CITY COUNCIL MEETING AGENDA
Council Chambers, 1000 Laurel Street

February 8, 2016
Monday

Executive Session
6:30 p.m.

For the purpose of discussing the negotiations of the IBEW Local 483 labor contract as per RCW 42.30.140(4)(b).

Study Session
7:00 p.m.

1. **Call to Order**
2. **Roll Call of Council Members**
3. **Study Items**
    a. **Introduction to Milton's Electrical Utility and System**
    b. **Ordinance – Amending Electric Utility Code**
    c. **Ordinance – Amending Public Services Code**
4. **Adjournment**

Note: Public comment is generally not taken at Study Sessions. However, on some occasions, public comments may be allowed at the discretion of the Chair and Council. The public may also submit written communications, via letters or emails to dperry@cityofmilton.net. Any item received by noon on the day of the meeting will be distributed to Council.

If you need ADA accommodations, please contact City Hall at (253) 517-2705 prior to the meeting. Thank you.

Back to Agenda

Agenda Item #: **3**A

To: Mayor Perry and City Council Members

From: Aaron C. Nix, Community Development and Public Works Director

Date: February 8, 2016

Re: Introduction to Milton's Electrical Utility System.

ATTACHMENTS: July 2014 EES Utility Strategic Plan

TYPE OF ACTION:

[X] Information Only [X] Discussion [ ] Action [ ] Public Hearing [X] Expenditure

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Issue: At the City Council's December meeting, Staff was asked to bring back information as it pertained the rate study that was completed by EES Consulting in 2014 in developing the utilities strategic plan into the future. This is the purpose of these materials and an item of discussion at the February 8, 2016 Council Study Session.

Discussion: As new Council members are currently sitting on the Council and it has been sometime since Staff provided information to the Council on the issue of the City's Electric Utility, Staff wants to give the Council a general overview of the City's Electric Utility (What it is, consists of and how we deliver power to our customers). In addition, Staff will provide data as it pertains to the City's current rate structure and the proposed option provided by EES when they were working on the strategic plan for the utility. Suggestions will be provided to the Council as it relates to the Utility's next steps and data needs by Staff in order to develop a plan to help ensure future stability of the Utility.

Staff Present: City Engineer Mark Howlett, and Public Works Superintendent Jeff Joy will be on hand to answer any questions.

Fiscal Statement: No proposed expenses as this time.

Recommendation: Not applicable at this time.

City of Milton

Electric Utility Strategic Plan
July 2014

Prepared by:

EES Consulting

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Kirkland, Washington 98033

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July 21, 2014

Ms. Letticia Neal
City of Milton
1000 Laurel Street
Milton, WA 98354

SUBJECT: Electric Utility Strategic Planning Study

Dear Ms. Neal:

Please find attached EES Consulting, Inc.'s (EES) Final Electric Utility Strategic Planning Study. This report represents the work product of EES in evaluating the City's electric system, developing a 10 year capital improvement plan, evaluating the relative merits of the City of Milton (City) purchasing the BPA substation, and developing a strategic plan that incorporates the capital plan, forecast revenue requirement, future Tier 2 power supply options, staffing needs and alternative operating scenarios.

We would like to thank you and your staff for your assistance in preparing this study. It has been a pleasure to work with you on this project.

Please contact me directly if there are questions or if we may be of any further assistance in this regard.

Very truly yours,

Gary Saleba
President

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Kirkland, Washington 98033

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A registered professional engineering and management consulting corporation with offices in Kirkland, WA and Portland, OR

Contents

CONTENTS ..... **I**

SECTION 1 – INTRODUCTION **1**

ORGANIZATION OF REPORT 1
ANALYSIS OVERVIEW 1
NEXT STEPS 2

SECTION 2 – BASE ASSUMPTIONS **3**

REVENUE REQUIREMENT METHODOLOGY 3
DEVELOPMENT OF THE PROJECTED LOAD FORECAST AND FORECAST REVENUES 4
POWER SUPPLY & TRANSMISSION 4
Assumptions *4*
Load and Tier 2 Projections *5*
Power Cost Projections *6*
Conclusion *7*
OPERATIONS & MAINTENANCE 7
CAPITAL PLAN 8
Condition and Age *8*
Load Growth *8*
Existing System Review *9*
Recommended Capital Projects *9*
DEBT SERVICE 13
RECOMMENDED LEVEL OF FINANCIAL RESERVES 14
SUMMARY 14

SECTION 3 – BUSINESS AS USUAL (BAU) **15**

UTILITY DELIVERY CHARGE – STATUS QUO 15
ANALYSIS 16
CONSIDERATIONS 19
ALTERNATIVE FINANCING 19

SECTION 4 – BPA SUBSTATION PURCHASE **21**

SUBSTATION VALUATION 21
Substation Rebuild *21*
Substation Purchase Results *22*
SUBSTATION OPERATIONS AND MAINTENANCE 22
SUMMARY AND CONCLUSIONS 23
CONSIDERATIONS 25
Additional Expenses Beyond Substation Purchase Price *25*
Transformer Age/Failure Mode *25*
Oil Leaks, Contamination, Liability *26*
Mitigating Risk *27*
SUMMARY 27

SECTION 5 – UTILITY OWNERSHIP SCENARIO **28**

SALES PRICE 28
COSTS AND REVENUES ASSOCIATED WITH THE SALE OF THE UTILITY 28
CONSIDERATIONS 29
Potential Rate impact *30*
Loss of Employees *30*

Response Time *31*
SUMMARY 31
SECTION 6 – SUMMARY 32
Tier 2 Purchases *32*
Business As Usual Scenario *32*
Purchase of Substation Scenario *32*
Sale of Utility Scenario *33*
APPENDIX 34
RECOMMENDED LEVEL OF FINANCIAL RESERVES 34
Milton's Minimum Reserves Level Estimate *35*

Section 1 – Introduction

The City of Milton (City) is located in both King and Pierce County, Washington. The population of the City is approximately 8,000. Currently, electric customers within the City are served by the City with power purchased from the Bonneville Power Administration (BPA).

The City owns and operates a 15-kV electric distribution system that serves load primarily within the City limits. The City's electric system delivered 60,532 MWh to approximately 5,275 residential, commercial, apartment, and municipal customers during 2013.

The City is served from a single power supply source: the Bonneville Power Administration (BPA) Surprise Lake substation. BPA's assets at the substation consists of a radial tap off of a 115-kV transmission line, fused disconnects, a 12 MVA power transformer without voltage control, a 15-kV recloser serving as a main disconnect, and metering. The City takes delivery at 12.5-kV at the metering point, and owns assets including three distribution circuit breakers, relaying, and cables to exit the substation.

The City asked EES Consulting, Inc. (EES) to perform a long-term strategic electric system plan, including a ten-year capital improvement plan. EES was also asked to evaluate the cost effectiveness of purchasing the BPA substation and review the different option to provide electric service to the City's residents. With the completion of the strategic plan, EES will perform a cost of service study using the City-selected planning scenario to develop the revenue requirement.

Organization of Report

This report first provides detail on the basic assumptions for the analysis including power supply forecast, capital plan, and recommended level of reserves. Section 3 outlines the Business as Usual (BAU) scenario. Section 4 reviews the cost effectiveness of the City's purchase of BPA substation. Finally, Section 5 addresses the potential sale of the utility.

Analysis Overview

For this study, EES looked at three utility operation scenarios and compared several metrics across these results. The three scenarios include the Business as Usual scenario under two different financing strategies, the purchase of the BPA substation and the potential sale of the utility. For each scenario, a revenue requirement was developed over the 11 year period of 2014 through 2024.

Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required annually. The convention used by most public utilities to determine their revenue requirement is called the "cash basis" of cost accounting. As the name implies, a public utility aggregates its cash

expenditures to determine its total revenue requirement for a specified period of time. This methodology conforms nicely to most public utility budgetary processes, and is a very straightforward and easily understood calculation.

Under the "cash basis" approach, there are four component costs. They are operation and maintenance expenses, taxes, debt service, and capital improvements funded from rates. Capital costs under the cash basis approach are calculated by adding debt service to capital improvements financed with rate revenues. It should further be noted that the two portions of the capital expense component are necessary under the cash basis approach because utilities often cannot finance all capital facilities with long-term debt.

Revenues and expenses for the 11 year period from 2014 through 2024 were projected. In order to compare scenarios using a single metric, the net present value (NPV) was used. The NPV adjusts a future stream of costs into today's dollars adjusting for inflation. In other words, the NPV is what it would cost the utility today to operate for the next 11 years.

Annual rate adjustments were projected with the goal of meeting annual expenses using both retail electric rates and the Electric Fund. The Electric Fund served as a rate stabilization account as long as the minimum required reserves level of $2.5 million was maintained. The 2024 year end Electric Fund balance target is $4 million.

Next Steps

Once the utility operating and capital funding scenario has been determined, a cost of service study can be performed. The cost of service analysis takes the results of the revenue requirement analysis and attempts to equitably allocate those costs to the various customer classes of service (e.g., residential, commercial, etc.) based on how each customer uses the utility system. This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

Section 2 – Base Assumptions

This section of the study outlines the Base Scenario assumptions for the strategic planning study. EES Consulting staff corresponded with the City and BPA to acquire all pertinent data on utility operations and costs.

EES reviewed the following data in preparing this report:

- Paper distribution system maps, dated 2005
- R W Beck Electric system plan, dated 2005, with completed projects identified
- Surprise lake substation transformer data from BPA
- Surprise lake substation single line diagram
- BPA load forecast through 2024
- Field visit notes
- 2012, 2013 and 2014 budgets
- Customer billing data

Revenue Requirement Methodology

In order to determine the impact of alternative scenarios, it is necessary to develop a revenue requirement or budget for the electric utility. In summary form, The City's components to its revenue requirement include the elements shown in Table 1.

Table 1
Elements of a Cash Basis Revenue Requirement

+ Operation and Maintenance Expenses (O&M)
  - ✓ Power Supply Expense
  - ✓ Transmission Expense
  - ✓ Operation and Maintenance
+ Capital Improvements Financed with Operating Revenues
+ Debt Service (Principle & Interest)
+ Taxes
  = Total Revenue Requirement

Each of the components to the revenue requirement is discussed below.

Development of the Projected Load Forecast and Forecast Revenues

The load forecast for Calendar Year (CY) 2014 through CY 2024 was calculated based on BPA load forecast growth. Forecast revenues at present rates were calculated for the analysis period using current retail rate schedules and forecasted loads.

Power Supply & Transmission

This section of the study outlines the projected power costs.

Assumptions

The power cost model developed by EES Consulting for the City includes the following assumptions:

- Forecast monthly peak and energy loads were provided by BPA's load forecasting department for the period January 2014 through December 2024. BPA's load forecast includes a load growth rate of 7.2 percent in 2015 and 2.2 percent in 2016. The average annual load growth rate included in BPA's load forecast in 2017 through 2024 is 0.6 percent. Loads were assumed to increase at 0.6 percent in 2025 through 2033. Based on BPA's load forecast the average monthly load factor for the City is 68.7 percent. The heavy and light load hour energy split was provided by BPA's FY14-15 rate case model.

- Monthly Contract Demand Quantities were provided by BPA's FY14-15 rate case model.

- FY14-15 BPA power and transmission rates, monthly customer refunds and billing determinants, including the FY14-15 Rate Period High Water Mark (RHWM) of 7.468 aMW, were provided by the BPA FY14-15 general rate schedule provisions.

- BPA power and transmission rates are assumed to escalate by 6 percent each rate period with the exception of the utility delivery charge which is assumed to escalate by 25 percent during the next two rate periods (FY16-17 and FY18-19) and 6 percent in each subsequent rate period.

- It was assumed that the City's total system load is subject to the utility delivery charge.

- Based on BPA rate case models it was assumed that the City's monthly system peaks are 92 percent coincident with BPA's transmission system monthly peaks.

- It was assumed that new BPA power and transmission contracts begin in October 2028 with the same rate structures and billing determinants as the current contracts.

Load and Tier 2 Projections

Figure 1 below shows the City's projected loads through 2033. The City's RHWMs are assumed to be equal to its Contract HWM of 7.548 aMW beginning in 2016.

Figure 1
Projected Loads and RHWMs (aMW)

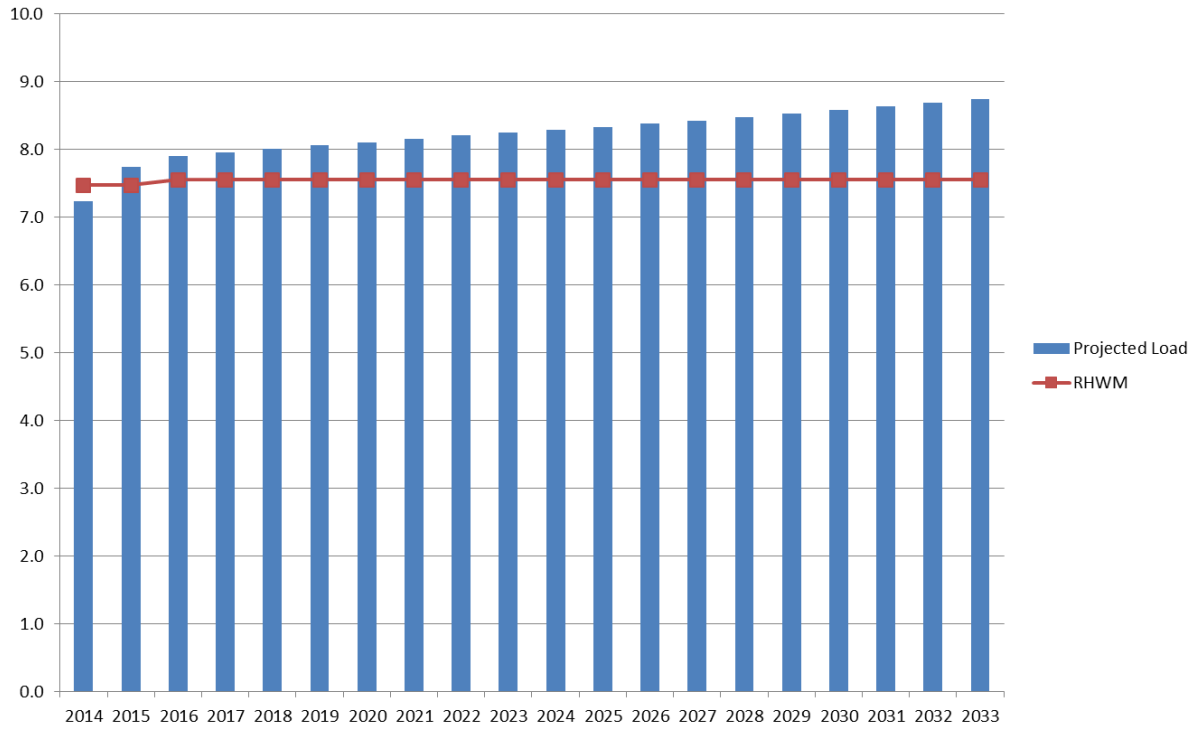


Figure 1 shows that the City does not have more than 1 aMW of above-HWM load 2014 through 2029. Based on the load forecast provided by BPA, above-HWM loads are 0.33 aMW in 2016, 0.50 aMW in 2019, 0.76 aMW in 2025 and 0.96 aMW in 2029.

BPA requires utilities that have at least 1 aMW of above-HWM load to purchase Tier 2 products or non-federal purchases to serve above-HWM loads. Loads in excess of the RHWM are served by BPA's load shaping product until above-HWM loads exceed 1 aMW. Above-HWM loads are 1.01 aMW in 2030, 1.06 aMW in 2031, 1.12 aMW in 2032 and 1.17 aMW in 2033.

The City signed up for BPA's load growth Tier 2 product to serve above-HWM load. If no action was taken the City's above-HWM loads in 2030 through 2033 would be served by BPA's load growth product. However, the City can notify BPA that it would like to purchase either a different BPA Tier 2 product or power from a non-federal resource to serve above-HWM load. Such notification must be provided to BPA by October 31st of the year preceding a rate case year. For example, notice would have to be given by October 31, 2014 in order to opt out of

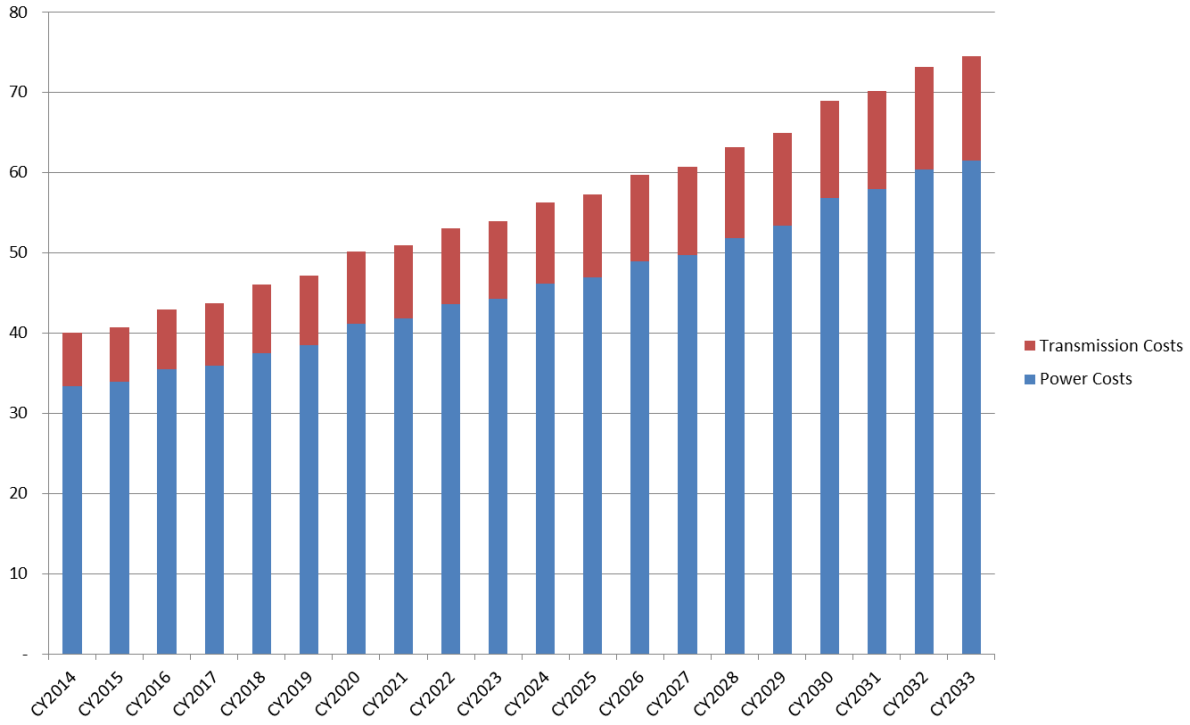
the load growth product for the rate period FY16-17. Utilities that opt out of the load growth product could be assessed charges if BPA has stranded power costs associated with purchases it has made to serve projected above-HWM loads. Milton is not projected to have above-HWM load greater than 1 aMW under the base case load forecast through the contract term (1 aMW is the minimum requirement). If conditions changed and Milton was projected to have greater than 1 aMW of above-HWM it could notify BPA that it wanted to opt out of the load growth product and be obligated to purchase no power at the load growth rate. Milton would be required to notify BPA of its decision to opt out prior to October 31st of the year prior to the commencement of the upcoming rate period (as noted above). At that point Milton could serve above-HWM load with a different BPA Tier 2 product, most likely the short-term Tier 2 product, or a non-federal resource.

The City should consider its options for serving above-HWM load in the years prior to its projected above-HWM loads exceeding 1 aMW. If BPA's assumed load growth rate of 0.6 percent turns out to be too high, that will be later than 2030. If BPA's assumed load growth rate of 0.6 percent turns out to be too low that will be before 2030. Above-HWM load projections could increase if the loads of any of Milton's customer classes grew at a more rapid rate than anticipated. For example, if a few new residential subdivisions came to town or some large commercial loads, then Milton's above-HWM load would increase above current projections. It should also be noted that the current BPA contracts expire in 2028.

Power Cost Projections

Figure 2 below shows projected power and transmission costs through 2033. The 2030 through 2033 power costs shown below assume the City purchases BPA's Tier 2 load growth product to serve above-HWM load.

Figure 2
Projected Power and Transmission Costs ($/MWh)



Given the assumptions noted above, the City's power supply costs are projected to increase by an average of 3.3 percent per year over the 20-year study period. The City's projected total power supply costs increase from $2.53 million in 2014 to $5.70 million in 2033.

Conclusion

Based on the analysis of the City's load forecast and power supply needs, it is premature to perform further Tier 2 modeling.

Operations & Maintenance

The O&M expenditures were based on historical data and 2014 budget received from the City. The base scenario assumes the following:

- Staffing levels assumed to remain at 2014 level over 10 year planning period
- Other revenues, including interfund transfers in, assumed to remain constant over 10 year planning period
- O&M based on City 2014 budget, 2013 projected and 2010 – 2012 actual expenses
    - Salaries and wages escalated 3.0 percent per year beyond 2014
    - Benefits escalated 5.0 percent per year beyond 2014

- All other O&M escalated 3.0 percent per year excluding capital lease, LOCAL financing, and interfund transfers.
- Utility tax = 6.0 percent of gross retail sales
- Excise tax = 3.8734 percent of gross retail sales plus 1.8 percent of penalties

Capital Plan

This section of the report reviews the distribution system and determines a 10 year capital plan for the City to consider.

Condition and Age

The average age of the distribution system was estimated to be 24 years (average installation date of 1990) based on data from the 2005 system planning study, City staff and EES engineering staff opinion.

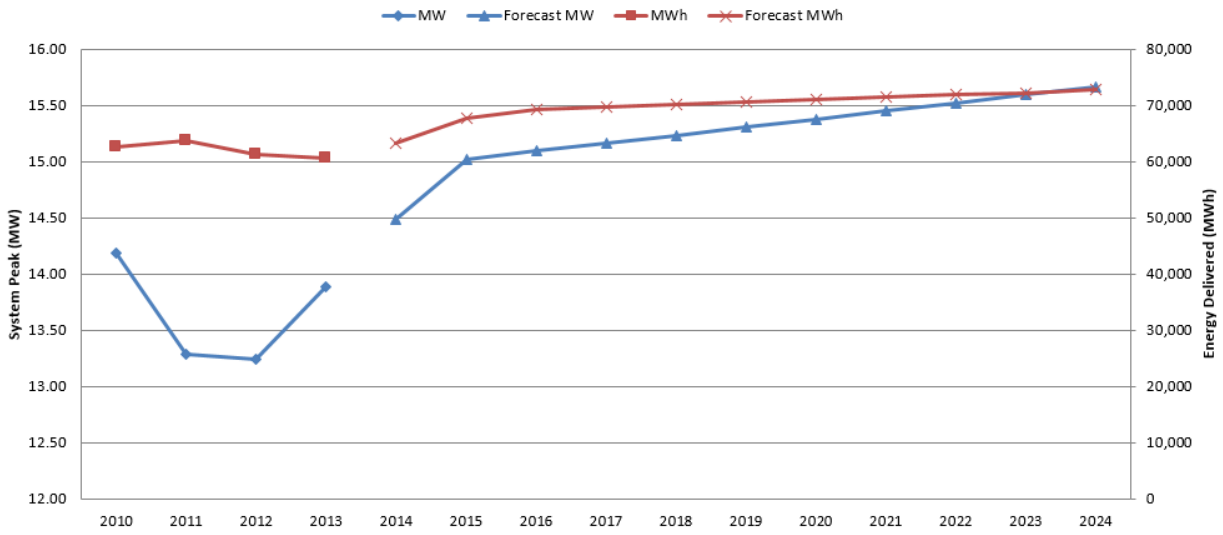
Based on a site visit by an EES Engineer, the City's electric distribution system appears to be in overall good condition. The capital improvement projects recommended in the 2005 R W Beck system plan have largely been implemented, which provides various and numerous benefits to the overall distribution system.

Load Growth

There are three distribution feeders served by the Surprise Lake substation, and the system peak demand is approximately 13.2 MW as of January 2014. Peak loads have historically been decreasing; however BPA forecasts a projected increase to 15.67 MW by 2024. System peak loads occur during the winter months. Figure 3 below shows historical and forecast peak demand and energy estimates prepared by BPA.

Figure 3

Surprise Lake Substation Demand/Energy



Substation equipment is by convention rated in mega volt-amperes (MVA) rather than megawatts (MW) of capacity. For simplicity in this report, assume MVA and MW are equivalent.

The Surprise Lake substation has a single transformer rated for 12/16/20 MVA with 13.4/17.9/22 MVA limits at 65-degrees Celsius rise. However, upon inspection only one bank of fans was installed on the transformer, therefore the top forced-air rating should not be used. Further, due to the age of the transformer, loading should be restricted to below 85% of the first forced-air rating (17.9MVA), or 15.2 MVA. The BPA load forecast indicates peak loading will reach 15.2 MVA in the year 2018. The substation should be rebuilt before this occurs, as it will be unable to safely and reliably meet the forecast demand MVA beyond the year 2018.

Existing System Review

A computerized distribution system engineering analysis model was not developed or used during this planning study. As such, individual circuit and conductor loading were not reviewed.

The overall system power factor, measured at the BPA meter, is excellent. It ranges between 99% and 100% across peak and light loading levels.

Recommended Capital Projects

Because the City takes delivery of power at a single substation, a contingency switching scenario must be developed for situations where the Surprise Lake substation is out of service for either planned or unplanned maintenance.

Two locations have been identified where the City could create metered distribution switching points to interconnect with Tacoma Public Utilities/Tacoma Power (TPU) and one location has been identified on the Puget Sound Energy (PSE) system. EES envisions that a contractual

arrangement should be set up, permitting the City connect to TPU and/or PSE during contingency situations to receive power at one or more switching points until repairs are complete. EES did not contact TPU or PSE as part of this review to determine if this is feasible. However, City staff has indicated distribution interties have been created with TPU's system in the past, on a temporary basis.

EES identified and recommends two switching points be constructed, to permit sharing of City load between two TPU substations. TPU may not have the capacity available at a single substation to serve the entire City. In addition or as an alternate, a third location with PSE may be constructed.

As an additional action item, a storm recovery plan should be developed and agreed upon between the City and TPU/PSE. This would formalize the process for activating the distribution interconnection point(s) and allow the parties to understand the scope of their responsibilities and risks. The City would be subject to an additional wheeling charge for the use of TPU and PSE's facilities. These charges are not included in this planning study as the use of these facilities is considered backup and loading estimates have not been developed.

EES recommends the City pursue the following capital projects during the next ten-year planning period.

2015-2024 Annually

Asset Replacement – In addition, a reserve account should be established for replacement of plant items nearing the end of their service life, such as poles, service transformers, etc. Typically this is funded with annual contributions in the amount of the total distribution plant value divided by the expected service life of 40 years.

Equipment replacement such as trucks and machinery are included in the annual operating budget and not the capital work plan.

2015 Construction Work Plan

Tacoma Public Utilities Interconnection #1 (20th Avenue) – The first switching point is located at 20th Ave and Milton Way. This location currently has TPU and City feeders separated by an air break switch. EES proposes the site be upgraded to use a NOVA recloser with electronic controls, bypass switching, and revenue metering. These upgrades will provide better billing data for the agreement, as well as offering protection to TPU in the event that a fault occurs on a City feeder tied to the TPU substation. EES anticipates that TPU will want the City to provide some level of fault protection in the contractual agreement.

EES estimates the cost of constructing this first switching point to be approximately $110,000.

Feeder Cable Installation on Milton Way – City electric staff indicated that a project is planned for the section of feeder between approximately 1700 Milton Way, continuing along Milton

Way to approximately the intersection with 23rd Ave. The existing overhead feeder will be replaced with underground cable, continuing the underground circuit along Milton Way.

City staff has estimated the project cost to be $465,000.

EES agrees that this project would be valuable to the City, and should be completed.

2016 Construction Work Plan

Substation Cable Replacement – The 15-kV cable in the substation is nearing the end of its useful life and should be replaced before a failure occurs. Cable is used between the 15-kV bus structure and the 15-kV switchgear and also between the 15-kV switchgear and the feeder riser poles.

This project will require a substation outage for several days while the cable is replaced. EES recommends this be completed following the negotiation and construction of the distribution interconnection points discussed earlier. Further, this work should be done when electric demand is off-peak to minimize the impact to the interconnected neighboring utility.

EES estimates this work will include replacing several hundred feed of cable, 18 cable terminations, and testing. EES also recommends that the jumpers between the exposed 15-kV bus and the cable terminations at the bus be evaluated for ampacity and upgraded if necessary. Larger jumpers could alleviate a potential bottleneck and reduce losses during heavy loading.

EES estimates the cost of this work to be approximately $150,000 not including any contractual payments for energy to neighboring utilities. Energy payments will be governed by the duration of the outage and the system load at the time the outage is taken.

If the Surprise Lake substation is acquired by the City, and is subsequently rebuilt, this project will not be necessary in 2016 as it will be included in the scope of the rebuild.

Tacoma Public Utilities Interconnection #2 (Porter Way) – The second switching point is located at Porter Way and Pacific Highway East. A City feeder stops about 100 feet from an existing TPU line. EES proposes the installation of the necessary conductor to connect the two feeders, as well as a NOVA recloser with electronic controls, bypass switching, and revenue metering. This equipment would be similar to the other TPU switching point, with the addition of the single slack-span of new conductor.

EES estimates the cost of constructing this second switching point to be approximately $110,000

2017 Construction Work Plan

Puget Sound Energy Interconnection – In addition or as an alternate to one of the TPU distribution interconnection points, a location on the East end of the City has been identified as a candidate for a distribution tie point with PSE.

The third switching point is located at approximately 28th Ave S and Milton Way. There is an existing PSE overhead line that dead-ends near an existing overhead City feeder. EES proposes that following an acceptable interconnection agreement, PSE would install a NOVA recloser with electronic controls, bypass switching, and revenue metering on its dead-end pole. The PSE pole was selected because the nearest City-owned pole does not currently have sufficient available space for the proposed equipment. Next, the City would install a new span between the PSE line and the existing City line. The equipment may need to be located on the PSE pole due to the arrangement of the City feeder. There would likely be a use of facilities charge associated with installing City equipment on a PSE pole. The new span would connect the PSE line to the cable in the riser on the City's pole, creating a three-phase interconnection point. Alternatively, it may be possible to install a riser on the PSE pole and connect to the feeder cable in the adjacent City owned electric vault.

EES estimates the cost of constructing this third switching point to be approximately $130,000 not including any ongoing use of facilities charges for locating City equipment on PSE poles. EES included $20,000 in this amount as an order-of-magnitude estimate of PSE's charge to initially install the City-owned equipment on PSE-owned poles. Note that this charge is difficult to estimate and may be substantially different. EES recommends getting an estimate from PSE once the project has been designed. Other design alternatives such as a pad-mounted recloser or building a line or cable extension that would permit the City to install the equipment in its own service territory should also be considered.

2018 Construction Work Plan

Feeder Cable Replacement at Surprise Lake Apartments – City electric staff indicated that a cable replacement project is planned for the section of feeder cable passing through the Surprise Lake Apartments.

City staff has estimated the project cost to be $200,000.

Based on the age of the cable, EES agrees that this project should be scheduled and completed within the next five to ten years.

Other Projects

The following projects should be considered for implementation in the next planning period, 2024-2034.

Second Transmission Source – EES recommends that the City study the benefits of adding a second substation to improve reliability of service and provide contingency switching in the event that the City's peak demand load grows to the point where the distribution interconnection points are no longer able to carry it. It would be prudent to conduct this study prior to building the distribution interconnection points.

Underground cable at 8th Ave and Oak Street – Investigate the potential for installation of an underground feeder cable through the gulley at 8th Ave and Oak Street to replace a difficult to maintain overhead span. City electric staff indicated that this location is difficult to maintain especially in poor weather. An underground cable would reduce the risk of weather-related outages.

Table 2 outlines the complete list of recommended capital improvement projects to be completed over the 10 year planning period.

Table 2
Estimated Capital Project Costs
($ 2014)

Project	2015	2016	2017	2018	2019	2020 to 2024	10 Year Total
Tacoma Public Utilities Interconnection #1 (20th Avenue)	$ 110,000						**$110,000**
Tacoma Public Utilities Interconnection #2 (Porter Way)		$110,000					**$110,000**
Puget Sound Energy Interconnection			$130,000				**$130,000**
Substation Cable Replacement*		$150,000					**$150,000**
Feeder Cable Replacement at Surprise Lake Apartments				$200,000			**$200,000**
Feeder Cable Installation on Milton Way	$465,000						**$465,000**
Asset Replacement	$175,000	$175,000	$175,000	$175,000	$175,000	$875,000	**$1,750,000**
TOTAL	**$740,000**	**$435,000**	**$305,000**	**$375,000**	**$175,000**	**$875,000**	**$2,905,000**

*Project to be included with substation rebuild if Surprise Lake Substation is purchased by the City from BPA.

Debt Service

At this time, the City's electric utility does not have any debt. Because the initial capital outlay related to the purchase and rebuild of the Surprise Lake substation is very large, the analysis assumed the City would use 100 percent debt financing for the Substation purchase and rebuild. The debt financing assumptions area the following:

- Borrowing rate = 5.0 percent
- Borrowing term = 10 years
- 100% debt financing of major Capital Improvements

Recommended Level of Financial Reserves

Minimum reserves were determined to be $2.5 million (see the appendix for this analysis). For purposes of this report, the reserve account target is set at $4 million based on past precedence. This allows Milton to invest in the proposed CIP projects and ensures sufficient reserves in case the substation is purchased. The assumption used for the analysis related to the reserve account balances – restricted and unrestricted are:

- Ending reserve account balance by 2024 is $4 million.
- Reserve account balance will not be less than $2.5 million in any one year

Summary

Once all of the expense accounts have been forecast, the parts can be summed to equal the total revenue requirement. This information is used in the scenarios developed in the remainder of the report.

Section 3 – Business as Usual (BAU)

This section of the study outlines the Business as Usual scenario for the strategic planning study. This scenario assumes that the City continues operating the utility and does not purchase the substation.

The BAU scenario assumes the following:

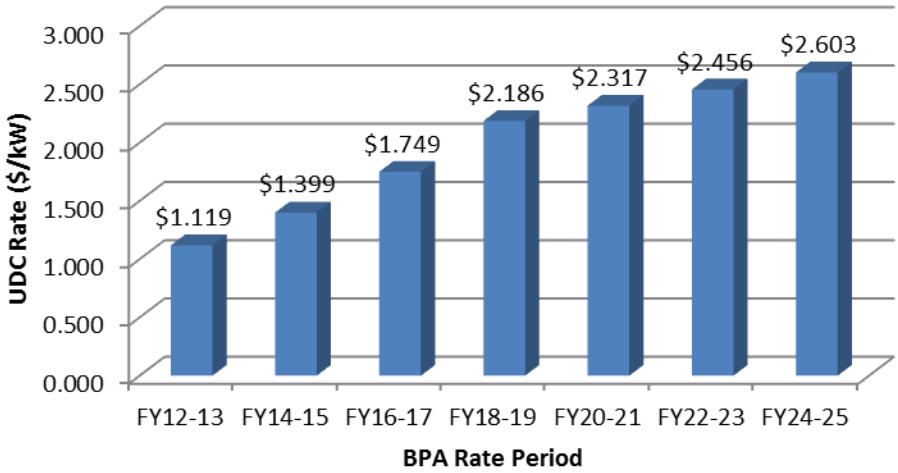
- City maintains ownership of the electric utility
- City does not purchase the BPA substation
- City continues to pay BPA's delivery charge
- City does not establish interconnection points to TPA or PSE
- Capital project include:
  - Annual repair and replacement
  - Feeder cable installation on Milton Way (2015)
  - Feeder cable replacement at Surprise Lake apartments (2018)

Utility Delivery Charge – Status Quo

The City incurs a Utility Delivery Charge (UDC) on BPA power that is delivered over non-BPA low-voltage transmission facilities, such as the Surprise Lake Substation. Low-voltage facilities are those operated below 34.5 kV. The UDC increased significantly (25 percent) in the BP-14 rate case and is expected to continue to increase dramatically in subsequent rate periods. For this study, a 25 percent increase per rate period was assumed through FY18-19. An additional 6 percent per rate period increase was assumed beginning in FY 20-21 through the remainder of the study period. This assumption is based on the current plan, however, it is expected that the UDC rates will continue to be addressed in future BPA rate cases.

Figure 4 illustrates the assumed UTC over the 10 year planning period.

Figure 4
Estimated BPA Utility Delivery Charge

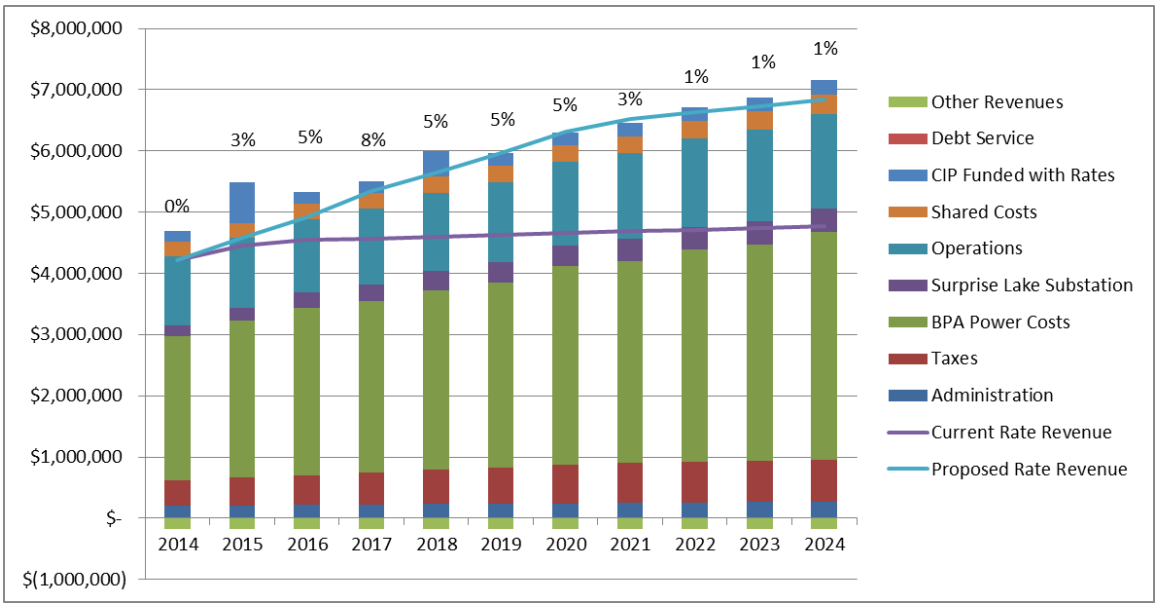


The City will pay the delivery charge on all power delivered over the Surprise Lake substation as long as it is owned by BPA. Based on the rates in Figure 4, the City's payment will range from $177,500 in 2014 up to $371,000 in 2024.

Analysis

The base scenario results show the significant impact the projected increase in the UDC and needed capital improvements have on the City's needed rate increases. Figure 5 shows that under the BAU scenario, rates have to increase between 1 percent and 8 percent during the next 10 years to meet the electric utility's revenue requirement and maintain the Electric Fund balance.

Figure 5
Business As Usual Revenues and Expenses



It should be noted that using current rates, revenues to not meet expenses in 2014 and beyond. Given the level of rate increases needed, the reserve levels dip to $3.5 million in 2018, but ends at $4 million by 2024 as can be seen in Figure 6.

Figure 6
Utility Fund Ending Balance

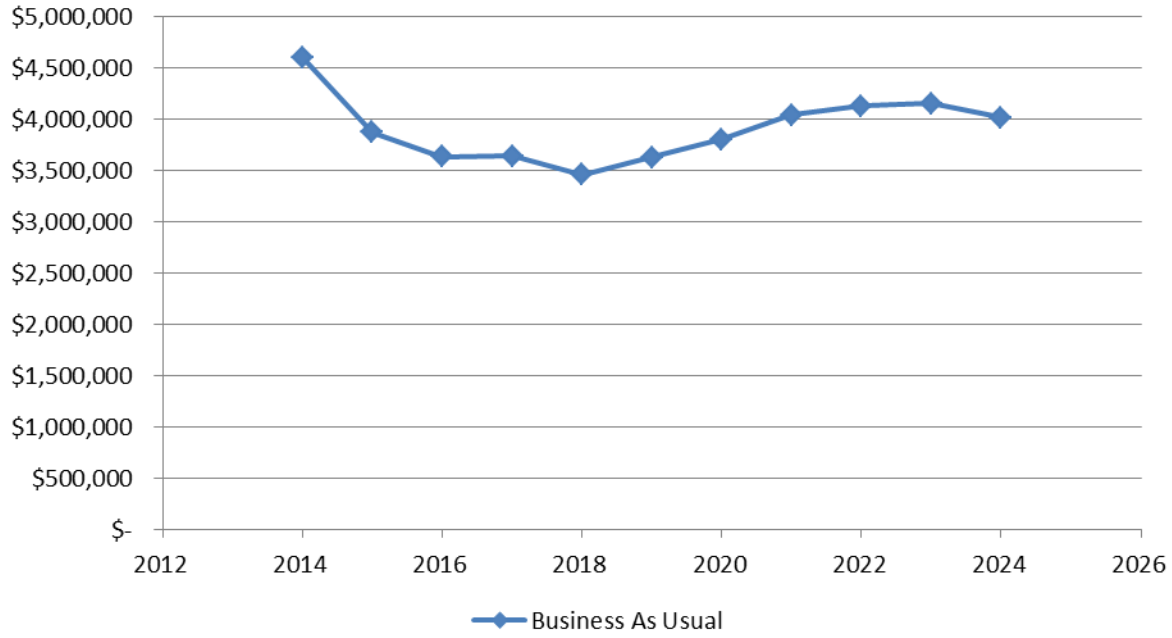


Table 4 shows that the overall NPV of the 11-year revenue requirement for the BAU scenario is $47.9 million, while the revenue to the City is estimated at $5.5 million over the same period. Finally, this scenario has the monthly residential bill increasing from $51.60 to $74.04.

Table 4
Business as Usual
(2014 Dollars)

CY	Revenue Requirement	Proposed Rate Adjustment	Revenues to the City from Electric Utility	Residential Estimated Monthly Bill
2014	$ 4,518,472	0.0%	$ 544,830	$ 51.60
2015	$ 5,316,293	3.0%	$ 570,090	$ 53.15
2016	$ 5,156,233	5.0%	$ 598,492	$ 55.81
2017	$ 5,329,395	8.0%	$ 632,275	$ 60.27
2018	$ 5,828,672	5.0%	$ 659,280	$ 63.28
2019	$ 5,793,020	5.0%	$ 687,550	$ 66.45
2020	$ 6,131,981	5.0%	$ 717,692	$ 69.77
2021	$ 6,289,479	3.0%	$ 740,532	$ 71.86
2022	$ 6,541,589	1.0%	$ 756,807	$ 72.58
2023	$ 6,703,962	1.0%	$ 773,473	$ 73.31
2024	$ 6,982,902	1.0%	$ 791,126	$ 74.04
NPV	$47,883,780		$5,539,289	

Considerations

The BAU scenario is the scenario that all other options should be compared. It is important to note that this scenario assumes no financing of capital projects and also assumes no new interconnection points with TPU or PSE.

The results of this scenario can be seen in the table below:

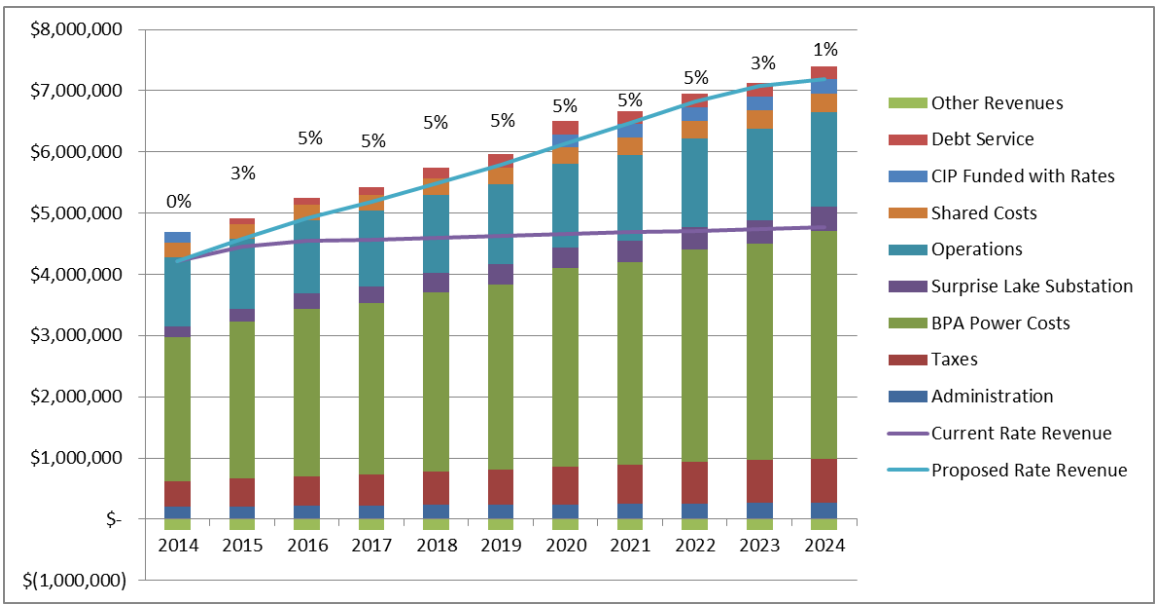
Table 5
Business as Usual Metric for 2014 - 2024
(2014 Dollars)

	BAU
Revenue Requirement (NPV)	$47,883,780
Avg. Annual Rate Adjustment	3.5%
Payments to City (NPV)	$5,539,289

Alternative Financing

In order to minimize rate adjustments in the near term, it was assumed the electric utility would borrow all capital spending from 2015 to 2019. However, this pushes costs out requiring larger rate adjustments at the end of the study period.

Figure 7
BAU with Financed CIP Revenues and Expenses



The results of this alternative financing of the BAU scenario can be seen in the table below:

Table 6
BAU with Financed CIP Metric for 2014 - 2024
(2014 Dollars)

	BAU-Financed CIP
Revenue Requirement (NPV)	$47,772,856
Avg. Annual Rate Adjustment	4.0%
Payments to City (NPV)	$5,539,899

Section 4 – BPA Substation Purchase

EES was asked to evaluate the cost effectiveness of purchasing the Surprise Lake Substation currently owned and operated by BPA.

This scenario assumes the following:

- City maintains ownership of the electric utility
- City purchase the BPA substation in 2015
- 5 years after purchase, the City rebuilds the substation
- 100 percent financing of the substation cost and rebuild
- City does not pay BPA's UDC after substation is purchased
- Power supply losses decrease 2 percent
- Additional capital project include:
    - Annual repair and replacement
    - Feeder cable installation on Milton Way (2015)
    - Establish new interconnection points to TPA (2015, 2016)
    - Establish new interconnection points to PSE (2017)
    - Feeder cable replacement at Surprise Lake apartments (2018)

Substation Valuation

EES estimates the portion of the substation owned by BPA has a Replacement Cost New (RCN) value of $1,972,000. The value of the land at the substation site was assumed to be $150,000. Because of the age of the assets, the substation is fully depreciated, however, for this analysis it was assumed the substation has a remaining life of five (5) years. In estimating the value of the substation, assets already owned by the City were not included in the total. This figure is meant to reflect the estimated reconstruction cost of the portion of the substation owned by BPA. The Original Cost, as reported in the BP-14 Transmission Segmentation Study, is $760,077.

Based on the above data, a Market value of $500,000 was determined based on general knowledge about BPA substation sales, the life left and the condition of the plant.

Substation Rebuild

The substation is nearing the end of its useful life, and should be rebuilt within the next five to ten years, if purchased by the City. EES estimates that the rebuild would include new steel structures and foundations, a 115-kV circuit switcher, a 15/20/25 MVA transformer with oil containment, a voltage regulator bank, a new 15-kV main and transfer bus structure, and three new NOVA reclosers with electronic controls and metering. This would refresh the age of the

substation components as well as provide updated functionality and improved safety at the site. EES estimates the cost of rebuilding the Surprise Lake Substation to be $3,573,000.

Substation Purchase Results

In order to evaluate the purchase of the Surprise Lake substation, it was assumed the City would rebuild the substation in the next five years. Therefore, the resulting capital investment is summarized in Table 7 below in 2014 dollars.

Table 7
Substation Purchase
(2014 Dollars)

Cost Approach	Valuation	Substation Rebuild	Total Capital
Market Value Estimate	$500,000	$3,573,000	$4,073,000

It is important to note that the cost of the substation does not take into account the possibility of any liabilities associated with the substation, such as responsibility for any prior polychlorinated biphenyl (PCB) contamination, soil contamination due to oil leaks, etc. These and other liabilities should be reviewed (and investigated further if warranted) before a purchase agreement is reached.

Substation Operations and Maintenance

Operations and maintenance (O&M) for the entire substation would become the responsibility of the City. This work would likely need to be contracted, at least in the short term. The City electric staff is currently not trained or equipped to work with transmission voltages (115-kV), or substation control and protection equipment. Although the City does have a highly knowledgeable distribution line crew, the skills necessary to maintain a substation are different than a distribution system, albeit with some overlap of basic electrical concepts. The City electric staff could be trained to perform O&M on some substation components; however there is time and money involved in training, and it must be weighed against contracting the O&M work. If the City plans to sell the utility in the near term, contracting the work may make more sense.

Some substation O&M procedures require an outage in order to be completed. The alternate source provided by the distribution interconnection projects discussed above could be used during such outages. The BP-14 Transmission Segmentation Study estimates annual O&M for the Surprise Lake substation to be $58,734 in 2010 dollars.

It would be prudent to develop a small spare parts inventory for substation components. Note that some of the required spare parts will likely change once station is rebuilt due to changes in technology since the original installation.

For this study, EES developed a high, medium and low O&M estimate that includes O&M expenses. The low range assumes existing crews can perform the substation testing after minimal training and no major repairs are required prior to the rebuilding the substation. The medium scenario assumes the City will perform the maintenance with existing crews and the substation is rebuilt within 5 years. Finally the high scenario assumes the City will contract the O&M. In addition, a fourth scenario is included using the BP-14 segmentation study estimate of $58,734 escalated by inflation. The resulting 2014 estimates are in Table 8, below.

Table 8
Substation O&M Scenarios

	Annual O&M (2014 $)
Low	$5,000
Medium	$15,000
High	$35,000
BP-14 Segmentation Study	$66,106

For this study the medium scenario was used to establish the additional O&M cost due to the purchase of the substation.

Summary and Conclusions

Given the following assumptions, the results are summarized in Table 8:

- Substation purchased in 2015 using 100 percent debt financing for $500,000
- Substation rebuild to occur in 2017 and 2018, 100 percent debt financed
- Borrowing/discount rate = 5.0 percent
- Borrowing term = 10 years
- Annual O&M based on Medium scenario
- Power Supply purchases reduced by 2.0 percent for loss savings

Table 9 compares the total costs associated with the substation under BAU and the Substation purchase scenarios. The BAU scenario includes the UDC costs and the needed substation cable replacement, while the Substation Purchase includes the cost of purchasing, the cost to rebuild, the interconnection additions and the reduction in power costs due to reduced losses.

Table 9
Substation Purchase Cost Effectiveness
(2014 Dollars)

Scenario	11 Year NPV	Annual Levelized Cost
Business As Usual (no new interconnection)	$2,497,790	$300,706
Substation Purchase	$4,084,425	$491,719

Figure 8 provides the needed rate impacts for the Substation purchase scenario.

Figure 8
Substation Purchase Revenues and Expenses

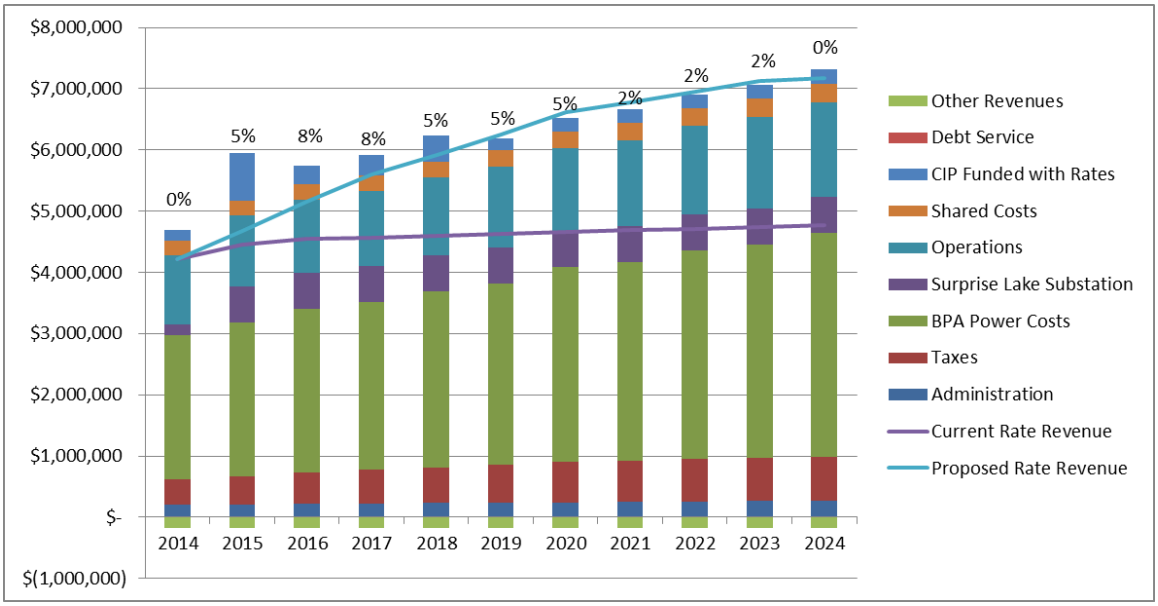


Figure 9 provides the resulting reserve balance for the two scenarios.

Figure 9
Utility Fund Ending Balance

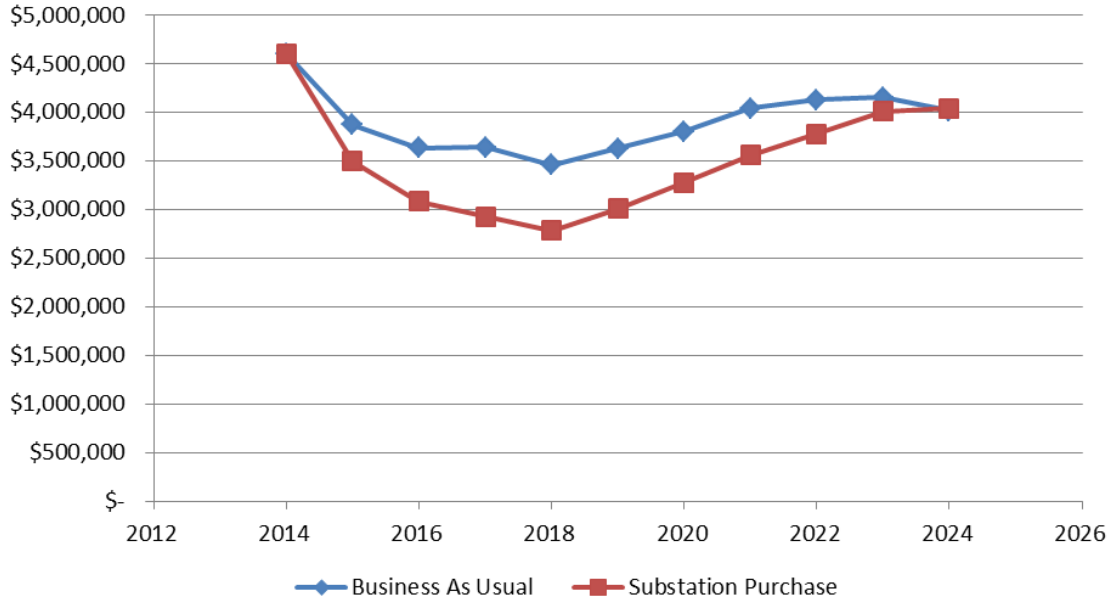


Table 10 shows that the overall NPV of the 11-year revenue requirement for the Substation Purchase scenario is $50.0 million, while the revenue to the City is estimated at $5.7 million

over the same period. Finally, this scenario has the monthly residential bill increasing from $51.60 to $77.63.

Table 10 Substation Purchase				
CY	Revenue Requirement	Proposed Rate Adjustment	Revenues to the City from Electric Utility	Residential Estimated Monthly Bill
2014	$ 4,518,472	0.0%	$544,830	$51.60
2015	$ 5,775,439	5.0%	$575,428	$54.18
2016	$ 5,572,772	8.0%	$612,817	$58.51
2017	$ 5,754,205	8.0%	$647,829	$63.20
2018	$ 6,066,638	5.0%	$675,719	$66.36
2019	$ 6,024,682	5.0%	$704,919	$69.67
2020	$ 6,347,122	5.0%	$736,066	$73.16
2021	$ 6,491,374	2.0%	$755,554	$74.62
2022	$ 6,732,831	2.0%	$776,153	$76.11
2023	$ 6,894,200	2.0%	$797,311	$77.63
2024	$ 7,147,558	0.0%	$811,057	$77.63
NPV	$49,994,761		$5,657,126	

Considerations

Based on the results in Table 10, the purchase of the substation, assuming the purchase price is $500,000, would be slightly higher than the cost of continuing to pay the UDC to BPA under the BAU scenario which has an 11-year NPV of $47.9 million. In addition, the City must consider the associated risks and City goals. Some of these considerations are listed below:

Additional Expenses Beyond Substation Purchase Price

If the substation is purchased, several improvements should be made as soon as practical.

- Distribution interconnection points with TPU and PSE, as well as storm recovery plan and contracts in place (included in analysis)
- Complete substation rebuild (included in analysis)

Transformer Age/Failure Mode

Based on data provided by BPA, transformer number T01447 was manufactured by Standard Transformer Company in 1965, and was acquired by BPA in 1974 for use at Brush College substation. The transformer was installed at Surprise Lake substation in 1981.

Transformer T01447 is rated for 12/16/20 MVA with 13.4/17.9/22 MVA limits at 65-degrees Celsius rise. However, upon inspection only one bank of fans was installed on the transformer, therefore the top forced-air rating should not be used. Further, due to the age of the

transformer, loading should be restricted to below 85% of the first forced-air rating (17.9MVA), or 15.2 MVA.

The expected useful life for substation assets is 40 years from the date of manufacture. As age increases, the risk of failure increases.

In contrast to the relatively short duration of a transmission line outage, such a transformer failure would most likely create a long duration substation outage (multiple days or even weeks) while replacement equipment is being procured, delivered, and energized. In the case of the transformer, a failure would likely mean total loss of the substation. In other cases, it may mean the inability to serve load or operate safely. With only a single substation, the City would not have its own contingency source to provide power in the event of a substation outage. Contracts with neighboring utilities should be in place prior to the substation being acquired. This is discussed in further detail below.

Due to its age, the City should plan to rebuild the substation within the next five to ten years, as soon as practical. Following a rebuild, the risk of failure is drastically lower.

Oil Leaks, Contamination, Liability

If the City acquired the balance of the substation assets, it may also assume additional risk. For example, if the substation transformer were to leak a large amount of oil, the City would be responsible for containment, cleanup, and any associated penalties. The substation does not have an oil containment structure surrounding the transformer, and a massive leak would likely contaminate the soil. Further, the transformer was observed to be leaking a small amount of oil during the site visit by EES in March 2014. The leak is being managed with absorbent pads, replaced at regular intervals. A leak of this magnitude is not unusual for a transformer of this vintage; however, it should be monitored regularly.

When a distribution line experiences a fault, the substation transformer is subject to current levels much higher than typical, known as fault current. Exposure to fault current can cause internal damage to transformer winding insulation due to the electromagnetic forces involved. Due to its age, the likeliness of the Surprise Lake substation transformer having an internal fault due to insulation failure is higher than average. The transformer oil should be tested at regular intervals to monitor insulation condition changes. This will become the City's responsibility upon taking ownership.

The transformer is protected by fuses, which may allow the transformer to carry the full fault current for up to several seconds, increasing the likeliness of insulation damage. Fuses on a transformer of this size and installation year are common practice. However, coupled with its age, the risk of a total loss of the transformer in the event of a substation fault is high. A replacement substation transformer for similar to the Surprise Lake unit typically costs around $500,000 and has a lead time between 8 and 16 months. Finally, transformer failures are quite often spectacular, resulting in a large oil fire and the loss of the entire substation and possibly surrounding properties.

In the interim period following a transformer failure, a mobile substation could be leased; however, this will be expensive and will take a few days to deliver and energize.

This level of risk must be weighed in the decision to acquire the Surprise Lake substation.

Mitigating Risk

Although it is not possible to know exactly when a transformer or other equipment will fail, regular testing of transformer oil and other substation equipment can reveal a downward trend in equipment condition. Presently, BPA is responsible for transformer oil testing. If the City purchases the substation, EES recommends an aggressive testing schedule due to the age of the substation equipment. Further, the complete substation rebuild should be completed as soon as practical.

Summary

The Substation Purchase scenario is slightly higher than the BAU scenario under the 10 year analysis horizon. However, this assumes that the City purchases the substation for $500,000 and borrows 100 percent of the purchase and rebuild costs. In addition, the City will have to consider intangible issues, such as training staff to maintain substation, additional risk associated with owning a substation and unknown liabilities.

Table 11
Substation Purchase Comparison Metric for 2014 - 2024
(2014 Dollars)

	BAU	Substation Purchase
Revenue Requirement (NPV)	$48,883,780	$49,994,769
Avg. Rate Adjustment	3.5%	4.0%
Payments to City (NPV)	$5,539,289	$5,657,126

Section 5 – Utility Ownership Scenario

The City may consider the sale of the Electric Utility to another utility, such as TPU or PSE, or a newly formed electric cooperative. In this scenario, the impact to the City can be quantified through the gains and losses outlined below:

This scenario assumes the following:

- City sells the electric utility as is
- City does not purchase the BPA substation

If the City plans to sell the electric utility in the near future, acquisition of the substation brings additional risk to both parties in the sale. The City (seller) would assume risk of equipment failure until a suitable buyer can be found and it may not bring much additional asset value to the deal as it is already fully depreciated. Further, the buyer may not want to assume the liability and would prefer that BPA had kept the substation. It was therefore assumed that in the scenario, the City would not purchase the substation.

Sales Price

The estimated value of the Electric Utility assets is between $3.5 million and $4.725 million based on the methodologies described in Table 12 below. This is consistent with valuations seen for other Northwest utilities.

Table 12
Electric Utility Estimated Value

	Estimated Net Plant
Market Value – 0% Premium Over Book	$3,500,000
Market Value – 35% Premium Over Book	$4,725,000

Costs and Revenues Associated with the Sale of the Utility

In addition to receiving the sales price for the utility, the City would charge the new utility owner a franchise fee for operating the utility within City limits. The City can charge a 6 percent of gross operating revenues franchise fee. However, this franchise fee is a direct offset to the 6 percent gross operating revenue utility tax resulting in no net impact.

If the City sells the utility, the City will lose revenues in the form of a 6 percent of gross operating revenues utility tax, shared costs, and a share of the administrative salaries and wages. In addition to the monetary losses, the Electric Utility employs 6.1 full time equivalent employees for operations alone. These employees would no longer be required following the sale.

The utility tax is budgeted to be $257,506 in 2014. The electric utility also pays for 1.27 FTE's in shared staff and 0.45 FTE's in administrative staff. Assuming these employees would transfer to other areas within the City, the loss associated with administrative wages and benefits currently charged to the utility is $51,000. The shared costs assigned to the electric utility total $236,337 in 2014. Therefore, the total annual lost revenues to the City from a sale of the utility are approximately $540,000.

Considerations

Based on a 10 year analysis, Table 13 shows that the City will gain approximately $1.7 million when comparing revenues from operating the utilities with revenues from the sale of the utility assuming a $3.5 million purchase price.

Table 13
Impact to City Revenues
Utility Sale at $3.5 Million

CY	BAU Lost Revenues to the City *a*	Franchise Fee with TPU Sale[1] *b*	Annuity with Sale Proceeds *c*	Utility Sale Revenues *d = b + c*	Net Gain/(Loss) to City *e = d – a*
2014	$544,830	$0	$0	$544,830	$0
2015	$562,084	$344,750	$431,518	$776,268	$214,184
2016	$576,254	$364,124	$431,518	$795,642	$219,388
2017	$586,184	$378,148	$431,518	$809,666	$223,482
2018	$596,762	$393,184	$431,518	$824,703	$227,940
2019	$607,601	$408,713	$431,518	$840,231	$232,631
2020	$619,119	$425,367	$431,518	$856,885	$237,766
2021	$630,123	$441,324	$431,518	$872,843	$242,719
2022	$641,841	$458,447	$431,518	$889,965	$248,124
2023	$653,885	$476,140	$431,518	$907,659	$253,773
2024	$666,678	$495,125	$431,518	$926,644	$259,966
NPV	$5,001,184			$6,722,012	$1,720,828

1. This assumes a sale to Tacoma Public Utilities

Based on a 10 year analysis, Table 14 shows that the City will gain approximately $2.8 million when comparing revenues from operating the utilities with revenues from the sale of the utility assuming a $4.725 million purchase price.

Table 14 Impact to City Revenues Utility Sale at $4.725 Million					
CY	BAU Lost Revenues to the City *a*	Franchise Fee with TPU Sale[1] *b*	Annuity with Sale Proceeds *c*	Utility Sale Revenues *d = b + c*	Net Gain/(Loss) to City *e = d – a*
2014	$544,830	$0	$0	$544,830	$0
2015	$562,084	$344,750	$582,550	$927,299	$365,215
2016	$576,254	$364,124	$582,550	$946,674	$370,420
2017	$586,184	$378,148	$582,550	$960,698	$374,513
2018	$596,762	$393,184	$582,550	$975,734	$378,972
2019	$607,601	$408,713	$582,550	$991,263	$383,662
2020	$619,119	$425,367	$582,550	$1,007,916	$388,797
2021	$630,123	$441,324	$582,550	$1,023,874	$393,751
2022	$641,841	$458,447	$582,550	$1,040,996	$399,155
2023	$653,885	$476,140	$582,550	$1,058,690	$404,805
2024	$666,678	$495,125	$582,550	$1,077,675	$410,997
NPV	$5,001,184			$7,832,702	$2,831,518

1. This assumes a sale to Tacoma Public Utilities

There are several non-economic impacts that are part of the consideration in selling the utility.

Potential Rate impact

The sale of the utility would result in customers being charged based on the new owner's rate schedule. As a comparison, The City's residential average electric bill is compared to average residential bill paid by TPU and PSE customers under current rates.

Table 15 Monthly Bill Comparison		
2014 Rates	Residential (750 kWh/mo)	Impact to Customer
Milton Current Rates	$51.60	--
Tacoma Power[1]	$66.97	30%
Puget Sound Energy[1]	$78.93	53%

1. Includes 6% City franchise fee.

This comparison shows that TPU residential rates are approximately 30 percent higher than the City's, while PSE's rates are 53 percent higher than the City's currently. Once the sale has occurred, the City will no longer have any control over rates or rate increases.

Loss of Employees

One consideration in the sale of the utility is the loss of jobs due to the sale. The Electric Utility employs 6.1 full time equivalent employees for operations alone. These employees would no longer be required following the sale.

Response Time

The City's electric utility has an excellent customer service reputation. Even in the worst storm, the outages are short and crews are on site immediately addressing any issues. If the City sells the utility, the service area will become part of a larger service area and crews will have to travel further to respond to outages or issues. As such, it is highly likely that the service level for the residents of the City will decline.

Summary

While it is clear that selling the utility would gain the City significant revenues assuming the sales price is between $3.5 – 4.725 million, the resulting rate impact to customers is significant. The first year, rates are likely to increase by 30% if the utility is sold to TPU and 53% if the utility is sold to PSE. In addition, the average annual rate increases below are calculating assuming PSE and TPU's rates going forward grow at the same rate as BPA's rates. This assumption is very conservative.

Table 16
Sale of Utility Comparison Metric for 2014 - 2024
(2014 Dollars)

	BAU	Substation Purchase	Utility Sale[1] TPU	Utility Sale[1] PSE
Revenue Requirement (NPV)	$47,883,780	$49,994,761	n/a	n/a
Avg. Rate Adjustment	3.5%	4.0%	5.5%	7.2%
Payments to City (NPV)	$5,539,289	$5,657,126	$6,722,012	$7,245,828

1. Assumes sale price of $3.5 million

Section 6 – Summary

The City asked EES Consulting, Inc. (EES) to perform a long-term strategic electric system plan, including a ten-year capital improvement plan. EES was also asked to evaluate the cost effectiveness of purchasing the BPA substation and a potential sale of the utility. Finally, EES was asked to discuss Tier 2 purchases form BPA.

Tier 2 Purchases

BPA requires utilities that have at least 1 aMW of above-HWM load to purchase Tier 2 products or non-federal purchases to serve above-HWM loads. Loads in excess of the RHWM are served by BPA's load shaping product until above-HWM loads exceed 1 aMW. Above-HWM loads are 1.01 aMW in 2030, 1.06 aMW in 2031, 1.12 aMW in 2032 and 1.17 aMW in 2033.

The City should consider its options for serving above-HWM load in the years prior to its projected above-HWM loads exceeding 1 aMW. If BPA's assumed load growth rate of 0.6 percent turns out to be too high, that will be later than 2030. If BPA's assumed load growth rate of 0.6 percent turns out to be too low that will be before 2030. It should also be noted that the current BPA contracts expire in 2028.

Business As Usual Scenario

The Business as Usual scenario for the strategic planning study assumes that the City continues operating the utility and does not purchase the substation. In addition, this scenario assumes that new interconnection points are not built.

The BAU scenario assumes the following:

- City maintains ownership of the electric utility
- City does <u>not</u> purchase the BPA substation
- City continues to pay BPA's delivery charge
- City does not establish interconnection points to TPA or PSE

This scenario was the scenario that all other options were compared to.

Purchase of Substation Scenario

EES was asked to evaluate the cost effectiveness of purchasing the Surprise Lake Substation currently owned and operated by BPA. This scenario assumes the following:

- City maintains ownership of the electric utility
- City purchase the BPA substation in 2015 for $500,000
- Establish new interconnection points to TPA and PSE

- 5 years after purchase, the City rebuilds the substation
- 100 percent financing of the substation cost and rebuild
- City does not pay BPA's UDC after substation is purchased
- Power supply losses decrease 2 percent

The Substation Purchase scenario is more expensive than the BAU scenario. This assumes that the City borrows 100 percent of the purchase and rebuild costs and repays the costs over 10 years. In addition to the cost impacts, the City will have to consider intangible issues, such as training staff to maintain substation, additional risk associated with owning a substation and unknown liabilities associated with the substation.

Sale of Utility Scenario

The City may consider the sale of the Electric Utility to another utility, such as TPU or PSE, or a newly formed electric cooperative. In this scenario, the impact to the City can be quantified through the gains and losses outlined below:

This scenario assumes the following:

- City sells the electric utility as is
- City does not purchase the BPA substation

While the City would receive between 1.7 and 2.8 million in additional revenues from a sale, there are numerous non-economic benefits that are part of the consideration in selling the utility. Based on a current residential bill comparison, if the City sold to TPU, residential rates would on average increase by 30 percent, while a sale to PSE would result in 53 percent higher residential bills. Other considerations are the loss of control of the utility operations, loss of employees and likelihood that the service level for the residents of the City will decline.

Table 17 provides the summary results for all three scenarios.

Table 17
Sale of Utility Comparison Metric for 2014 - 2024
(2014 Dollars)

	BAU	Substation Purchase	Utility Sale[1] TPU	Utility Sale[1] PSE
Revenue Requirement (NPV)	$47,883,780	$49,994,761	n/a	n/a
Avg. Annual Rate Adjustment	3.5%	4.0%	5.5%	7.2%
Payments to City (NPV)	$5,539,289	$5,657,126	$6,722,012	$7,245,828

1. Assumes sale price of $3.5 million

Appendix

Recommended Level of Financial Reserves

There are three basic reasons for collecting reserves for utilities: liquidity, pre-funded Capital Improvement Plan (CIP) and emergency or risk-management reserves. The appropriate reserve level is often utility specific. It depends on the range of costs that the utility may be facing, and it also depends on the financial options available to the utility.

At a minimum, utilities keep working capital on hand for liquidity. This level of reserves handles short-term fluctuations due to monthly, bimonthly or seasonal variation in revenues and expenses. The reserve target is typically set based on a "numbers of days", such as 30, 60 or 90 days of operation and maintenance (O&M) costs. We often use $1/12^{th}$ of power supply costs (equivalent to 30 days) plus $1/8^{th}$ of O&M costs (equivalent to 45 days) on hand as a minimum to provide liquidity.

In addition to working capital, utilities maintain emergency reserves in order to handle unexpected costs, such as a power supply cost increase or a failure of major equipment. Some of the options available to offset the level of emergency reserves on-hand include a bank line of credit, insurance, and automatic rate mechanisms, such as Power Cost Adjustments. The reserve target for emergency reserves due to equipment failure is often either a percentage of total gross utility assets or the cost of a major repair or replacement. The reserve target for emergency reserves due to increased costs or reduced revenues is usually expressed as a percent of operating expenses.

Finally, utilities collect reserves to pre-fund Capital Improvements Projects (CIP). These capital improvements can be separated into repair and replacement and expansion costs. Utilities, at a minimum, should collect sufficient reserves to fund repair and replacement equal to its annual depreciation expense. Depending on the age of the utility system, additional reserves may be needed. Reserves for pre-funding CIP can be offset by debt financing or rate increases as CIP funding is needed.

To summarize, the types of reserves and the standard targets include the following:

Liquidity: Based on number of days (minimum 30 days of power supply costs and 45 days of O&M costs)

Emergency Reserves – Operating contingency: As a percentage of O&M costs (target: 0 – 10% of total O&M)

Emergency Reserves – Equipment Failure: As a percentage of plant or cost of major repair or replacement (Target: 1% - 2% of utility gross plant)

CIP (New) Reserves: Based on Utility CIP financing plan and program.

CIP (Repair & Replacement) Reserves: CIP reserves should at a minimum equal depreciation. The City is currently budgeting $300,000 in restricted reserve for equipment replacement.

Milton's Minimum Reserves Level Estimate

Currently, the electric utility keeps approximately $4 million in reserves both restricted and unrestricted. As part of the $4 million in reserves, the City requires 25% of previous year's operating costs (or approximately $1 million) to be held by the Electric utility in restricted reserves.

Based on the guidelines above, the proposed minimum level of reserves is described in Table A-1 below:

Table A-1 Proposed Minimum Reserve Levels	
Liquidity: Based on 1 Month Power Supply Costs and 1/8th of O&M	$500,000
City Restricted Reserve Requirement: 25% of Operating Costs	$1,200,000
Emergency Reserves – Operating contingency: 10% of O&M Expenses	500,000
Emergency Reserves – Equipment Failure: 2% of Gross Plant	$140,000
CIP (New) Reserves: Based on Projected Need for New CIP	TBD
CIP (R & R) Reserves: Based on Annual Depreciation (Restricted)	$175,000
Minimum Reserves Total	$2,515,000

The above reserve level is the minimum reserves needed prior to considering any potential for new capital improvement projects. If Milton does not plan to rely on lines of credit or borrowing, these minimum reserve levels will have to be increased to ensure the utility does not experience a shortfall in funds.

For purposes of this report, the reserve account target is set at $4 million based on past precedence. This allows Milton to invest in the proposed CIP projects and ensures sufficient reserves in case the substation is purchased. The assumption used for the analysis related to the reserve account balances – restricted and unrestricted are:

- Ending reserve account balance by 2024 is $4 million.
- Reserve account balance will not be less than $2.5 million in any one year

City of Milton

Business As Usual, 100% Debt Financed Major Capital

Revenues/Expenses	Actual	Actual	Actual	Projected	BUDGET	Forecast -->									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Proposed Rate Adjustments					***0.0%***	***3.0%***	***5.0%***	***8.0%***	***5.0%***	***5.0%***	***5.0%***	***3.0%***	***1.0%***	***1.0%***	***1.0%***
Revenues															
Retail Rate Revenues	$ 4,109,175	$ 4,116,094	$ 4,049,875	$ 4,187,616	$ 4,208,554	$ 4,447,818	$ 4,547,700	$ 4,571,978	$ 4,601,912	$ 4,630,845	$ 4,665,570	$ 4,685,965	$ 4,712,263	$ 4,737,786	$ 4,769,306
Proposed Additional Rate Revenues					-	133,435	370,638	768,184	1,041,969	1,332,489	1,642,883	1,840,146	1,916,100	1,993,121	2,074,138
Other Revenues	220,399	260,257	162,269	186,033	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071
Total Revenues	**$ 4,329,574**	**$ 4,376,351**	**$ 4,212,144**	**$ 4,373,649**	**$ 4,377,625**	**$ 4,750,323**	**$ 5,087,409**	**$ 5,509,233**	**$ 5,812,952**	**$ 6,132,405**	**$ 6,477,524**	**$ 6,695,181**	**$ 6,797,434**	**$ 6,899,979**	**$ 7,012,515**
Expenses															
Administration															
Administration	94,091	111,844	236,930	126,490	204,257	210,462	216,865	223,474	230,294	237,334	244,601	252,101	259,844	267,836	276,087
Utility Tax	249,751	253,582	249,553	259,902	257,506	274,875	295,100	320,410	338,633	357,800	378,507	391,567	397,702	403,854	410,607
Excise Tax	166,573	156,419	148,281	162,129	164,512	178,948	192,005	208,344	220,108	232,482	245,850	254,280	258,241	262,213	266,572
Subtotal Administration	510,415	521,845	634,764	548,521	626,275	664,285	703,970	752,227	789,035	827,616	868,958	897,948	915,787	933,904	953,265
Operations															
Operations	741,211	840,176	934,775	993,181	1,119,872	1,155,901	1,193,203	1,231,827	1,271,823	1,313,241	1,356,137	1,400,566	1,446,586	1,494,258	1,543,645
BPA-Electricity for Resale	1,910,318	2,123,696	2,250,102	2,249,693	$2,111,420	2,299,407	2,455,809	2,505,025	2,632,517	2,715,538	2,928,367	2,984,296	3,127,855	3,194,254	3,356,542
BPA-Transmission	-	-	-	-	241,105	261,347	276,978	283,317	296,477	303,275	317,347	324,517	339,465	347,237	363,373
BPA-Substation Delivery Charge	-	-	-	-	177,534	202,777	240,300	258,899	303,087	309,767	324,209	331,357	346,807	354,446	370,941
BPA Conserv Credit/Prof Svcs	-	17,723	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Conserv Credit	-	88,614	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Operations	*2,651,529*	*3,070,209*	*3,184,877*	*3,242,874*	*3,649,931*	*3,919,432*	*4,166,291*	*4,279,068*	*4,503,904*	*4,641,822*	*4,926,060*	*5,040,736*	*5,260,713*	*5,390,195*	*5,634,501*
Shared Costs															
Shared Costs	340,770	351,561	204,317	229,979	236,337	242,447	248,777	255,335	262,129	269,170	276,467	284,029	291,867	299,991	308,413
Subtotal Shared Costs	*340,770*	*351,561*	*204,317*	*229,979*	*236,337*	*242,447*	*248,777*	*255,335*	*262,129*	*269,170*	*276,467*	*284,029*	*291,867*	*299,991*	*308,413*
Capital Projects Funded in Rates															
Capital Improvements	$27,061	$182,747	$52,241	-	175,000	659,200	185,658	191,227	422,066	202,873	208,959	215,228	221,685	228,335	235,185
Substation Purchase/Rebuild Capital				-	-	-	-	-	-	-	-	-	-	-	-
Debt Service															
Capital Project Debt Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation Purchase/Rebuild Debt Service				-	-	-	20,609	20,609	20,609	20,609	20,609	20,609	20,609	20,609	20,609
Total Expenses	**$ 3,529,775**	**$ 4,126,362**	**$ 4,076,199**	**$ 4,021,374**	**$ 4,687,543**	**$ 5,485,364**	**$ 5,325,304**	**$ 5,498,466**	**$ 5,997,743**	**$ 5,962,091**	**$ 6,301,052**	**$ 6,458,550**	**$ 6,710,660**	**$ 6,873,033**	**$ 7,151,973**
Net Revenues	**$ 799,799**	**$ 249,989**	**$ 135,945**	**$ 352,275**	**$ (309,918)**	**$ (735,041)**	**$ (237,895)**	**$ 10,767**	**$ (184,791)**	**$ 170,314**	**$ 176,472**	**$ 236,631**	**$ 86,775**	**$ 26,946**	**$ (139,458)**

Fund Balance	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Beginning Balance	$3,378,461	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$3,871,510	$3,633,615	$3,644,382	$3,459,591	$3,629,906	$3,806,378	$4,043,009	$4,129,784	$4,156,729
Additions/(Reductions)	$799,799	$249,989	$135,945	$352,275	-$309,918	-$735,041	-$237,895	$10,767	-$184,791	$170,314	$176,472	$236,631	$86,775	$26,946	-$139,458
Ending Balance	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$3,871,510	$3,633,615	$3,644,382	$3,459,591	$3,629,906	$3,806,378	$4,043,009	$4,129,784	$4,156,729	$4,017,271

City of Milton

Business As Usual, Financed CIP, 100% Debt Financed Major Capital

Revenues/Expenses	Actual	Actual	Actual	Projected	BUDGET	Forecast -->									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Proposed Rate Adjustments					***0.0%***	***3.0%***	***5.0%***	***5.0%***	***5.0%***	***5.0%***	***5.0%***	***5.0%***	***5.0%***	***3.0%***	***1.0%***
Revenues															
Retail Rate Revenues	$ 4,109,175	$ 4,116,094	$ 4,049,875	$ 4,187,616	$ 4,208,554	$ 4,447,818	$ 4,547,700	$ 4,571,978	$ 4,601,912	$ 4,630,845	$ 4,665,570	$ 4,685,965	$ 4,712,263	$ 4,737,786	$ 4,769,306
Proposed Additional Rate Revenues					-	133,435	370,638	619,846	885,195	1,166,841	1,467,648	1,782,065	2,117,283	2,334,747	2,421,476
Other Revenues	220,399	260,257	162,269	186,033	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071
Total Revenues	**$ 4,329,574**	**$ 4,376,351**	**$ 4,212,144**	**$ 4,373,649**	**$ 4,377,625**	**$ 4,750,323**	**$ 5,087,409**	**$ 5,360,895**	**$ 5,656,178**	**$ 5,966,757**	**$ 6,302,290**	**$ 6,637,101**	**$ 6,998,617**	**$ 7,241,605**	**$ 7,359,853**
Expenses															
Administration															
Administration	94,091	111,844	236,930	126,490	204,257	210,462	216,865	223,474	230,294	237,334	244,601	252,101	259,844	267,836	276,087
Utility Tax	249,751	253,582	249,553	259,902	257,506	274,875	295,100	311,509	329,226	347,861	367,993	388,082	409,773	424,352	431,447
Excise Tax	166,573	156,419	148,281	162,129	164,512	178,948	192,005	202,598	214,036	226,065	239,062	252,031	266,034	275,445	280,026
Subtotal Administration	510,415	521,845	634,764	548,521	626,275	664,285	703,970	737,581	773,556	811,261	851,656	892,214	935,650	967,634	987,559
Operations															
Operations	741,211	840,176	934,775	993,181	1,119,872	1,155,901	1,193,203	1,231,827	1,271,823	1,313,241	1,356,137	1,400,566	1,446,586	1,494,258	1,543,645
BPA-Electricity for Resale	1,910,318	2,123,696	2,250,102	2,249,693	$2,111,420	2,299,407	2,455,809	2,505,025	2,632,517	2,715,538	2,928,367	2,984,296	3,127,855	3,194,254	3,356,542
BPA-Transmission	-	-	-	-	241,105	261,347	276,978	283,317	296,477	303,275	317,347	324,517	339,465	347,237	363,373
BPA-Substation Delivery Charge	-	-	-	-	177,534	202,777	240,300	258,899	303,087	309,767	324,209	331,357	346,807	354,446	370,941
BPA Conserv Credit/Prof Svcs	-	17,723	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Conserv Credit	-	88,614	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Operations	*2,651,529*	*3,070,209*	*3,184,877*	*3,242,874*	*3,649,931*	*3,919,432*	*4,166,291*	*4,279,068*	*4,503,904*	*4,641,822*	*4,926,060*	*5,040,736*	*5,260,713*	*5,390,195*	*5,634,501*
Shared Costs															
Shared Costs	340,770	351,561	204,317	229,979	236,337	242,447	248,777	255,335	262,129	269,170	276,467	284,029	291,867	299,991	308,413
Subtotal Shared Costs	*340,770*	*351,561*	*204,317*	*229,979*	*236,337*	*242,447*	*248,777*	*255,335*	*262,129*	*269,170*	*276,467*	*284,029*	*291,867*	*299,991*	*308,413*
Capital Projects Funded in Rates															
Capital Improvements	$27,061	$182,747	$52,241	-	175,000	-	-	-	-	-	208,959	215,228	221,685	228,335	235,185
Substation Purchase/Rebuild Capital				-	-	-	-	-	-	-	-	-	-	-	-
Debt Service															
Capital Project Debt Service	-	-	-	-	-	85,369	109,413	134,178	188,837	215,110	215,110	215,110	215,110	215,110	215,110
Substation Purchase/Rebuild Debt Service				-	-	-	20,609	20,609	20,609	20,609	20,609	20,609	20,609	20,609	20,609
Total Expenses	**$ 3,529,775**	**$ 4,126,362**	**$ 4,076,199**	**$ 4,021,374**	**$ 4,687,543**	**$ 4,911,533**	**$ 5,249,059**	**$ 5,426,770**	**$ 5,749,035**	**$ 5,957,973**	**$ 6,498,861**	**$ 6,667,926**	**$ 6,945,633**	**$ 7,121,873**	**$ 7,401,377**
Net Revenues	**$ 799,799**	**$ 249,989**	**$ 135,945**	**$ 352,275**	**$ (309,918)**	**$ (161,210)**	**$ (161,651)**	**$ (65,875)**	**$ (92,858)**	**$ 8,784**	**$ (196,571)**	**$ (30,825)**	**$ 52,984**	**$ 119,731**	**$ (41,524)**

Fund Balance	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Beginning Balance	$3,378,461	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$4,445,341	$4,283,690	$4,217,815	$4,124,957	$4,133,741	$3,937,170	$3,906,346	$3,959,329	$4,079,061
Additions/(Reductions)	$799,799	$249,989	$135,945	$352,275	-$309,918	-$161,210	-$161,651	-$65,875	-$92,858	$8,784	-$196,571	-$30,825	$52,984	$119,731	-$41,524
Ending Balance	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$4,445,341	$4,283,690	$4,217,815	$4,124,957	$4,133,741	$3,937,170	$3,906,346	$3,959,329	$4,079,061	$4,037,536

City of Milton

Substation Purchase, 100% Debt Financed Major Capital

Revenues/Expenses	Actual	Actual	Actual	Projected	BUDGET	Forecast -->									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Proposed Rate Adjustments					***0.0%***	***5.0%***	***8.0%***	***8.0%***	***5.0%***	***5.0%***	***5.0%***	***2.0%***	***2.0%***	***2.0%***	***0.0%***
Revenues															
Retail Rate Revenues	$ 4,109,175	$ 4,116,094	$ 4,049,875	$ 4,187,616	$ 4,208,554	$ 4,447,818	$ 4,547,700	$ 4,571,978	$ 4,601,912	$ 4,630,845	$ 4,665,570	$ 4,685,965	$ 4,712,263	$ 4,737,786	$ 4,769,306
Proposed Additional Rate Revenues					-	222,391	609,392	1,027,415	1,315,944	1,621,971	1,949,119	2,090,511	2,238,534	2,390,427	2,406,330
Other Revenues	220,399	260,257	162,269	186,033	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071	169,071
Total Revenues	**$ 4,329,574**	**$ 4,376,351**	**$ 4,212,144**	**$ 4,373,649**	**$ 4,377,625**	**$ 4,839,280**	**$ 5,326,163**	**$ 5,768,464**	**$ 6,086,927**	**$ 6,421,887**	**$ 6,783,760**	**$ 6,945,547**	**$ 7,119,868**	**$ 7,297,285**	**$ 7,344,707**
Expenses															
Administration															
Administration	94,091	111,844	236,930	126,490	204,257	210,462	216,865	223,474	230,294	237,334	244,601	252,101	259,844	267,836	276,087
Utility Tax	249,751	253,582	249,553	259,902	257,506	280,213	309,426	335,964	355,071	375,169	396,881	406,589	417,048	427,693	430,538
Excise Tax	166,573	156,419	148,281	162,129	164,512	182,394	201,253	218,385	230,720	243,694	257,711	263,978	270,730	277,602	279,439
Subtotal Administration	510,415	521,845	634,764	548,521	626,275	673,068	727,543	777,822	816,086	856,198	899,194	922,668	947,622	973,131	986,064
Operations															
Operations	741,211	840,176	934,775	993,181	1,119,872	1,155,901	1,193,203	1,231,827	1,271,823	1,313,241	1,356,137	1,400,566	1,446,586	1,494,258	1,543,645
BPA-Electricity for Resale	1,910,318	2,123,696	2,250,102	2,249,693	$2,111,420	2,253,419	2,406,693	2,454,924	2,579,867	2,661,228	2,869,800	2,924,610	3,065,298	3,130,369	3,289,411
BPA-Transmission	-	-	-	-	241,105	261,347	276,978	283,317	296,477	303,275	317,347	324,517	339,465	347,237	363,373
BPA-Substation Delivery Charge	-	-	-	-	177,534	-	-	-	-	-	-	-	-	-	-
BPA Conserv Credit/Prof Svcs	-	17,723	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Conserv Credit	-	88,614	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation O&M	-	-	-	-	-	15,450	15,914	16,391	16,883	17,389	17,911	18,448	19,002	19,572	20,159
Subtotal Operations	*2,651,529*	*3,070,209*	*3,184,877*	*3,242,874*	*3,649,931*	*3,686,117*	*3,892,788*	*3,986,459*	*4,165,049*	*4,295,133*	*4,561,195*	*4,668,141*	*4,870,351*	*4,991,435*	*5,216,588*
Shared Costs															
Shared Costs	340,770	351,561	204,317	229,979	236,337	242,447	248,777	255,335	262,129	269,170	276,467	284,029	291,867	299,991	308,413
Subtotal Shared Costs	*340,770*	*351,561*	*204,317*	*229,979*	*236,337*	*242,447*	*248,777*	*255,335*	*262,129*	*269,170*	*276,467*	*284,029*	*291,867*	*299,991*	*308,413*
Capital Projects Funded in Rates															
Capital Improvements	$27,061	$182,747	$52,241	-	175,000	772,500	302,357	333,282	422,066	202,873	208,959	215,228	221,685	228,335	235,185
Substation Purchase/Rebuild Capital				-	-	-	-	-	-	-	-	-	-	-	-
Debt Service															
Capital Project Debt Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Substation Purchase/Rebuild Debt Service				-	-	570,379	570,379	570,379	570,379	570,379	570,379	570,379	570,379	570,379	570,379
Total Expenses	**$ 3,529,775**	**$ 4,126,362**	**$ 4,076,199**	**$ 4,021,374**	**$ 4,687,543**	**$ 5,944,510**	**$ 5,741,843**	**$ 5,923,276**	**$ 6,235,709**	**$ 6,193,753**	**$ 6,516,193**	**$ 6,660,445**	**$ 6,901,902**	**$ 7,063,271**	**$ 7,316,629**
Net Revenues	**$ 799,799**	**$ 249,989**	**$ 135,945**	**$ 352,275**	**$ (309,918)**	**##########**	**$ (415,680)**	**$ (154,812)**	**$ (148,782)**	**$ 228,134**	**$ 267,567**	**$ 285,102**	**$ 217,965**	**$ 234,013**	**$ 28,078**

Fund Balance	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Beginning Balance	$3,378,461	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$3,501,320	$3,085,640	$2,930,828	$2,782,046	$3,010,179	$3,277,746	$3,562,848	$3,780,814	$4,014,827
Additions/(Reductions)	$799,799	$249,989	$135,945	$352,275	-$309,918	-$1,105,231	-$415,680	-$154,812	-$148,782	$228,134	$267,567	$285,102	$217,965	$234,013	$28,078
Ending Balance	$4,178,260	$4,428,249	$4,564,194	$4,916,469	$4,606,551	$3,501,320	$3,085,640	$2,930,828	$2,782,046	$3,010,179	$3,277,746	$3,562,848	$3,780,814	$4,014,827	$4,042,905

Back to Agenda

Agenda Item #: **3B**

To: Mayor Perry and City Council Members

From: Betty J. Garrison, Finance Director

Date: February 8, 2016

Re: Ordinance Amending Electric Utility Code

ATTACHMENTS: **Ordinance 16-####**

TYPE OF ACTION:

☐ Information Only ☒ Discussion ☐ Action ☐ Public Hearing ☐ Expenditure

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Recommendation/Action: Only discussion at this time.

Issue: Milton Municipal Code and current practice need to be brought into alignment.

Discussion: These changes are recommended by Public Works Staff to meet current and best practice.

13.08.040 New service connection – Conversion and rewiring

Section A.3 and B.2 – Changing out the inspecting authority from Washington Department of Labor and Industries to Tacoma Power.

Section B.3 – Amending requirements.

13.08.070 – Amending requirements.

13.08.100 – Underground distribution installation on private property

Section A.2 – clarification of costs

Section A.4 – changing cost calculations

Section A.5.b – clarification of responsibility

13.08.110 – Service Connection – Overhead and underground requirements

Section B – Clarification of responsibility

13.08130 – Meter – Installation - Testing

Section B – Updating Cost

13.08.280 – Electric utility – Regular and commercial service rates

Section B – Clarification

Section C – Changing effective date to May billing.

13.08.310 – Yard light rentals. – rates covered in Section 13.08.280

CITY OF MILTON, WASHINGTON
ORDINANCE NO. 16 - ####

AN ORDINANCE OF THE CITY OF MILTON, WASHINGTON, CONCERNING THE PROVISIONS OF THE CITY OF MILTON'S ELECTRICAL UTILITY CODE; AMENDING MILTON MUNICIPAL CODE SECTIONS 13.08.040, 13.08.070, 13.08.100, 13.08.110, 13.08.130, 13.08.140, 13.08.280, AND 13.08.310; PROVIDNG FOR SEVERABILITY AND, AUTHORIZING SUMMARY PUBLICATION BY ORDINANCE TITLE, AND ESTABLISHING AN EFFECTIVE DATE.

WHEREAS, the City of Milton strives to maintain consistency between the Milton Municipal Code and current and best practices; and

WHEREAS, the City Code for the Electric Utility requires updates to bring current code consistent with current and best practices; **NOW, THEREFORE,**

THE CITY COUNCIL OF THE CITY OF MILTON, WASHINGTON DO ORDAIN AS FOLLOWS:

Section 1. That the following Sections of Chapter 13.08 ELECTRIC UTILITY are amended as follows (additions shown by underline and deletions shown by strikeout):

13.08.040 Permit fees – New service connection – Conversion and rewiring.

A. New Service.

1. A new service is not to exceed 150 feet.

2. Service shall include placing a temporary meter on an approved placed pole as determined by the electrical department and erected by the applicant or his contractor.

3. Connection shall be complete with the setting of the permanent electric meter and when final approval of electrical inspection has been posted by Tacoma Power. ~~the Electrical Inspection Section of the Department of Labor and Industries, State of Washington~~.

B. Conversion and Rewiring.

1. The service provided will be a review by the electric department to determine if the conversion or rewire requested will require increased transformer capacity or service drop replacement.

2. The installation or alteration to meet the increased load will be made by the electric department when necessary after the posted approval of the conversion or rewire by Tacoma Power. ~~the State Electrical Inspection Section.~~

3. The city will ~~not~~ require a permit modification if that modification is determined to be any ~~installation of a new light fixture, one or two receptacles in an existing room or some other minor~~ change to the wiring of a building.

13.08.060 Electric bills – Payment – Delinquency – Turn on fees.

All electric bills are payable at the administration office of the City Hall ~~from 8:00 a.m. to 5:00 p.m~~. during regular business hours, Monday through Friday. The City Hall is closed on legal holidays. Payment may be made by mail, electronic payment or via the drop box as well as in person during regular business hours. All electric bills are past due after the 15th day of the month following billing or after the first business day following the 15th if that date is on the weekend or holiday, and service may be discontinued until paid in full. In the event service is discontinued, energy will not be made available until all balances are paid in full, plus a turn on fee, according to the city's fee schedule.

13.08.070 Underground distribution systems required when – Trench separation.

A. It is the desire of the city to require the distribution system to be installed underground in plats and subdivisions. Exceptions to this rule could be certain short and long plats where a continuation of the existing overhead distribution would be determined by the city.

B. In areas where underground distribution is required, the developer shall furnish and install at his expense all items necessary to complete the distribution system within the plat. Prior to construction, the developer shall submit a plan designed by an engineer and approved by the city.

C. Where primary distribution is required to be extended into private property, the alternatives of overhead versus underground construction shall be determined by the city. In most situations, underground installation will be preferred.

D. Both underground primary and secondary installation shall not be jointly trenched with water or sewer, and a minimum distance of three ~~five~~ feet separation shall be maintained at all times.

E. All underground primary will be in conduit. Telephone or cable TV wiring will not be allowed in the same conduit used for electrical wires.

13.08.100 Underground distribution installation on private property.

A. When the length of service exceeds capabilities of servicing by a secondary connection, then primary distribution shall be installed. The customer shall pay for the following items based upon the city's cost of materials at the time of purchase:

1. Conductor, per foot: from pole top to transformer;

2. Pad-mount transformers:

   a. Residential development: shall pay the entire cost of transformers, to include vaults, and hardware;

   b. Commercial development: shall pay the entire cost of transformers, to include vaults, and hardware;

3. Transformer pad;

4. Trenching and backfill at time and material plus inspection ~~$1.25 per foot~~ (the customer may be required to trench and backfill);

5. Conduit:

   a. Primary from pole to trans-former;

   b. Secondary from the splice box ~~transformer~~ to the meter is the customer responsibility ~~if city is responsible for secondary~~.

B. Before construction, the customer shall provide the city with a feasible location of construction. A consideration of location will be provisions to connect other customers to the distribution system. An easement stipulating location and condition of use by others will be furnished to the city by the customer.

C. All equipment furnished and installed either by the customer or the city shall become and remain the property of the city.

13.08.110 Service connection – Overhead or underground requirements.

A. Overhead service, including all necessary equipment will be furnished and installed by the city from the existing or new pole to the customer's point of connection, the distance not to exceed 150 feet.

B. The electrical customer ~~except single-family dwelling~~ will be responsible for the secondary line from the splice box ~~transformer~~ to the meter.

C. Underground service will be optional on services less than 150 feet and shall be required where distance is between 150 feet and the maximum length allowable for secondary conductor, usually not to exceed 260 feet total.

13.08.130 Meter – Installation – Testing.

A. The city shall have the right to install a meter on every service connection, with or without notice to the customer, which meter shall be installed in accordance with the National Electrical Code. The property owner shall be responsible for the protection of any equipment used to service his property, excepting natural depreciation.

B. Any customer protesting that the meter on his premises is not registering correctly may apply to the electric department for a meter test. The meter shall be tested by an accredited laboratory and test results furnished. In the event the meter is in good order, applicant shall pay the cost of the test, plus $100.00 ~~$10.00~~ for delivery and labor. If the meter is in bad order, it shall be paid for by the electric department.

C. In case a service is without a meter for a period of time, the bill shall be estimated based upon previous consumption.

D. If a meter does not function or operate correctly due to faulty wiring on the part of the customer, the consumer shall correct said faulty wiring within 10 days, or the service will be discontinued.

E. A single phase 200 amp, 120/240 volt meter will be furnished by the city for each connection. if the customer required any other type of a meter they will pay the difference in the cost of the meter.

F. The meter shall be installed at a location approved by a representative of the city. The meter shall be accessible at all times.

13.08.280 Electric utility – Regular and commercial service rates.

A. Rates and charges for residential, schools, churches, apartments, and other accounts not covered by commercial rates are as follows:

Base Rate = $6.80

Charges for Each Kilowatt Hour = $0.0636

B. Commercial rates and charges for all uses not listed in subsection A of this section are as follows:

Commercial Base Rate	$14.16
Booster Stations Electric	$21.07
100-Watt Yard Light Electric	$10.20
200-Watt Yard Light	$10.48
400-Watt Lights	$24.72
Low Income SR/Disability Yard Light	$7.43
Charges for Each Kilowatt Hour	$0.0703

C. On May Billing ~~of~~ each year, the rates established in this section shall be adjusted according to the June CPI-U index for the previous year for the Seattle-Puget Sound area.

13.08.310 Yard light rentals.

The city will install, own and maintain the fixture and pole, if a pole is required. Rental rates are identified in MMC 13.08.280, as may be amended from time to time. ~~Pole rental will be $1.25 per month. The rental charge for the fixture shall be as follows: Energy will be provided on an unmetered basis:~~

~~175 watt~~	~~$3.75~~
~~250 watt~~	~~4.25~~
~~400 watt~~	~~5.70~~

Section 2. Effective Date. This ordinance shall be in full force and effect five (5) days after proper posting and publication. A summary of this ordinance by ordinance title may be published in lieu of publishing the ordinance in its entirety.

Section 3 **Severability.** If any provision of this ordinance, or ordinance modified by it, is determined to be invalid or unenforceable for any reason, the remaining provision of this ordinance and ordinances and/or resolutions modified by it shall remain in force and effect.

PASSED AND APPROVED at the regular meeting of the Council of the City of Milton, this 16th day of February, 2016.

_____

Debra Perry, Mayor

Attest/Authenticated:

Approved As To Form:

_____

Katie Bolam / City Clerk

_____

Greg A.Rubstello, City Attorney

Date of Publication:
Effective Date:

Back to Agenda

Agenda Item #: **3C**

To: Mayor Perry and City Council Members

From: Betty J. Garrison, Finance Director

Date: February 8, 2016

Re: Ordinance Amending Public Services Code

ATTACHMENTS: **Ordinance 16-####**

TYPE OF ACTION:

☐ Information Only ☒ Discussion ☐ Action ☐ Public Hearing ☐ Expenditure

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Recommendation/Action: Only discussion at this time.

Issue: Milton Municipal Code and current practice need to be brought into alignment.

Discussion: These changes are recommended by Staff to meet current and best practice, terminology and positions.

13.04.010 Assignment to collection company authorized. – updating for current positions and terminology to meet practice.

13.28.070 – Amending for new software ability.

13.36.010 – Policies and procedures established

Section F.1 and F.3 – update wording for new electronic abilities.

Section F.3 and F.4 – changing cut off time from 2:30 to 3:30.

Section H.1 – addition for clarification

Section H.3 – addition to allow for some flexibility and provision of service options.

Section J.1 – addition to allow for some flexibility and provision of service options.

Fiscal Impact: The addition of flexibility could provide an avenue for a more consumer friendly atmosphere. With the change it may take a few extra days to receive the funding, but the fact that Finance worked with the consumer can end up paying off in the long run since we continue to provide service, when possible, and we are building trust and positive relationships that put us at the top of the list. Negative relationships have a tendency to be put at the bottom of the list. This still has limitations so that no one has the ability to gift public funds or services and still requires high level authorization. This also allows for faster processing of consumer requests.

CITY OF MILTON, WASHINGTON
ORDINANCE NO. 16 - ####

AN ORDINANCE OF THE CITY OF MILTON, WASHINGTON, AMENDING MILTON MUNICIPAL CODE SECTIONS 13.04.010, 13.28.070, AND 13.36.010 AND PROVIDNG SEVERABILITY AND ESTABLISHING AN EFFECTIVE DATE.

WHEREAS, the City of Milton strives to maintain consistency between the Milton Municipal Code and current and best practices; and

WHEREAS, the City Code for the Public Services requires updates to bring current code consistent with current and best practices; **NOW, THEREFORE,**

THE CITY COUNCIL OF THE CITY OF MILTON, WASHINGTON DO ORDAIN AS FOLLOWS:

Section 1. That Chapter 13.04.010 is amended as follows:

13.04.010 Assignment to collection company authorized.

The ~~clerk~~ Finance Director is authorized and directed to assign delinquent accounts from the utility department ~~of of the city~~ to the collection company, provided, that the ~~clerk~~ Department shall maintain a list of those accounts assigned, and provided that the charges for collection shall not exceed the usual collection charges prevailing in Pierce County. (Ord. 514 § 1, 1965).

Section 2. That Chapter 13.28.070 is amended as follows:

13.28.070 Turn on and turn off – Single charge required when.

Each customer will have only one charge made for each request. In the case of dual service, the charge ~~will go to the electric utility~~ will be prorated between utility services. (Amended at city's request 2/9/84; Ord. 844 § 2, 1980).

Section 3. That Chapter 13.36.010 is amended as follows:

13.36.010 Policies and procedures established.

F. To reconnect a utility service which has been discontinued:

1. The account holder must pay the full balance due, including both past due and current amounts, plus a ~~dispatch~~ service fee.

2. Payments made after shut-off must be made in cash, by money order or by credit card or debit card.

3. Payments must be received before 3:30 p.m. for same day reconnections, and must include a $50.00 ~~dispatch~~ service fee. Utility reconnections will be made by close of each business day.

4. For same day connections on payments received after 3:30 p.m. there will be an additional fee of $185.00.

H. Exemptions.

1. Individual Circumstances. If it is determined by the utility clerk and the finance director that an account has become past due because of circumstances beyond the control of the account holder, a time payment plan on the past due amount may be arranged, with one percent per month interest charged on past due amounts. This request must be requested by the property owner.

2. Payments received insufficient to cover both current balances and the scheduled payment on past due amounts shall be credited first to the older balance.

3. In an effort to assist customers due to individual circumstances the Finance Director is authorized to accept short term arrangements to avoid discontinuation of services. This must be authorized by the property owner and cannot exceed 90 days.

J. Corrections & Adjustments.

1. The Finance Director with concurrence from the Public Works Director has the authority to authorize the correction of billing errors and to make adjustments to Utility Accounts as necessary as a result of billing errors, or for expediency. Any major adjustment must also be approved by the Mayor or their designee.

Section 4. **Ratification and Confirmation.** Any previous actions by the City that fall within the scope of the subject matter of this ordinance are hereby ratified and confirmed.

Section 5. **Effective Date.** This ordinance shall be in full force and effect five (5) days after proper posting and publication. A summary of this Ordinance may be published in lieu of publishing the ordinance in its entirety.

Section 6. **Severability.** If any provision of this ordinance, or ordinance modified by it, is determined to be invalid or unenforceable for any reason, the remaining provision of this ordinance and ordinances and/or resolutions modified by it shall remain in force and effect.

PASSED AND APPROVED at the regular meeting of the Council of the City of Milton, this 16th day of February, 2016.

_____

Debra Perry, Mayor

Attest/Authenticated:

Approved As To Form:

_____

Katie Bolam / City Clerk

_____

Kristin Eick, City Attorney

Date of Publication:
Effective Date: