STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Robert M. Pickett, Chairman Stephen McAlpine Rebecca L. Pauli Norman Rokeberg Janis W. Wilson

In the Matter of the Tariff Revisions, Designated as) TA357-121, filed by the MUNICIPALITY OF) ANCHORAGE D/B/A MUNICIPAL LIGHT AND) POWER DEPARTMENT))	U-16-____

PREFILED DIRECT TESTIMONY OF GARY S. SALEBA

Q1. Please state your name, title, and business address.

A1. My name is Gary S. Saleba. I am President of EES Consulting, Inc. ("EES"). My business address is 570 Kirkland Way, Suite 100, Kirkland, Washington 98033.

Q2. Please briefly describe your professional experience.

A2. I received a Bachelor of Arts degree in Economics and Mathematics from Franklin College in Indiana. I received my Masters of Business Administration in Finance from Butler University in Indiana. For the last 30 years, I have been a principal and owner of EES or Economic and Engineering Services, Inc. My responsibilities have included supervision and preparation of electric, water, wastewater and natural gas studies in the area of strategic planning, financial studies, cost of service, rate design, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning, and overall utility operations. Before that I was employed by a national

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management consulting firm in a similar practice, and prior to that I was employed as an economist with Indianapolis Power and Light Company.

I have provided expert witness testimony on utility planning, cost of service, rates, power supply, contract matters, and overall utility operations in a number of state and provincial jurisdictions, as well as before the Federal Energy Regulatory Commission, the National Energy Board and numerous courts of law. A summary of my professional experience and background is attached to this testimony.

Q3. On whose behalf are you submitting this testimony?

A3. I am testifying on behalf of the Municipality of Anchorage d/b/a Municipal Light and Power ("ML&P") in this proceeding.

Q4. What issues does your testimony address in this proceeding?

A4. In this proceeding, ML&P has filed a Revenue Requirement Study and a Cost of Service Study/Rate Design Analysis ("COSS") to support requested revisions to its electric demand and energy charges. My testimony includes two separate sections in support of ML&P's request for interim and permanent rate revisions.

In Section A, I discuss the appropriateness of the addition of Plant 2A as a pro forma adjustment in the revenue requirement used in the COSS. My conclusions regarding Plant 2A are based on the Integrated Resource Plan and other analyses completed by EES. My testimony describes and supports the approach used in determining the need for Plant 2A and explains why the approach proposed by ML&P is

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valid, appropriate and in keeping with generally accepted utility practice for use in determining the need for new power supply resources.

Section B includes my testimony related to the COSS and rate design. A COSS is a study that classifies the revenue requirements into categories based on the services that they support, and then allocates those classified costs to the various customer rate groups. EES was retained by ML&P to perform a retail electric COSS. My testimony describes and supports the approach used in developing the COSS and explains why the approach proposed by ML&P is both valid and appropriate for use in developing interclass revenue requirements and rate design. The COSS report and all of the accompanying schedules are provided in Exhibit 10 to ML&P's TA357-121 filing.

SECTION A: INTEGRATED RESOURCE PLANNING

I. OVERVIEW OF ELECTRIC UTILITY RESOURCE PLANNING

Q5. Please describe your involvement with ML&P's decision to build Plant 2A.

A5. EES has been ML&P's Engineer of Record since 2002. As part of this role, EES staff have supported ML&P staff by performing the following tasks:

- 20-Year Energy and Peak Demand Load Forecasting
- Triennial Report required by Bond Covenant
- System Analysis and Planning Studies
- Integrated Resource Planning Studies
- Cost of Service and Rate Analysis

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I have overseen all of the work and studies performed on behalf of ML&P by EES staff since the inception of EES's consulting relationship with ML&P.

Q6. Please describe the general principles governing utility resource planning.

A6. Electric utilities are obligated to serve and provide sufficient resources to meet customers' expected electricity needs in a reliable, safe and least costly manner. In order to ensure ongoing reliability and least costly priced electricity service to customers, many utilities engage in long-term resource planning. These resource plans must be flexible enough to deal with uncertainties in future customer demands, resource costs and availability, as well as a changing regulatory environment.

Q7. Are there any regulatory requirements for long-term resource planning?

A7. Alaska does not require long-term electric resource plans to be filed with the RCA. However, many other state regulatory commissions require electric utilities to perform long-term resource plans or Integrated Resource Plans ("IRPs"). The vast majority of states require the filing of some type of a long-term resource plan. (For a list of states requiring resource plans see, for example: Best Practices in Electric Utility Integrated Resource Planning.[1]) Most of the states require utilities to file an IRP to meet this regulatory requirement.

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[1] http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpractices inirp-2013-jun-21.pdf

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Q8. What is Integrated Resource Planning ("IRP")?

A8. An IRP is a utility plan for meeting forecasted annual peak and energy demands, plus an established reserve margin, through a combination of supply-side and demand-side resources over a specified future period of time. It is an improvement over just a resource plan in that an IRP integrates both supply-side (i.e. generation) resources and demand-side (i.e. conservation) into the plan. Utility practice is to rank the resource options by comparing the impacts of each reserve on a utility's revenue requirement and by comparing the impacts in a structured framework that takes into account more than just costs. Once ranked, strategies are developed to meet resource requirements while balancing various costs and benefits, and accounting for risk.

Q9. How often do utilities typically develop IRPs?

A9. The frequency of IRP updates depends on the specific utility's circumstance and regulatory requirements. Most states require IRP updates every two to three years. However, if a utility is planning a new resource, more frequent updates may occur. On the other hand, if a utility has a current plan that is unlikely to change, less frequent updates would be needed.

It must be emphasized that the resource planning process is generally dynamic. Resource plans will undergo constant review, both internally and externally, and will be updated and modified as new and better information becomes available. Action items and resource acquisitions anticipated in the IRP are subject to change to the extent that contractual commitments have not been made. New technologies may come on the

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market to replace planned resources. New regulations may be brought forward that prohibit some resource alternatives. The preferred strategies put forward in IRPs are preferred at the time; however, a prudent planning process requires that IRPs be continually reviewed to see if it can be improved upon.

II. HISTORY OF INTEGRATED RESOURCE PLANNING AT ML&P

Q10. Please describe the Integrated Resource Planning process used by ML&P.

A10. During the last 15 years, ML&P has developed numerous resource plans, IRPs and studies to determine its best path forward. In 2002, when EES was first retained as Engineer of Record, ML&P was concerned with the aging mix of generating resources. Because ML&P is not integrated into a large grid system, as is common in the Lower 48, unreliable generating resources can result in customers being without power during critical periods.

Over the 15-year period since then, EES has performed five triennial Engineer of Record ("EOR") reports, four IRPs, and one generation study, in addition to participating in many other Railbelt-wide evaluations of new resource acquisitions and power pooling.

Q11. Please describe the triennial EOR studies prepared by EES for ML&P.

A11. ML&P completes their Three-Year Electric System Report ("Triennial EOR Report") every third year as required by Municipality of Anchorage Ordinance No. 96-83(S). Section 16(g) of the Ordinance states:

> For as long as any Senior Lien Parity Bonds are outstanding, the Municipality shall retain a nationally recognized independent Consulting Engineer on a continuous basis for the purpose of providing the Municipality with immediate and continuous engineering counsel in the

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> operation of the System. In addition to other duties, the Consulting Engineer shall, at least once during each three-year period, make a physical examination of the System and prepare a report based on such examination. Such reports shall be filed with the Municipal Clerk and shall be available during normal business hours for inspection by the owners of the Senior Lien Parity Bonds.

ML&P also has other ordinances for bonds that have not been refunded in advance that contain similar provisions requiring a report from a Consulting Engineer. Ordinance No. 89-88(S) required a physical examination of the System and report not later than five months after the close of the Electric Utility's 1990 fiscal year, and thereafter at least once during each succeeding three-year period.

EES developed the Triennial EOR Reports in 2003, 2006, 2009, 2012, and 2015. The Triennial EOR Report is a state of the system report which includes a physical examination of the distribution, transmission, and generation systems for the purpose of forming an opinion as to whether the properties have been maintained, preserved, and kept in good repair as required by the Ordinance Section 16(b).[2] These Triennial EOR Reports include recommendations related to operations, maintenance and capital investments based on EES' review of the ML&P generation, transmission, and distribution systems.

[2] Section 16(b) of the Ordinance requires the Municipality to "maintain, preserve and keep the System and every part and parcel thereof in good repair, working order and condition; and will from time to time make or cause to be made all necessary and proper repairs, renewals and replacements thereto so that the business carried on in connection therewith may be properly and advantageously conducted."

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Q12. What has been the conclusions of the Triennial EOR Studies since 2002?

A12. The findings of the Triennial EOR studies have been consistent since 2002. These findings were:

- ML&P generation fleet was the poster child for General Electric ("GE") when installed.
- ML&P's existing units represented the oldest units in GE inventory.
- Repair of broken parts is difficult as they were no longer available for the older generating units. ML&P also found it very difficult to find anyone to fabricate replacement parts.
- Safety was an ongoing concern listed in the reports. For example, the failure at Unit #3 in 2004 and the broken steam line at Plant #2 in the winter of 2012 were examples of these concerns.
- Units were not efficient given currently available heat rates.
- Need to replace NOW for efficiency, reliability, and safety reasons.
- These comments were pushed by EES for 10-12 years before ML&P moved forward with replacing its generation fleet.

Q13. Please describe the IRP plans prepared for ML&P.

A13. During the last 15 years, ML&P has developed IRPs in 2002, 2004, 2006, and 2009. Each of these IRPs developed a load forecast for ML&P, quantified the amount of available generation from current resources, evaluated supply and demand resource options, used ML&P's dispatch model to evaluate existing and proposed resources, developed 20-year cost of operation under several resource scenarios, and examined risk under each scenario.

Q14. What caused ML&P to explore an IRP in 2002?

A14. In 2002, ML&P was concerned that existing generation was aging and would require a significant amount of maintenance each year. EES agreed with this concern. At that

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time, ML&P's budget included a new turbine in 2011 at Plant #2. ML&P wanted to understand if moving up the new turbine would be cost effective when accounting for capital cost compared to fuel and maintenance savings from a new more efficient generating unit. The IRP concluded that ML&P should proceed with installation of two combined-cycle LM6000 units with duct firing with on-line date targeted for 2005 for a total additional 135 MW. This study assumed retirement of Plant #1 generating units once new generation was online (expected August 2005). The IRP concluded that ML&P could save approximately $100 million over the 20-year analysis period by building two LM6000 units rather than relying on existing resources.

Q15. What changed in the IRP developed in 2004?

A15. In 2004, another IRP was developed after load at the two Anchorage area military bases was expected to increase significantly. The recommendation in the 2004 IRP was to proceed with installation of one combined-cycle LM2500+ unit with an on-line date targeted for 2006 in place of Unit #5. In addition, it was recommended to add three new 6C combined-cycle units (3 into 1) with an on-line date targeted for 2009. These additional turbines were to be built at a new site (Plant #3) pending further investigation. This recommended plan resulted in the addition of 232 MW of capacity due to the increased load projection. This 2004 IRP assumed retirement of Plant #1 when new generation is completed and reliably online (2010). The IRP concluded that ML&P could save $70 million over the 20-year analysis period with the construction of three 6C combined cycle units.

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Q16. Please describe the main finding in the 2006 IRP.

A16. The 2006 IRP once again addressed concerns related to reliability and the aging of the existing generation. Due to the age of the existing generating units, significant maintenance was required every year. In addition, Unit #3 failed in 2004 prior to the planned replacement date of 2007. Unit #7 was scheduled to have a rotor replacement in 2006.

Prior to the Unit #3 failure, the ML&P budget included a new turbine in the 2006 time-frame at Plant #2 to replace Unit #5. The budget also included additional generation in 2008, 2009, and 2010 at a new site (Plant #3). Given the Unit #3 failure and planned replacements, the 2006 IRP was developed to explore if the current plan is still the best path forward and what would be the best turbine options for ML&P. The 2006 IRP showed that the base case (keep operating existing generation) would not be sustainable as it was very unlikely that all units could continue operating through 2030. The recommended plan in the 2006 IRP was to build two 6B combined-cycle units based on the native load scenario. This study assumed retirement of Plant #1 generating units by 2010 when new units are online and proven. The IRP concluded that ML&P could save approximately $55 million over the 20-year analysis period.

Q17. What were the key generation issues explored in the 2009 IRP?

A17. Similar to the 2006 IRP, the 2009 IRP addressed the question of what would be the best turbine options for ML&P going forward. The planned Unit #7 rotor replacement occurred in 2006 and a joint project with Chugach Southeast Power Plant ("SPP") was planned to come online in 2014. The 2009 IRP showed that while ML&P's existing

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resources provided sufficient capacity to meet reserve obligations, significant reliability and safety risks were found due to the age of the existing generating units. ML&P's generating portfolio in 2009 is profiled below in Table 1.[3]

Table 1

Plant	Unit	Technology	Capacity (MW)	Role	In Svc	Age in 2009
Hydro			54	Base Load	54/91	
Nikkels (Plant 1)	1	CT	14	Peaking	1962	47
	2	CT	14	Peaking	1964	45
	3	CT	29	BL + Peak	2007	2
	4	CT	31	Peaking	1972	37
Sullivan (Plant 2)	5-6	CT/ ST	44	Base Load	1979	30
	7-6	CT/ ST	97	Base Load	1979	30
	8	CT	77	Peaking	1984	25
Total			360			
Peak Load			186			
Reserve Margin			94%			

Source: Compiled from ML&P 2009 Integrated Resource Plan

As indicated in Table 1, ML&P's generating portfolio in 2009 was dominated by thermal units (principally gas-fired), referred to hereinafter as the "Legacy Gas Units." Shares in hydro generation augmented the portfolio with 54 MW of base load capacity, or 15 percent of total. The 2009 IRP showed ML&P capacity exceeding peak load by 174 MW, for a reserve margin of 94 percent. However, notwithstanding a seemingly ample reserve margin, the 2009 IRP concluded that ML&P's reserve margin was [based on unreliable capacity and that new resources would be needed]:

[3] ML&P 2009 Integrated Resource Plan at p. 6, Exhibit 15 to ML&P's TA357-121 filing at p. 19.

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> The load/resource balance…shows that ML&P currently has the capacity to meet both its current and projected load contractual reserve obligations; however, the current system suffers significant reliability and safety risks due to the age of its existing generating units.[4]

Indeed, many of the Legacy Gas Units had reached or exceeded their design lives (approximately 30 years).[5] As a result, Unit #2 (14 MW) had been recently rebuilt, and Unit #3 (29 MW) was replaced in 2007.[6] Meanwhile the 2009 IRP reported that Unit #5 (44 MW) was removed from service for more than a year in 2001 – 2002 due to a generator rotor failure.

The 2009 IRP elaborated as follows:

> The generator failure on Unit #5 is indicative of problems that the utility faces with its aging fleet of generation equipment. Unit #5's failure in this case was likely mainly due to a large incident of cycling of the machine, but the age of this machine, and those that back it up, is also a major contributing factor.[7]

The 2009 IRP also stated:

> [I]t is considered infeasible for ML&P to perform necessary on-going major refurbishments and replacements and simultaneously provide reliable service to meet ML&P's native load, because these units are past their expected design life.[8]

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[4] ML&P 2009 Integrated Resource Plan, p. 17, Exhibit 15 to ML&P's TA357-121 filing at p. 30.

[5] ML&P 2009 Integrated Resource Plan, Appendix A – Review of Existing Generation Resources, p. A-3 to A-6, Exhibit 15 to ML&P's TA357-121 filing at p. 80-83.

[6] ML&P 2009 Integrated Resource Plan, Appendix A – Review of Existing Generation Resources, p. A-3, Exhibit 15 to ML&P's TA357-121 filing at p. 80.

[7] ML&P 2009 Integrated Resource Plan, Appendix A – Review of Existing Generation Resources, p. A-5, Exhibit 15 to ML&P's TA357-121 filing at p. 82.

[8] ML&P 2009 Integrated Resource Plan, p. 42, Exhibit 15 to ML&P's TA357-121 filing at p. 56.

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Additionally, the 2009 IRP also observed that load requirements could reasonably be expected to pressure generator performance going forward. While ML&P's peak load was not expected to grow dramatically—approximately 0.5 percent per year—ML&P has contractual obligations to maintain capacity and operating reserves under the Alaska Intertie Agreement.[9] ML&P's capacity reserve obligation is 30 percent of peak load. Operating reserve requirements include spinning and non-spinning resources that can aggregate 60 MW. In addition, cycling could reasonably be expected to be an ongoing demand on the Legacy Gas Units. The 2009 IRP noted that system load fluctuated from 40 MW to 60 MW daily, a range difficult to address with the generators existing at that time.

As a measure of system vulnerability, the 2009 IRP assessed the impact of failure of the two largest units on which the system had come to rely heavily. These so-called "N-1" and "N-2" reserve contingencies are well-established metrics in ML&P system planning. As shown below in Table 2, a loss of Unit #7 (age 30) would bring the reserve margin down to 41 percent, 11 percent over the 30 percent requirement, while the additional loss of Unit #8 (age 25) would bring the reserve margin down to 0 percent (i.e., capacity would just equal peak load).

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[9] Per the 2009 IRP, "[t]he Alaska Intertie Agreement (1985), which ML&P and all other interconnected Railbelt utilities (except Seward) are parties to, provides for interconnected operation, transmission between utilities, reserve sharing and sales of operating reserves (but not energy, except in an emergency). It also provides for sale of emergency power. *See* ML&P 2009 Integrated Resource Plan, p. 7, Exhibit 15 to ML&P's TA357-121 filing at p. 20.

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Table 2

Plant	Unit	Technology	Capacity (MW) Base	N-1	N-2
Hydro			54	54	54
Nikkels (Plant 1)	1	CT	14	14	14
	2	CT	14	14	14
	3	CT	29	29	29
	4	CT	31	31	31
Sullivan (Plant 2)	5-6	CT/ ST	44	44	44
	7-6	CT/ ST	97	-	-
	8	CT	77	77	-
Total			360	263	186
Peak Load			186	186	186
Reserve Margin			94%	41%	0%

Source: Compiled from ML&P 2009 Integrated Resource Plan

It is important to note that the 2009 IRP contemplated the addition in 2014 of the SPP with 54 MW of gas-fired combined cycle generation allocated to ML&P.[10] However, the 2009 IRP viewed SPP as "inadequate to meet all of ML&P's attendant safety and reliability issues".[11] Given these changes, the 2009 IRP recommended that ML&P install one LM2500 simple-cycle unit at Plant #1 and one LM6000 combined-cycle unit at Plant #2 in addition to participating in SPP.

[10] SPP was being jointly developed with Chugach Electric Association, Inc..

[11] ML&P 2009 Integrated Resource Plan, p. 17, Exhibit 15 to ML&P's TA357-121 filing at p. 30.

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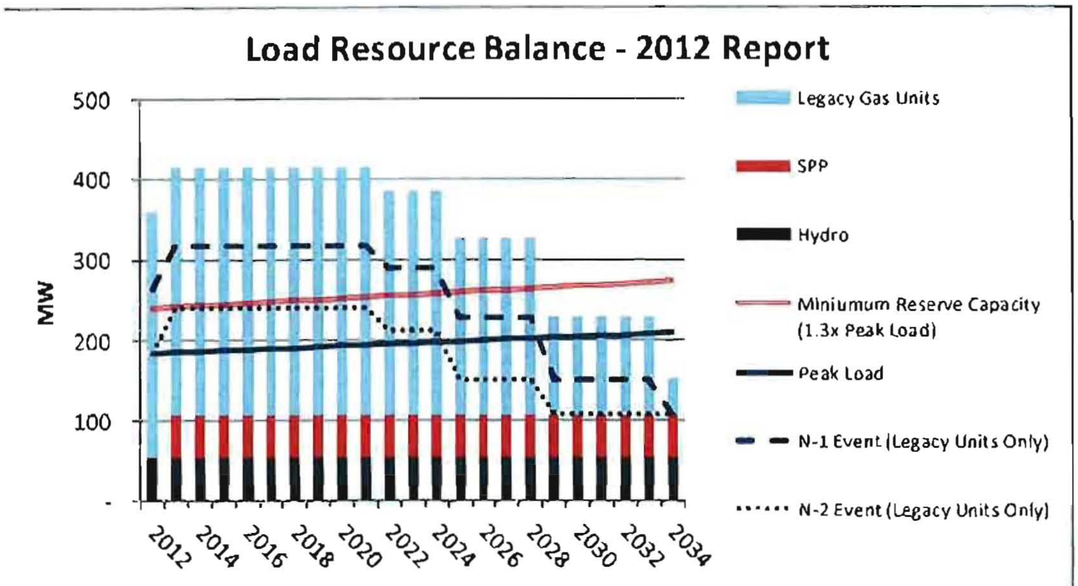
Q18. How was the 2012 Generation Study different from the other IRPs?

A18. The 2012 Generation Study[12] integrated updated developments and assumptions into the 2009 analysis. Among other things, the 2012 report reflected forecast retirement dates for the Legacy Gas Units, reflected below in Figure 1:

Figure 1



Source: Compiled from 2012 Report

Figure 1 shows expected retirements against a Base Case forecast of peak load and the 30 percent required reserve margin. Observations include:

- Retirement of Legacy Gas Units were expected to occur well within the planning period, with 86 percent of capacity retired by 2033;

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[12] The 2012 Generation Study Exhibit 16 to ML&P's TA357-121 filing.

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- Available capacity, if not augmented, would breach the 30 percent required reserve margin by 2029, and cause load shedding by 2034;
- An N-1 event would breach the 30 percent required reserve margin by 2025, and cause load shedding by 2029; and
- An N-2 event would breach the 30 percent required reserve margin immediately, and cause load shedding by 2025.

Thus, the capacity need identified in the 2009 IRP, based on concern about the reliability of the Legacy Gas Units, would only become more acute in the future as retirements occurred.

The 2012 Generation Study focused on comparing two generation equipment plans to ensure the recommended plan from the 2009 IRP was still the preferred plan prior to proceeding with equipment purchases. The two plans evaluated were:

- Plan 1: 2009 IRP Preferred Plan
  - Install one LM2500+ in simple-cycle at Plant #1 (45-50 MW)
  - Install one LM6000PF in combined-cycle at Plant #2 (57.5 MW)
  - Includes planned addition of SPP
- Plan 2: Case 4 from 2009 IRP
  - Install two LM6000PF in combined-cycle at Plant #2 (116 MW)
  - Includes planned addition of SPP

The 2012 Generation Study found that the estimated Plan 1 and Plan 2 costs were within 5 percent over the analysis period, well within the uncertainty range of cost estimates. Plan 2 was the least-cost plan with estimated costs ranging from \$109/MWh to \$162/MWh, depending on the estimated natural gas price. Plan 2 was selected because it

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provided additional benefits to ML&P and its customers. The qualitative considerations in the 2012 Generation Study included:

- Additional generation at Plant #2 will provide additional benefit to municipal water heating.
- Generation located at Plant #1 may help meet downtown Anchorage commercial business district ("CBD") loads during outages of the 115kV system.
- EPA caps emissions on new units at 1,000 lbs/MWh, SCCT unit in Plan 1 may exceed this cap increasing costs.
- Plan 2 would reduce spinning reserve requirement as unit 7/6 would be offline.
- Under Plan 2, ML&P would be able to meet generation reserve requirements using equipment aged 30 years or younger up to 2020.

Q19. What other generation studies did ML&P participate in during the last 15 years?

A19. During the last 15 years, several generation studies for the Railbelt were performed as well. ML&P participated in a 2003 Railbelt Energy Study developed by RW Beck. This study concluded that based on expected loads and natural gas prices, a total of 725 MW of new generating capacity should be built in the Railbelt between 2008 and 2030 – 205 MW in the Fairbanks area, 520 MW in the Anchorage area.

During the 2008-2009 period, ML&P worked with Chugach Electric Association, Inc. ("Chugach"), to explore joint resource options for the Railbelt. As a result of a Navigant Joint Resource Study, ML&P joined together with Chugach in the ownership and operation of as the SPP which came online in 2013. ML&P receives a dedicated 30 percent share of the output of SPP, varying from 45 MW to 54 MW depending on the season.

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Q20. Did ML&P's resource planning include examination of demand-side management?

A20. Yes. As part of the 2009 IRP, a Conservation Resource Assessment was performed to determine the amount of cost effective and achievable energy efficiency. It was determined that energy efficient lighting could provide up to 26 MW of savings between residential and commercial customers over the 20-year period. While the 2009 IRP encouraged ML&P to explore conservation, it was also found that conservation resources were not sufficient to replace aging generation units. This evaluation therefore did not change the recommendation of adding new generation to ML&P's resource mix.

Q21. Does ML&P use the dual fuel capability of the current units?

A21. Yes. The most recent event was December 5, 2015, when the gas pressure regulating valve sensing line froze causing Unit #7 to automatically transfer to fuel oil. Prior to that, on December 27, 2010, a Beluga River Unit ("BRU") gas compressor tripped causing gas line pressure to drop and Units #4, #5, and #7 transferred to fuel oil.

Q22. Should ML&P discontinue the availability of dual fuel?

A22. Dual fuel provides back-up if gas supply is interrupted. It can be a valuable option for ML&P's customers. However, major capital investments are coming up and ML&P may be able to reduce costs if the dual fuel units are retired. However, this decision is a policy decision that EES cannot make, trading reliability for cost savings.

Q23. Will retirements be made now that Plant #2A is on line?

A23. Yes. As discussed in Mr. Ori's testimony, Units #1, #2, #5, #6 and #7 boiler will be retired from service.

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Q24. In determining to proceed with Plant 2A, did ML&P go through an evaluation process that is in keeping with generally accepted utility practice?

A24. Yes. ML&P has studied the addition of generation units for over 10 years with numerous studies and analyses. Initially, ML&P evaluated the need based on an IRP methodology examining the general size of units needed. Lastly, a Generation Study was performed to fine-tune the size and type of units to pursue. The process used to determine that Plant #2A was needed was very thoughtful and conservative.

Q25. Do you support the methodology used to recover the cost of Plant 2A through a rate stabilization fund?

A25. Yes. The methodology reduces the initial impact to customers, while shaping the costs to reflect benefits to future customers. Customers benefit more in the future from Plant #2A because the savings in gas costs will be greater as gas prices increase. In addition, generating equipment is depreciated over time resulting in a lower dollar return in rates the older the equipment. Delaying some capital costs recovery therefore evens out the recovery collected from customers.

SECTION B: COST OF SERVICE AND RATE DESIGN

I. OVERVIEW OF UTILITY RATE SETTING PRINCIPLES

Q25. Please describe the general principles governing utility rate setting.

A25. The setting of electric utility rates that are fair, just and reasonable is a complex process, involving judgments about which costs should be assigned to different customers. This process is guided by generally accepted rate setting practices and guiding principles.

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These guiding principles often include setting rates that are cost-based, fair, equitable, not unduly discriminatory, and simple enough to be understood by the average ratepayer. These types of principles may be referred to as global principles.

Q26. Are there other considerations that should be taken into account?

A26. In addition to the global guiding principles mentioned above, there are a number of financial principles or guidelines that are specifically applicable to the utility in question that must be taken into consideration. Therefore, the setting of electric rates that are fair, just and reasonable is a marriage of these generally accepted rate setting principles, financial policies, and considerations specific to ML&P.

Q27. Please list the general principles used in the COSS and rate setting process for ML&P.

A27. The following principles are the basis around which ML&P determines its costs and sets its rates:

- Rates should be cost-based and set at a level such that they recover an appropriate share of the utility's total revenue requirement from each rate class.
- Rates should be just, reasonable and not unduly discriminatory.
- Rates should promote the economically efficient use of electricity.
- Rates should be easy to understand and administer.
- Rates should be stable to meet customers' expectations, and sufficient to provide adequate revenues to meet the utility's financial requirements.
- Rates should reflect continuity in rate setting philosophy.

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- Rates should reflect cost causation principles.

II. OVERVIEW OF THE COSTS AND RATE PROCESS

Q28. Please explain the general methodology used to set utility rates.

A28. In developing utility rates, three separate and inter-related studies are performed. These are:

- Revenue Requirement Study
- Cost of Service Study
- Design of Rates

Q29. What is the purpose of the revenue requirement study?

A29. The revenue requirement study determines the costs incurred to provide service during a specified test period, in this case, the calendar year 2015, adjusted as necessary, to make the test year representative of the period during which rates are expected to be in effect. The revenue requirement study also compares the test year revenue requirement to the test year revenue to determine a revenue deficiency, both as a quantity and as a percentage of test year revenue. This can be used as a basis for adjustment of all rates, in the case of an "across the board" rate adjustment. The revenue requirement study used in the ML&P COSS was developed by ML&P and is addressed in the testimony of Ms. Anna Henderson. I have reviewed Ms. Henderson's testimony and ML&P's revenue requirement study and have used this revenue requirement as the basis for the COSS.

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Q30. What is the next study performed?

A30. The next study performed is the cost of service study or COSS. The COSS takes the results of the revenue requirement study and equitably allocates these costs to the various customer classes of service (e.g., residential, general service, etc.). The COSS provides a framework to compare the revenues received from each class of service to its allocated costs. The COSS also determines unit costs of various rate components that can be used to set rates for billing determinants in the rate design phase.

Q31. Please describe how a COSS assigns costs to customer classes.

A31. A COSS begins by functionalizing a utility's revenue requirement into the following functions: production, transmission, distribution or a combination of these functions. Next, the functionalized costs are classified into demand-, energy-, and customer-related component costs based upon cost causation principles. Demand–related costs are those that the utility incurs to meet a customer's maximum rate of usage during a given period of time and are usually measured in kilowatts (kW). Energy–related costs are those that vary with energy consumption and are usually measured in kilowatt-hours (kWh). Customer–related costs are those that vary with the number of customers served.

These three component costs are then allocated to each class of service (e.g., residential, small general service, large general service, etc.) based upon the most equitable method available for each specific cost. The most equitable method of allocating costs generally embraces the principle of cost causation. Once allocated, each class's costs are compared to its test year revenues to determine if any revenue

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adjustments among classes of service are necessary to balance revenues and allocated costs.

Q32. Explain the remaining study to be performed in order to set rates.

A32. Finally, once the levels of adjustments, if any, proposed for each class of service have been determined, rates for each billing determinant can be designed. Rate designs can take many different forms or structures, but each rate design has the stated goal of collecting the appropriate level of revenues, as determined within the revenue requirement and cost of service study, in the most equitable and appropriate fashion.

Q33. What is the foundation of the theories behind rate design?

A33. The basic theories behind rate design are founded in the economic literature. Economic theory dictates that the price of a commodity must roughly equal its cost,[13] if economic efficiency is to be achieved. In designing rates, the utility must take into consideration the characteristics of overall power supply and distribution, and the characteristics of the customers to which the utility will sell. Rates can take many forms, but ultimately they should reflect the component costs that the utility incurs (demand–, energy– and customer–related costs) and collect the desired level of revenues.

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[13] In the regulated utility context, the concept of cost is fraught with conflicts between the concepts of marginal vs. total cost, short run vs. long run cost, and independent vs. joint vs. common costs. These conflicts must be resolved through compromise and rules of thumb, and it can never be said that there is any uniquely correct allocation or rate design.

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III. DEVELOPMENT OF COST OF SERVICE STUDY

Q34. What are the objectives of a COSS?

A34. There are two primary objectives for a COSS. They are to:

- Allocate total revenue requirements among customer classes of service.
- Derive average unit costs for practical billing determinants (e.g., kW and kWh) for subsequent rate designs.

Q35. What time period was used by ML&P for rate setting purposes?

A35. The test year used in ML&P's COSS was calendar year 2015 as adjusted for known and measurable changes. Actual rate base, revenues, and expenses from 2015 were used with pro forma adjustments to determine the revenue requirement used in the COSS. Energy consumption and demand from 2015 by customer class were also used. The COSS model uses a revenue requirement on a utility/accrual basis. The utility/accrual basis calculates revenue requirement by summing a utility's operation and maintenance ("O&M") expenses, taxes, depreciation and return on rate base.

Q36. What customer classes were evaluated in the COSS study?

A36. The customer classes modeled in the COSS included Residential, Small General Service, General Service Secondary, General Service Primary, AWWU Replacement Energy, 770 Partial Requirements Service at Primary Voltage, Interruptible Service, and Street and Area Lighting.

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Q37. Please describe the revenue requirement used in the cost of service study.

A37. As described in the testimony of Ms. Henderson, the base cost of power and the cost of power adjustment ("COPA") have been excluded from this analysis in both revenues and expenses. Therefore, total adjusted retail rate revenues (excluding base cost of power and COPA) for 2015 were $93,651,116, while the revenue requirement less other miscellaneous revenues amount to $133,134,621. This results in a retail rate revenue deficiency of $39,483,505, which is 42.2 percent of the test year revenue.

For purposes of the COSS, the net revenue requirement is defined as the total costs less other miscellaneous revenues. The total revenue requirement in this case reflects the 2015 actual costs or expenses plus pro forma adjustments, including the addition of costs related to Plant 2A. In addition, ML&P is proposing to implement a rate stabilization methodology in the revenue requirements based on depreciation adjustments, as discussed in the direct testimony of Ms. Henderson. This provides a credit in the 2015 revenue requirements of $12.875 million. After the rate stabilization credit, the revenue requirement is equal to $120,258,663, reflecting a revenue deficiency of $26,607,547 and 28.4 percent.

Q38. Please explain the process used to develop the COSS.

A38. Once the revenue requirement was determined, the next step was to develop the detailed load data and the associated allocation factors. The COSS was then completed by functionalizing, classifying and allocating costs appropriately.

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Q39. What load data was used in the COSS?

A39. Monthly kWh and kW were obtained from ML&P's billing records and load research program for use in the COSS. The load research program places hourly meters on a sample of customers in each rate class to determine their peak load and their loads at the time of the peak for the class as a whole and at the time of the system peak. This provides a statistical estimation that can be used to determine the peak loads for those rate classes for use in the COSS. Based on the billing data and estimated line losses, energy consumption at system input was determined for each customer class. Coincident and non-coincident peak demands were calculated for each customer class based on actual billed kW and the load research data.

Q40. How did you functionalize the rate base and revenue requirement?

A40. The first step in preparing the ML&P COSS was to functionalize rate base and revenue requirements. Functionalization is the arrangement of cost data to the functional activities performed in the operation of an electric system (i.e., production, transmission, distribution). Functionalization of most costs was accomplished through ML&P's system of accounts, which largely segregates costs in this manner.

Q41. How were general plant and administrative and general ("A&G") expenses functionalized?

A41. General plant and A&G were functionalized based on labor ratios. ML&P provided actual labor expenditures by production, transmission and distribution functions. Based on the ratio of labor expenditures charged to the functions, general plant and A&G were

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functionalized 52.0 percent to production, 0.2 percent to transmission, 36.9 percent to distribution and 10.8 percent to customer.

Q42. What was the next step?

A42. The second step in the ML&P cost of service study was to classify the functionalized rate base and expenses to cost components. Functionalized production and transmission costs were classified as demand-related or energy-related while distribution costs were classified as demand-related, customer-related or directly assigned to customer classes of service based on cost causation principles. In addition to facilitating allocation of costs to customer classes, classification also provides convenient unit cost billing determinants.

Q43. Please explain what kind of costs are demand-related costs.

A43. Demand-related costs are those that vary with the maximum demand, or the maximum rates of flow of electricity to customer classes. Demands are typically measured in average kilowatts ("kW") over very short time periods, e.g. 15, 30 or 60 minutes. Demand costs are generally related to the size of facilities needed to meet either a customer's maximum demand or the system aggregate maximum demand over some period. Within this study, demand costs were classified as either coincident peak demand ("CP") or non-coincident peak demand ("NCP"). Coincident peak demand refers to the demand placed upon the system by each customer or customer class at the time of the ML&P maximum system peak (sometimes referred to as the customer or class *contribution* to system peak). Coincident peak is generally used to size production or transmission facilities. The non-coincident peak demand refers to the individual or group

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customer peak demands regardless of the time of occurrence. Distribution facilities are typically sized to meet the specific individual customer demands for a limited geographic area within the utility's service territory. This sizing is an example of non-coincident demand costs.

Q44. What are energy–related costs?

A44. The energy–related costs are those that vary with the total amount of electric energy consumed by a customer. Energy usage is generally measured in kilowatt-hours ("kWhs"). Energy costs are the costs of consumption over a specified period of time such as a month or year. Fuel expense is a good example of an energy–related cost.

Q45. Please describe the customer–related cost categories.

A45. Customer–related costs are those that vary as a function of the number of customers. They do not vary with system output levels. There are two types of customer related costs - actual and weighted. Actual customer costs vary proportionally with the addition or deletion of a customer, regardless of the size or usage characteristics of the customer. An example of an actual customer–related cost is postage for customer billing. In contrast, a weighted customer cost reflects a disproportionate cost attributable to the addition or deletion of a customer. An example of weighted customer costs is meter-reading expense. In some cases, it takes less time and effort to read a residential kWh (energy) meter than it does to read the meter of a large commercial customer with a kWh and kW (demand) meter. This type of difference is accounted for in the weighted customer allocation factors.

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In the COSS for ML&P, three weighted customer classifications were developed in addition to the actual customer classification. These were meter cost, billing and collection, and meter reading. All of these categories have different weights for each customer class.

Q46. Were any other classification categories used in the cost of service study?

A46. Yes. Some costs were directly assigned to certain customer classes without being classified as demand–, energy– or customer–related. Also, some costs were allocated to customer classes based on gross revenues. These joint and common costs,[14] or revenue credits such as miscellaneous revenues, vary with overall system operation, rather than with any specific category.

Q47. Please explain how production costs were classified?

A47. Classifying production costs to demand and energy components requires evaluation of a number of factors. Consideration must be given to what or who caused the investment in the production plant and the uses of the production plant (i.e., meeting demand requirements and meeting energy requirements). Consideration must also be given to the

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[14] Joint costs are costs that support the provision of more than one service in such a way that there is no trade-off between the services. A change in production of one service does not require a compensatory change in the provision of its joint services. Common costs are costs that support the provision of more than one service in such a way that there is a trade-off between the services. A change in production of one service does require a compensatory change in the provision of its common services. There is often overlap between joint and common costs, and in regulation, they are often treated as a single category.

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utility's generation system planning and operation. Traditionally, there have been many acceptable approaches to classifying production costs to demand and energy.

As required by 3 AAC 48.540(e)(1)(A), demand-related costs associated with production and transmission were allocated using both the peak responsibility method and the average and excess method. To determine the demand-related costs under the peak responsibility method, this COSS used the load factor method for classifying production cost. The load factor method used ML&P's system load factor to determine the split between energy-related and demand-related costs. This methodology is a cost causation methodology and attempts to determine what influences a utility's production plant investment decisions. Given the characteristics of ML&P's system and resource portfolio, it is appropriate to classify ML&P's production costs as energy-related based on ML&P's load factor, and then classify the remaining costs as demand-related. ML&P's annual system load factor for 2015 was 62.9 percent. Therefore, this method resulted in classification of 69.9 percent energy and 30.1 percent demand for production-related plant. This is the approach recommended by EES and is the basis for rates proposed by ML&P.

The average and excess method can be used to perform the classification and allocation in one step and will be further described under allocation of production costs. For the average and excess methodology, all production costs were classified as demand. One additional approach was examined for purposes of the application based on feedback from ML&P's last rate case. This additional approach classified all production plant as 100 percent demand-related. This approach was included for comparison purposes only,

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and is not proposed as the appropriate method for ML&P. The treatment of production plant in the COSS is discussed in greater detail in the next section of this testimony.

Q48. What classification method was used to classify transmission costs?

A48. Transmission costs are typically considered to be coincident peak demand-related. The cost of providing transmission service to a customer is considered proportional to the customer's contribution to the coincident peak demand of the system. In this COSS, transmission rate base and expenses were classified as 100 percent coincident peak demand.

Q49. Please describe the methods generally used to classify distribution costs.

A49. Most distribution costs are driven by non–coincident demand and customer-related costs. The demand component represents the cost of distribution facilities built to serve a particular load. The customer component is the cost of facilities that varies with the number of customers. Poles, conductors, transformers, and services could arguably be 100 percent non-coincident demand, 100 percent customer-related, or a combination of demand and customer. Using a 100 percent demand non-coincident classification approach assumes that distribution investment is based entirely on meeting non-coincident peak demands. A minimum system approach assumes that distribution investments (i.e., poles, conductors, and transformers) are based not only on meeting non-coincident peak demands, but also on number of customers. The minimum system approach attempts to split these costs to demand and customer components by valuing the distribution system as if it were built to serve a minimum load requirement. The

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distribution costs necessary to meet minimum load requirements are considered customer-related. Costs in excess of the minimum are considered demand-related.

Q50. How did you classify distribution costs?

A50. Based on 3 AAC 48.540(f)(2)(A), distribution system costs "will be considered and classified as demand-related costs." Therefore, the majority of distribution plant was classified as 100 percent non-coincident peak ("NCP") demand. The only exceptions were account 370 - Meters, which was classified as customer weighted for meter and service costs (CUSTM), account 373 - Street Lighting Systems, which was direct assigned to Street Lights and account 362 – Station Equipment, which was partially direct assigned to 770 Partial Requirements Service at Primary Voltage. The remainder of account 362 was classified as 100 percent NCP-Primary demand. The distribution expenses in the revenue requirement, except for any customer service expenses, were classified in the same manner as the distribution plant.

Q51. How did you allocate costs to customer classes?

A51. The third step in performing this COSS was to allocate ML&P's total functionalized and classified rate base and revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology. There are two ways to allocate costs to customer classes: Direct Assignment and Allocation Factors. Some costs to AWWU–Replacement Power, Street Lighting and 770 Partial Requirements Service at Primary Voltage were directly assigned based on their specific usage. Allocation factors were used for the remaining costs and customer classes.

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Q52. What was the methodology used to direct assign costs?

A52. In this study, three customer classes were directly assigned costs using three different methods. The allocation methodology used to assign costs to AWWU-Replacement Power was approved by the Commission in Order No. U-90-090(7). The AWWU-Replacement Energy charge was calculated based on the share of energy "purchased" by AWWU through the diversion of water that ML&P could have otherwise used to generate energy. In 2015, AWWU purchased/diverted 14,180,598 kWh or 1.39 percent of total retail kWh (excluding Sales for Resale). The replacement power rate does not include distribution or customer accounting costs because the power is not delivered to AWWU and customer accounting costs are trivial. Because no power is actually delivered to AWWU, AWWU is only assigned costs related to generation and a small share of transmission expense.

The street lighting customer class was direct assigned Account 373 – Street Lighting Systems in the rate base and Account 585 – Street Lighting and 596 - Street Lighting in the revenue requirement. In addition, Street Lighting received the appropriate share of remaining expenses based on allocation factors.

The 770 Partial Requirements Service at Primary Voltage customer class was direct assigned a share of account 362 – Station Equipment based on equipment dedicated to this class. In addition, the 770 Partial Requirements Service at Primary Voltage class received the appropriate share of remaining costs based on allocation factors.

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Q53. How did you allocate costs to customer classes using allocation factors?

A53. Allocation factors or percentages were developed for each of the demand, energy, and customer classification categories previously identified. These factors are summarized in Exhibit C-2 and Exhibit D-1 in the COSS report.

Q54. What methodology was used to determine the demand allocation factors?

A54. Two types of demand allocation factors were developed. First, non-coincident peak demand allocation factors for primary service and secondary service were developed for each customer class. Items classified and allocated by the non-coincident peak demand allocation factors included those predicated on maximum demands such as distribution substations, poles, conductors and line transformers.

For each class of service, a contribution to the monthly ML&P system coincident peak was also derived from the non-coincident peak by use of a coincidence factor. There are three generally-accepted methods used to allocate coincident demand costs that have stood the test of time. These are the peak responsibility method (1 CP method or 12 CP method) and the average and excess demand method (A&E method). Each of these approaches has its appropriate application. Each method is discussed in more detail below.

The peak responsibility - 1 CP method allocates demand costs to customer classes based on their contribution to the highest system coincident peak that occurs during the year. Next, the peak responsibility — 12 CP method allocates demand costs on the basis of the sum of the contributions to monthly system peak demands by each class. Finally,

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the average and excess demand method considers the load factor of the system in allocating demand costs. The percentage of demand-related costs equal to the load factor is allocated to customer classes on the basis of energy consumption. The balance of the demand costs is allocated to customer classes on the basis of class excess demands, or their non-coincident demands above their average demand.

Q55. Which of the CP demand allocation factors was used in the base case?

A55. In this study, under the base case, demand–related costs associated with production were allocated using the 12 CP method. This methodology was chosen based on the belief that these costs are driven by system, rather than individual or class peaks, and that each of the monthly system peaks has some importance as a cost driver. Transmission demand-related costs were allocated based on 12 CP, because the transmission system is planned based on meeting the 12 monthly peaks. Note that because Schedule 27 Interruptible class can be interrupted, its load is not included in the 12 CP allocation for production and transmission. Further support for the use of the 12 CP method is provided in the next section of this testimony.

Distribution-related demand costs were allocated based on non-coincident peak primary, except for transformers, which were allocated based on non-coincident peak secondary. Transformers step down the voltage from the higher primary voltage level to the lower secondary voltage level. Transformers are only used by customers receiving service at secondary voltage and the costs of transformers are therefore allocated to customers based on their service at the secondary level. The Schedule 27 Interruptible

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class was included in the NCP allocation as distribution facilities because distribution facilities would be needed to serve their loads whenever they occurred.

Under a separate scenario as required by 3 AAC 48.540(e)(1)(A), demand–related costs associated with production and transmission were allocated using the average and excess method with all other assumptions remaining the same. A further scenario was developed classifying all generation and transmission costs as 100 percent demand-related and using the 12 CP allocator. While this approach is not recommended, it is provided for illustrative purposes.

Q56. What methodology was used to determine the energy allocation factors?

A56. Energy costs vary directly with kWh consumption. Accordingly, energy allocation factors were based upon energy sales for each class adjusted for system line losses. The adjustment for line losses reflects the fact that customers are served at different voltage levels and often have different line loss responsibilities.

Q57. Please describe the customer allocation factors?

A57. The allocation factor for actual customers was derived from the actual number of customers served in each class of service. Three weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences of meter costs between the various customer classes. The second weighted customer allocation factor considered the difference between customer classes for billing and collecting type costs. The last weighted customer allocation factor considered the cost differential in reading meters.

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IV. SUPPORTING EVIDENCE FOR GENERATION CLASSIFICATION AND ALLOCATION METHODS

Q58. The treatment of production costs has been a contested issue among the various parties in past ML&P rate cases. Can you please further describe the issue?

A58. Based on 3 AAC 48.540(e)(1)(A), demand-related costs associated with production and transmission are to be allocated using both the peak responsibility method and the average and excess method. The Alaska Administrative Code ("Code") is silent on the matter of classification of production costs. Our interpretation has always been that the inclusion of the term "demand-related" costs allows for the classification of production costs between demand and energy prior to the allocation of costs on the basis of peak demand. Other parties have argued that the Code requires that all production costs be allocated on the basis of peak demand. Because of the difference in interpretations, we have provided the results with and without the classification of some production costs to energy for illustrative purposes.

Q59. Is it common for production costs to be classified between both demand and energy?

A59. Yes, it is common for both demand and energy to be considered when classifying and allocating generation costs. There are many different approaches used, however, and they vary with the circumstances of the utility and with different regulatory policies. We have not seen one specific approach that was used by the majority of utilities. Rather, we found that there is a wide range of approaches used, and that the majority of them consider both demand and energy. Among the approaches we have seen are the load

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factor method, as recommended to ML&P. This approach has been used by Avista and Idaho Power.

Other approaches we have seen used by utilities include the peak credit method, the average and excess method, the base-intermediate-peak method, a 75 percent demand and 25 percent energy method and a 50 percent demand, 25 percent on-peak energy and 25 percent total energy method. Given the wide range of approaches used by different utilities, we believe the load factor approach used for ML&P is well within the range of approaches used by electric utilities.

Q60. How does the classification of generation between demand and energy relate to cost causation?

A60. When looking at cost causation, it is important to look at the underlying reasons for building generation facilities and at the planning related to the generation resources. While peak demand is often the driving factor for the need for additional generation, other factors are considered when selecting the most appropriate type of generation. In the case of ML&P, there are a mix of resources used to meet peak demand, meet energy requirements, provide reliability and minimize costs. If peak demand was the only driving factor, ML&P would have installed only peaking facilities which require a lower capital cost per kW. When other types of generating plants with a higher capital cost are used in order to provide greater efficiency when operating, cost causation would indicate that both demand and energy were considerations in the capital cost of the facility. Even if there were only one type of generating plant available, it would still be appropriate to

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classify production plant to both demand and energy because they are joint products. All production plant supports both demand and energy, and therefore, the cost should be distributed in some manner between both of those products.

The load factor approach follows cost causation because a utility with a very low load factor, and therefore a large peak demand, would primarily need peaking plants and the majority of its generation costs would be classified as demand-related. In this case, fuel costs per kW would be high but the plants would not be operated that much. Conversely, a utility with a very high load factor would primarily need baseload plants and the majority of its generation costs would be energy-related. In this case, fuel costs per kWh would be low but the plant would be operated frequently. The savings in fuel costs would offset the higher capital costs of the baseload plant.

Q61. Do you believe there is sufficient evidence to support the load factor classification method for ML&P?

A61. Yes. The load factor approach reflects cost causation, it is consistent with the common practice of classifying costs to both demand and energy, and it is used by other utilities. In addition, it provides rate and revenue stability for ML&P and its customers because it is consistent with past practice. Changing the generation treatment in the COSS would lead to wider swings in the rate increases needed from the various customer classes to match the COSS results.

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Q62. The 12 CP allocation factor is being used for generation and transmission within the COSS. What evidence did you look at to support the use of this factor?

A62. In looking at the appropriate demand allocation factors, I looked at both past practice for the utility, planning done by the utility, and the specific circumstances of the utility's load profile. To determine which allocation factor to use given the load profile of ML&P, I followed the approach used by FERC in such matters. FERC uses the following peak ratio tests to determine which of the peak allocation methodologies a utility should use:

- **Test No. 1** - On and Off Peak Test - This test first compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19 percent or less.

- **Test No. 2** - Low-to-Annual Peak Test – This test compares the lowest monthly peak as a percentage of the annual system peak. A range of 66 percent or higher is considered indicative of a 12 CP system.

- **Test No. 3** - Average to Annual Peak Test – This test compares the average of the twelve, monthly peaks as a percentage of the annual system peak. A range of 81 percent or higher is considered indicative of a 12 CP system.

The purpose of these tests is to determine whether a utility plans and operates its system to meet its peak demands throughout the year or to meet pronounced peaks during one, three, or four consecutive months. Where the peak ratio tests demonstrate that a utility's system demand curve is relatively flat throughout the year, utilities are to use a 12 CP allocation methodology.

Q63. Have you performed the above referenced peak ratio tests?

A63. Yes. The results of the various peak ratio tests for ML&P using 2015 data are provided in the following table:

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	Table 3 Calculation of FERC Test for 2015 Actual Loads		
	Analysis	2015 Actual	
A	Average 11 Off-Peak Months (kW)	157,444	
B	Max Peak (kW)	169,070	
C	Lowest Peak (kW)	145,880	
D	Average peak (kW)	158,413	
	FERC Tests	2015 %	FERC Condition to Meet 12 CP
	Test 1: 1-(A)/(B)	7%	< 19%
	Test 2: (C)/(B)	86%	> 66%
	Test 3: (D)/(B)	94%	> 81%

Q64. Given the results in the three different FERC tests, what are your conclusions about the appropriate demand allocator?

A64. Each of FERC's three tests for the use of 12 CP is met. I consider this as unambiguous evidence that the 12 CP allocator is appropriate, at least in FERC's view. This, along with the other factors previously discussed, provide strong support for the use of the 12 CP approach.

V. COST OF SERVICE RESULTS

Q65. What were the results of the cost of service study?

A65. The resulting percentage difference between present rate revenues and COSS rate revenues using the peak responsibility (12 CP) methodology is presented in Table 4 and the average and excess methodology is presented in Table 5 below. For illustrative purposes, the results are also provided using a 100 percent demand approach for generation classification with a 12 CP allocator in Table 6, below. Note that in each case the results are presented before and after the rate stabilization credit.

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Table 4
Summary of COSS Results
Load Factor Method

	Total	Residential	Small Gen. 21	Large Gen. Sec. 22	Large Gen. Prim. 23	Partial Req at Prim. 770	Interr. Rate 27	Street/ Area Light.	AWWU 25
Before Rate Stabilization									
Revenue to Cost Ratio at Current Rates	70.3%	73.5%	75.5%	71.2%	74.9%	53.5%	25.5%	74.5%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	104.5%	107.4%	101.2%	106.5%	76.0%	36.2%	106.0%	141.4%
% Increase Retail Rates to Equal Allocated Cost	42.2%	36.1%	32.4%	40.5%	33.5%	87.0%	292.2%	34.1%	0.6%
After Rate Stabilization									
Revenue to Cost Ratio at Current Rates	77.9%	79.2%	82.6%	79.1%	83.9%	61.4%	26.8%	76.6%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	101.7%	106.1%	101.6%	107.7%	78.8%	34.4%	98.3%	127.7%
% Increase Retail Rates to Equal Allocated Cost	28.4%	26.2%	21.0%	26.4%	19.2%	62.9%	273.8%	30.6%	0.6%

Table 5
Summary of COSS Results
Average & Excess Method

Forecast Year: 2015	Total	Residential	Small Gen. 21	Large Gen. Sec. 22	Large Gen. Prim. 23	Partial Req at Prim. 770	Interr. Rate 27	Street/ Area Light.	AWWU 25
Before Rate Stabilization									
Revenue to Cost Ratio at Current Rates	70.3%	63.9%	76.6%	73.6%	84.8%	53.9%	12.3%	65.9%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	90.8%	108.9%	104.6%	120.5%	76.6%	17.5%	93.6%	141.4%
% Increase Retail Rates to Equal Allocated Cost	42.2%	56.5%	30.5%	35.8%	18.0%	85.7%	711.0%	51.8%	0.6%
After Rate Stabilization									
Revenue to Cost Ratio at Current Rates	77.9%	69.5%	83.8%	81.8%	94.4%	61.9%	13.6%	68.6%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	89.3%	107.6%	105.0%	121.2%	79.4%	17.5%	88.1%	127.7%
% Increase Retail Rates to Equal Allocated Cost	28.4%	43.9%	19.4%	22.3%	6.0%	61.6%	634.1%	45.8%	0.6%

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Table 6
Summary of COSS Results
100% Demand Classification Method

Forecast Year: 2015	Total	Residential	Small Gen. 21	Large Gen. Sec. 22	Large Gen. Prim. 23	Partial Req at Prim. 770	Interr. Rate 27	Street/ Area Light.	AWWU 25
Before Rate Stabilization									
Revenue to Cost Ratio at Current Rates	70.3%	79.8%	76.0%	69.3%	79.4%	52.0%	36.8%	78.0%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	113.5%	108.0%	98.4%	112.9%	73.9%	52.3%	110.9%	141.4%
% Increase Retail Rates to Equal Allocated Cost	42.2%	25.3%	31.6%	44.4%	25.9%	92.5%	171.7%	28.2%	0.6%
After Rate Stabilization									
Revenue to Cost Ratio at Current Rates	77.9%	85.4%	83.1%	77.1%	88.7%	59.7%	36.8%	79.6%	99.5%
Revenue to Cost Ratio After Across-the-Board	100.0%	109.7%	106.7%	99.0%	113.9%	76.7%	47.3%	102.3%	127.7%
% Increase Retail Rates to Equal Allocated Cost	28.4%	17.1%	20.3%	29.7%	12.8%	67.5%	171.7%	25.6%	0.6%

VI. RATE ADJUSTMENTS AND RATE DESIGN

Q66. Are you proposing any rate increases?

A66. Yes, the required rate increase for the utility as a whole is 42.2 percent before the rate stabilization credit and 28.4 percent after the rate stabilization credit. Note that these percent increases are calculated in comparison to the entire retail rate revenue (demand, energy, and customer charges), excluding the annualized COPA revenue. This differs slightly from the percentages shown in Schedule 1 of the Revenue Requirement Study because those numbers were calculated in comparison to retail revenue from demand and energy charges only, excluding the customer charge revenues. For completeness, I have developed proposed rates before and after rate stabilization, although I recommend that the rate stabilization credit be approved and used for setting rate. There are two methods

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to achieve an overall average rate increase of 28.4 percent. The first is to implement cost of service rates. The second is to apply a flat rate increase to all customer classes (i.e., across-the-board). The past several rate increases have been applied using the across-the-board approach as the revenue to cost ratios from the COSS fell within a range of reasonableness. Because several classes fall outside of the range of reasonableness using the 2015 COSS, I believe the time has come to implement rates based on the COSS. I propose that the rates reflect the unit costs within the COSS using the load factor method.

Q67. Please provide the unit cost results from the COSS that are proposed to be used for rate design.

A67. Table 7 presents the per unit costs resulting from the 2015 COSS using the load factor method for generation classification. These results are the basis for the proposed rate design for the various customer classes. For comparison purposes, the current components of each rate schedule are also shown below.

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Table 7

Summary of Unit Costs
Load Factor Method

	Residential	Small Gen. 21	Large Gen. Sec. 22	Large General. Prim. 23	Partial Req at Prim. 770	Interruptible Rate 27
Customer Charge						
Current Rate	$6.56	$12.88	$44.15	$159.55	$159.55	$44.15
Unit Cost - $/Cust. Month	$13.76	$30.96	$93.93	$638.28	$689.81	$93.93
% Difference	109.7%	140.3%	112.8%	300.0%	332.4%	112.8%
Demand Charge						
Current Rate			$16.96	$19.07	$6.87	
Before Rate Stabilization						
Unit Cost - $/kW Billed			$25.26	$23.67	$16.29	
% Difference			48.9%	24.1%	137.1%	
After Rate Stabilization						
Unit Cost - $/kW Billed			$23.63	$22.03	$14.50	
% Difference			39.4%	15.5%	111.1%	
Energy Charge						
Current Rate	$0.10734	$0.10314	$0.04829	$0.04548	$0.03517	$0.04829
Before Rate Stabilization						
Unit Cost -$/kWh (excluding demand costs)			$0.06385	$0.06256	$0.06256	
(including demand costs)	$0.13517	$0.12664				$0.19039
% Difference	25.9%	22.8%	32.2%	37.5%	77.9%	294.3%
After Rate Stabilization						
Unit Cost -$/kWh (excluding demand costs)			$0.05485	$0.05374	$0.05374	
(including demand costs)	$0.12316	$0.11382				$0.18139
% Difference	14.7%	10.4%	13.6%	18.2%	52.8%	275.6%

Note that Street and Area Lighting and Rate 25 AWWU do not have the same rate components as the other classes. These rates should increase based on the percent increase required for the class overall.

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Q68. Please provide the unit cost results from the COSS for the other two methods used.

A68. For illustrative purposes, we have also provided the unit cost results for the average and excess method and the 100 percent demand classification approach in Tables 8 and 9.

Table 8
Summary of Unit Costs
Average and Excess Method

Forecast Year: 2015	Residential	Small Gen. 21	Large Gen. Sec. 22	Large General. Prim. 23	Partial Req at Prim. 770	Interruptible Rate 27
Customer Charge						
Current Rate	$6.56	$12.88	$44.15	$159.55	$159.55	$44.15
Unit Cost - $/Cust. Month	$13.76	$30.96	$93.93	$638.28	$689.81	$93.93
% Difference	109.7%	140.3%	112.8%	300.0%	332.4%	112.8%
Demand Charge						
Current Rate			$16.96	$19.07	$6.87	
Before Rate Stabilization						
Unit Cost - $/kW Billed			$46.75	$45.26	$41.75	
% Difference			175.7%	137.4%	507.7%	
After Rate Stabilization						
Unit Cost - $/kW Billed			$41.81	$40.29	$36.06	
% Difference			146.5%	111.3%	424.8%	
Total Unit Costs - Energy Charge						
Current Rate	$0.10734	$0.10314	$0.04829	$0.04548	$0.03517	$0.04829
Before Rate Stabilization Unit Cost -$/kWh (excluding demand costs)			$0.00498	$0.00488	$0.00488	
(including demand costs)	$0.16010	$0.12448				$0.39490
% Difference	49.2%	20.7%	-89.7%	-89.3%	-86.1%	717.8%
After Rate Stabilization Unit Cost -$/kWh (excluding demand costs)			$0.00498	$0.00488	$0.00488	
(including demand costs)	$0.14467	$0.11198				$0.35736
% Difference	34.8%	8.6%	-89.7%	-89.3%	-86.1%	640.0%

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Table 9
Summary of Unit Costs
100% Demand Classification Method

Forecast Year: 2015	Residential	Small Gen. 21	Large Gen. Sec. 22	Large General. Prim. 23	Partial Req at Prim. 770	Interruptible Rate 27
Customer Charge						
Current Rate	$6.56	$12.88	$44.15	$159.55	$159.55	$44.15
Unit Cost - $/Cust. Month	$13.76	$30.96	$93.93	$638.28	$689.81	$93.93
% Difference	109.7%	140.3%	112.8%	300.0%	332.4%	112.8%
Demand Charge						
Current Rate			$16.96	$19.07	$6.87	
Before Rate Stabilization						
Unit Cost - $/kW Billed			$49.88	$48.57	$43.36	
% Difference			194.1%	154.7%	531.2%	
After Rate Stabilization						
Unit Cost - $/kW Billed			$44.49	$43.12	$37.44	
% Difference			162.3%	126.1%	445.0%	
Energy Charge						
Current Rate	$0.10734	$0.10314	$0.04829	$0.04548	$0.03517	$0.04829
Before Rate Stabilization						
Unit Cost -$/kWh (excluding demand costs)			$0.00498	$0.00488	$0.00488	
(including demand costs)	$0.12200	$0.12572				$0.13152
% Difference	13.7%	21.9%	-89.7%	-89.3%	-86.1%	172.4%
After Rate Stabilization						
Unit Cost -$/kWh (excluding demand costs)			$0.00498	$0.00488	$0.00488	
(including demand costs)	$0.11200	$0.11304				$0.13152
% Difference	4.3%	9.6%	-89.7%	-89.3%	-86.1%	172.4%

Given the results from the two alternative methods shown in Tables 8 and 9, these two approaches do not result in unit costs that are reasonable for those classes with demand charges. In both cases, the demand charges would need to increase to unacceptable levels

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and the energy charges would need to decrease considerably. This further supports our conclusions that the load factor method is the most appropriate approach for ML&P.

Q69. Please summarize the RCA's relevant requirements for electric rate design.

A69. The RCA's requirements are set forth in 3 AAC 48.550. First, the customer charge may recover only those customer costs defined in 3 AAC 48.540(f)(1)(A) and (B). Second, the RCA requires electric utilities to use "flat rates" as the standard rate form. Third, three-part rates (customer charge, demand charge, and energy charge) are required for customers with a maximum demand of at least 20 kW per month for three consecutive months. For customers that do not satisfy those conditions, demand costs are recoverable through the energy charge instead of through the demand charge.

Q70. Does ML&P's current rate design satisfy those requirements?

A70. Yes, it does. For decades, ML&P has employed "flat rates" and imposed demand charges on large commercial customers having a demand of at least 20 kW. For residential and small commercial customers, ML&P's rate design recovers demand costs through the energy charge.

Q71. Do you recommend that ML&P change to a different type of rate design?

A71. No, I do not. ML&P's "flat rate" rate design complies with RCA requirements and fairly recovers costs from ML&P's customers in accordance with the RCA's rate objectives.

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Q72. Do you recommend that ML&P implement rates that equal the unit costs found in the COSS?

A72. Yes, I do. The results of the COSS show that the customer charge, energy charge and demand charge (where appropriate) all need to increase to reflect the COSS results and meet the overall revenue deficiency. ML&P requested approval from the Assembly to increase the demand and energy charges only, which would require that customer charges be kept at current levels. Therefore, the proposed rates reflect no change in the customer charge, the unit cost per kW-month from the COSS as the demand charge. The energy rate is then set at a level that allows for full recovery of the allocated costs for each customer class.

Q73. Based on your experience, do ML&P's proposed rates meet the criteria set forth by the Commission of rates being fair, just and reasonable?

A73. Yes. ML&P developed a COSS using generally accepted methodologies. Rates that are based on the COSS are therefore fair, just and reasonable. In addition, ML&P's current "flat rate" rate design meets the RCA's requirements and provides a fair and reasonable recovery of costs within ML&P's rate classes. Monthly bill comparisons for customers at various usage levels have been provided in an Appendix to the COSS, which can be found in Exhibit 10 to ML&P's TA357-121 filing.

Q74. Does this conclude your testimony?

A74. Yes, it does.

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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:		Robert M. Pickett, Chairman Stephen McAlpine Rebecca L. Pauli Norman Rokeberg Janis W. Wilson
In the Matter of the Request Filed by the MUNICIPALITY OF ANCHORAGE d/b/a MUNICIPAL LIGHT & POWER DEPARTMENT for Approval to Establish Depreciation Rates	)	U-16-094
In the Matter of the Tariff Revision Designated as TA357-121 Filed by the MUNICIPALITY OF ANCHORAGE d/b/a MUNICIPAL LIGHT & POWER DEPARTMENT	)	U-17-008

EXPERT DISCLOSURES FOR GARY S. SALEBA

1. Statement of all opinions to be expressed and the basis and reasons therefor.

I express the following opinions in the Prefiled Direct Testimony of Gary S. Saleba ("Saleba Direct"), dated December 30, 2016:

In determining to proceed with Plant 2A, the Municipality of Anchorage d/b/a Municipal Light & Power ("ML&P") went through an evaluation process that was in keeping with generally accepted utility practice. ML&P has studied the addition of generation units for over 10 years with numerous studies and analyses. Initially, ML&P evaluated the need based on an Integrated Resource Plan ("IRP") methodology examining the general size of units needed. Lastly, a Generation Study was performed to fine-tune the size and type of units to pursue. The process used to determine that Plant 2A was needed was very thoughtful and conservative and is detailed in Saleba Direct at pages 3 to 19.

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As explained in Saleba Direct at page 19, I support the methodology proposed by ML&P to recover the cost of Plant 2A through a rate stabilization fund. The methodology reduces the initial impact to customers, while shaping the costs to reflect benefits to future customers. Customers benefit more in the future from Plant 2A because the savings in gas costs will be greater as gas prices increase. In addition, generating equipment is depreciated over time resulting in a lower dollar return in rates on the older the equipment. Delaying some capital costs recovery therefore evens out the recovery collected from customers.

It is my opinion that the results of the Cost of Service Study ("COSS") prepared on behalf of ML&P is an appropriate tool in considering whether various customer classes are paying more or less than their share of costs. The results can be used in determining whether any classes should receive an above average or below average rate increase. Furthermore, the unit costs determined in the COSS are useful in determining the actual rate components for each customer class.

The past several rate increases have been applied using the across-the-board approach as the revenue to cost ratios from the COSS fell within a range of reasonableness. Because several classes fall outside of the range of reasonableness using the 2015 COSS, I believe the time has come to implement rates based on the COSS. I propose that the rates reflect the unit costs within the COSS using the load factor method.

ML&P's "flat rate" rate design complies with RCA requirements and fairly recovers costs from ML&P's customers in accordance with the RCA's rate objectives. The results of the COSS show that the customer charge, energy charge and demand charge (where appropriate) all need to increase to reflect the COSS results and meet the overall revenue

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deficiency. ML&P requested approval from the Assembly to increase the demand and energy charges only, which would require that customer charges be kept at current levels. Therefore, the proposed rates reflect no change in the customer charge, the unit cost per kW-month from the COSS as the demand charge. The energy rate is then set at a level that allows for full recovery of the allocated costs for each customer class.

Pages 19 to 49 of Saleba Direct describes and supports the approach used in developing the COSS and explains why the approach proposed by ML&P is both valid and appropriate for use in developing interclass revenue and rate design.

2. ***Data or other information considered in forming the opinions.***

I considered the following documents:

- ML&P Triennial EOR Reports for 2003, 2006, 2009, 2012, and 2015;
- ML&P Integrate Resource Plans (IRPs) for 2002, 2004, 2006, and 2009;
- ML&P 2012 Generation Study;
- 2003 Railbelt Energy Study;
- ML&P 2015 Revenue Requirement Study; and
- All other data and information referred to in my prefiled direct testimony.

3. ***Exhibits to be used as a summary of or support for the opinions.***

I support my testimony with the following exhibits:

- Exhibit 10, MLP COSS Report 2016;
- Exhibit 15, MLP IRP 2009; and

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- Exhibit RSS Disclosure-1, Resume of Gary S. Saleba (Attached).

4. ***Qualifications of the witness, including a list of all publications authored by the witness within the preceding ten years.***

Please see the attached resume of Gary S. Saleba, attached as Exhibit RSS Disclosure-1.

5. ***Compensation to be paid for the testimony.***

I have been retained by ML&P to provide testimony as well as to respond to data requests and as needed prepare rebuttal testimony and appear at bearing. EES Consulting is being compensated at our standard rates in this proceeding:

Gary Saleba	\$190/hour
Senior Associate	\$180/hour

6. ***Listing of any other cases in which the witness has testified as an expert at trial or by deposition within the preceding four years.***

- Prefiled Direct Testimony of Gary S. Saleba on Behalf of Microsoft Corporation, *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Docket UE-161123, October 12, 2016.

Regulatory Commission of Alaska Dockets:

- Prefiled Direct and Reply Testimony of Gary S. Saleba
  Docket No. U-15-097
  November 16, 2015 and February 16, 2016; and

- Prefiled Direct Testimony of Gary S. Saleba
  Docket No. U-13-184
  September 9, 2013.

DATED this 7th day of April 2017.

By: /s/ Gary S. Saleba
Gary S. Saleba

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CERTIFICATE OF SERVICE

I hereby certify that on April 7, 2017, a copy of the foregoing document was served on the following persons by electronic means authorized by the RCA.

KEMPPEL, HUFFMAN AND ELLIS, P.C.
By: /s/ Tina M. Torrey
Tina M. Torrey, Legal Assistant

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PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GARY S. SALEBA

EDUCATION

MBA, Finance
Butler University
Indianapolis, Indiana

BA, Economics and Mathematics
Franklin College
Franklin, Indiana

EMPLOYMENT

October 1978 to Present	EES Consulting, Inc. 570 Kirkland Way, Suite 100 Kirkland, Washington 98033 Registered Professional Engineering and Management Consulting Firm
Position:	Principal/Owner
Responsibilities:	Overall supervision for all of EES Consulting's electric, water, wastewater and natural gas engagements in the areas of strategic planning, financial analysis, cost of service, valuations, mergers and acquisitions, rate design, engineering, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning and overall utility operations. Overall responsibility for firm's quality assurance/quality control.
Activities:	Numerous testimony presentations before regulatory bodies on utility economics, strategic planning, finance, utility operations and requests for proposals. Supervised several integrated resource planning studies, average embedded and marginal cost of service studies, RFPs, technical assessments and financial planning studies for electric, water, gas and wastewater utility clients. Participated in comprehensive resource acquisition, strategic planning and demand side management analyses. Developed and verified interclass usage data. Conceptualized and implemented compliance programs for the Public Utility Regulatory Policies Act and the Energy Policy Act of 1992. Contract negotiation and energy conservation assessments. Presentation of management audit, forecasting, cost of service, integrated resource planning, financial management, and rate design seminars for the American Public Power Association, Electricity Distributors Association of Ontario,

American Water Works Association, and Northwest Public Power Association. Past Board member of Northwest Public Power Association and ENERconnect, Ltd. Past Chairman of Financial Management Committee and Management Division of the American Water Works Association. Project manager for construction of 248 MW gas turbine, and acquisition of over $1 billion of utility service territory and equipment. Supervised engineer's report for over $5 billion in revenue bonds.

October 1977 to October 1978	National Management Consulting Firm
Position:	Supervising Economist
Responsibilities:	Analyzed various energy related topics to determine economic impacts. Reviewed utility financial activities.
Activities:	Participated in several utility rate/financial regulatory proceedings. Provided clients with critique of issues, position papers and expert testimony on the topics of cost of service, rate design, utility finance, automatic adjustment factors, sales perspectives and class load characteristics. Conceptualized load forecasting models and assisted in economic and environmental impact analyses.
June 1972 to October 1977	Indianapolis Power & Light Company P.O. Box 1595 B Indianapolis, Indiana 46206 Investor-owned Utility
Position:	Economist, Department of Rates and Regulatory Affairs
Responsibilities:	Provided general economic and rate expertise in Rates, Regulatory Affairs, Customer Service and Engineering Design Departments.
Activities:	Calculated retail and wholesale electric and steam class revenue requirements and rates. Prepared expert testimony and exhibits for state and federal agencies regarding rate design theory, application of rates and revenues generated from rates. Determined long range revenue and peak demand projections. Supervised comprehensive load research program. Supported thermal plant Environmental Impact Statements. Provided industrial liaison.

PARTIAL LIST OF CLIENTS FOR WHOM FINANCIAL, OPERATIONAL AND STRATEGIC PLANNING PROJECTS HAVE BEEN DIRECTED BY GARY S. SALEBA

UNITED STATES OF AMERICA

<u>Alabama</u>

City of Birmingham Water and Wastewater

<u>Alaska</u>

City of Barrow
City of Wrangell
*Alaska Public Service Commission
*Municipal Light and Power
Alaska Village Electric Cooperative

<u>Arizona</u>

*Tucson Electric Power
City of Dodge
City of Page
Navopache Electric Cooperative

<u>Arkansas</u>

City of North Little Rock

<u>California</u>

City of Indian Wells
City of Palm Desert
City of Moreno Valley
*City of Corona
City of Redding
*Sacramento Municipal Utilities Board
City of Burbank
*State of California - Department of Water Resources
*Turlock Irrigation District
*City of Palo Alto
City of Anaheim
El Dorado Irrigation District
City of Glendale
*City of Pasadena
City of Roseville
Yucalpa Valley Water District
*Los Angeles Department of Water and Power
Nor–Cal Electric Authority

California (cont'd)

Jefferson JPA
City of San Marcos
City of Cerritos
Coachella Valley Association of Governments
California Power Authority
Santa Clara Valley Water District
Los Angeles County Community Choice Aggregation
San Bernardino County Community Choice Aggregation
Riverside County Community Choice Aggregation
San Jose Clean Energy Choice Aggregation

Colorado

*CFI Steel
*Moon Lake Electric Association
City of Denver - Wastewater
*Denver Water Board

Connecticut

City of Groton

Florida

City of Pompano Beach
Florida Public Service Commission
Dade County Water and Wastewater Utilities

Idaho

Kootenai Electric
*Northern Lights
Salmon River Cooperative
Prairie Power and Light
*Department of Energy
City of Moscow
Fall River Cooperative
Lower Valley Power & Light
*Industrial Customers of Idaho Power
Clearwater Power & Light
City of Heyburn

Illinois

*City of Highland
City of Collinsville
City of Peru
City of Winnetka

Indiana

*Indianapolis Power & Light Company

Iowa

*City of Iowa City

Kentucky

*Kentucky-American Water Company

Minnesota

Polk-Burnett Electric Coop

Missouri

*General Motor, Inc.

Montana

*Beartooth Electric Cooperative
*PPL Montana
Montana Associated Cooperatives
Sun River Electric Cooperative
*Montana Power Company
Colstrip Community Center
Flathead Electric Cooperative
Glacier Electric Cooperative
Vigilante Electric Cooperative
Montana Electric Cooperative Association
Western Montana G&T
*Northwestern Energy, Inc.
Yellowstone Valley Electric Cooperative

North Dakota

City of Watford City
Garrison Diversion Conservancy District

Oregon

*Emerald PUD
Clackamas Water District
Central Lincoln PUD
*Springfield Utility Board
Tri-Cities Service District
City of Portland

Oregon (cont'd)

City of Gladstone
City of West Linn
City of Oregon City
*Public Power Council
Central Electric Cooperative
Warm Springs Energy Cooperative
Northern Wasco PUD
West Oregon Cooperative

South Dakota

Black Hills Electric Cooperative

Texas

City of League City
City of Brownsville
*City of Lubbock
Pedernales Electric Cooperative
City of San Antonio
*Texas Municipal Power Agency

Utah

*Moon Lake Electric Association
Utah Association of Municipal Power Systems

Washington

*Western Public Agencies Group
TrendWest Resorts
Weyerhaeuser Corporation
Costco
*Pend Oreille County PUD
City of Richland
Industrial Customers of Grant County
*Benton REA
Seattle City Light
*Clark Public Utilities
City of Blaine
*Snohomish County PUD
*City of Port Angeles
*Clallam County PUD
Chelan County PUD
*City of Tacoma Electric, Water and Rail Utilities
*Mason County PUD No. 3
*Peninsula Light Company
Washington Utilities and Transportation Commission
*Grays Harbor County PUD

Washington (cont'd)

*Pacific County PUD
City of Gig Harbor
Ferry County PUD
*City of Ellensburg
City of Redmond
Grant County PUD
*Klickitat County PUD
Cascade Natural Gas
City of Kennewick
Daishowa Corporation
Seattle Water Department
*Building Management Owners Association
City of Bellingham
*US Ecology, Inc.
*Avista Corporation
*Cowlitz County PUD
*City of Cheney
*City of Yakima
City of Bellevue
City of Shoreline
*Douglas County PUD
AT&T
WorldCom
City of Toppenish
City of Shoreline

Wisconsin

*Wisconsin Manufacturing Association
Polk-Burnett Cooperative

Wyoming

*Lower Valley Power and Light

CANADA

Alberta

*University of Alberta
*City of Lethbridge
*City of Red Deer
City of Medicine Hat
Ocelot Chemicals
Aqualta
City of Calgary—Water and Wastewater Utilities

British Columbia

*Fortis, BC
Alcan, Ltd.
*Princeton Power & Light
*West Kootenay Power
*Ministry of Fisheries
Crows Nest Resources
Highland Valley Cooperative
*Council of Forest Industries
Crestbrook Industries
Royal Oak Mines
UtiliCorp Canada
*Joint Industrial Electric Steering Committee
*British Columbia Transmission Corporation
*Terasen Gas

Manitoba

*Manitoba Legal Aid

Northwest Territories

*Northwest Territories Power Corporation

Ontario

ENERconnect, Inc.
Ontario Hydro
*Municipal Electric Association
North York Hydro
Toronto Hydro
*Ottawa Hydro
Electricity Distributors Association
*Ontario Energy Board
*Association of Major Power Companies (AMPCO)

OTHERS

American Public Power Association
American Water Works Association
California Municipal Utilities Association
Northwest Public Power Association

*Prepared Expert Testimony