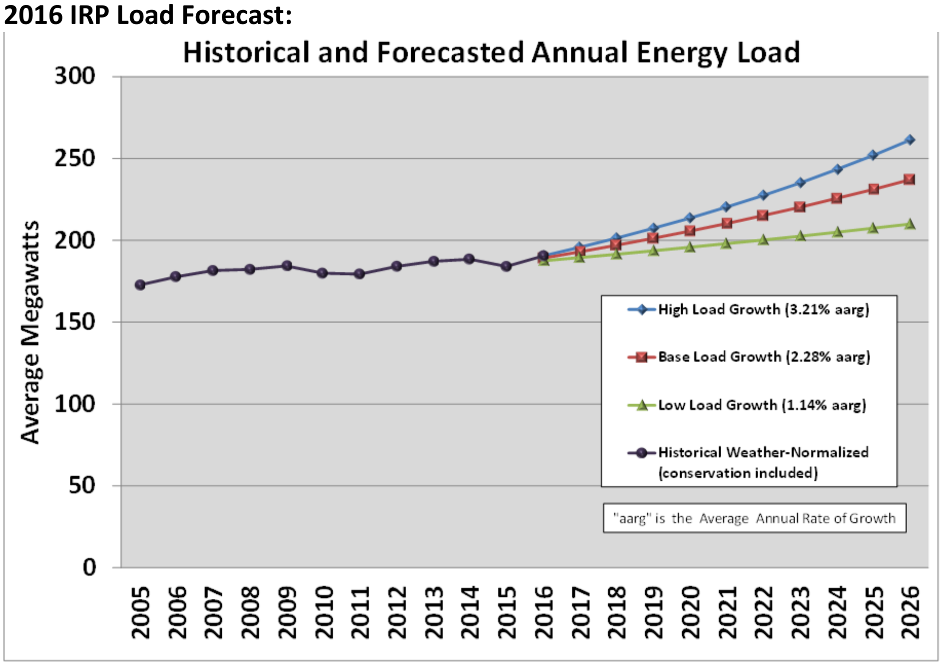
to evaluate improvements necessary for system growth, reliability, and safety. The load requests received in 2014-2015 far exceed this growth rate and have rapidly and unexpectedly moved substations from having available capacity to a point requiring additional investment in the short-term. The following graph shows the District's load forecast from its 2014 integrated resource plan.

2014 IRP Load Forecast:



The District recently completed its 2016 IRP forecast, shown below.

2016 IRP Load Forecast:



Unlike previous IRPs, the 2016 IRP includes forecasted HDL load growth. The forecast represents current policy and known service inquiries and applications and an estimate of potential effects of changes to rates and policies. Forecasting HDL load is challenging due to the District's limited experience with HDL loads, the inherent mobility of HDL loads, and the overall size and volatility of the HDL industry. The flexibility of HDL operations allows them to install large amounts of load wherever they can connect to the system. They appear to have little infrastructure requirements other than electricity, protection from the elements, and high-speed internet. When making inquiries to the District, prospective HDL customers often ask where there is available capacity on the system. The HDL customers often seek to use all available capacity all the time even though the District may have intended that capacity for multiple years of historical growth. This leaves the District at risk of being unable to serve other future customers or requiring accelerated investment in system upgrades.

Risks of Cost Recovery over Time and Stranded Assets
The size and mobility of HDL loads expose the District to excessive risks of not recovering the added capital costs of serving the HDL loads from HDL customers. While not always the case, many of the server farm load inquiries received by Chelan PUD do not intend to be long-term customers. One customer commented in the Feb 2, 2015 Board meeting that they will only be here a short time.[7] Staff has observed this occurring with existing HDL customers. When the value of a digital currency changes, the competition from other currency miners stiffens, technology becomes obsolescent, or cheaper rent is found, these customers can vacate their facility. The tendency to vacate leaves the District unable to recover the cost of the initial capital investment or maintenance of the asset from the class on average. Other classes of customers could have similar types of impacts when they come and go. However, as a whole and in the District’s experience over years, other customer classes tend to be fairly stable over time and far more stable than HDL customers. When a historically typical customer leaves, it tends to be replaced by a very similar customer. The District lacks long-term information for HDL customers, and what information it does have indicates abnormal instability. Additionally, if the District is required to add capacity to support a customer’s growth and then the customer discontinues taking service, the investment would have to be recovered from all other customers in future rates.

Increased Demands on Customer Service
Responding to the large number of inquiries from potential HDL customers involves customer service, engineering, and other District staffing resources. Prior to the moratorium, the sheer volume of inquiries was much greater than the District’s ability to respond and provide accurate and timely customer service while maintaining responsibilities to normal capital and maintenance planning activities necessary to meet system reliability and capacity planning. The District continues to receive inquiries from prospective HDL customers despite the moratorium. In addition, HDL customers require a heightened level of monitoring due to system impacts.

Cost of Uncertainty in Energy Planning
The large volume and uncertainty of HDL load adds to the District’s costs of managing its resources to meet load in the short- and long-term. The District has developed a program by which power generated in excess of local load is sold under contract to third parties. The program is designed to reduce the District’s exposure to energy market price fluctuations. The District commits power for periods of years taking into account forecasted District load. Server farm load[8], because it is a rapidly growing global industry with little geographic constraint, presents forecasting challenges unlike any other class of customers. Changes in load outside forecasted margins would impact the effectiveness of the marketing program, increase the District’s exposure to market risks, and could cause the District to buy additional market power.

[7] Richard Bundy, Telco214, Feb 2, 2015 Moratorium Hearing.
[8] U.S. Energy Information Administration, Annual Energy Outlook 2015, published April 2015.

Cost Recovery through Rates

The District's current rates were established in 2011 for the types of customers that existed at the time. Relevant to server farms, Schedules 2 and 3[9] were designed for the type of commercial and industrial customers, respectively, then existing. Unless the District creates a new rate class, virtually all server farms would fall under Schedule 2 or 3. Schedules 2 and 3 were not designed to and do not cover the cost of serving HDL customers, and therefore, the District cannot serve HDL customers under these rate schedules without risking the District's financial stability. As staff evaluated the proposed HDL class, the approach to mitigating the impacts has evolved. Supported by public input, specifically from HDL customers, staff proposes a rate structure for HDL service that includes an upfront capital charge to recover the incremental cost of system capacity required to serve the HDL customer, coupled with monthly charges to recover the forecasted ongoing cost of serving the customer.

Ongoing Monthly Rates

Staff recommends that the Board establish a rate schedule for HDL customers based on the District's cost of serving them according to the District's cost of service analysis. A cost of service analysis is a tool for tracking revenue requirements and attributing them to customers.[10]

Defining what is to be included in the costs for a customer class includes many decisions based on the business judgment of the District. The Board, staff, and the public had significant discussions regarding the rate design during staff presentations, informational meetings, and the rate hearing process.

The District typically analyzes the cost of serving load in three components, customer, delivery, and energy. Discussions included a variety of ways to value the cost of energy. Energy can be priced at the cost of producing the energy, which is the District's out of pocket energy cost of service. Or energy can be priced at market prices to reflect the value or "opportunity cost" of the energy. However, depending on how often the rate is updated to market prices, market pricing leads to less stable customer rates compared with cost of production pricing. Customers generally prefer relatively stable rates to allow them to better predict their own operating costs. Staff recommends basing the energy charge in the HDL rate on the cost of energy production. The cost of producing energy is essentially the same for all customer classes.

For the customer and delivery costs, the District's existing cost of service model categorizes the cost of existing customer classes but not the HDL class. The District lacks sufficient historical information for the new HDL class to be added into the cost of service model. Until the rate is revisited after additional information is gathered, staff recommends an HDL rate based on the cost to serve commercial and industrial customers, and thus staff used a blend of the costs of these classes to design a rate recommendation, which is detailed in Section 5.

Upfront Capital Charge

A rate based on the hybrid of the costs of commercial and industrial classes does not reflect the accelerated and higher capital investment costs associated with delivering energy to HDL customers. The ability of HDL customers to quickly relocate also increases the risk of the District overbuilding locally and having stranded assets. In addition, the increased volume of requests the District is experiencing consumes current and future capacity at an accelerated rate, taking away capacity that was planned for forecasted growth based on historical growth patterns. The rapid decline in available capacity on the system increases reliability and capacity risks. In order to maintain the necessary capacity for both normal growth and reliability contingency in the face of rapid HDL growth, large investments in the

[9] Schedule 3 is used here to refer to Schedules 3, 30, and 33, which are closely related.
[10] Cost of service is discussed at length in Section 5.

District's system may be required, at a higher cost than for the District's historical growth. An upfront charge based on the amount by which the incremental cost of the accelerated capital investment in the District's system exceeds what is already included in rates addresses some of this risk and provides an incentive to HDL customers to make longer-term decisions when choosing a location. Potential HDL customers have supported an upfront charge in public comment.[11] Unless these additional costs are recovered from HDL customers, they will be shifted to other customers. See section 5 for further discussion of the upfront charge.

Uncertainty in Rate Development

Staff's recommendations in this report attempt to balance the need to take rate action now to allow the District to serve HDL customers in a reasonable manner over the long-term with the desire to gather more data to gain a more complete picture of the cost characteristics of HDL load before taking action. However, due to the rapid influx of HDL load and the other costs identified in this report, staff recommends acting now.

Certain additional data, if it had been available to staff, would have informed staff's recommendation. For example, staff has no way to accurately forecast the actual number and size of HDL load that will be added to the District's system. Staff's recommended HDL rate, if adopted, will likely affect the growth rate of HDL load, but again there is no way to meaningfully forecast or test the effect without adopting the rate. Because the rate is higher than what would be paid under Schedule 2 and 3, some argue HDL load will be less than it otherwise would have. Staff does expect the upfront capital charge to decrease the frequency with which HDL customers relocate within or out of the District's system, thereby reducing the District's exposure to the risk of stranded distribution assets. However, because the proposed HDL rate is low compared with the rates generally available on a national level, such rate may have little impact on HDL load growth, and may even attract HDL customers that perceive improved rate certainty in a rate based on their load characteristics.

Another example of uncertainty is the actual cost of building and maintaining the District's distribution system to serve more high density, high load factor loads. Staff has made its best estimate based on the available information. But as described in this section and in Section 5, staff lacks adequate data to quantify precisely the cost to the system from the stresses of serving HDL loads. If the Board creates a new HDL rate class, it will facilitate staff's accumulation of data on HDL loads, which can be used at such time as the Board revisits the HDL rate. The District retains the ability to modify any of the rate components as deemed appropriate by the Board.

[11] Malachi Salcido, President, The Salcido Connection (December 7, 2015) (written comment); Jared Richardson, Partner, unidentified company (December 7, 2015) (written comment).

Section 2 - Criteria for Classification and Rate Setting

The District, in compliance with RCW 54.24.080, is required to establish, maintain, and collect rates or charges for electric energy and water and other services, facilities, and commodities sold, furnished, or supplied by the District. The rates and charges must be fair, nondiscriminatory, and must be adequate to provide revenues sufficient for the payment of the principal of and interest on such revenue obligations for which the payment has not otherwise been provided and all payments which the District is obligated to set aside in any special fund or funds created for such purpose, and for the proper operation and maintenance of the public utility and all necessary repairs, replacements, and renewals thereof.

The District has a duty to serve the electrical needs within its service territory in a manner that is fair and nondiscriminatory to all its customers, and to do so in a reasonable manner over the long term. Serving the proposed HDL customer class under existing rate schedules was not prudent or fair to other rate classifications. The growth of HDL customers in the District's service territory presents a type of load that is a significant departure from current and past customers and from forecasted load. Setting rates that reflect these characteristics furthers the District's duty to ensure it can serve this new type of load in a just and reasonable manner and consistently with prudent long-term planning.

Rates must apply alike to all persons within a class. A reasonable basis for distinguishing between customers must exist to create a rate class. Classification may rest on narrow distinctions. Classification criteria typically relate directly to the cost of serving the load. For example, the quantity of power used, the seasonality of use, or the maximum demand at any given moment are directly related to the cost of serving the load. However, other reasonable factors may be used. For example, it is reasonable to classify separately a type of business or power use where it has distinct load characteristics. This practice is common in the utility industry, and the District currently has such classifications (e.g., frost protection, street lights). Within a classification, the rate must not be excessive or disproportionate to service rendered. Just and reasonable rates provide fair compensation and return on investment to the utility. Conversely, rates are not reasonable where they do not provide for the long-term financial stability of the utility. The manner in which rates are fixed must not be arbitrary. Rates need not, and in fact cannot, be set to a mathematical certainty. Rather, rate setting is a legislative function in which reasonable considerations and philosophies are applied to generally accepted accounting principles.

The Board has the authority to establish reasonable connection charges for new customers. It is well established that charging different connection charges to different classes of customers is proper as long as the classifications are reasonable.

By Resolution No. 80-6286 (April 28, 1980), the District adopted certain standards and procedures related to ratemaking under Section 111(d) of the Pubilic Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. § 2621(d). This resolution includes procedures and ratemaking considerations associated with the process of ratemaking, including use of a cost of service analysis. Section 3, *infra*, contains the procedural history of the ratemaking process to date. The cost of service is addressed in Section 5, *infra*. The Board may waive the standards and procedures in the resolution when appropriate.

Section 3 - Notice and Procedural History

Notice of Moratorium and Hearings

The Board adopted a moratorium on December 15, 2014, which halted the acceptance of applications for loads greater than 1 aMW. Inquiries continued and customers were advised of the moratorium conditions and encouraged to visit the District website for future Board meetings and presentations.

The District established a moratorium and set a public hearing within 60 days to review and/or take further action on February 2, 2015. Public notice and information about the moratorium leading up to the public hearing included news releases (January 21) , radio interviews (January 28), Wenatchee World (January 25 and January 30) Lake Chelan Mirror, Leavenworth Echo, and Cashmere Record (January 28), online advertising with GoLakeChelan.com (January 26 – February 2), and social media outlets including Facebook throughout January 21 and February 2. Additionally, staff placed calls during the week of January 25 to various key accounts, county and city planning officials and staff to alert them of the upcoming hearing.

During the February 2, 2015 hearing, the Board continued the moratorium and set another hearing for July 6, 2015. Based on findings in staff's Board presentation during the July 6, 2015 hearing, the Board extended and modified the moratorium to continue to preclude applications for new services of 1 aMW or more, and any new or expanding high Energy Use Intensity (EUI) load applications of 250 kWh/Ft^2/Year or more. A further public moratorium hearing was set for December 7, 2015.

By December of 2015, staff had developed a draft definition for proposed HDL customers. Staff recommended lifting the moratorium on applications of non-HDL loads including loads of 1aMW and greater, and extending the moratorium on loads of 250 kWh/Ft^2/Year during the December 7, 2015 hearing. The Board adopted the modified moratorium and set a public hearing to revisit the moratorium for March 7, 2016. Following continued discussion and public comment, on February 16, 2016 the Board extended the moratorium hearing and set a public hearing date for October 3, 2016.

Policy Changes

In June 2014, the engineering and application fee for loads of 1aMW or greater was increased from $450 to $2,000 to better cover the costs associated with staff time dedicated to evaluating the system impacts associated with these varying load requests. The application process was strengthened to require additional pre-application meetings to thoroughly discuss customer intent and forecasted loads and establish processes specific to residential and non-residential services. During the moratorium, staff performed a review of the existing Utility Service Regulations and found opportunities for clarification and improvement that would also address some risks associated with the new loads; however, revisions were not server farm specific in nature. Resolution 15-13987 was presented to the Board and adopted on November 2, 2015. Changes included:

1. Section 8 – Security Deposits – Establishing distinct residential and non-residential deposit requirements;
2. Section 12 – Connection/Disconnection of Service – Provides ability to refuse or disconnect service if the customer provides inaccurate information to the District;
3. Section 27 – Demand meters & 31 Point of Delivery – Provides clarity of delivery points and metering configurations when faced with multiple end uses at a premises;

4. Section 45 – Separate Meter for Each Class of Service – Highest rate will apply if one meter serves multiple end uses that would typically be classified under different rate schedules; and
5. Section 41 – Changes in Load – Customer must convey change in load over 300 kW in writing and the District does not guarantee that existing facilities can accommodate such changes in loads or resumption of service.

Recognizing that non-residential service applications require a much more comprehensive impact study including system capacity planning, energy load characteristic modeling, and system improvement planning, the engineering fees were adjusted again. Effective January 1, 2016, engineering and application fees for non-residential service request are administered and charged based on the total requested connected load size. This change was necessary because the existing fees were not sufficient to recover costs associated with evaluating, designing and engineering these unique new loads.

Continued Outreach Performed

Keeping the existing industrial, large commercial and public agency customers (collectively referred to as "key accounts") apprised of the situation was a priority to the District. A key accounts customer luncheon was held March 16, 2015 to share staff concerns, potential policy considerations, and to obtain feedback. Invitations to these customers for the luncheon included postcards, phone calls and emails. The luncheon was well attended, including one industrial customer that has since been identified as an HDL type load. In general, staff's efforts were received positively. The desire for the District to mitigate the impacts of HDL loads on other rate classes was a common theme expressed by attendees. Staff continued to perform routine outreach with the key accounts customers via email newsletters providing an overview of Board presentations/actions, upcoming meetings, and providing links to the HDL webpage designed to share presentations, public comments received, and various media publications.

Staff and Commissioners engaged in several interviews for local radio and newspaper coverage to discuss the topics of large loads, high density loads, the moratorium, and policy issues being considered to ensure that a broad representative audience was engaged throughout the process. Links to media coverage and interviews can be found on the chelanpud.org website. The news coverage is described in Appendix C. Over forty (40) news articles were produced throughout 2015 and 2016, and staff and some of the HDL customers engaged in approximately nine (9) radio interviews to discuss the moratorium, proposed rate and the desired path forward.

Staff's Presentations to the Board in 2015 -2016

Throughout 2015 to the present, staff has provided numerous presentations. A majority of these presentations were held during regularly scheduled Board meetings, and no action was being sought by the Board. A summary of the Board presentation dates and content presented is provided in Appendix D.

Public comments

Information meetings and rate hearings provide opportunities for the members of the public to voice their opinions, ask questions, and express support for or opposition to proposed action. The District received written and verbal comments from members of the public during public meetings and outside public meetings. Customer comments are available on the chelanpud.org website for review.

Rate Setting Procedures

Resolution No. 80-6286 provides the procedure for rate proceedings. In preparation for any impending rate proceeding, the District conducts a total of three informational meetings, one each in Wenatchee, Leavenworth, and Chelan. Notice of informational meetings is provided at least seven (7) days in advance of the meeting, but not more than fifteen (15) days before the meeting. Legal notice of rate hearings is made by publication 30-days in advance of the hearing date. The hearing is continued from time to time at the discretion of the Board.

Notice of Information Meetings and Rate Hearing

The legal notice for the rate hearing was published in the Wenatchee World on December 31. This notice also included the dates, times and locations of the informational meetings. Informational meetings were held on January 4 (Leavenworth), January 5 (Chelan), and January 12 (Wenatchee). Initial display ads informing the public of the three informational meetings and the hearing were published in the Wenatchee World on December 27. Additional display ads including the same content for all pending meetings were published on December 30 in weekly publications including the Cashmere Record, Leavenworth Echo, and the Lake Chelan Mirror. Ads were published in the Leavenworth Echo, Cashmere Record, and Lake Chelan Mirror on January 6, and Wenatchee World Jan. 10. Online ads highlighting the Chelan and Wenatchee hearings were displayed on GoLakeChelan.com between December 29 and January 1. Display ads encouraging attendance of the Feb. 1 hearing were published in the Leavenworth Echo, Cashmere Valley Record, and Lake Chelan Mirror on January 27. An online ad was displayed on GoLakeChelan.com from January 25 – February 2. The Wenatchee World published display ads in the January 21 and January 31 publications. Emails inviting customers and people who had previously inquired about large amounts of power prior to and during the moratorium were sent in an attempt to maximize outreach and awareness of the pending hearing and potential Board action.

The public rate hearing was opened February 1, 2016, in Wenatchee, where staff presented rate alternatives, responded to feedback and customer comments collected at the informational meetings, and provided an opportunity for further public comment. No action was taken, and the rate hearing has been continued as necessary from time to time to permit staff time to provide alternatives and analysis supporting rate recommendations to the Board. Emails to the key account customers provide updates on Board action, dates and times for the continued hearings, and information as presented by staff continued to be distributed. The HDL webpage has been maintained to ensure information is current and readily accessible for customer review and input. At the April 4, 2016 rate hearing, the Board continued the rate hearing until June 6, 2016. Courtesy advertising encouraging attendance have been repeatedly published in local weekly publications including the Wenatchee World (May 22 and June 5), Leavenworth Echo, Lake Chelan Mirror, and Cashmere Record (May 25 and June 1), online with GoLakeChelan.com (May 22 – June 6) as well as social media outlets in the lead-up to the June 6 hearing. Postcards advising existing HDL customers that their accounts have been identified as potentially falling in the HDL classification and that a decision is possible at the June 6 hearing were sent the week of May 22.

Section 4 – Classifying High Density Load

Defining a rate class is the first step in designing a new rate. In developing the rate class definition, staff recognized that the customers having the impacts of greatest concern on the District (discussed *supra* in Section 1) tended to have much higher load densities than typical customers. The classification recommended by staff in this report is substantially the same as the classification proposed by staff to the Board on September 21, 2015 and used by the Board when it modified the moratorium on December 7, 2015. Staff crafted the calculation based on knowledge gained over months of experience with inquiries from and service to HDL customers. The following considerations and findings are fundamental to staff's recommended classification.

Key Considerations and Findings regarding the Classification

Identified Characteristics and Costs
First and foremost, staff crafted the classification language to closely match the characteristics of customers that have the distinct costs and risks, as discussed in Section 1. Staff tailored the classification closely to the identified characteristics with the objective of maximizing inclusion of intended load and minimizing inclusion of unintended load. This required some judgment because there is not always a clear line between one type of load and another, and one load may fall into one customer class even though it may be more similar to another class on average. The District has experienced several attempts by HDL customers to evade being classified as such during the moratorium by not informing the District of their presence or by gaming energy use intensity calculations or otherwise arguing the class definition does not apply to them. Because of some customers' propensity to evade classification, staff recommends erring on the side of a more inclusive classification with flexibility to prevent gaming.

Computer Servers, Server Farms, and Similar Technological Operations
As noted in Section 1, the majority of new applicants causing concerns are clusters of computer servers. The requests came in a variety of sizes, from small installations less than 10 kW of just a few servers squeezed in a small space, and large installations more than 1 MW. The load characteristics associated with serving HDL load (e.g., rapid growth, use of maximum available capacity, large potential for further growth, ability to leave suddenly, as described in Section 1) apply irrespective of their initial size. Staff's definition clarifies that "server farm" in this context can be few, or even one, computer server. For example, one of the existing bitcoin mining machines, which are about the size of a shoe box, has a demand of about 1.3 kW.[12] The trend in bitcoin mining machines has been toward higher demands and smaller size.

The District's costs are not associated with serving computers per se. Rather they are associated with serving high EUI loads that share the other load characteristics of HDL load described in Section 1. Therefore, staff recommends including similar high density technological operations in the class. Although "server farm" describes the currently known HDL loads, similar loads may be attracted to the District by its nationally low rates. In addition, because of a lack of a definitive term or terms to encompass the computer load that has the HDL characteristics, including in the class definition the phrase "similar technological operations" allows the District to apply the rate to new computational technologies that has similar load characteristics as the existing HDL loads.

[12] The Antminer S7 ASIC Bitcoin Miner consumes 1.293 kW and has the dimensions 11.8 x 6.1 x 4.8 inches.

Energy Use Intensity (EUI)

Staff's recommendation includes an EUI value in the class definition for two main reasons. First, high EUI loads tend to have the profiles described in Section 1 that add to the cost of serving the load. EUI is a single number that correlates with unpredictable load swings, higher load sizes, higher load factors, and outsized contribution to the diversity factor. Second, computer servers alone are an inadequate basis for a classification. Computers are pervasive, but the distinct costs described in Section 1 are driven by the high EUI computer operations.

In the recommended rate class definition, 250 or greater EUI is used to define high density load. Staff finds 250 to be a reasonable demarcation between customers causing and not causing the costs typical of an HDL load. Staff makes the following observations in support of this recommendation.

- The likely highest estimated EUI of any District non-server farm retail electricity customer within the commercial and industrial classes is less than 200 kWh/ft^2/yr.
- The lowest EUI of a known server farm is approximately 533 kWh/ft^2/yr, which is well over two times the highest known EUI of non-server farm load. Most server farms in the District likely have EUIs greater than 1000.
- A 2015 report prepared for the District by EES estimated the EUI of District residential and commercial customer ranges from 10 to 81 kWh/ft^2/yr.
- Server farms with low EUIs tend not to have the cost characteristics of HDL loads. For example, one data storage (rather than data processing or mining) server farm in the District is estimated to have an EUI of 26 kWh/ft^2/yr. It also is permanent in nature, unlikely to expand significantly, and fairly predictable.
- An EUI of 250 kWh/ft^2/yr has been an element of the District's moratorium on new applications since July 2015 and has proven to include server farms with the identified cost characteristics.

Similar Classifications in the Utility Industry

Research identified other utilities that have used electric load per square foot to classify customers; these utilities use the term "High Density Load". In the examples below, the utilities apply different up-front capital requirements and rate riders to their high density load classifications.

> Industry Example 1: Public Service Company of Colorado: The utility defines High Density Load as "a data center, indoor plant growing facility or similarly situated load where the customer's load requirements are increased significantly over normal load per square foot ratios such that the Company is required to install additional capacity over which it would normally provide and where the customer's electric demand is directly proportional to the sale of products or services."[13] The utility applies different construction allowance and construction payment requirements to these customers, categorizing them under "plan B – indeterminate service" schedule for construction allowance and construction payments.[14]
>
> Industry Example 2: Consolidated Edison Company of New York: Con Edison's "Rider Y Rates and Charges for Customers Requesting High Load-Density Service" applies to premises requesting higher than standard load density (standard density is the typical load density for the type of premises for which application for service is made).[15] The customer's load density is based on

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[13] Public Service Company of Colorado, Rules and Regulations Electric Service, Service Lateral Extension and Distribution Line Extension Policy, Sheet No. R113, effective Feb. 15, 2014

[14] Public Service Company of Colorado, Rules and Regulations Electric Service, Service Lateral Extension and Distribution Line Extension Policy, Sheet No. R121, effective Feb. 15, 2014.

[15] Consolidated Edison Company of New York, Inc, General Rules, Service Classification Riders, Rider Y Rates and Charges for Customers Requesting High Load-Density Service, Leaf No. 319, effective Feb. 21, 2014.

peak kW demand and square footage. The rider includes both an excess facilities charge and a rate component. The rate is the company's standard cost based rate, but it is billed on the higher of maximum demand or 70-75% (depending on class) of the contract/authorized peak demand. This establishes predictable minimum revenue for the company. A presentation in 2001 by the New York State Department of Public Service relating to the tariff entitled "Connection Tariffs for High Density Load Customers: Internet Data Centers in New York City" echoed many of the distribution system concerns identified by the District.

Fairness and Predictability

Staff structured the class definition to make it understandable and to minimize the burden for customers' new service applications. The 5 annual aMW limit in the proposed definition is consistent with upper limit in Schedule 3. The District has long required all customers larger than 5 aMW to enter into an individualized service contract with the District under Schedule 4 in order to address the customer's specific requirements and characteristics of the service.

Staff's Recommended Rate Class Definition

High Density Load - The HDL rate schedule applies to server farms and similar technological operations with an energy use intensity (EUI) of 250 kWh/ft^2/year or more and with average electrical loads up to and including 5 annual aMWs at a single Point of Delivery, where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District; and
- "Server farm" means an entity whose Energy use serves mostly one or more computer server machines and any ancillary loads including HVAC, UPS, power systems, and lighting.

When calculating an EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this rate schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft^2/year.

Section 5 – Cost of Service and Design of HDL Rate

Introduction

The Board directed staff to develop a rate for HDL customers that reflects in a fair, just, and non-discriminatory fashion the cost of serving such customers. Rate development is usually a two stage process of first attributing the cost of serving an aggregate class of customers (in this case the HDL class), then structuring individual charges for the rate to recover an appropriate share of the attributed class costs from individual HDL customers in approximate proportion to the costs incurred by the District to serve such individual customer. This first phase of rate development involves establishing an equitable allocation of the District's total revenue requirements, or cost of service, to the various customer classes taking electric service from the District based upon the general characteristics of each such class. Staff used the District's existing Cost of Service Analysis (COSA) tool, which was developed in 2008 and has been updated by the Strategic Financial Planning department, for analyzing and designing the HDL rate. Although a COSA ideally categorizes costs to a given customer class based on the known characteristics of that class, due to a lack of extensive historical data on HDL customers, the staff relied partly on the COSA-attributed costs of the two most similar customer classes, the commercial and industrial classes.

Because rate development involves a number of judgment calls, there is neither a uniquely correct way to carry out the analyses described in this section nor any uniquely correct resulting rate. At each stage, numerous decisions must be made regarding the calculation and assignment of costs. Board direction and principles, internal District financial policies and accounting practices, past District practices, and generally accepted industry standards of cost accounting and rate design all influenced staff's choices in designing its rate recommendations. In all cases, the resultant rate must be fair and reasonable, but the term "fair and reasonable" is widely acknowledged to define a general range of possible outcomes as opposed to a single result.

This section describes the principles and methodologies used to design staff's recommended HDL rate. It includes an overview of the COSA methodologies used to functionalize, categorize and allocate the District's revenue requirements. It also includes a description of the methodologies used to structure the rate based on the COSA. Last, this section explains staff's recommended upfront capital charge.

General Rate-setting Guidelines and Procedures

Developing rates that meet all the identified objectives and policies is a complex process. The 2008 COSA identified several general principles and objectives rates should reflect or further:

- Fair, Equitable & Non-Discriminatory
- Revenue Stability & Sufficiency
- Cost Based
- Continuity in Philosophy
- Ability to Pay
- Conservation & Efficient Usage
- Simplicity in Administration & Understanding
- Major Shifts Adjusted Over Time

General rate-setting objectives often conflict with each other, so the resultant rate depends in part on how the District balances these objectives. The District's COSA and rate setting process employ generally accepted methodologies as well as specific methodologies adapted as needed for the special characteristics of the District and the costs it incurs. For example, since the state utility tax imposed on the electric system is based on the amount of revenue obtained from the retail customers, it is allocated proportionately only to retail customers and is not assigned to wholesale service, interdepartmental service or any other service that is exempt from this tax.

Cost of Service Analysis

The Strategic Financial Planning department manages the District's COSA on an ongoing basis. Staff last presented the District's COSA to the Board in 2008 (the "2008 COSA"), when the Board approved the reasonableness of its calculations. The 2008 COSA informed the design of current electricity rates. Since 2008, some aspects of the methodology in the COSA have been updated by Strategic and Financial Planning to meet changing circumstances. These changes include the implementation of new long-term power contracts, financial policy changes, changes to the District's market hedging program, public power benefit actions, and enhanced financial forecast modeling to mention a few.

The three main steps in the COSA are to functionalize (assign revenue requirements to customer-related, delivery-related, or supply-related components), categorize (divide functionalized expenses among customer classes) and allocate (assign miscellaneous costs including District overheads) costs and revenues among the various customer classes. This process incorporates past practice, industry standards and the expertise and direction provided by key District employees to produce the cost of service result.

The initial steps of functionalization and categorization are closely related and have been combined in the District's cost of service supporting documentation. These combined steps involve assigning the revenue requirement among the general categories of supply-related, delivery/collection-related and customer-related (also referred to as energy, demand and basic, respectively) by customer class. This categorization closely resembles the existing structure of the District's financial accounting system and the financial forecasting system, but does require the application of some methodologies to properly assign or allocate some components of the revenue requirements. The following sections describe the general basis of the methodologies used in determining how the cost or revenue requirements have been categorized.

Functionalizing Costs into Customer, Delivery, and Supply Components

Customer (Basic) Cost Component - Customer costs are costs that vary primarily by the number of customers in a customer class and include customer billing, collections, records, meter reading, service, etc. along with a proportionate share of the District's administrative and general (A&G) cost that support all the District's activities. The costs in this category correlate to the number and characteristics of customers served by the District in each customer class and are not a direct function of the amount of energy used by the customer. Consistent with industry practice, these costs are the basic charge or minimum rate component in rates. The COSA methodologies for assigning these costs have not materially changed since 2008. Cost inputs are listed in Appendix E.

Delivery/Collection (Demand) Cost Component - Delivery costs include the costs of transmission and distribution services, including a proportionate share of A&G and depreciation of and a rate of return on the District's investment in transmission and distribution facilities serving the customer class. These costs are generally driven by the maximum demand requirement imposed by the various customer classes and customers, with the exception of the frost protection and street lights classes, for which costs are directly assigned. The assignment of this cost component varies by service and customer type and can be based on number of service drops, energy usage or demand. Key changes since 2008 include the centralization of the District's network transmission activity and the inclusion of the rate of return requirement. The network transmission was established as part of the new long term power contracts, which had the effect of shifting cost previously identified as "supply" to "delivery." The inclusion of the rate of return on distribution assets was also established as the District shifted to the new power contracts and established financial metrics focused on strengthening the District's financial position. Cost inputs are listed in Appendix E.

Supply (Energy) Cost Component – This cost category is often referred to as "energy" costs. Supply costs include internal and external power purchases[16] and activities directly related to acquiring power, along with a proportionate share of A&G costs. These costs are primarily driven by the actual amount of electricity consumed by customers in each class. Key changes to the COSA since 2008 are associated with the new terms in the District's long-term power contracts. These new contracts have shifted the financing of District resources from a continuous debt funding to an approach with increased cash funding. These funding requirements, which include a rate of return on generation assets, are now included in the supply component. The COSA assigns costs based on the actual cost of the commodity being consumed. Costs are split between both retail use and market wholesale sales proportionately to their consumption. Cost inputs are listed in Appendix E.

Categorizing Costs into Rate Classes

Once this functionalization has been completed, various methodologies are used to assign or "categorize" these cost components among the various rate classes and rate components. Rate classes include residential, commercial, industrial and other defined groups of customers that have similar service requirements. The methodologies used to accomplish the allocations are summarized below with supporting analysis in appendices. Note that the District's current division among customer classes is based in part on differences in total electricity (energy) use and the rate of use (demand).

The HDL revenue requirement is derived from the calculated requirements for the existing commercial and industrial classifications. Staff was unable to directly assign costs to the HDL class through historical weighting factors due to the lack of extensive historical operational data for HDL customers. Although the District's commercial and industrial classes may be an imperfect fit for HDL customers, they are the closest classifications for which the District has data. HDL customers range in size from below 10 kW up to a few megawatts, which spans the ranges of the District's commercial and industrial rate schedules. Given the size of HDL customers, a hybrid of costs attributable to the commercial and industrial classes makes a reasonable basis for HDL customer costs. The revenue requirement includes operating activity and the offsetting revenue associated with customer contributions in aid of construction, which is included as a credit to gross capital investment requirements.

Basic (Customer) Cost Component – The District performed an analysis to determine the proportion of costs assigned to this functional component of costs that are attributable to each customer class. Based on the number of customers in each customer class and the total customer costs of serving that class, the District created weighted customer allocation factors in the 2008 COSA. The weighting factors represent the cost of serving a customer of one class compared with the cost of serving a customer of another class. For example, the industrial class has a relatively high weighting factor because the District incurs more basic costs in serving a typical industrial customer than in serving a typical commercial or residential customer. This allocation factor has been applied to the basic cost component of the revenue requirement to determine the basic costs of each customer class. The weighting factors used here are unchanged from the 2008 COSA, but the customer counts have been updated. Table 1 lists customer counts and weighting factors for each class and shows the calculated percentage of total customer cost

[16] In the District's internal accounting, the District treats power from the District's generating resources used by the District's retail system as if the retail system purchased the power from the District's resources.

allocated to each class. As explained below in the Design of the HDL Rate section, staff's recommended HDL basic charge is based on the industrial customer costs.

Table 1 – Basic (Customer) Cost Allocation Factors			
	Count	Weight	%
Residential	37,594	2.50	*74.1%*
Commercial	6,353	4.00	*20.0%*
Industrial	30	100.00	*2.5%*
Irrigation	1,100	2.00	*1.7%*
Frost Protection	378	1.50	*0.5%*
Street Lights	4,196	0.25	*0.8%*
Inter-departmental	548	1.00	*0.4%*
Industrial			***2.5%***

Demand (Delivery) Cost Component - System demand costs are categorized based on analyzing peak usage expectations for each customer rate class. The COSA process associates various feeders with rate classes to provide independent load factor profiles for the various customer classifications. In addition, seasonal load use and customer classification subset attributes are applied when direct supporting details are limited. The District primarily used a 3-month coincidental peak (CP) allocation factor as summarized in Table 2. This represents a change from the non-coincidental peak basis used in 2008 and more accurately assigns cost between the customer classifications. As explained below in the Design of the HDL Rate section, staff's recommended HDL demand rate is based on a blend of the commercial and industrial delivery costs.

Table 2 – Demand (Delivery) Cost Allocation Factors		
	Load Factor Adjusted 3-Month Coincidental Peak (kW)	%
Residential	872,125	**63.9%**
Commercial	320,405	**23.5%**
Industrial	131,738	**9.7%**
Irrigation	34,682	**2.5%**
Frost Protection	* Direct Assignment	
Street Lights	* Direct Assignment	
Inter-departmental	5,286	**.4%**
Commercial/Industrial	**452,143**	**33.2%**
* Frost Protection based on service count ratio & Street Lights based on direct cost assignment.		

Energy (Supply) Cost Component – The costs assigned to this component are directly associated with customer's total consumption or use of the service, and are allocated based on the measured energy usage (kWh) of each of the customer classes, including line losses. Table 3 summarizes the supply base figures and allocations used for 2016. This allocation factor remains the same as was used in the 2008 COSA effort. As explained below, staff's recommended HDL energy rate is based on a blend of the commercial and industrial supply costs.

Table 3 – Energy (Supply) Cost Allocation Factors		
	Energy Usage (kWh)	%
Residential	777,388	**48.1%**
Commercial	480,113	**29.7%**
Industrial	293,154	**18.1%**
Irrigation	38,892	**2.4%**
Frost Protection	775	**0.1%**
Street Lights	3,503	**0.2%**
Inter-departmental	22,924	**1.4%**
Commercial/Industrial	**773,267**	**47.8%**

Design of the HDL Rate

Staff designed its recommended rate for HDL services based in part on the 5-year average of the forecasted costs attributable to commercial and industrial classes.

Basic (Customer) Cost Component – Staff recommends that the basic charge in the HDL rate be tiered into three levels to reflect the wide range of sizes of HDL customers. The tiers move the charges for individual customers closer to actual District costs for such customer than would be the case if all sizes of customers paid the same basic (customer) charge. Staff proposes using the same tier thresholds as the District uses for engineering and application fees: 300 kW and 1 MW. Unlike the delivery and supply components, the customer component is calculated using the cost per MW of the industrial class only because including the commercial class in the algorithm used to tier basic charges would have raised the charge to a higher level than appeared reasonable to staff.[17]

Demand (Delivery) Cost Component - The demand charge in the HDL rate uses the combined costs and three-month coincidental peak kW demand for commercial and industrial delivery developed in the COSA to determine a $/kW rate.[18]

Energy (Supply) Cost Component – The energy charge in the HDL rate uses the combined costs for commercial and industrial delivery under the COSA and translates that into a cents/kWh based on the combined usage of the two classes.[19]

Appendix F, Unit Costing Analysis, contains the values in the cost component calculations. Table 4 summarizes staff's rate recommendation.

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[17] Calculation of HDL Basic Charge: Costs assigned to this component are distributed to each customer class based on the number of service drops times the appropriate weighting factor. This calculated revenue requirement for the industrial class is then divided by the industrial class average monthly demand to produce an average monthly cost per kW.

[18] Calculation of HDL Demand Charge: Costs assigned to this component are distributed to each customer class using a three-month coincidental peak allocation factor. This calculated revenue requirement for commercial and industrial is combined and then divided by the combined commercial and industrial class average monthly demand to produce an average monthly cost per kW.

[19] Calculation of HDL Energy Charge: Costs assigned to this component are distributed to each customer class based on their proportionate amount of energy use. This calculated revenue requirement for commercial and industrial is combined and then divided by the combined commercial and industrial energy use to produce a cost per kWh.

Table 4 – Staff's Recommended Monthly HDL Rate (not including upfront charge)			
Size of Service	Basic Charge per Meter per Month	Demand Charge per kW	Energy Charge per kWh
up to 300 kW	$130	$5.50	2.7¢
300 kW to < 1 MW	$560	$5.50	2.7¢
1 MW to ≤ 5 aMW	$860	$5.50	2.7¢

In addition, staff's proposed HDL rate includes an upfront charge discussed below.

Upfront Capital Charge

As discussed in Section 1, the District incurs costs for expanding its distribution system to accommodate HDL customers, and it risks not recovering those costs over time if the HDL customers discontinue taking service (called "stranded asset risks"). The COSA-based rate recommended by staff above does not fully include these costs or ameliorate the stranded asset risks. Therefore, staff recommends an additional charge to recover the incremental costs associated with distribution system capacity expansion that are not embedded in the staff's COSA-based rate recommendation described above. Staff recommends that this additional charge be in the form of an upfront charge for new or expanded HDL services in order to partially mitigate the District's risk of not recovering its cost if the assets are subsequently stranded. Applying the charge upfront to all HDL service may also protect the District by creating a disincentive for HDL customers to locate within the District only for a short time or to move within the District.

Calculation of the Upfront Capital Charge

The District's COSA analysis discussed above establishes the District's revenue requirements based on annual projected costs of serving customers. The COSA depreciates distribution assets over their 30- to 50-year lifespan and spreads the corresponding revenue requirement over the same period. Consequently, a rate derived from the COSA analysis, such as staff's recommended rate above, recovers the District's capital costs of distribution infrastructure over the 30- to 50-year life of the assets.

Costs to add system capacity now are greater than costs over the last 30 to 50 years. Staff estimated the cost of adding new capacity to the distribution system by averaging the costs per kilowatt of recent and planned infrastructure additions to project the five-year future average cost. The substation, reconductoring, and other additions used in this calculation are listed in Appendix G. Staff estimates the current cost of adding capacity to the distribution system to be $308/kW.

Because the cost of distribution system assets are partially recovered through the COSA-based delivery charge, the amount so recovered must be excluded from an upfront charge; otherwise the rate would recover twice for the same assets. The asset component of the delivery charge is the depreciation of the net book value of the assets. Thus, an upfront charge equivalent to the asset value included in the delivery charge would equal the net book value of the assets. The 5-year future average net book value of the assets, based on historical growth, is $118/kW as calculated in Appendix H. This amount approximates the system asset costs that would be recovered on average from HDL customers through monthly rates, assuming HDL customers as a class had the same tendency to relocate as other customer classes.

In order to apply an upfront capital charge that does not include amounts to be recovered through the ongoing delivery charge, staff recommends an upfront charge equal to the current cost of adding distribution infrastructure minus the net book value of the District's distribution assets. As stated above, the current cost of construction is $308/kW and the cost recovered through staff's recommended ongoing delivery charge is $118/kW, so staff's recommended upfront capital charge is $190/kW.[20, 21]

Application of Upfront Capital Charge

Staff recommends that the upfront capital charge be a one-time, dollars-per-kilowatt charge assessed on HDL customers before their HDL load is connected to the District's system or before an HDL load increases its demand above the amount previously approved by the District. The kilowatt amount used to calculate the charge would be the maximum demand requested (and confirmed as available by the District), which is consistent with how the District structures its engineering fees.

Staff does not recommend applying the upfront capital charge only above a certain size threshold. Smaller HDL customers can locate on less robust portions of the system, such as remote areas, in which even a small HDL load can stress the distribution system. Furthermore, a cluster of smaller HDL loads in close proximity will have impacts similar to a single large HDL load due to their high load factor. Last, potential HDL customers have shown an ability to disaggregate to avoid size thresholds.

Staff has developed the charge to recover costs of expanding distribution infrastructure. In addition to the upfront capital charge, HDL customers will be responsible for any line extension costs under the District's line extension policy. The upfront capital charge will be due even if the HDL load replaces a load of the same maximum demand at the same location. However, staff recommends making a limited exception to the charge where one HDL customer follows another of the same load size at the same location with little or no time between services. Apart from that limited exception, staff believes it is appropriate to assess all new or expanding HDL customers this charge because, as discussed in Section 1, even if the preceding load had the same maximum demand, it likely would not have had the same load characteristics (e.g., load factor, diversity factor, EUI) as the HDL load.

Customer-Specific Contracts

Staff recommends that, in conjunction with adoption of the HDL rate, the Board considers negotiating, as appropriate, customer-specific electric service contracts with existing customers that would be subject to the HDL rate. Customer-specific contracts could take into account special factors relating to individual customers. Existing customers may have made plans and investments based on the expectation that current rates would not be changed. Phasing in the HDL rate through a contract could give HDL customer time to adjust. The District can effectively negotiate with existing HDL customers because of its understanding of their loads. Negotiating customer-specific contracts with new customers is not practical.

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[20] For a longterm customer, the upfront charge is modest when converted to ¢/kWh. Spread over 5 years for a 90% load factor customer, the $190/kW equates to 0.5 ¢/kWh. For a shortterm customer, the equivalent ¢/kWh would be higher (e.g., 2.4 ¢/kWh for a 1-year customer). This difference is consistent with one purpose of the upfront charge: to discourage shortterm installations thereby reducing the District's exposure to stranded assets.

[21] Note that the upfront capital charge calculation currently does not incorporate several of the District's distribution capital costs associated with serving HDL loads, including O&M costs for stranded assets, costs of building new distribution infrastructure at a pace faster than the historical pace, as well as the costs of additional infrastructure needed per kW to serve high load factor loads, including extra capacity due to lack of load diversity and shortened lifespan of equipment due to heavy loading.

Appendix A Draft High Density Load Rate Schedule

DRAFT High Density Load

Schedule [# TBD]

AVAILABILITY:

This Schedule applies to server farms and similar technological operations with an energy use intensity (EUI) of 250 kWh/ft^2/year or more and with average electrical loads up to and including 5 annual aMWs at a single Point of Delivery, where:

- "Energy Use Intensity" or "EUI" means the annual kilowatt-hours of Energy usage divided by the operating space square footage used by the Energy consuming activity as determined by the District; and
- "Server farm" means an entity whose Energy use serves mostly one or more computer server machines and any ancillary loads including HVAC, UPS, power systems, and lighting.

When calculating an EUI, the District may make reasonable assumptions and projections as necessary to estimate Energy usage and square footage based on the Customer's application, data regarding similar operations, and other sources. An entity otherwise subject to this Schedule will be excluded from this schedule if the entity demonstrates to the District's reasonable satisfaction, or the District determines on its own initiative, that the energy use intensity (EUI) of the subject facility is less than 250 kWh/ft^2/year. A Customer otherwise subject to this Schedule on its effective date may, at the District's discretion, have the option of entering into a customer-specific service Contract that may include a phase-in of the rate in this Schedule based on the special circumstances of the Customer.

Service under this schedule may require a power sales Contract between the Customer and the District prior to connection of service. Changes in Load, as defined in Utility Service Regulation 41, will require a new service application to be submitted to the District to evaluate the impact of that changed load to existing Electrical Service Facilities.

Customers subject to the terms and conditions of Schedule __ must meet the following characteristics:

- Be served at one Premise through a single Point of Delivery as defined in the District's Service Regulations;
- Be in compliance with Chapter 296-46B WAC electrical safety standards, administration and installation; and
- Maintain satisfactory Power Factor determined in Schedule 24.

Customers with multiple locations and Energy loads will not be aggregated for billing purposes unless the District, in its sole discretion, determines the Customer is circumventing the 5 annual aMW Energy cap to meet the load requirements of a common Premise. A Customer with measured total connected loads greater than 5 annual aMWs may be required to be served under Rate Schedule 4.

UPFRONT CAPITAL CHARGE

Prior to approval of service or increase in capacity, Customers to be served under this Schedule must pay an Upfront Capital Charge based upon the requested size of the new or increased amount of electric load. The Upfront Capital Charge does not apply to load amounts approved by the District prior to the effective date of this Schedule where: (1) the Customer has properly obtained District approval of the load prior to the effective date of this Schedule; (2) the load has not changed materially in load factor, size, or otherwise from the load approved by the District; (3) the Customer has fully complied and continues to fully comply with the District's rules, policies, and regulations; and (4) the load is transferred onto this Schedule as of the effective date of the Schedule. Current amounts are included in the District's Fees and Charges schedule. Additional state and local taxes may apply. Additional charges may apply, including Line Extension costs.

CHARACTER OF SERVICE:

Service to be furnished under this schedule may be either:

- Three phase, sixty hertz alternating current at primary voltage, or.
- Secondary power single phase, three phase or four wire three phase, 60 cycle, alternating current at available phase and voltage up to 2MW.

RATES:

Basic Charge:	**Per month per meter**
Up to 300 kW	$130
300 kW to < 1 MW	$560
1 MW to ≤ 5 aMW	$860
Monthly Demand Charge:	$5.50 per kW of Demand
Energy Charge:	2.70¢ per kWh
Upfront Capital Charge	**Per kW of new or expanded Electric Service under this schedule** Amount of upfront capital charge is set forth in the District's Fees and Charges Schedule

TAX ADJUSTMENT:

The amount of any tax levied by any city or town in accordance with R.C.W 54.28.070 of the laws of the State of Washington, will be added to all charges for electricity sold within the limits of any such city or town.

SERVICE POLICY:

Service under this schedule is subject to the rules and regulations as defined in the District's Utility Service Regulations.

EFFECTIVE: **TBD**

Appendix B HDL Case Studies

Cargo containers - Wenatchee:
This case involves a line extension for 2aMW service and four large cargo containers hosting Bitcoin machines. The load never materialized as planned, and the infrastructure remains idle. Another Bitcoin operation sub-leased but later found cheaper rent in Entiat.

Laundromat- Wenatchee:
A customer established Bitcoin mining operations in an old laundromat. The service was overloaded causing an overloaded utility transformer and melted the insulation off of the overhead secondary service conductor. A transformer and wire replacement was conducted by the District. A few months later, the customer left the building and an unpaid power bill of ~$2,300.00. It was later discovered that the customer relocated his operations with another HDL customer in Cashmere. The remaining power bill was later paid by another known HDL customer.

Bitcoin operations discovered in two apartments:
In this case, an individual utilized residential premises for commercial purposes without notice to the District. The customer set up two separate Bitcoin operations in two separate residential apartments. A load study determined the installations were consuming ~10x the normal load in the apartments. The District performed on site evaluation and operational and safety concerns were identified. Discussions occurred with the customer and the property owner to determine if this was sustainable as a commercial business.

U-Haul from Florida:
This is a case in which a man loaded a U-Haul truck full of Bitcoin machines and drove out from Florida with aspirations of connecting the Bitcoin machines in a storage facility in Cashmere. During the application process, an on-site visit was performed. The facility showed signs of electrical service panel modifications that were lacking Department of Labor & Industries approval. The square footage on the application was altered or “gamed” to keep the EUI under 250. Service was denied.

Upper Entiat Valley Bitcoin:
An old fruit packing warehouse in the upper Entiat Valley was leased to a customer to perform Bitcoin mining. During the application process it was determined that the existing Delta-Wye transformer bank would need to be replaced in order to serve the high demand factor. The Customer was responsible for the costs to replace the transformers and reconfigure voltages leading to controversy over the upfront costs.

South Wenatchee Bitcoin:
An old machine shop was occupied by Bitcoin miners. The facilities have mining machines that are managed remotely from California. No onsite staff.

Bitcoin operations discovered in Cashmere:
A shop was leased to out-of-state Bitcoin miners. According to the property owner, the miners occupied an additional shop area on the property without owner consent. Both shops had separate meters that were running at full capacity due to bitcoin mining. Following an on-site investigation to verify that Bitcoin mining was in fact happening, contact was made with the property owner, who is also the

Customer of record, to ensure District service policies including Commercial service operations and deposit requirements where adhered to. Through these discussions, the owner informed the District he wanted the miners out of the two building because they were not paying the agreed rental. The owner/customer requested that the PUD activate the 72-hour notice to disconnect the two shops which allows a landlord to authorize disconnection of service at an address where a tenant resides. Following the 72-hours as prescribed, both facilities were disconnected and the meters were removed.

Appendix C Summary of News Coverage

Wenatchee World Articles and Editorials

- PUD moratorium extended on big power – Feb. 3, 2015
- PUD studies slowing expansion of data mining – June 1, 2015
- County to study high density load zones – June 9, 2015
- PUD expands moratorium – July 6, 2015
- PUD seeks more rules, high rates for elusive data miners – July 19, 2015
- Rate could double for bitcoiners – Nov. 23, 2015
- Bitcoiners say proposed new power rate would break them – Dec. 8, 2015
- Bitcoiners call for PUD to change high-density rate proposal – Jan. 13, 2016
- PUD to delay vote on high-density power rate, moratorium – Jan. 21, 2016
- PUD rates and bitcoin effect – Jan. 25, 2016
- Salcido makes case against high density rates – Jan. 31, 2016
- PUD forums on high density loads set – Jan. 31, 2016
- Can energy-intensive businesses create economic benefit here? – Feb. 1, 2016
- Big-name fruit companies favor PUD rate proposal – Feb. 1, 2106
- Facts behind the bitcoin discussion – Feb. 15, 2016
- Chelan PUD extends bitcoin moratorium until October – Feb. 17, 2016
- Chelan PUD Commissioner: Grant PUD not out of power – Feb. 29, 2016
- PUD ponders more upfront costs for bitcoiners – Mar. 22, 2016
- A compromise for a bitcoin – Mar. 27, 2016

Other media sources

- Rise in bitcoin mining has Chelan PUD considering new rate class – Clearing Up, June 5, 2015
- Chelan PUD staff offers three models for energy – Clearing Up, June 19, 2015
- Chelan PUD sets proposed high-density load rate at 5 cents kWh – Clearing Up, Nov. 6, 2015
- Chelan PUD extends large load pause – Clearing Up, Dec. 12, 2015
- Is bitcoin breaking up? – Wall Street Journal, Jan. 17, 2016
- Death of bitcoin – Washington Post, Jan. 19, 2016
- Chelan PUD plans forum with intense energy users – KPQ News, Jan. 19, 2016
- PUD staff and commissioners begin process to finalize new rates – GoLakeChelan, Jan. 20, 2016
- Chelan PUD plans forum with customers subject to proposed HDL rate – Clearing Up, Jan. 22, 2016
- Forum lets high-density power users share their side of the story – Leavenworth Echo, Jan. 27, 2016
- Low electricity rates in Washington – CryptoCoinsNews, Feb. 1, 2016
- Vertical integration gives Salcido an edge – Wenatchee Business Journal, Feb. 1, 2016
- High-density power users invited to state their case – Wenatchee Business Journal, Feb. 1, 2016
- PUD considers higher rates for big power users – KPQ News, Feb. 2, 2016
- Bitcoin mining prompts utility rate hike – Data Center Frontier, Feb. 2, 2016
- Carbon footprint of data centers downplayed – Greenwire, Feb. 4, 2016
- Chelan PUD to hold another hearing on high energy users – KPQ News, Feb. 12, 2016
- Bitcoin miners have discovered Washington – Crosscut, Mar. 1, 2016
- Bitcoin mining, megawatts and the making of rates – Clearing Up, Mar. 11, 2016

- High density load rate proposal revision – KOHO News, Mar. 23, 2016
- Chelan PUD mulls smaller rate hike for bitcoin miners – KPQ News, Mar. 24, 2016
- Chelan County PUD tweaks rate proposal for high density loads – Clearing Up, Mar. 25, 2016

Radio interviews provided

- KOZI and KOHO radio interviews with Director of Customer Service Andrew Wendell – Jan. 27, 2015
- KPQ Radio interview with Director of Customer Service Andrew Wendell and PUD Commissioner Dennis Bolz – July 7, 2015
- KOHO and KOHO Radio interview with Customer Service Director Andrew Wendell and Director of Customer Utilities John Stoll – Dec. 29, 2015
- KOZI Radio interview with Customer Service Director Andrew Wendell – Jan. 19, 2016
- KOHO Radio interview with Director of Customer Utilities John Stoll – Jan. 19, 2016
- KPQ "Business Beat" with Customer Service Director Andrew Wendell, and Director of Customer Utilities John Stoll – Jan.26, 2016
- KOHO Radio interviews (1 and 2) with Malachi Salcido – Feb. 4, 2016
- KOHO Radio interview with Commissioner Carnan Bergren – Feb. 17, 2016

Appendix D Relevant Staff Presentations to the Board in 2015 -2016

- **December 15, 2014 – Moratorium Implemented**
  - Moratorium on applications for 1aMW or greater
- **February 2, 2015 – Public Hearing**
  - Examples of average loads and historical growth
  - Connection to strategic planning efforts
  - Operating impacts overview
  - Typical substation planning
- **March 2, 2015 – Status Update**
  - Working group overview
  - Industrial rate comparison
  - Work plan guidelines
  - Planned critical path items
- **April 6, 2015 – Status Update**
  - Existing industrial rate structures
  - Review rate approach concepts
  - Community benefit tool
- **June 1, 2015 – Status Update**
  - Stakeholder feedback
  - Characteristics of new large loads
  - Introduction of Energy Use Intensity (EUI)
- **June 15, 2015 – Status Update**
  - Continued EUI discussion
  - Classification concept/characteristics
  - Framework for 3 EUI rate approaches
  - Plans for July 6 moratorium public hearing
- **July 6, 2015 – Moratorium Public Hearing**
  - Summary of staff actions to date
  - Proposed actions forward
  - Public comment
  - Motion extending moratorium and modifying to include high EUI loads
  - Public hearing set for December 7, 2015
- **July 20, 2015 – Policy work plan**
  - Policy Committee forming two smaller work groups; policy and rates
  - Revised residential and non-residential service applications
  - Timeline for policy efforts
- **August 17, 2015 – Rate work plan**
  - Rate analysis and development scope
  - Timeline for rate efforts
- **September 21, 2015 – Draft policy proposals** *(no action, discussion only)*
  - Security deposit
  - Disconnection of service
  - Metering
  - Definitions and aggregation
  - Changes in load
- **September 21, 2015 – Rate Classification discussion** *(no action, discussion only)*

    - Rate class considerations
    - EUI threshold considerations
    - Draft rate class definition
- **October 19, 2015 – Draft Policy Proposals** *(no action, discussion only)*
    - Review of proposed policy changes presented on Sept 21
- **November 2, 2015 – Resolution seeking adoption of proposed Policy changes**
    - Policy proposals presented on Sept 21 and Oct 19 (minus aggregation) were approved via resolution
- **November 16, 2015 – HDL Rate Design Discussion** *(no action, discussion only)*
    - Review HDL rate class definition
    - Review established rate setting guidelines
    - Cost of service rate components
    - HDL rate components
    - HDL rate recommendation
    - Next steps including 12/7 moratorium public hearing and fees and charges review
- **December 7, 2015 – Moratorium Public Hearing**
    - Moratorium purpose
    - Review staff actions to date
    - Conclusions of staff findings
    - Public comments
    - Proposed motions
    - Modify moratorium by lifting 1aMW restriction but continuing restriction on high EUI loads
    - Set Moratorium Public Hearing for Mar. 7
    - Set Rate Hearing for Feb. 1
    - Set 3 informational meetings
- **January 4, 2016 – Information meeting #1 – Leavenworth**
- **January 5, 2016 – Information meeting #2 - Chelan**
- **January 12, 2016 – Information meeting #3 Wenatchee**
- **February 1, 2016 – Opened Rate Hearing**
    - Overview of public comments received
    - Discussed Board requested follow up on 6 topics
    - Hearing continued – no action taken
- **February 3, 2016 – Continued Rate Hearing - Community Information Forum (hosted by HDL Customers)**
    - Discussion lead by Malachi Salcido
    - Topics included: What is bitcoin? Examples of emerging technologies
- **February 16, 2016 – Continued Rate Hearing**
    - Reviewed rate options as presented on 2/1
    - Hypothetical example of added 100aMW to our system
    - Moratorium continued to October 3, 2016
    - Rate hearing continued to March 21, 2016
- **March 21, 2016 – Continued Rate Hearing**
    - Revised HDL definition
    - Reviewed rate options, upfront capital charges concept, and possible rate implementation plans

    - Rate hearing continued to April 4, 2016
- **March 23, 2016 – Presentation provided to Cashmere Economic Development Group**
- **April 4, 2016 – Continued Rate Hearing (no presentation given)**
    - Continued hearing until June 6, 2016
- **May 24, 2016 – Presentation provided to Wenatchee Chamber of Commerce**

Appendix E Rate Component Cost Inputs

CHELAN COUNTY PUD

ELECTRIC DISTRIBUTION SYSTEM

CUSTOMER COST RATE COMPONENT ANALYSIS

		($000's)				
	Reference	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**	**2019 Forecast**	**2020 Forecast**
Customer Accounting	901x-905x	$ 3,001	$ 3,028	$ 3,137	$ 3,220	$ 3,232
Customer Service	907x-910x	$ 3,315	$ 3,804	$ 4,525	$ 5,123	$ 5,695
Meter Operation & Maintenance	586X/5970	$ 365	$ 380	$ 395	$ 411	$ 428
Customer Installations	5870	$ 95	$ 99	$ 103	$ 108	$ 112
Transformer Maintenance	595x	$ 505	$ 379	$ 394	$ 409	$ 425
Allocated A&G Cost	Direct O&M	$ 2,367	$ 2,284	$ 2,675	$ 2,943	$ 3,223
Taxes	Gross Cost	$ 243	$ 254	$ 300	$ 323	$ 341
Transformer Invest (25 yr Life)	368x	$ 1,667	$ 1,807	$ 1,954	$ 2,070	$ 2,152
Secondary Service Invest (25 yr life)	369x	$ 904	$ 980	$ 1,060	$ 1,123	$ 1,167
Meter Investment (25 yr life)	370x	$ 248	$ 269	$ 291	$ 308	$ 320
Less: Trnsfmr/Meter/Secondary CIA	4366	$ (1,211)	$ (1,121)	$ (953)	$ (981)	$ (1,010)
Less: Svc & Late Chgs		$ (311)	$ (312)	$ (315)	$ (318)	$ (321)
		$ 11,190	$ 11,851	$ 13,565	$ 14,739	$ 15,763
County Load - excluding losses (MWh's 000's)		1,617	1,623	1,639	1,655	1,673
Avg Customer Cost in Mills		**6.92**	**7.30**	**8.28**	**8.90**	**9.43**

	Weighting	2016	2017	2018	2019	2020
Residential Customers (Meters)	2.50	37,594	37,970	38,350	38,733	39,121
Commercial Customers (Meters)	4.00	6,353	6,416	6,481	6,545	6,611
Industrial Customers (Meters)	100.00	30	31	31	31	32
Irrigation Customers (Meters)	2.00	1,100	1,111	1,122	1,133	1,145
Frost Protection Customers (Meters)	1.50	378	382	385	389	393
Street Lights	0.25	4,196	4,237	4,280	4,323	4,366
Interdepartmental Customers (Meters)	1.00	548	554	559	565	571

Customer Cost Per Class	Allocate	2016	2017	2018	2019	2020
Residential	Cust Wt	$ 8,295	$ 8,785	$ 10,056	$ 10,925	$ 11,685
Commercial	Cust Wt	$ 2,243	$ 2,375	$ 2,719	$ 2,954	$ 3,159
Industrial	Cust Wt	$ 267	$ 283	$ 324	$ 352	$ 377
Irrigation	Cust Wt	$ 194	$ 206	$ 235	$ 256	$ 273
Frost Protection	Cust Wt	$ 50	$ 53	$ 61	$ 66	$ 70
Street Lights	Cust Wt	$ 93	$ 98	$ 112	$ 122	$ 130
InterDepartmental	Cust Wt	$ 48	$ 51	$ 59	$ 64	$ 68
		$ 11,190	$ 11,851	$ 13,565	$ 14,739	$ 15,763
Commercial/Industrial		$ 2,510	$ 2,659	$ 3,043	$ 3,306	$ 3,536

NOTES:
Weighting identifies the comparable impact of one customer type to another related to the customer cost rate component

CHELAN COUNTY PUD

ELECTRIC DISTRIBUTION SYSTEM

DELIVERY COST RATE COMPONENT ANALYSIS

	Reference	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast
		($000's)				
T&D Operation & Maintenance		$ 15,511	$ 15,124	$ 14,621	$ 15,041	$ 15,100
Allocated A&G Cost	Direct O&M	$ 6,044	$ 5,400	$ 5,602	$ 5,862	$ 6,091
Taxes	Gross Cost	$ 731	$ 714	$ 763	$ 794	$ 810
CTSRR (Transmission)	56510	$ 8,973	$ 9,311	$ 9,778	$ 10,033	$ 10,412
Less: CTSRR assigned to Wholesale	56510	$ (5,722)	$ (5,916)	$ (6,143)	$ (6,267)	$ (6,481)
Less: Pole Contact Revenues	45420	$ (170)	$ (340)	$ (340)	$ (340)	$ (340)
Rate of Return	4%	$ 6,057	$ 6,564	$ 7,100	$ 7,521	$ 7,819
T&D Plant Invest Depreciation	4032/4033	$ 3,809	$ 4,010	$ 4,450	$ 4,949	$ 5,410
Less: Line Extension CIA	4365	$ (1,287)	$ (1,192)	$ (1,014)	$ (1,043)	$ (1,075)
Less: Misc Other CIA	436X	$ (344)	$ (319)	$ (271)	$ (279)	$ (287)
Net Distribution Cost		$ 33,601	$ 33,355	$ 34,547	$ 36,272	$ 37,459
Less: St Light Assign O&M	585/596	$ (23)	$ (24)	$ (25)	$ (26)	$ (27)
Less: St Light Assign Invest (25 yr life)	3730	$ (32)	$ (34)	$ (37)	$ (41)	$ (45)
Less: St Light Assign A&G	Direct O&M	$ (9)	$ (9)	$ (10)	$ (10)	$ (11)
Less: Frost Assign (Retail Meter %)		$ (273)	$ (271)	$ (281)	$ (295)	$ (305)
Net Distribution Cost to Allocate		$ 33,264	$ 33,018	$ 34,194	$ 35,899	$ 37,071
County Load - excluding losses (MWh's 000's)		1,617	1,623	1,639	1,655	1,673
Avg Delivery Cost in Mills		**20.57**	**20.35**	**20.86**	**21.69**	**22.17**
3 Month CP Allocation Summary						
Residential		63.9%	63.5%	63.5%	63.5%	63.5%
Commercial		23.5%	23.1%	23.1%	23.1%	23.1%
Industrial		9.7%	9.8%	9.8%	9.8%	9.8%
Irrigation		2.5%	2.6%	2.6%	2.6%	2.6%
Frost Protection						
Street Lights						
InterDepartmental		0.4%	1.0%	1.0%	1.0%	1.0%
		100.0%	100.0%	100.0%	100.0%	100.0%
Delivery Cost Per Class	Allocate					
Residential	3 Mo CP	$ 21,265	$ 20,968	$ 21,714	$ 22,797	$ 23,542
Commercial	3 Mo CP	$ 7,812	$ 7,631	$ 7,903	$ 8,297	$ 8,568
Industrial	3 Mo CP	$ 3,212	$ 3,236	$ 3,351	$ 3,518	$ 3,633
Irrigation	3 Mo CP	$ 846	$ 857	$ 887	$ 932	$ 962
Frost Protection	Assign	$ 273	$ 271	$ 281	$ 295	$ 305
Street Lights	Assign	$ 64	$ 66	$ 72	$ 78	$ 83
InterDepartmental	3 Mo CP	$ 129	$ 327	$ 339	$ 356	$ 367
		$ 33,601	$ 33,355	$ 34,547	$ 36,272	$ 37,459
Commercial/Industrial		$ 11,024	$ 10,867	$ 11,254	$ 11,815	$ 12,200

NOTES:
Delivery cost has been primarily identified as 100% Demand related and is allocated using a 3 month CP methodology
Street Lights cost directly assigned based on specific infrastructure and related O&M
Seasonal Frost Protection cost allocation assigned based on Retail Meter % due to unique usage pattern
(Frost Protection usage occurs during the shoulder months & leverages excess delivery system capacity)
Transmission costs allocated between retail delivery and wholesale based on energy sold
90% of demand to usage ratio for commerical customers 40 KW and greater is used to estimate the demand of 39 KW
and below which is not metered.

CHELAN COUNTY PUD

ELECTRIC DISTRIBUTION SYSTEM

SUPPLY COST RATE COMPONENT ANALYSIS

			($000's)								
			2016		2017		2018		2019		2020
	Reference		Forecast		Forecast		Forecast		Forecast		Forecast
Firm Purchased Power Cost	555XX	$	110,085	$	111,783	$	105,579	$	105,606	$	106,792
Misc Power Supply Cost	548x/557x	$	4,851	$	6,128	$	5,806	$	6,010	$	6,224
Hydro Operating & Maintenance	53x/54x/55x	$	812	$	526	$	548	$	571	$	595
Allocated A&G Cost	Direct O&M	$	1,841	$	1,977	$	1,987	$	2,089	$	2,222
Taxes	Gross Cost	$	2,617	$	2,636	$	2,577	$	2,559	$	2,562
Production Plant Invest Depreciation	4031	$	101	$	107	$	118	$	131	$	144
Power Supply Cost Component (gross)		$	120,307	$	123,157	$	116,615	$	116,966	$	118,539
Less: Supply Cost Assigned to Wholesale		$	76,717	$	78,255	$	73,262	$	73,060	$	73,782
Power Supply Cost (net)		$	43,590	$	44,902	$	43,353	$	43,906	$	44,758
County Load - excluding losses (MWh's 000's)			1,617		1,623		1,639		1,655		1,673
Adjusted Purchased Power Rate (mills)			**26.96**		**27.67**		**26.45**		**26.52**		**26.76**

Supply Cost Per Class											
Residential	Allocate	$	20,959	$	21,590	$	20,846	$	21,112	$	21,521
Commercial	KWH	$	12,945	$	13,334	$	12,874	$	13,038	$	13,291
Industrial	KWH	$	7,904	$	8,142	$	7,861	$	7,961	$	8,116
Irrigation	KWH	$	1,049	$	1,080	$	1,043	$	1,056	$	1,077
Frost Protection	KWH	$	21	$	22	$	21	$	21	$	21
Street Lights	KWH	$	94	$	97	$	94	$	95	$	97
InterDepartmental	KWH	$	618	$	637	$	615	$	623	$	635
		$	43,590	$	44,902	$	43,353	$	43,906	$	44,758
Commercial/Industrial		$	20,848	$	21,476	$	20,735	$	21,000	$	21,407

NOTES:
All direct power supply cost assigned to Power Supply 100% (Hydro pirimary source for Base & Peak related loads)
State Utility Tax associated with delivered retail power (not assigned to Wholesale)
Adjusted purchased power rate (mills) applied equally to County Load w/Losses & Wholesale activity

Appendix F Unit Costing Analysis

CHELAN COUNTY PUD

ELECTRIC DISTRIBUTION SYSTEM

UNIT COSTING ANALYSIS

	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	5 Year Average	
Costomer Cost Component ($000's)							
Residential	$ 8,295	$ 8,785	$ 10,056	$ 10,925	$ 11,685	$ 9,949	
Commercial	$ 2,243	$ 2,375	$ 2,719	$ 2,954	$ 3,159	$ 2,690	
Industrial	$ 267	$ 283	$ 324	$ 352	$ 377	$ 321	
Irrigation	$ 194	$ 206	$ 235	$ 256	$ 273	$ 233	
Frost Protection	$ 50	$ 53	$ 61	$ 66	$ 70	$ 60	
Street Lights	$ 93	$ 98	$ 112	$ 122	$ 130	$ 111	
InterDepartmental	$ 48	$ 51	$ 59	$ 64	$ 68	$ 58	
	$ 11,190	$ 11,851	$ 13,565	$ 14,739	$ 15,763	$ 13,422	
Commercial & Industrial	$ 2,510	$ 2,659	$ 3,043	$ 3,306	$ 3,536	$ 3,011	
Customer Base Charge							
Industrial Customers (Meters)	30	31	31	31	32	31	
Cost per Customer	$ 743	$ 761	$ 871	$ 947	$ 981	$ 862	
Use Per Customer (aMW)	1.0	1.0	1.0	1.0	1.0	1.0	
Customer Cost per aMW	$ 743	$ 761	$ 871	$ 947	$ 981	**$ 861**	
Delivery Cost Component ($000's)							
Residential	$ 21,265	$ 20,968	$ 21,714	$ 22,797	$ 23,542	$ 22,057	
Commercial	$ 7,812	$ 7,631	$ 7,903	$ 8,297	$ 8,568	$ 8,042	
Industrial	$ 3,212	$ 3,236	$ 3,351	$ 3,518	$ 3,633	$ 3,390	
Irrigation	$ 846	$ 857	$ 887	$ 932	$ 962	$ 897	
Frost Protection	$ 273	$ 271	$ 281	$ 295	$ 305	$ 285	
Street Lights	$ 64	$ 66	$ 72	$ 78	$ 83	$ 73	
InterDepartmental	$ 129	$ 327	$ 339	$ 356	$ 367	$ 303	
	$ 33,601	$ 33,355	$ 34,547	$ 36,272	$ 37,459	$ 35,047	
Commercial & Industrial	$ 11,024	$ 10,867	$ 11,254	$ 11,815	$ 12,200	$ 11,432	
Demand Charge (KW 000's)							**Per KW**
Commercial Demand	1,410	1,416	1,430	1,444	1,459	1,432	$ 5.62
Industrial Demand	625	627	634	640	647	635	$ 5.34
Irrigation Demand	116	116	117	118	120	117	$ 7.65
Frost Protection Demand	41	41	42	42	43	42	$ 6.79
Commerial & Industrial Demand	2,035	2,043	2,064	2,084	2,106	2,066	**$ 5.50**
Supply Cost Component ($000's)							**Per KWh**
Residential	$ 20,959	$ 21,590	$ 20,846	$ 21,112	$ 21,521	$ 21,206	2.7 ¢
Commercial	$ 12,945	$ 13,334	$ 12,874	$ 13,038	$ 13,291	$ 13,097	2.7 ¢
Industrial	$ 7,904	$ 8,142	$ 7,861	$ 7,961	$ 8,116	$ 7,997	2.7 ¢
Irrigation	$ 1,049	$ 1,080	$ 1,043	$ 1,056	$ 1,077	$ 1,061	2.7 ¢
Frost Protection	$ 21	$ 22	$ 21	$ 21	$ 21	$ 21	2.7 ¢
Street Lights	$ 94	$ 97	$ 94	$ 95	$ 97	$ 96	2.7 ¢
InterDepartmental	$ 618	$ 637	$ 615	$ 623	$ 635	$ 625	2.7 ¢
	$ 43,590	$ 44,902	$ 43,353	$ 43,906	$ 44,758	$ 44,102	2.7 ¢
Commercial & Industrial	$ 20,848	$ 21,476	$ 20,735	$ 21,000	$ 21,407	$ 21,093	**2.7 ¢**
Statistics (MWH's 000's)							
Residential	777	780	788	796	804	789	
Commercial	480	482	487	492	497	487	
Industrial	293	294	297	300	303	298	
Irrigation	39	39	39	40	40	39	
Frost Protection	1	1	1	1	1	1	
Street Lights	4	4	4	4	4	4	
InterDepartmental	23	23	23	23	24	23	
	1,617	1,623	1,639	1,655	1,673	1,641	
Commercial & Industrial	773	776	784	792	800	785	

Appendix G Current Cost of Capacity Analysis

WO	Description	Cost (actual or estimate)	Capacity inc	Cost per MW
Stations				
234291	DS Okanogan Substation	$ 2,052,811	28	$ 73,315
144052	Crum Canyon Substation 7MVA (Entiat Valley) to 20 MVA	$ 2,383,190	13	$ 183,322
302921	North Shore Chelan Substation 28 MVA	$ 3,282,149	28	$ 117,220
305299	Bavarian Leavenw orth Substation 28MVA	$ 3,372,146	28	$ 120,434
346190	Wenatchee Substation Capacity Increase 28 MVA addition	$ 4,006,624	28	$ 143,094
			Average	**$ 127,477**
Getaways				
232190	Okanogan Sub 15KV Getaw ays North	$ 276,355		
290093	Okanogan Sub 15KV Getaw ays South	$ 301,131		
		$ 577,486	28	**$ 20,625**
Feeders				
336117	Feeders - North Shore Chelan - 28MW	$ 681,326	28	$ 24,333.07
Reconductor				
Reconductor 3-832 (inc w inter capacity 712 amp [5-yr plan] to 958 amp)				
251819, 268674	DI: Leavenw orth 3-832 Re-Conductor & Getaw ays - Chumstick Hw y: Re-conductor existing w ith 636AAC	$ 586,549	3.25	$ 180,715
South Lakeshore Reconductor (inc w inter capacity 150 amp to 958 amp)				
258980	South Lakeshore Reconductor #6 CU conductor along So Lakeshore Rd.	$ 821,041	10.66	$ 77,015
Camp 12 Road Reconductor (inc w inter capacity 373 amp to 958 amp)				
276121	Camp 12 Road Reconductor: 2/0 ACSR at 81% of w inter rating (2011)	$ 363,619	7.72	$ 47,110
Entiat Valley 3-742 Crum Cyn to Ard (inc w inter capacity 712 amp to 958 amp)				
277228	Entiat- Valley 3-742 CrumCyn - Ard	$ 656,908	3.25	$ 202,392
Entiat Valley 3-741 Ard to Mud Creek (inc w inter capacity 712 amp to 958 amp)				
276124	Entiat Valley 3-741 Ard-Mud Cr	$ 416,999	3.25	$ 128,477
Wapato Cooper Gulch (inc w inter capacity 150 amp to 373 amp)				
252546	Wapato Cooper Gulch	$ 223,142	2.94	$ 75,840
			Average	**$ 118,592**
	2015 estimated dollars per MW (total of stations, getaw ays, feeders, conductor)			**$ 291,025.96**
	Escalate at past 5 year CPI Average = 1.9264%		**2016**	$ 296,632.28
			2017	$ 302,346.60
			2018	$ 308,171.01
			2019	$ 314,107.62
			2020	$ 320,158.59
			Average	**$ 308,283.22**

Appendix H Marginal Cost Analysis

Year End	2010	2011	2012	2013	2014	2015
Electric Distribution	Actual	Actual	Actual	Actual	Actual	Actual
Elecdist Land & Land Rights (36000)	3,844,959	3,844,959	3,844,959	3,844,959	4,091,758	4,091,758
Elecdist Strctrs & Imprvmnts (36100)	4,294,949	4,294,949	4,294,199	4,838,838	4,881,860	4,881,860
Elecdist Station Equipment (36200)	31,442,856	31,582,944	31,789,979	35,426,140	37,346,512	38,715,958
Elecdist Poles Towers Fixtures (36400)	25,101,254	25,278,950	25,665,331	26,015,019	26,644,543	26,692,640
Elecdist OH Cndctrs & Devices (36500)	21,247,637	21,627,101	21,951,655	22,401,903	23,004,871	22,467,690
Elecdist Underground Conduit (36600)	22,137,473	22,590,697	23,530,503	24,256,865	24,854,809	25,574,307
Elecdist UG Conduit Trenching (36610)	212,389	212,389	212,389	212,389	212,389	212,389
Elecdist UG Cndctrs & Devices (36700)	32,469,347	32,917,552	34,032,828	34,938,017	35,851,105	36,833,731
Elecdist OH Line Transformers (36800)	14,745,144	14,960,873	14,978,579	15,557,304	15,521,713	15,917,472
Elecdist UG Line Transformers (36810)	22,436,491	22,854,087	23,260,828	23,606,285	23,565,443	23,854,381
Elecdist Regulators (36820)	1,567,921	1,567,921	1,567,921	1,567,921	1,567,921	1,567,921
Elecdist Services (36900)	18,365,846	18,876,838	20,438,227	21,501,482	22,051,285	23,860,844
Elecdist Meters (37000)	5,236,325	5,458,512	5,423,663	5,611,539	6,048,080	6,317,778
Elecdist St Lt & Signal System (37300)	786,928	786,928	786,928	786,928	786,928	784,580
Distribution Plant	*203,889,516*	*206,854,700*	*211,777,990*	*220,565,588*	*226,429,216*	*231,773,309*
Accum Depr Distribution Plant (10850)	-89,928,076	-94,899,415	-99,396,017	-104,258,384	-108,850,759	-111,163,427
Distribution Plant (Exclude lights and customer funded)	*152,130,209*	*154,354,097*	*158,046,564*	*164,637,263*	*169,034,984*	*173,045,401*
Accum Depr Distribution Plant (Exclude lights and customer)	-67,098,972	-70,813,540	-74,177,675	-77,821,818	-81,259,772	-82,996,269
NBV Distribution Plant (Exclude lights and customer)	*85,031,237*	*83,540,557*	*83,868,889*	*86,815,445*	*87,775,212*	*90,049,133*
% Growth		*-1.75%*	*0.39%*	*3.51%*	*1.11%*	*2.59%*
Calculated Current Cost (per MW)						*291,025*

	2016	2017	2018	2019	2020	5-year	5-year	5-year
	Forecast	Forecast	Forecast	Forecast	Forecast	Average	Average per MW	Average per kW
NBV Distribution Plant (Exclude lights and customer)	*91,102,592*	*92,168,375*	*93,246,626*	*94,337,492*	*95,441,119*	*93,259,241*	*118,199*	*118*
% Growth (Average 2011-2015)	*1.17%*	*1.17%*	*1.17%*	*1.17%*	*1.17%*			
Calculated Current Cost (see Appendix F)	*296,631*	*302,346*	*308,170*	*314,107*	*320,158*		*308,282*	*308*
% Growth (Average 2011-2015 annual CPI)	*1.93%*	*1.93%*	*1.93%*	*1.93%*	*1.93%*			
						Margin	**$ 190,083**	**$ 190**