NAVIGANT CONSULTING'S RESPONSES TO QUESTIONS FROM CHUGACH ELECTRIC ASSOCIATION ON THE PHASE 1 DRAFT REPORT ON COST SAVINGS FROM ALTERNATIVE COMBINATION OF MUNICIPAL LIGHT & POWER AND CHUGACH ELECTRIC ASSOCIATION DATED NOVEMBER 16, 2007

November 24, 2007

1. General questions

(a) Why are retail rate savings numbers for Case 5 in Table E-1 (on p. 6 of the Executive Summary) different from numbers for Case 5 in Table 10 (on p. 51 of the main Report)? Which set of numbers is correct?

Response:
The numbers on Table E-1 on page 6 of the Executive Summary for Case 5 are correct. The values for Case 5 on Table 10 on page 50 were from a prior version of the model inserted by error in the draft report preparation.

(b) What is the basis for Navigant's statement that there would be a "multiplier effect" of $30-$40 of additional economic activity for every $10 of savings in electric service costs (see, e.g., pp. 2 & 11)?

Response:
Unlike other consumer expenditures for goods and services, electric customers do not generally perceive utility bills as a discretionary expenditure, but a necessity – electricity is not a "consumable good". As a result, any reduction in costs for such a necessity results in a dollar for dollar increase in discretionary income that goes back into the economy for others goods and services. In the case of commercial and industrial customers, any reduction in costs for electric services, all other expenditures held the same, results in an increase in net income, which in turn becomes a form of discretionary income for the ultimate recipient of that net income. In that regard, consumer or business expenditures for utility services are generally more like an involuntary obligation for payment of a tax than a discretionary payment for goods and services. Keynesian economic theory, addressed in most any macro-economic text, concludes that each dollar of reduction in tax, which in turn creates a dollar of discretionary income, multiplies by a factor of 3 in the economy due to the wide spread effect of the discretionary income increase across the affected consumer and business population effected.

More directly on point, a study performed by Dr. Irwin Keller of Hofstra University (Long Island, NY) in 2003 regarding the economic benefits of a 20% utility rate cut achieved from the 1998 negotiated acquisition of the Long Island Lighting Co by the State of New York Long Island Power Authority added $2.5 billion of direct discretionary income to Long Island ratepayers in its first 5 years of existence. Dr. Keller further concluded that each dollar added to Long Island's disposable income "turns over at least five times a year" to help stimulate the local economy. Dr. Keller concluded that the $2.5 billion in 5-yr rate reductions on Long Island provided over $12 billion of expansion to the region's economy. NCI has assumed, as a general guide, a lower regional economic multiplier of 3 to 4 in the statement made in the Phase 1 report. This is the basis of the statement in the executive summary of our report that each $10 million in annual electric rate reduction is expected to result in $30 million to $40 million in local economic benefit.

(c) Please describe in greater detail the "many modifications" to the utility-supplied data that Navigant made "to place the two system requirements and costs of the two utilities' systems on a reasonably comparable basis." (p. 16).

Response:
Provided below is a list of some of the modifications to the standalone utility information which were made primarily to compute the savings associated with each of the combination cases compared with the status quo. Please note that, in general, the need for the modifications was not due to any perceived errors or unreasonableness of the two utilities' forecasts, data or assumptions, but rather to either (a) achieve consistency between assumptions for the two utilities where appropriate, (b) provide information or assumptions beyond the period where one or both of the utilities estimate future costs or performance, or (c) to avoid using directly information which one of the utilities considered confidential .

1. Calculation of Return Modifications: A Debt Service Coverage ratemaking formula (compared with the Weighted Average Cost of Capital approach currently in place for MLP or TIER/split TIER currently in place at CEA) to calculate return- changes are as follows:
    a. In Case 2 a system TIER approach with TIER assumed to be 1.5 during the new generation construction period and 1.2 thereafter.
    b. In Case 3, a Return on Ratebase approach assuming an 11% Cost of Equity for the private ownership option
    c. In Cases 4 and 5, as in Case 1, a Debt Service Coverage formula rather than either a weighted cost of capital or TIER approach was used

2. Fuel and Purchased Power:
    a. Fuel and purchased power were modified somewhat from ML&P's forecasts, based on discussions with ML&P, to reflect a moderated set of assumptions on economy energy sales from those in internal assumptions.
    b. For Chugach, MEA, HEA, and SES related purchased power costs were directly assigned to wholesale operations (and not to retail). All other purchased power costs were assigned to retail operations.
    c. Economy energy sales (and associated fuel and purchased power to meet those sales) for Chugach were eliminated, despite expected future economy sales at some level, based on discussions held with Chugach as discussed in response to a question on this topic later in this Q&A document.

3. Other Operations and Maintenance: The fixed and variable costs associated with a 260MW unit (contained in CEA's 2006 IRP) were used as other production related expenses in combination cases 1-5 and for case 7, rather than each utility installing a separate 130 MW generating plant. This also changed fuel costs from each utility's forecast due to the improved heat rate from the larger plant (by an assumed average 190 btu/kWh equivalent).

4. General and Administrative Expenses: Utility supplied levels of general and administrative expenses escalated by inflation were used in the analysis, whereas some items in this category estimated by the utilities varied by different levels annually. This change was made for consistency in assumptions between the two utilities. The section on Operating Efficiencies describes in greater detail, adjustments that were made.

5. Assessments in Lieu of Taxes and Other Governmental Payments/Fees: For each case, regardless of the ownership, NCI assumed the same levels of assessments in lieu of taxes and other governmental fees or assessments. While any such charges for different ownership would likely require changes in municipal ordinance or other legal modifications, the assumptions were applied to have revenue applicable to local governmental uses be the same in each case (or an endeavor to do so). Actual circumstances could be different.

6. Depreciation Expense: In Cases 1-5, an average (of the two utilities) depreciation accrual rate was used for the purpose of calculating depreciation expense and reserve for each of the combinations.

7. Gross-up Factor: Applicable to Combination Case 3 only, a Standard FERC and State PUC approach was used to calculate the gross up factor (on Return) for Federal and State Income Taxes. This was applicable to neither CEA nor MLP on a standalone basis.

8. Cash Balance/Working Capital Assumptions: NCI sought to have a target level of year-end cash balances for the combined utilities (Cases 1 through 4) of at least $30 million or more, which is generally higher than the combined levels of the two standalone utilities' combined historic levels. In most cases, the actual year-end cash balances in the combined cases were higher than this target level. Case 5 generally has a lower cash balance since the savings numbers in this analysis reflect only the G&T costs with no assumed changes to the respective distribution and other utility costs of the respective utilities.

9. Capital Additions: Annual capital addition assumptions had to be extrapolated after 2014 for ML&P due to the time frame over which the utility projects long-term capital improvement requirements.

2. **Acquisition pricing questions**

(a) What is the source and form of ML&P retained earnings number of $153 million?

Response

ML&P Detailed Financial Statements for December 31, 2006 provided the Total Electric Retained Earnings number of $147.742 million. Added to that number was the 2007 amount of Current Year Retained Earnings of $5.549 million. The sum of those two numbers produces $153.291 million.

Current Year Retained Earnings number of $5.549 million was derived by computing:

Return Net of Dividend Payment

(Less) Interest Expense

Where, Return Net of Dividend Payment is equal to Total Return on Rate Base (Less) MUSA Gross Receipts & Dividend Payment.

This basis results in a beginning of year 2008 retained earnings level, and upon further review, a beginning of year 2009 level should have been used, recognizing that any of the combination transactions are assumed to occur as of January 2009. Using year-end 2008 estimated values for ML&P, retained earnings are estimated at $159.6 million, which increases acquisition costs for any acquiring entity by $6.3 million more than reflected in the draft report (excluding the assumed 2% debt issuance costs). The table below shows the changes in key cost factors with this higher retained earnings value for Case 2. The result would flow through Cases 2- Chugach acquires ML&P, Case 3 – Private Entity Acquires Both Utilities and Case 4 – Government Entity Acquires Both Utilities.

ADJUSTMENT FOR HIGHER EOY 2008 ML&P RETAINED EARNINGS ($000)

		Case 2 In Report		Case 2 Corrected for ML&P 2008 EOY Retained Earnings		Difference	
	Retained Earnings for ML&P w/o Financing Costs	$ 153,291		$ 159,563		$ 6,272	
Report Appendix Page		2009	2010	2009	2010	2009	2010
2C	Interest on Long Term Debt	$ 44,796	$ 45,601	$ 45,208	$ 46,006	$ 412	$ 405
2C	Principal Payment	$ 16,215	$ 17,897	$ 16,289	$ 17,976	$ 74	$ 79
2D	Statement of Cash Flows						
2D	Ending Cash	$ 42,124	$ 37,251	$ 42,252	$ 37,396	$ 128	$ 145
2E	Long-Term Debt	$ 810,514	$ 898,619	$ 816,838	$ 904,863	$ 6,324	$ 6,244

b) What is the basis for assuming that the value of each utility's assets is equal to sum of outstanding debt + defeasance premium + capital credits/retained earnings?

(i) Was any attempt made to establish market value for assets of either utility?

<u>Response</u>:
A specific "market value" of the assets of either utility was not established in this screening analysis. As stated in meetings with the Advisory Panel and in our scope of work, a market value assessment would be undertaken after Phase 1, recognizing that, depending upon acquisition circumstances, market value estimation can be a complex (and hence expensive in consulting hours) undertaking. Our analysis used a consistent basis among all cases for screening purposes. The acquisition price method used in this screening analysis is essentially reflecting a value that is recognized in present rate base and retail rates. Any market value higher than this level would result in increasing retail rates, all else held equal. Recognizing that both Chugach and ML&P are consumer-owned, not-for-profit entities with the objective of achieving lowest possible cost of service (while maintaining satisfactory quality of service), in the instance where either utility acquires the other, or a third party governmental entity acquires both utilities, it would seem inconsistent to increase retail rates by establishing a market value higher than the outstanding debt + defeasance premium + capital credits/retained earnings, unless rates could be meaningfully reduced while still paying a higher acquisition price. A determination of purchase levels vs. resultant retail rate levels is one that presumably the two utilities, and most likely the RCA would have to make as a policy matter. We made no such assumptions regarding ability to achieve a higher purchase value in those cases where the screening analysis showed savings potential.

Theoretically, an investor-owned utility or other private party could warrant paying a higher value than the method used in this screening analysis if at such higher value the purchaser could acquire the utility, achieve rates that are acceptable to the RCA and consumers, and have a long-term expectation of recovering an acquisition price greater than the basis assumed in our analysis at an acceptable market rate of return. However, our Case 3 analysis shows that a private party purchase would significantly increase rates compared to the same acquisition price basis used in the other 3 full utility combination cases. It would seem unlikely that an acquisition with rate increases of 13% shown in the draft screening analysis (in the updated Table 10, enclosed) would be endorsed by both utilities and the RCA. It is also unlikely that a private party would purchase the two utilities at this cost and reflect significantly lower levels of return in rates to avoid having a rate increase, with the future hope of achieving improved returns from some uncertain means. For this same reason, it seems unlikely that a private party would pay a purchase price higher than the screening level basis used by NCI.

This is not to say that with a detailed accounting analysis, more detailed due diligence on future costs and cost savings potential, and consideration of alternative rate making processes, among other factors, that market value could not be higher than the acquisition value used in this screening analysis for some of the alternatives. If the two utilities elected to consider an acquisition of one another or both utilities acquired by another party, a more detailed assessment of the market value and the net effect on retail and wholesale rates would be warranted. A more detailed analysis would only be warranted for a shorter list of options.

(ii) Is there any historical market experience with this question that would help the parties to establish the market values of their respective assets?

Response:

As noted in the response above, in a regulated market, market value of utility assets are highly constrained by the levels of return that a purchaser can make and achieve retail and wholesale rates that are acceptable to consumers and regulators. In larger geographic markets where sales of electricity across utility boundaries in open competitive markets with many sellers can be achieved at open market, rather than cost-based rates, generation and, in some circumstances, transmission assets can sell at prices which are well above their cost basis. Neither ML&P or Chugach is in such geographic or regulatory situation. Sales of electricity are confined to the areas within the Railbelt, which cumulatively is smaller than most of even the smallest individual investor-owned utilities in the lower 48 states. Furthermore, there is not an open market power sales regulatory environment in the Railbelt.

A recent market example of a failed third party acquisition in a much larger market in the Pacific Northwest is instructive in this regard. Texas-Pacific Group (TPG) in 2005 sought to acquire Portland General Electric (PGE) out of the Enron bankruptcy (PGE was owned by Enron). The transaction was rather complex, but in general, regulators denied the transaction based on lack of adequate savings expected in the long-term from the acquisition due, in part, to a perceived inability of TPG as a private purchaser to be able to maintain long-term lower costs than could PGE either under Enron as a debtor in possession, or with the prospect of PGE being "spun out" of Enron as its own publicly traded company. TPG, as purchaser, was unwilling to commit to long-term rate reductions on the basis that they had determined that they could not cut costs of operations any further than assumed in their acquisition assumptions supporting their purchase offer and had no other notable source of return on its proposed investment. While PGE is not directly within an open and competitive market, it is within a larger region where power sales are fluid, and competitive markets to the south within California can be reached. However, TPG did not own other utility operations, either contiguous or anywhere in the region from which economies of scale or shared services could be achieved other than those that can be achieved through "back office" operations that do not rely upon geographic proximity.

In contrast, in 1998, when California went through deregulation, many of the generation assets of the California investor-owned utilities, most of which were highly aged and inefficient, were divested and sold at multiples of book value to private parties. Those parties, in turn, were able to sell energy into an unregulated short-term market at rates which, in 2000-2001 were at times in excess of 10 times of what prices were in 1999, a year after the assets were purchased. Litigation regarding the conditions under which such transactions for power sale were made continues today, seven years after the "boom" days of 2000-2001. Many of the owners of that generation purchased in 1998, or repurchased by others between 2001 and the present, now represent that absent obtaining some form of long-term quasi cost-based contract, they cannot justify continuing operation of their generation assets.

A third market example is the general situation in Texas. The Electric Reliability Council of Texas (ERCOT) has established an open and competitive market. Many utilities in Texas have divested themselves of much or all of their generation and private parties have acquired them and constructed their own generation in an open market. The Texas market is physically separated from the rest of the United States other than limited circumstances, such that, like Alaska, they are not regulated by the Federal Energy Regulatory Commission. However, Texas (ERCOT) is a very large and robust market. Equally importantly, Texas has been actively enhancing its transmission system for the past decade to better enable energy to be delivered from existing and new generating resources with the goal of making generation more competitive in the market and avoiding the transmission congestion that has been experienced in other open markets in the U.S. and elsewhere. This market has created sales prices for some generation at prices well above book value, and it has created a market for investment in electric transmission as well. There are varied opinions as to how successful the Texas experience has been for consumers, but it has not generally experienced some of the retail price spike problems that have been experienced in markets such as California, New York, the Northeast and elsewhere.

These are but three of many market examples. The instructive value of each of these examples is that neither ML&P nor Chugach operates in a large market with opportunities to combine with other larger utilities to achieve large economies of scale, and wholesale transactions are limited in volume and are regulated by the RCA. Unlike Texas, the Railbelt does not have a strong transmission link throughout its limited geographic extent. The limited size of the utilities within the Railbelt likely influences the ability to achieve a transmission system as robust as that which Texas has developed, but NCI has made no such assessment. The prospects for different market structures for ML&P and Chugach are not within the scope of our analysis.

The differences between the physical, customer size, and regulatory market faced by ML&P and Chugach will likely make market value relatively close to the present cost basis reflected in rates, which is the basis that NCI used for the screening analysis. More detailed analysis of the more promising cases evaluated in Phase 1 would be needed to determine whether market value would vary significantly from the acquisition cost basis used in this screening analysis. Our analysis should not be considered a market value, only a basis for a screening comparison of the alternatives.

3. **Financing questions**

(a) In light of the tentative conclusion (expressed in the K&L Gates memo attached as Appendix A to the Draft Report) that a governmental entity could not issue tax exempt bonds to finance the acquisition of the assets of Chugach (in Case 1) or Chugach and ML&P (in Cases 4 and 5) without satisfying the prerequisites for issuance of tax-exempt private activity bonds, what is the basis for the assumption that tax-exempt financing might be used in Cases 1, 4 and 5 but not Cases 2 and 3?

Response:

There is not a tentative conclusion in the K&L Gates memo attached to the report that a governmental entity could not issue tax-exempt bonds. The memorandum notes there are a number of conditions that would need to be met and the application and interpretation of those conditions requires further legal analysis, potentially requiring a federal Internal Revenue Service legal ruling on the unique facts facing the circumstances. NCI similarly notes the need for further legal analysis in the main body of the report. That additional legal analysis was not undertaken due to the cost of such an assessment. The results of the potential cost savings from the cases using tax-exempt financing can be reviewed by the utilities and the Advisory Panel to determine whether the prospect of savings is sufficient to warrant undertaking the legal analysis to confirm the ability to issue tax-exempt debt for the acquisition of Chugach electric utility property.

Tax-exempt financing was assumed only in Cases 1, 4 and 5 due to the difference between long-term ability of the acquiring entity to use tax-exempt debt for future capital improvements. The limitations on the use of tax-exempt financing for a governmental (tax-exempt) entity to use tax-exempt financing for the acquisition of a non-governmental entity's utility property apply only to the initial acquisition. Once the non-governmental utility property is acquired, the new combined entity is a tax-exempt entity, and all future capital improvements can be funded with tax-exempt debt unless there is a long-term use by non-governmental entities.

If Chugach acquired ML&P, theoretically, subject to further legal counsel review, it may be possible to apply volume cap for the acquisition debt and use tax-exempt financing. However, to obtain the same benefits of a tax-exempt entity acquiring Chugach, Chugach would need to obtain volume cap and qualify for use of tax-exempt financing for all future capital improvements as well as for the acquisition financing. As noted in the draft Phase 1 Report, there will be challenges in getting volume cap applied for tax-exempt financing for the one time acquisition by ML&P of Chugach assets. If Chugach acquired ML&P, it would be a significantly greater challenge to compete with other uses of volume cap, if it is legally possible, for all future capital improvements required for the combined utility. To put this in context, below are lists of the estimated future capital improvements that would require funding after the acquisition. The combined estimated future capital improvements after the initial acquisition in January 2009, between 2009 and 2020, is estimated to be over $1 billion.

Capital Additions - **Chugach Standalone assuming 260 MW** - Sum over the period 2009-2020 (in nominal 000s dollars)

Production	163,705
New Generation	148,393
Transmission	93,895
Distribution	146,465
General and Intangible	108
Subtotal	552,565

Capital Additions – **ML&P Standalone assuming 260 MW** - Sum over the period 2009-2020 (in nominal 000s dollars)

Production from ML&P CIP Budget [1]	60,188
Production CIP (2015-2020) [2]	40,479
New Generation ½ of a 260 MW [3]	148,393
Transmission [4]	37,155
Distribution [4]	153,621
General and Regulatory Compliance [4]	55,978
Total	495,814

[1] Capital Improvement Budget 2008-2014 provided by ML&P.
[2] Source for the Years 2015-2020 is ML&P 2006 IRP Appendix B, Option 3 (2x6B CC) Capital Maintenance Costs and excludes the costs of 260 MW unit, See Note 3 below.
[3] ½ of the cost of a 260 MW Unit COD 1/1/2012.
4] Capital Investment for 2008-2014 was supplied by ML&P from their Capital Improvement Budget. After 2014 CIP Budget for Transmission, Distribution, General Plant and Regulatory

Compliance escalated by the rate of inflation

The majority of this capital requirement would require the issuance of new debt. Therefore, if a non-governmental purchaser of ML&P (or of ML&P and Chugach combined) sought to gain the benefit of tax-exempt financing, not only would they face the same initial challenge of competing for volume cap for the initial acquisition (estimated at $336 million for Chugach acquiring ML&P, or $864 million for a private party acquiring both utilities), the new utility as a continued non tax-exempt entity would have to compete for several hundred million more in tax-exempt financing from volume cap, if such opportunity is legally possible now and continues to exist legally over the study period.

The largest single financing obligation after the acquisition would be the approximately $300 million financing required for the 260 MW combined cycle plant beginning 2009. NCI's analysis assumed that the volume cap for the initial acquisition of the utility would have to be carried over three years (2009 through 2011). To simultaneously place an additional up to $300 million over 2009 through 2012 for the new generating plant (or perhaps spread out for an additional 2 years to ease the annual impact on total volume cap, if it is legally possible to spread the volume cap contribution over so many years) was considered an extraordinary challenge. To add to that prospect, an expectation of tapping the state volume cap for several hundred million dollars more in 2012 through 2020 seemed unlikely. The potential basis for getting statewide concurrence on using a large portion of the volume cap over three years for the acquisition of Chugach by a governmental entity would be that it is a one-time use of volume cap, after which a governmental owner of the utility could issue tax-exempt debt without further reliance on sharing volume cap.

(b) Has Navigant investigated whether any portion of Alaska's volume cap has already been allocated for future years?

Response:
The investigation of volume cap availability was undertaken by counsel and ML&P's financial advisor, and this review was at a preliminary level. It is our understanding that while there may be desired multi-year applications of volume cap, there is only an annual allocation of volume cap. There clearly are many parties interested in using the volume cap for their purposes and there is no assurance that the amounts need for a utility acquisition could be obtained. The approach NCI used in modeling the debt issuance, as explained in the report is the assumption that an initial $150 million of volume cap would be released for the acquisition as a pre-condition of undertaking the acquisition. The balance of the acquisition financing would be in short-term taxable debt that would then be taken out with long-term tax-exempt debt in annual increments from available volume cap within three years. We assumed, at this preliminary stage, that the increments of volume cap would have to successfully compete with other

applications for volume cap in each of those years. Moreover, we assumed that each utility acquisition case would successfully compete, which may not be the case. The reasonableness of this assumption is one of the items that we indicated would need to be evaluated in light of the amount of estimated savings achieved from the utility acquisition.

(c) Is the assumption that the acquiring entity in Case 4 could be capitalized with 100% debt realistic?

Response:

Our experience has been that any governmental entity acquisition of utility enterprises or property is typically undertaken with 100% debt due to the lack of equity being available. Examples include:

» The 1998 $7 billion of combined new money tax-exempt debt issuance and existing debt assumption by the Long Island Power Authority when it negotiated for the purchase of the Long Island Lighting Co. A 100% debt issuance acquisition was achieved by an entity that had never operated a utility and had never issued debt, in an amount that is over 13 times the size of the acquisition financing of an ML&P acquisition of Chugach as preliminarily estimated in this report.

» On a more modest level, in the mid 1990's the City of Sante Fe, New Mexico and the City of Rio Rancho, New Mexico, in separate transactions, acquired the water and waste water utility operations serving those respective cities from private utilities using 100% debt financing in volumes in the $80 million to $115 million level.

Several smaller utility acquisitions by governmental entities have also been undertaken in the past 15 years, virtually all of which involve 100% debt financing due to the lack of any source of equity to apply. Financial markets are comfortable with such financings provided the resultant utility rates are within reason, rates are set at levels which achieve adequate reserves and debt service coverage levels and there are demonstrated means to achieve funds required to meet operations, maintenance and debt repayment for foreseeable contingencies that may be encountered.

Alaska is one of the few states that regulate governmental utilities and establish rate regulation that includes return on equity rather than using the more typical financial market criteria of debt service coverage for such entities. The issue of whether the RCA would approve, for example, in the instance of Case 4 – a governmental entity acquiring both ML&P and Chugach with 100% debt and using debt service coverage as the basis for establishing rates would have to be discussed with the RCA. The purpose of evaluating that option as part of our Phase 1 report was in response to a request by the Advisory Panel for such an evaluation. The objective of including that alternative was to determine whether such an alternative holds enough promise for meaningful savings compared to the other alternatives to warrant more detailed consideration of implementation requirements after this Phase 1 screening.

4. **<u>Operating efficiencies questions (see Table 9, p. 49 of Draft Report)</u>**

(a) "Net Staff Reductions"
(i) What explains the difference in Net Staff Reductions between:
(A) Cases 1/2/4 and Case 3? Why is Case 3 assumed to have the highest operating efficiencies?
(B) Cases 1/2/4 and Case 6?

<u>Response:</u>
(i)(A) The differences in Net Staff Reductions between Cases 1/2/4 and Case 3 is attributable almost entirely to the potential to reduce more positions in the Customer Service and Engineering functions should a private entity (utility) acquire both utilities. 27 of the additional 32 positions assumed to be reduced between Case 3 compared to Cases 1,2 and 4 would be in these functional areas. The remaining 5 positions would come from the finance and regulatory groups. The conclusion that more staff reductions would be possible in customer service and engineering functions is based upon our experience with the organization approach common to investor-owned utilities that operate with several local operating companies. Typically, in these multi-state operating company structures, some customer service functions (such as call center operations and billing operations) are centralized, resulting in higher efficiencies than could be achieved with multiple, decentralized operations. The same principal applies to certain design and technical support functions within engineering. We are not concluding, however, that all customer service and engineering functions would be centralized. Our staffing analysis still allows for some positions, that require local presence and field support will remain.

(i)(B) The differences in Net Staff Reductions between Cases 1/2/4 and Case 6 recognizes that providing a joint contracted operation of many of the day-to-day operations of both utilities to a single entity will still result in similar levels of staff reductions as the combination cases for line operations such as: customer service, engineering, generation, operations, power management, and systems and communications. The key differences are related to senior management, administration, finance, and regulatory functions. Reductions in senior management and administrative functions will be far less (net reduction of 22 vs. 8) since Chugach and ML&P will each still require some senior managers and administrative personnel to oversee their responsibilities and administer the contract(s) with the contracted entity, while the contracted entity will also require its own management and administrative team. More dramatically, we also project a net <u>increase</u> of 8 persons to allow each of the current entities to meet its financial, accounting, and budgeting operations, while adding new personnel to oversee and execute accounting and payroll functions in the contracted entity.

(ii) Please provide detailed basis for assumption relating to staff reductions and resulting estimates of cost savings appearing in Table 9 (p. 49 states this information is available). Please provide a list of employee reductions by functional area within each organization.

Response:

We have the information of assumed reductions by level for each of the functional areas noted in Appendix C. The Muncipality of Anchorage has asked that at this preliminary stage of review of the alternatives that such sensitive information not be released regarding their utility. We cannot release information about the combined utility reductions without providing information by function that would result in speculation within the management and non-management employees of both utilities as to whether their positions are among those assumed to be eliminated. We can release this information when given the approval by both utilities to do so, but we do not have that approval at this time. Presumably, if the two utilities and the Advisory Panel elect to pursue in more detail any option that involves increased labor-related operational efficiencies, then review of our assumptions regarding combined staff level reductions by function would be authorized.

(iii) Has Navigant considered the terms of the parties' existing collective bargaining agreements in its assumptions relating to personnel reductions? What percentage of anticipated labor savings are attributable to reductions in the number of employees in collective bargaining units?

Response:

NCI has considered the parties' existing collective bargaining agreements in our analysis. First, during the interview process each organization's managers were questioned as to whether there were any overriding conditions in the agreements, specifying whether staff reductions would be precluded should a change in structure occur. No such conditions were identified. Second, we verified with each utility's representatives whether an assumption of estimated implementation costs for personnel reductions of one year's base salary would be consistent with the agreements. The staffs each agreed that this is a reasonable assumption for this screening level, and that more detailed analysis could be undertaken later.

It is not possible to attribute a percentage of staff reductions to employees covered by collective bargaining agreements, since positions covered by agreements varies between the two organizations and we did not need to identify in our analysis which organization's positions would be eliminated for purposes of this screening level analysis.

(b) "Other Savings" (non-labor)
(i) What explains the difference in Other Savings between:
(A) Case 1 and Cases 2/3/4?
(B) Cases 2/3/4 and Case 6?

Response:
Differences in "Other Savings" are broken down into Contract Services and Other Non-Labor Costs in the table presented below. Contract services included certain services

Summary of Non-Utility Labor Cost Savings From Utility Combinations
(Annual $Millions Savings)

	Case 1	Case 2	Csee 3	Case 4	Case 5	Case 6	Case 7
Total Contract Services	1.66	2.725	2.725	2.725	none	2.29	n/a
Total Non-Labor Costs	0.85	0.85	0.85	0.85	none	0.7	n/a

common to both utilities such as: information systems services, purchasing costs, and accounts payable services, as well as some services that were unique to ML&P's municipal form of government, such as payments to the Mayor and Municipal Manager's offices, intergovernmental charges, and payments to emergency management. Non-labor charges include: advertising charges, office supplies, reductions in materials/inventory costs, and building expenses.

The difference between Case 1 and Cases 2/3/4 is largely attributable to the need to continue costs/payments for the Mayor, Municipal Manager, and some part of the intergovernmental payments should the combined operation remain under the Municipality of Anchorage, and an assumed discontinuation of those costs/payments in cases where other parties own ML&P. Our assessment is that these costs would also continue to be incurred, but to a slightly lesser extent, under the Case 6 analysis.

(ii) Please described the detailed basis for assumptions relating to non-labor cost savings supporting the estimates appearing in Table 9 (p. 49 states this information is available)

Response:
Each of the services/costs listed in Appendix C of the Phase 1 report was individually evaluated for elimination or reduction based upon the form of the structure (the case) being analyzed. The potential for reducing costs was specific to each type of cost, and was largely based upon the evaluator's experience with other utilities in this area. For instance, in the case of ML&P, accounts payable services are provided by MOA, while in the case of Chugach it is provided by its own staff. In the combination cases (1/2/3/4/6), this would represent a duplication of services, while in the new G&T case (5), it would not. Similarly, each of the individual services and costs were evaluated for each case. If

a detailed review of these assumptions is sought as a part of work after Phase 1, we can provide the assumptions made in more detail.

(iii) What assumptions were made in each Case relating to whether MOA would continue to provide services to the combined entity? What assumptions were made concerning size of transfer payments made to MOA for such services in each Case?

Response:
NCI assumed that the MOA would continue to provide services to ML&P and would continue to receive transfer payments from ML&P for the Mayor's Office, the Municipal Manager's Office, emergency management, and other intergovernmental services under Cases 1, 5, and 6. These services would remain, at current levels (approximately $1 million annually), except for the Case 6 reductions, noted above.

For the remainder of the services and costs in this category, we did not specify whether cost reductions attributable to the combination would come from MOA/ML&P or Chugach, or alternatively which organization would continue to provide these services to the new entity examined in the case. (In fact, it is possible that one entity or the other could potentially perform joint services for the other utility, or for a portion of the combined services. See the responses to Question 6.)

(c) Other than severance costs, what additional costs of consolidation have been taken into account in calculating savings from Operating Efficiencies?

Response:
For each of the cases additional implementation costs have been assumed as a lump sum allowance for the cumulative costs of the following:

» Due diligence costs by each utility
» Engineering due diligence/confirmation
» Legal costs for agreements, further organizational assessments, and transactions in addition to the costs of debt issuance
» Financial advisory costs in addition to that required for debt issuance
» Labor counsel costs
» Accounting/audit costs
» Legislative advisory services
» Agreement facilitation

The total of these costs for each combination case were shown as line items in an exhibit in the appendices of the model exhibits included in Appendix B and are summarized in the table below for convenience. The estimates began with detailed breakdowns by area of cost, but after further consideration of uncertainties of the different levels of support required for each of the cases, we provided gross level assumptions based on the anticipated level of difficulty and complexity of each case. As shown in the details of the exhibits in Appendix B, we assumed these implementation costs were recovered 50% each year for the first two years of operations after the combination (in other words, in 2009 and 2010 and that the costs were shared evenly between ML&P and Chugach for simplicity).

Sum of One-Time Additional Implementation Costs ($000s)

Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
6,000	6,000	6,000	8,000	5,000	2,000	2,000

It is possible that there could be additional costs to the extent that new office space was required for one or more of the options. There may be other implementation costs for combining operations for communications, control and dispatch of operating crews. There could potentially be additional costs for the creation of new benefit plans, and other factors. However, similarly, there are other many potential savings that we have not captured, including but not limited to the following:

» Line crew size optimization has not been done – we assumed no net reduction in line crews or crew size, despite the geographic proximity of the service areas
» The potential of having shared rolling stock (crew trucks, bucket trucks, cable trailers, loaders, equipment trailers etc) – we assumed no reductions here due to the assumption, for screening level purposes, of no net line crew reductions
» The potential of retiring other generation earlier due to the reduced need of capacity reserves as a combined utility has not been evaluated.
» While the generation of each utility is of similar age and efficiency, we have undertaken no combined utility generation dispatch to determine if there may be any incremental savings in fuel or generation costs beyond the combined 260 MW combined cycle project.
» The combined utility should be able to obtain net lower insurance premiums, outside accounting/audit costs, and other professional services over time, but no such estimated savings have been assumed.

On balance, we believe our net savings assumptions to be conservative, but more detailed review with the benefit of input and assumptions of each utility would be appropriate for whichever short list of alternatives are to be evaluated in subsequent phases of this effort.

5. Questions relating to Joint Contracted Operations

Please provide a detailed description of the features that constitute "Joint Contracted Operations" contemplated by Case 6. In particular:

(a) Would there be only one new contracting entity performing services for Chugach and ML&P, or multiple entities?

Response:
There could be one entity or multiple. We have not made specific assumptions regarding the form of the contracted operations at this early stage. As an example, it could be possible for one utility to assume some functions in total and the other utility assume others. By way of example only, one utility could provide all line crew operations, one could provide all generation operating and maintenance, etc. Alternatively all services capable of being contracted out could go to a single entity. Many options exist, the details of which would best be evaluated with the input of representatives of each utility if this is an option to be pursued further. Our analysis has conservatively identified savings largely where redundancies of services commonly available to be performed in a joint fashion among neighboring utilities exist. The optimum method of achieving, and perhaps enhancing, those savings will require more review.

(b) Would contracting entity(ies) operate on break-even basis (no profit, no taxable income)?

Response:
We have not assumed that contracting entities would operate on a break even basis with no profit or no taxable income. Our estimates of savings have been conservatively estimated, as explained above. As an example, when the Long Island Power Authority contracted for its electric distribution and transmission system operations, fuel purchases and procurement and related matters, for a system over 10 times the size of the combined ML&P and Chugach, the contracting party, under an incentive arrangement, is expected to generally make a net profit of $10 million to $15 million. Scaling this down to the size of operation for ML&P and Chugach, a profit in the general range of $1 million to $3 million annually would be well within top expectations. As noted earlier, we have not identified optimization opportunities in net savings from combining the utilities. Savings from such optimization in the range of $1 million to $3 million per year more than levels we have assumed from a combined operation should be readily achievable with detailed review of consolidation efforts.

As noted in the response to the prior question, it may be possible to have major portions of the combined utility functions performed by one of the two utilities such that, as consumer-owned organizations, some of these services would be provided at cost, or cost plus an incentive level tied to achieving certain levels of cost savings. For purposes of a screening level analysis, we believe our estimates of savings, as noted above, on balance are conservatively low.

(c) What functions would be moved to the new entity? What functions and costs (e.g., personnel, depreciation, financing costs) would be left in ML&P and Chugach?

Response:
See the above response – we have identified savings potential based on redundancies. The savings are in labor and various limited numbers of outside services. We assume that virtually no equipment is moved. As noted in the report, the only categories of savings are labor and limited existing outside contracted services. To get into more detail on personnel and functions assumed to be moved outside of the respective utilities would require release of the same level of sensitive information noted earlier, which the MOA has requested not be released until a determination of which alternatives would be evaluated in more detail.

(d) How would costs incurred by operating entity be allocated between ML&P and Chugach?

Response:
This level of detail has not been evaluated at the screening level. The purpose of this stage of analysis is to determine how large of a savings, conservatively estimated, might be available to compare it to other alternatives.

6. **<u>Specific questions regarding contents of model</u>**

(a) Can you supply a year-by-year comparison table showing margins, TIER and DSC for the combined entity for all Cases?

<u>Response:</u>

A Table showing Net Income, TIER and DSC for all cases is provided as "Response to 6(a).xls"

(b) Was any attempt made to model the effect on retail rates if the accumulated cash balances were levelized for all Cases?

<u>Response:</u>

NCI began preparation of a model for the standalone cases that created a rate stabilization fund that would enable levelizing accumulated cash for the base cases to then allow a comparable levelization of revenue for the combination cases. The respective utilities expressed some discomfort at using such a method since there is no precedent for that mechanism with the RCA and it made it difficult to compare to the respective utilities' own projections of cash levels and other factors.

We abandoned that effort when it became clear that in those cases where large cash balances accumulated, the net increases in costs (compared to the standalone status quo) were similar to the end balances of accumulated case. Effort could be undertaken to levelize the use of accumulated cash by using greater levels of equity for new capital, or by applying cash balances to fund operating expenses to reduce retail rates. However, any such analysis immediately creates variances between the cases that NCI believed made the comparisons less transparent. If the cases which resulted in high accumulations of cash resulted in cash balances which, at face value, appeared large enough to reverse the results from being a net revenue requirement increase to being a savings at levels that were at all close to the other cases, then some greater attention to applying the cash accumulations would have been necessary, likely requiring additional time and effort. For purposes of the screening effort, a comparison of net differences in revenue requirements and cash balances seems sufficiently transparent to compare the seven alternatives.

(c) Why doesn't equity (retained earnings) for Cases 1 and 2 seem to track the annual income statement results? For example, in Case 1, net income does not appear to be sufficient to build the equity shown in Report. And in Case 2, the schedules show equity growth while the increase in equity is shown as negative.

<u>Response:</u>

Upon further review of the different models, we made an error in how equity contributions to future capital requirements were reflected in the various exhibits in the model, which contributes to this inconsistency. We have corrected the models and have provided a revised Table 10 summary to that which is in the report, enclosed as a separate file. We will provide, under separate cover on Monday, November 26, the revised exhibit pages that were in the Appendix which support these changes. As can be seen in the revised Table 10, enclosed, Case 1 results show slightly higher savings, Cases 2 and 3 have higher losses, and Case 4 has slightly lower savings compared to the prior version after making the adjustments.

(d) Explain the assumptions and components of the Current Liabilities numbers appearing in the balance sheets in each Case.

<u>Response:</u>
The current liabilities in each case are actually a net of current liabilities and current assets and are used as a balancing between the two. Detailed assumptions for the components of current liabilities were not modeled.

(e) Total Electric Revenue numbers for Chugach standalone operations (p. 36, line 5) appear to be incorrect in all years. How (if at all) does this error affect the comparative results?

<u>Response:</u>
This line changes with the modification of the proper application of equity contributions to capital improvements within the model. The revised exhibits from the model that will be forwarded Monday will show this change and the change is reflected in the revised Table 10. It does not change the comparative results in terms of relative preference of results.

7. **Questions regarding interpretation of savings numbers**

(a) Is it accurate to say the retail rate savings from the combination of Cases 6 and 7 would simply be the sum of the numbers for Cases 6 and 7 in each row of Table 10? Can you prepare a table (similar to Tables E-1 and 10) showing Cases 6 and 7 combined into a single combined Case? Also, can you provide a line graph (similar to Figures 7 through 13) showing Cases 6 and 7 combined into a single Case?

Response:
Yes. The NPV of savings from the combination of cases 6 and 7 would be, as shown in the revised Table 10 provided in response to 6(c), the $97 million from Case 6 plus the $86 million from Case 7 resulting in a total of $183 million. The calculation of the savings from the combination of Cases 6 and 7 as well as the requested line graph are provided in the attachment "Response to 7(a) 112207.xls".

(b) Why is sum of savings resulting from actions described in Cases 6 and 7, which are actions that would presumably also result from Case 1, greater than the savings from Case 1 alone?

Response:
Case 1 assumes that MLP (as the acquirer of Chugach) will be responsible for (among other things), funding a payment of equity of Chugach members and defeasing existing Chugach debt, both of which have additional costs associated with them. Neither apply to cases 6 and 7. In particular, in Case 1, a cash payment of $159 million (with a bond issue of $162 million to provide the proceeds of $159 million) is being made to Chugach members. No acquisition of assets is made in Cases 6 and 7, and therefore this $159 million in equity payment to Chugach members is not part of the Case 6 and 7 combination, as indicated on Table 10..

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(c) If Chugach could use tax-exempt debt to acquire assets of ML&P, would savings for Case 2 exceed that for Case 1? By how much?

Response:
This scenario was not considered by NCI in its screening analysis for reasons explained in an earlier response.

(d) Can you rank, in terms of certainty of whether savings will occur, the different elements of savings shown in the report?

Response:
No effort has been made to do any probabilistic analysis of outcomes of savings. Such an analysis is premature for this screening level.

8. **<u>Partial list of necessary corrections (Note: List of simple typos will be transmitted separately)</u>**

(a) In first full on p. 22, second sentence, should "CEA" instead read "ML&P"?

Response
Yes, it should say "ML&P"

(b) In Table 4 (p. 27), should add a line for Chugach's share of Bradley Lake (as with ML&P's share of Bradley Lake listed in Table 3).

Response
Correct, it should be included.

(c) If Report discusses ML&P's economy energy sales to GVEA (as it does on p. 21), shouldn't it also discuss (on p. 20) Chugach's economy energy sales to GVEA?

Response
In discussions w/ Chugach staff in preparing the standalone cases, we were instructed not to include GVEA economy energy. It was included in ML&P's case because due to their favorable price of gas, they receive some level of net revenue from such sales which contribute more than just what a heat rate differential would otherwise contribute due to the manner in which transfer payments for gas are established by the RCA.

(d) Table 10 (p. 51) – Case 4 Average Debt/Equity Ratio: Shouldn't "100% equity" instead read "100% debt

Response:
Yes, it should say 100% debt.

9. **<u>When will Navigant produce a Phase 1 Final Report?</u>**

<u>Response:</u>
As explained in the September Advisory Panel meeting, in the interest of saving costs to both utilities, at present there is no intention in having a final Phase 1 report. Instead, the plan has been to determine which alternative combinations indicate sufficient potential savings to evaluate in more detail. A Phase 2 report would be prepared instead, based on analysis in more detail of a lesser number of alternatives.