Plant 2 Expansion Project
Generation Options Economic Analysis

Prepared for

Anchorage Municipal Light & Power
821 E 1st Avenue
Anchorage, Alaska 99501

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Prepared by

Sacramento, CA
Portland, OR

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Regulatory Commission of Alaska
U-16-094 By: (w) U-17-008
Northern Lights Realtime & Reporting, Inc.
(907) 337-2221

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Summary

In order to determine the best economical course of action for the replacement of ML&P's aging electrical generation fleet, IEC evaluated a combination of nine (9) different generation asset configurations to meet the wide range of peak and off-peak loads. Since ML&P's electrical loads vary seasonally and daily, the generation requirements were separated into six load category levels to reasonably model the range of loads in a simplified manner. The generation asset configurations were then arranged at specific generation levels to represent a typical dispatch scenario for each of the load categories. Using the heat rate (efficiency) data for each of the turbines, IEC derived annual fuel costs for each option. These fuel costs were then combined with the capital costs of the particular generation option to portray an annual total cost of energy relative to the other evaluated options.

While the technical calculations showed that using a 116 MW 2X1 combined cycle plant at the Plant 2 location with no other additional generation (CASE 7) was the least (levelized) cost approach, that option would require that ML&P divest itself of the Southcentral Power Project (SPP), or at least recover its cost through long term power sales. If SPP is assumed to be a permanent part of the power generation mix, then the next least cost approach is using SPP with a 116 MW 2x1 Combined Cycle and no other new generation (CASE 4).

The goal of this analysis was to evaluate the generation asset options relative to each other, therefore IEC used simplifying assumptions to eliminate factors that would not change the outcome and would require significant modeling to develop. Due to the simplifying assumptions used in this analysis, this report should only be used as a tool to evaluate the generation options relative to each other and not as a representative picture of total generation costs or dispatch strategy.

Background

The ML&P Board issued Resolution 2009-04 on September 23, 2009, based on the 2009 Integrated Resource Plan (IRP), authorizing the beginning of a generation replacement program. This was prompted by the fact that most of ML&P's generation fleet had exceeded its 30-year design life and was notably inefficient compared to today's turbine technology. The IRP recommended the installation of a new 58 MW 1X1 GE LM6000 combined cycle plant at Plant 2 and a new 30 MW GE LM2500+ peaker unit at Plant 1 (CASE 2).

After additional detailed analysis of construction costs for several other possible generation scenarios, including a 2X1 combined cycle at Plant 2 and a GE LM6000 peaker at Plant 1 (CASE 6), it was evident that other scenarios may be even more economical in the long term than the initial IRP suggestion, if an additional level of detail was analyzed. This additional detail would include site-specific plot plan development, turnkey cost estimates, and heat rate (BTU/kWh) curve modeling. In addition to this further level of scrutiny, ML&P may find it necessary, or at least advantageous, to supply a level of firm power sales to neighboring utilities as part of a long term power purchase agreement. How this would affect the IRP recommendation is in question and will be evaluated. This report is the culmination of this analysis effort and can be used as a technical and economic resource in determining the final generation asset replacement strategy.

Assumptions

Due to the unlimited possible generation scenarios, operational strategies, and operational costs, an effort was made to focus this analysis on the goal of choosing the best generation asset mix to reliably support ML&P's electrical generation needs in a cost effective way for years to come. The potential new replacement generation asset options are analyzed <u>relative</u> to each other, which allows for many simplifying assumptions to eliminate factors that would be difficult to analyze and would not noticeably affect the outcome of the study. For example, if a particular cost factor would be relatively the same between all options, it was eliminated. Because of these simplifying assumptions, <u>this report should only be used to compare the generation options against each other and should not be used for any other purpose.</u> It is not intended to be used as a dispatch strategy model, a representation of the inclusive cost of energy, or even an authoritative analysis of the efficiency of various turbines.

Listed below is a series of assumptions IEC developed to reasonably frame the discussion of generation options:

1. The 2009 IRP firmly established the need for the replacement generation and this question is not discussed in this report.
2. The capital cost of any existing ML&P generation is constant across the options and is eliminated from the comparative evaluation.
3. The gas turbines used for this analysis are the GE LM6000PF and GE LM2500+, due to their popularity in the U.S. electrical generation industry. Also, the SPP project uses the GE LM6000PF gas turbine.
4. The maintenance cost of the GE fleet of aeroderivative turbines is similar (on aMWh basis) between models and is primarily in direct proportion to the run hours of the

particular turbine. As such, it is considered a constant between options and is not included in the evaluated costs.

5. Operator costs would be relatively constant at Plant 1 and Plant 2 and are not considered. Plant 1 operates primarily as a peaker facility and Plant 2 is manned 24/7 for combined cycle operation. Nothing in this analysis would significantly change this fact.
6. The bond/commercial paper interest rate assumed is 6%. Capital cost financing is for 30 years and is evaluated on a levelized cost basis.
7. Inflation is modeled at 3%.
8. ML&P's discount rate (minimum rate of return) is modeled at 6%.
9. Heat rates for the GE LM6000PF turbines was taken from GE's performance models (Lower Heating Value-LHV), converted to Higher Heating Value (HHV) by multiplying by a factor of 1.11 (industry standard factor), and adjusted by IEC's estimate of parasitic plant electrical loads for each option. Parasitic loads diminished with part load operation, due to the assumed use of VFD drives on major equipment and reduced gas compression.
10. The steam turbine generator output for combined cycle operations was modeled by entering GE's exhaust performance data into IEC's GateCycle model of the 2X1 and 1X1 combined cycle facilities to predict the generator electrical output.
11. Unit 3 (existing GE LM2500+) heat rate curve formula was provided by ML&P.
12. Unit 4 (existing Westinghouse W251) heat rate is modeled as 12,000 BTU/kWh at 37 deg F and 100% load. The heat rate is then linearly degraded to 14,000 BTU/kWh at 50% load.
13. Unit 7/6 (existing GE Frame 7E and associated steam turbine) heat rate is modeled as 10,000 BTU/kWh at 37 deg F and 100% load. The heat rate is then linearly degraded to 12,000 BTU/kWh at 50% load.

Technical Discussion

As with any utility, ML&P electrical loads vary from summer to winter, as well as over a twenty-four hour day. With these load fluctuations, ML&P's generation assets ramp up and down and are turned on in various configurations to optimize efficiency and to carry appropriate amounts of spin at all times. To more accurately model the variety of dispatch strategies throughout the year, IEC broke the ML&P annual electrical loads into six categories. First, the seasons were split between summer (May-Oct) and winter months (Nov-April) in six month blocks. This is important due to the fact that ML&P is a winter peaking utility and the generation options need to be compared at both high and low generation levels. Next, each season was broken into the subcategories of average minimum load, daily average load, and average maximum load.

In analyzing the hourly electrical load data throughout the year, IEC noted that the daily load fluctuations typically involve a lengthy period at both minimum and maximum loads linked by transitory load hours passing through the average daily generation levels. The average maximum and minimum load levels were developed by averaging the summer and winter daily minimums and maximums for the years 2008-2011. The average load level was derived by dividing the entire summer and winter MWhs by the number of hours in the seasonal period over the years 2008-2011.

Using these load categories, IEC analyzed the hourly load data from years 2010-2011 to determine what percentage of the season the load centered on these generation levels. The hours included in the summer and winter minimum, average, and maximum load levels are shown in Figure 1 below. Each season was assumed to be 4,000 hours long to allow some downtime for unit maintenance. The resulting load categories from the data analysis above are as follows:

	Required Load (MW)/ % of Operating Hours (100%=4,000 hrs)					
	Summer (May-Oct)			**Winter (Nov-Apr)**		
Ave. Min. Load	90 MW	12am-6am	25%	102 MW	12am-6am	25%
Daily Ave. Load	126 MW	6am-10am 5pm-12am	46%	139 MW	6pm-8am 8pm-12am	25%
Ave. Max. Load	161 MW	10am-5pm	29%	174 MW	8am-8pm	50%

Figure 1: Electrical Load Categories

Evaluated Generation Options

Numerous power generation options are possible with only a few choices of gas turbines and resulting configurations. Because of the aging ML&P power generation fleet, IEC developed these options assuming that most, if not all, of normal power generation would need to be produced using newer gas turbine technology coupled with hydro power. Of the existing generation, only SPP and the new Unit 3 (GE LM2500+) qualify as newer gas turbine technology. All other generation would be developed from the new power generation options.

Since there remains a possibility that the SPP ownership or power generation could be used for long term power sales, the proposed new ML&P generation was evaluated with and without SPP in the power generation mix. The resulting power generation options used for this study are listed in the following cases:

- **CASE 1:** SPP & 58 MW 1x1 Combined Cycle
- **CASE 2:** SPP & 58 MW 1x1 Combined Cycle with 30 MW Peaker
- **CASE 3:** SPP & 58 MW 1x1 Combined Cycle with 46 MW Peaker
- **CASE 4:** SPP & 116 MW 2x1 Combined Cycle
- **CASE 5:** SPP & 116 MW 2x1 Combined Cycle with 30 MW Peaker
- **CASE 6:** SPP & 116 MW 2x1 Combined Cycle with 46 MW Peaker
- **CASE 7:** 116 MW 2x1 Combined Cycle
- **CASE 8:** 116 MW 2x1 Combined Cycle with 30 MW Peaker
- **CASE 9:** 116 MW 2x1 Combined Cycle with 46 MW Peaker

Dispatch Strategy

Based on these electrical generation requirements, IEC then built a dispatch model for each generation option considered using the six subcategories listed above. In building the individual dispatch models, IEC not only considered the unit heat rate, but also unit minimum load. Each unit was not allowed to be loaded less than 50% load, with the exception of SPP, which is part of a greater 3x1 combined cycle plant scenario. The unit dispatch priority used in this analysis is as follows (from most efficient to least efficient):

1. New ML&P combined cycle plant (1x1 or 2x1 GE LM6000)
2. ML&P's portion of SPP
3. New Plant 1 Peaker Unit, if applicable (Unit 2)
4. Plant 1 Unit 3 (GE LM2500+)
5. Plant 1 Unit 4 (Westinghouse W251)

Individual full and part-load heat rates were determined as described in the *Assumptions* section of this report. The remaining ML&P generation assets were considered as backup units and did not enter into the analysis. The ML&P hydro power was arranged to best use the gas turbine generation assets, but was kept at the same generation levels for each evaluated generation option. Hydro power was capped at 452 MWhs per day. IEC used part load hydro generation levels (well under 58 MW) in the analysis to allow the hydro to be used as spin for the purposes of this analysis.

Economic Analysis

Given the simplifying assumptions listed earlier, the economic portion of the study focused on the primary cost drivers that would determine the viability of each generation option: fuel cost, and capital cost. Earlier engineering efforts developed site plans and cost estimates for each of the four potential turbine installation projects. In addition, the ML&P portion of the SPP capital cost was provided by ML&P for the purposes of this analysis. Even though the SPP facility exists, there remains a possibility of either selling ML&P's interest or selling the entire power generation output from it. With this possibility, several of the generation options do not include SPP, and, therefore, the inclusion of the SPP capital cost is necessary to compare options. The turbine installations and their associated initial cost estimates are listed below:

- Southcentral Power Project (ML&P portion) (54 MW) $101,209,744
- 1x1 GE LM6000PF Combined Cycle Facility at Plant 2 (58 MW) $142,675,774
- 2x1 GE LM6000PF Combined Cycle Facility at Plant 2 (116 MW) $226,764,728
- GE LM2500+ Peaker Facility at Plant 1 (30 MW) $46,546,549
- GE LM6000PF Peaker Facility at Plant 1 (46 MW) $63,895,771

Financing

The model assumes ML&P has a 25% equity stake (down payment) in the project and the remaining portion is financed. Interest during construction is modeled using principal amounts of 25%, 50%, and 75% of the project cost, respectively, for the three years of the project construction. Long term financing for the capital cost of each option is modeled by 30-year bonds or commercial paper amortized at an interest rate of 6%, such that the principal amount is paid off by the end of the nominal project life (30 years). The 30-year life starts at commissioning (after construction). Payments are expected to remain constant throughout the life of the financing vehicle.

Fuel Costs

Due to the complexities of predicting fluctuating natural gas prices in future years, IEC used the natural gas forecast data provided by ML&P. This forecast assumes fuel costs start at $3.73 per Million Cubic Feet (MCF) of natural gas delivered and increase over the life of the projects due to multiple factors. The following three price forecast scenarios were considered in this analysis.

1. No ASAP/Low LNG—The Alaska Stand Alone Pipeline (ASAP) is not constructed and limited Liquefied Natural Gas (LNG) is imported.
2. ASAP 250 MMCF/D—The ASAP is constructed and industrial anchors (LNG exports and mines) require 250 MMCF/Day.

3. ASAP/Mid LNG—The ASAP is constructed and a moderate amount of LNG is imported.

Many other assumptions are involved with the natural gas fuel forecast, but are not relevant to this analysis. The data for these forecasts continue through the year 2035. However, the turbines life expectancy is 30 years, so the fuel cost was increased by rate of long-term inflation (3%) from 2036 - 2045. The "ASAP/Mid LNG" case is assumed to be the most probable scenario and was used as the basis for this report. As a sensitivity check, the analysis also looked at the price of fuel with the other two forecast scenarios to see what affect it would have on the recommended solution. The result of this exercise is discussed in the *Results* section. Figure 2, below, shows the variance in price for the possible fuel options. All costs are shown in the Money of the Day (MOD).

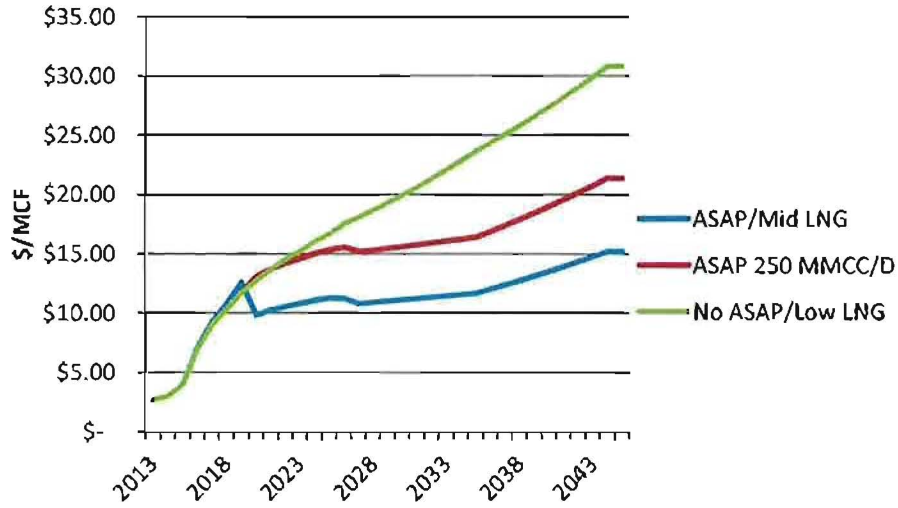

Figure 2: Annual Blended Gas Price

Using the heat rate curves developed for each turbine configuration IEC calculated the rate of fuel usage by convolving these heat rate curves with the amount of generation produced by the turbines in the six annual load categories. This fuel usage rate was then multiplied by the assumed cost of fuel to arrive at that year's fuel cost.

Levelized Cost

The fuel costs and capital investment costs of each generation option are different and the timing of the costs are different. Fuel costs will increase over time, but the financing costs will largely remain fixed—even decreasing in relative cost due to inflation over the years. Since one option will have the lower fuel costs and another option lower capital cost, inflation and ML&P's internal discount rate need to be included to accurately portray the investment comparison between these generation options. For the purposes of this study, the discount rate

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is considered to be the utility's minimum attractive rate of return. In simple terms, this means that unless a project is able to generate this minimum attractive rate of return, the utility will not invest in it. It is this "discount rate" that establishes the financial weighting between capital cost and fuel costs (or other ongoing expenses). The higher the discount rate, the more weight is placed on costs early in the project, since it is increasingly in the utility's interest to invest the funds elsewhere for the short term.

Both the fuel and capital project costs are levelized to a Levelized Energy Cost (LEC) on a dollars per MWh basis using the formula below. The formula is an industry typical calculation that usually includes maintenance cost as well, but that is not included in this analysis for the reasons discussed in the *Assumptions* section.

$$LEC = \frac{\sum_{t=1}^{30} \frac{I_t + F_t}{(1+d)^t}}{\sum_{t=1}^{30} \frac{E_t}{(1+d)^t}}$$

LEC = Levelized Energy Cost ($/MWh)
I_t= Investment Cost (capital) in year *t*
F_t= Fuel Cost in year t
E_t = Energy (MWh) produced in year *t*
t = Time in years (1-30 yrs)
d = Discount Rate (%)

Results

Based on the technical analysis described in the sections above, the least cost approach was calculated to be CASE 7 (116 MW 2x1 Combined Cycle). This assumes that ML&P sells SPP, or sells the power generated by it under long term contract in order to recoup the capital and operational cost of the project. It is possible, given the relatively low heat rate of SPP, ML&P may have enough demand for the power to generate significant power sales income from their ownership share. It is also important to note that three of the four least expensive options are options that DO NOT include SPP. These include CASE 7 listed above and adding either a 30 MW or 46 MW peaker to the 2x1 Combined Cycle (CASES 8 & 9). In these cases, only the capital cost is affected in the analysis, since the peaker units would not be used under normal circumstances. However, they would be put into use on extreme peaking winter days, or as load growth extends just beyond the normal reach of the CASE 7 capabilities (to avoid using any old generation for peaking). These new peakers would also allow one of the other new generation units to undergo a maintenance outage without using old generation for replacement energy.

Of the cases that assume the continued use of SPP generation, CASE 4 (SPP & 116 MW 2x1 Combined Cycle) is the least expensive option. This would allow the remaining older ML&P turbines to be used in a true backup role, as well as provide the option of power sales at any time, as illustrated by comparing it to CASE 7. Since the bulk of the base load power is provided by the same 2x1 turbine configuration as CASES 5, 6, 7, 8, & 9, this may leave the option of selling SPP and/or installing additional ML&P peaking assets open for a later decision while locking in the most efficient generation power block in Alaska.

The analysis results, as discussed above, produced the following ranking of the generation options, based on the levelized cost of energy approach. See *Attachment 1, Generation Options Economic Analysis* for calculation details.

Rank	Description	Levelized Cost ($/MWh)
1	**CASE 7: 116 MW 2x1 Combined Cycle**	**$70.43**
2	**CASE 8:** 116 MW 2x1 Combined Cycle & 30 MW Peaker	$74.83
3	**CASE 9:** 116 MW 2x1 Combined Cycle & 46 MW Peaker	$75.97
4	**CASE 4: SPP & 2x1 Combined Cycle**	**$78.09**
7	**CASE 1:** SPP & 1x1 Combined Cycle	$80.45
5	**CASE 5:** SPP & 2x1 Combined Cycle & 30 MW Peaker	$82.12
6	**CASE 6:** SPP & 2x1 Combined Cycle & 46 MW Peaker	$83.63
8	**CASE 2:** SPP & 1x1 Combined Cycle & 30 MW Peaker	$88.60
9	**CASE 3:** SPP & 1x1 Combined Cycle & 46 MW	$89.71

Figure 3: Power Generation Options Ranking

<u>*Fuel Price Sensitivity*</u>

As a sensitivity check, the price of fuel was adjusted based on the use of the ASAP 250 MMCF/D and No ASAP/Low LNG models to see what affect it would have on the recommended solution. While the total costs of each option varied based on the fuel price, the rankings described in Figure 3 remained the same.

Conclusions

In this analysis, CASE 7 using the 116 MW 2x1 Combined Cycle without SPP is the least cost approach from a long term levelized cost perspective. From an initial capital cost perspective, CASE 7 is also the most advantageous, reducing the initial out-of-pocket expenditures for ML&P by recovering the cost of SPP. However, if SPP is assumed to be a permanent part of the power generation mix, then the next least cost approach is using SPP with the 116 MW 2x1 Combined Cycle and no other new generation (CASE 4).

Using the 116 MW 2x1 Combined Cycle at Plant 2 as the utility's main base load generation would position ML&P with a hedge on future gas prices, along with providing the utility with multiple long term options regarding potential growth and/or power sales. It would also allow the utility to make the most of the economy of scale in building out the Plant 2 site completely from the beginning. If the additional capital financing is readily available, IEC recommends ML&P pursue the CASE 4 option and install the 116 MW 2x1 Combined Cycle at Plant 2.

Attachment 1

GENERATION OPTIONS ECONOMIC ANALYSIS

Levelized Cost Approach

GENERATION OPTIONS ECONOMIC ANALYSIS
Leveled Cost Approach

[illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

New Project Capital Cost, Output, & Heat Rate [illegible]

	Capital Costs	MW	Heat Rate at 100% Load	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Existing Generation Output & Heat Rate [illegible]

Unit	MW	Heat Rate at 100% Load	
[illegible]	30	10,124	[illegible]
[illegible]	30	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

Generation Configuration Chart [illegible]

[illegible]

Levelized Cost of Fuel ($/MWh) [illegible]

[illegible]

Levelized Capital Cost ($/MWh) [illegible]

[illegible]

Total Levelized Cost of Energy ($/MWh) [illegible]

[illegible]

NOTES:

1. [illegible]
2. [illegible]
3. [illegible]
4. [illegible]