Answers to Review Panel Questions from 2017-2022 Load Forecasting 1/5/2016

1. Explain the assumptions about where the 14 MW of conservation comes from?

   14 aMW assumption is based on discussions with previous a City Council as a good targeted goal for the amount of energy efficiency we should get under contract (i.e. a budget goal) each year in order to ensure that we achieve our I-937 requirements. Since then, it has evolved into an unofficial goal that we target for achievement also, since we can roll-over over achievement.)

Answers to Review Panel Questions from 2017-2022 Baseline Presentation 1/5/2016

1. It will be confusing to explain SCL rates versus BPA pass through—net impact to customers. Need to work on this.

   An alternative presentation can be made which has BPA pass-through more clearly into 2016 rate level so it is hopefully less confusing.

2. Can overhead/labor costs be reduced as CIP shrinks? Utility will need a good explanation around this issue (Noted: FTE count has been relatively stable since 2012)

   This is possible. And, we are working on refining this forecast.

   For background, the utility's headcount has remained relatively static since the plan was implemented. A sizable amount of the CIP work is being resourced by temporary hires and consultants to avoid an unsustainable increase in workforce as projects are completed.

3. Need more information on the drivers/details in the growth of O & M costs.

   A full report detailing all details and drivers of costs will be available once the baseline is finalized. O&M is the result of inflating the 2016 adopted budget. Inflation assumptions (which average about 3.3%) are:

Labor	2.4%
Labor Benefits	5.0%
Non-Labor	2.4%
Transfers to City (for City services)	3.0%
Operating Supplies (steel, copper, etc.)	8.0%

4. Can the utility run a scenario of what happens to rates with zero load growth?

	2016	2017	2018	2019	2020
Current Load Forecast GWh	9,441	9,432	9,456	9,501	9,565
Rate Path from Jan 5		5.6%	5.3%	4.9%	4.5%
Zero Load Growth Scenario		5.5%	5.6%	5.4%	5.2%

5. What portion of the rate path increase is attributable to the drop in load forecast?

   As shown on slide 11, the rate path impact is 0.4%, that is, the average rate increase over 2016-2020 would be 4.7% rather than 5.1% annual average increase if the load forecast had not dropped.

6. Can utility show how it will plan to respond if future load growth gets even flatter or begins to shrink? This should be addressed somehow in the Strategic Plan, even if to note there is a longer-term piece of work around this yet to be completed.

   Adjusting rate design and/or decoupling (incorporating retail revenue in the RSA) are load hedging strategies the utility has discussed incorporating in the Plan.

7. Show what we would have to change about current operations if we were to keep the average rate path at 4.4% average annual rate increases over the next 6 year planning period.

   Little would change in the area of current operations. We have identified some underspending of the budget that can be carried forward, minor reductions in consulting and advertising services, and acceleration of sales of the utility's unused real estate. While we have a few areas of increased spending which cannot be avoided (e.g., streetlights, cyber security, dam safety), we have achieved efficiencies in the operational and financial areas that largely offset the increases. We also expect minor revenue increases in the future, such as from an investment in regional wholesale market enhancements, and plan to defer the planned Master Service Center project for two years. All these changes will make it possible to stay on the 4.4% rate path for the 2017-2022 period.

8. What are the targets/metrics for reliability and quality of power in the baseline? These should be identified. How have results changed with the investments that the utility has made?

   We have two metrics for reliability which are standard in the industry: SAIDI (avg. time a customer is without power in the year) and SAIFI (avg. number of times a customer experiences an outage in the year). For 2015, our target outage duration was 65.3 minutes and as of November we were at 55.6 minutes. Our target frequency was 0.9 and as of November we were at 0.47. Our annual targets are based on 5% improvement over the previous three-year average.

In 2012, our actual SAIDI was 69.0 and SAIFI was 1.0. Comparing 2015 targets to these actuals, we can say that SAIDI was expected to improve by about 5% and SAIFI by about 10%. If we compare the November 2015 actuals to 2012 actuals, we can estimate improvements of about 19% and 50%, respectively. While we can't identify reductions in outages directly with specific projects, we can say that our improved programs of vegetation management and underground cable replacement, as well as efforts to catch up with deferred maintenance, have made a difference.

With respect to power quality, SMC 21.49.120 (Equipment and facilities provisions) prescribes phase, voltage and frequency standards. Electrical service is furnished as alternating current at the 60 Hertz frequency, available at the phase and voltage prescribed by the utility. The nominal 60 Hertz frequency is maintained within 2% for normal operating conditions and 10% under severe operating conditions. Variations in steady state average voltage permitted are 6% above and 5% below the nominal voltage.

While the utility does not report power quality metrics, we adhere to system operating levels mandated by NERC (North American Electric Reliability Corporation), ANSI (American National Standards Institute) standards for distribution voltage, and required annual transmission studies. We assess transmission lines annually and distribution lines every year or every other year.

9. Can you explain the source of the jump in transmission costs in 2021?

   This additional transmission capital cost is associated with the construction of the Denny Substation.

10. Given how much of the rate increase is attributable to capital investment, it is important to have a message around how these investments are helping customers save money or otherwise benefit? Anecdotes are helpful to tell this story.

    Benefits include the ability of customers to operate at the high level of reliability that their businesses require. Investments in this area include the Denny Substation, underground cable replacement, network improvements, and capacity additions to substations and distribution lines. A new Energy Management System is being implemented to manage power reliably from our dams to our customers.

    AMI will help customers control the timing of their energy use and in many cases reduce bills if they can use more energy in off-peak periods. Movement of some consumption to off-peak periods is also likely to decrease the utility's need to install more capacity, which in turn reduces the future capital requirement and the accompanying debt service that is included in rates. AMI will also help the utility to find and repair outages more quickly.

Fulfilling the terms of our Boundary and Skagit licensing agreements means that these projects not only protect environmental resources but that the power they produce will be available to customers for generations to come. We also continue to invest in our low-cost hydro power by rewinding generators and upgrading equipment to increase output and extend the useful life—and both outcomes keep rates lower by avoiding expenditure for higher cost purchased resources and providing more power to be sold on the wholesale market.

In general, all Generation, Transmission and Distribution investments insure that customers have sufficient and reliable power to meet their needs.

Investments in communications, facilities and information systems keep the power flowing, allow customers to be billed correctly, provide timely power restoration when outages occur, and provide all the supporting infrastructure that allows the utility to provide a high level of service to its customers.

Security is a high priority for City Light to both protect customer data and secure our assets and utility systems. We are investing in physical security at substations and dams to comply with NERC regulations and to make sure our energy facilities can continue to provide power when needed. We are improving IT systems to meet the many threats and compliance needs for both the system and data security.

In the transportation arena, we are required to relocate our assets to support projects such as the Alaskan Way Viaduct replacement, the Seattle Waterfront improvements, and Sound Transit and streetcar projects—all of which are directed toward improving the local economy and making public transportation available and convenient for all.

Conservation investments help customers use energy efficiently and also save money on their bills. They also help City Light avoid purchases of resources to meet increasing consumption needs. We have converted the majority of streetlights to LEDs, and upgraded our own vehicles and facilities to reduce energy consumption.

11. What are the CIP V5 costs?

The costs for NERC mandated Critical Infrastructure Protection (CIP) V5 are approximately $2.2M.