RESPONSES TO PEER REVIEW COMMENTS ON HYDROPOWER AND RETAIL RATE RESULTS PRESENTED IN THE GLEN CANYON DAM LONG-TERM ENVIRONMENTAL AND MANAGEMENT PLAN DRAFT ENVIRONMENTAL IMPACT STATEMENT

Prepared by

Les Poch, Tom Veselka, and Ed Bodmer
Energy Systems Division, Argonne National Laboratory

March 2016

The following report addresses peer review comments pertaining to the evaluations presented in Section 4.13 and Appendix K (Hydropower Systems Technical Information and Analysis) of the Glen Canyon Dam Long-Term Experimental and Management Plan (LTEMP) Draft Environmental Impact Statement (DEIS).

REVIEWER 1

Comment: One potentially significant question goes to the uncertainty of the hydropower impacts. For example, each Alternative is represented with a single NPV of future system costs, based on a single stream of future annual costs. However, due to uncertainties in the underlying parameters (e.g., future gas prices, future loads or future regulations), each Alternative will also have a range of potential NPVs, based on a distribution of future annual costs. Long-term planning studies sometimes reveal that alternative operational scenarios and expansion paths are more or less robust (i.e., have tighter distributions of NPVs) in the face of uncertainties in markets and regulations. Something to consider. Might be too late to change the analysis, but perhaps a paragraph of text could discuss this source uncertainty and how it might affect the results.

Response: Analyzing macro-economic and electric sector regulatory uncertainties such as those in the parameters listed in the reviewer's comment were not within the scope of the analysis. We did however perform sensitivity analyses for several key modeling parameters such as alternative capacity replacements at Glen Canyon Dam, different discount rates, several capacity exceedance levels for determining Glen Canyon Dam Capacity, and the impact of a range of SLCA/IP regulation and spinning reserve requirements. We found that results in terms of alternative ranking from these sensitivity runs were very consistent. While adding additional sensitivity analyses may have provided more information in terms of absolute system costs and perhaps a different expansion plan for some of the large Western customers, in our judgement the relative ranking of the alternatives would not have significantly changed. For example higher natural gas prices would increase system Locational Marginal Prices (LMPs) by nearly identical magnitude across all alternatives, but not the ranking of alternative energy replacement cost.

Comment: My understanding is that public preference applies to energy as well as capacity. However, I find no reference to preference to energy in this document. Perhaps the SLCA/IP region is generally subject to capacity constraints that typically bind before energy constraints, or the LTF obligations of WAPA to its customers are expressed in terms of capacity, not energy. If that is the case, then focusing on capacity to the exclusion of energy could be reasonable. If not, then I'm not sure how the risk of meeting annual LTF energy obligations is considered in the analysis.

Response: This bullet describes the purpose of the spreadsheet developed for the analysis; it finds the marketable capacity at a user-specified risk or exceedance level. It does not mean that capacity is any more or less important than energy – both capacity and energy are treated equally in the net present value calculation. This capacity level is used towards the reserve margin in the Aurora expansion model.

Comment: I suggest a brief statement here that explains why these 21 were chosen.

Response: There are explanations elsewhere in the draft EIS that describe how the 21 out of 105 traces were chosen.

Comment: Figure K.1-22 is illegible, although I think I understand the point.

Response: We are not sure what the reviewer means by Figure K.1-22 being illegible. The authors feel it is legible.

Comment: Can a modifier be inserted here? Monthly? Daily? Annual? All of the above?

Response: Marketable capacity, as used here, is the amount of hydroelectric capacity credited to the system reserve margin and input to the Aurora expansion model. It is the capacity at the 90% exceedance level in the month of August which is the peak load demand month. We will make this clearer in the final EIS.

Comment: This may be a nit, but the 15% planning reserve margin is non-coincidental, as I understand it: each LSE is supposed to plan for 15% above its own forecasted peak. The sum of non-coincidental peaks will be greater than or equal to the aggregated coincident peak. In this case, coincidental peak may be a reasonable approximation for the utilities with LTF rights. If so, it would be appropriate to point out the simplification.

Response: Expansion plans were based on individual utility system projected peak loads and reserve margin targets. The assumed 15% reserve margin was a typical level that is used for individual Integrated Resource Plans (IRPs) not for the entire Western Interconnection. We are therefore consistent with actual planning targets that were used for IRPs that individual systems use.

Comment: The section in Appendix K describing the alternative discount rate should be specified.

Response: We now direct the reader to where the alternative discount rate is discussed in the final EIS, which is in Appendix K.1.10.5.

Comment: Decrease compared to what? I recommend a general check on "increase" and "decrease" and make sure that the nature of the comparison is clear.

Response: Use of increase or decrease throughout much of this report is relative to the value in the No Action (Alternative A) scenario.

Comment: This comparison of gas-fired plants is a bit confusing. In my planning experience, we distinguish between simple cycle and combined cycle plants, of various sizes. These may or may not be described as "advanced", which will have different meanings in different contexts. (For example, "advanced" has a very specific regulatory meaning for air quality in southern California.) If my insertion is correct, I'm not sure what 230 MW simple-cycle units are referred to. If my insert is not correct, then I'm not sure what the technological difference is between the 400 MW and 230 MW plants. Perhaps examples from IRPs could be pointed out. Appendix K doesn't clear this up for me.

Response: The use of the term "advanced" is from the usage in EIA's Assumptions to the Annual Energy Outlook 2014 (http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf). In the final version of this chapter we refer the reader to Appendix K.1.6 for details. The term "advanced" is from the EIA document used in the selection of expansion candidates. The combustion turbine is a "single cycle" plant; a gas turbine, which is solely used to generate during peak demand periods, would be another name for this type of plant. From the document Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (EIA April 2013), "advanced" for combustion turbines means are state of the art (as of 2012) F-class CT and associated electric generator. The CT is equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output (see p. 9-1 of the EIA report). An advanced NGCC plant is the same as a conventional NGCC, except an H-class CT is utilized in lieu of F-class, and there is only one CT/HRSG supporting the ST included. Since the H-class CT design employs steam cooling of both stationary and rotational hot parts, the HRSG systems and the ST are both considered "advanced" designs, as compared to a conventional NGCC (see p. 6-1 of the EIA report). More details are in Appendix K; namely, the text before and after Table K.1-1 or in the section titled Capacity Expansion Candidate Unit Characteristics. This section is not numbered but is in K.1.6.3 (SLCA/IP Market System Projections)

Comment: My comments on the retail rate methodology pointed out the lack of any elasticity discussion or analysis. I cannot find any remedy for that omission in this document or the supporting materials. Given the schedule and budget, I recognize that this omission may not be fixed by analysis. However, it should not be overlooked entirely. The summary here and the supporting documentation should point out the problem, provide a short discussion, and then explain the decision not to incorporate any elasticity effects.

Response: The primary reason for not accounting for (and not discussing) price elasticity in the rate impact analysis is the fact that rate impacts were very small relative to even low incomes. The low rate impacts are documented in Appendix K.3 and further explained in response to Reviewer 4 comment number 16. For example, the maximum rate impact for LTEMP Alternative D is 15 cents per month (in real 2015 dollars). It is highly doubtful that this change in electric bills of 15 cents will cause the consumption behavior of customers to change with respect to electricity or anything else. Further, to incorporate the effects of price elasticity, the fixed and variable costs would have to be estimated for each system as well as short-run and long-run price elasticity coefficients. Estimation of fixed and variable costs for each cooperative and municipal system would be necessary because, if a price change results in a change in consumption of electricity, then to the extent that costs are variable, the quantity change would not have a secondary effect on prices. By contrast, if all costs are fixed, the change in quantity would have to be covered by further price increases and there would be a secondary impact. This analysis of fixed and variable costs would create a much more complex analysis with very limited effects on the final outcome. Finally, it is noted that the comments of Reviewer 4 on the proposed approach implied that the price elasticity issue was adequately addressed. Adding a paragraph similar to this paragraph to Appendix K.3 will be considered for the final EIS.

REVIEWER 2

Comment: Page 4-8: The discussion of residential rate impacts is not clear.

Response: Rate impacts measured are not residential rate impacts, but both overall retail rate impacts and residential bill impacts. Appendix K.3 has been written to clarify the meaning of rate impacts. Rate impacts are measured in terms of overall retail rate impacts to all retail consumers (residential and non-residential) as well as impacts on residential bills in 2015 dollars. For example, the third paragraph in *the introduction to Appendix K.3 states: "The primary output from the rate impact analysis is a set of figures and tables that present the percent increase or decrease in [retail] electric rates and the changes in monthly electricity bills paid by residential consumers of municipal utilities, cooperative distribution utilities, tribal authorities, and irrigation districts. (Retail consumers include businesses and households, while residential only includes households.)" Additional sources in Appendix K.3 that explain the definition of retail rates and residential bills are described in the response to points 28 and 29 of Reviewer 4. This comment is appreciated and consideration will be given to including an alternative summary of the rate impact measurement in Chapter 4 as both Reviewer 2 and Reviewer 4 had similar comments.*

Comment: The equation on p. K-137, line 11 ("1 + 1 + Sales Growth Rate from EIA") is incorrect. I assume this is a typographical error, but if not, the retail rate calculations will be incorrect.

Response: This typo was corrected.

Comment: It also appears to be the case that the analysis is assuming a constant residential percentage of total distribution entity sales for all years. This should be noted in the write-up.

Response: This is noted Appendix K.3 as follows: "To compute the residential bill impact, costs must be allocated between residential and non-residential consumers … For this allocation, the assumption is made that capacity and energy costs are allocated in the same proportion as existing overall rates." This statement from Appendix K.3 as well as an equation describing the same are deemed sufficient.

Comment: The use of the EIA price adjustment factor in this same equation may not be correct. Specifically, the equation includes an adjustment factor: "(1 + Electricity Price Inflation from EIAt)." The EIA electricity price inflation measure is a general measure of the gross domestic product, implicit price deflator, not a measure of "electricity price inflation."

Response: This is noted in Appendix K.3 as follows: "To compute the residential bill impact, costs must be allocated between residential and non-residential consumers … For this allocation, the assumption is made that capacity and energy costs are allocated in the same proportion as existing overall rates." This statement from Appendix K.3 as well as an equation describing the same are deemed sufficient.

Comment: It is not clear how the annual retail rate impacts are addressed in Table 4.13-1. I suggest that all impacts be reported in real, inflation-adjusted dollars (say 2014$) to avoid any confusion. That would also be consistent with the real-dollar basis for the Aurora modeling.

Response: Appendix K.3 states numerous times that residential bills are expressed in 2015 dollars consistent with the power systems analysis. For example, in Section 3.3.1, Appendix K.3 states: "Residential bill impacts in Figure K.3-10 and in the rest of the subsequent rate impact presentation are measured in real 2015 dollars." Clarifying the fact that residential bill impacts are stated in 2015 dollars in Table 4.13-1 will be considered for the final EIS.

Comment: Page 4-10, Table 4.13-1: Provide a table before this one with a quick description of each of the alternatives, so as to remind readers what they are. I believe this would be helpful in light of the cost reductions modeled under Alternative B. Also, a general question: is there any way to discuss the uncertainty associated with the projected impacts of each alternative?

Response: The requested information is provided in Chapter 2 of the EIS. In addition, there is some discussion of uncertainty in the EIS, especially as it relates to modeling future river flows.

Comment: Page 4-13: Add a short explanation as to why, under Alternative B, the decrease in annual generation production nevertheless results in a slight decrease in total energy production costs.

Response: Alternative B has slightly lower generation levels that Alternative A because it has significantly more non-power water releases (a.k.a, spills) due to more frequent occurrences of HFEs that require water release rates that exceed the GCD powerplant maximum turbine flow rate (a function of unit availability and reservoir elevation). From an economic standpoint however, it has a higher economic value than Alternative A because most of the time (e.g., when a HFE does not occur) Alternative B has operational criteria that allows it to generate power when it has a higher economic value (i.e., market price). This higher value of power gained by the more favorable operational criteria outweighs the loss in generation due to non-power water releases. We will add this explanation to the final EIS in the section discussing Alternative B

REVIEWER 3

Reviewer 3 had no major concerns other than suggesting increasing the scope of EIS. However, the scope of the EIS is determined by the action agencies with input from the public during the scoping period at the beginning of the analysis. The reviewer also indicated that factors other than hydrology affect the market for energy, and should be evaluated. Such factors include the effect of water availability on population and load growth and the penetration of renewable generation such as household photovoltaic systems. In response to another comment, we listed the sensitivity studies performed in the analysis. Furthermore, regarding the two factors cited by the reviewer,

(1) We used load growth projections shown in current Integrated Resource Plans of each of Western's large customers. It was assumed that water availability constraints on load growth were incorporated into these projections; the utilities are better acquainted with local issues than Argonne staff.
(2) The Aurora model includes a forecast of solar penetration and is therefore reflected in model results (e.g., Western Interconnection capacity expansion, LMPs, etc.)

These forecasts are uncertain and additional insights may have been gained by incorporating additional sensitivity parameters into the analysis. However, as stated in response to Reviewer 1's first comment above, in our judgement, overall conclusions (i.e., ranking) would most likely not change.

The reviewer prepared a chart that shows the percent change in electric rates, electricity costs, and marketable capacity of each alternative compared to No Action. The reviewer suggested adding such a table to the EIS. We will consider that recommendation for the final EIS.

REVIEWER 4

Comment: Specify page numbers in Appendix K when reference is made to it on pages 4-4 and 4-7.

Response: When referring the reader to Appendix K, in the final version of the DEIS we specify the section number rather than the page number.

Comment: Define economic value

Response: We provided more detail in the final version of the EIS.

Comment: Define concept of impacts on retail rates.

Response: This is presented in a separate analysis on retail rates and impacts.

Comment: Explain key inter-relationships among models and spreadsheet tools.

Response: We showed some of the relationships in Figure 4.13-1. In the final version of the public draft EIS we direct the reader to specific sections of Appendix K where the models/spreadsheets are discussed in detail.

Comment: Explain reasonableness and importance of each major simplifying assumption.

Response: We provided more detail in the draft final version of the EIS.

Comment: Explain role of demand-side management programs in the analysis.

Response: Because of limited space in Chapter 4 we do not discuss in detail how each piece of data is used. However, in Appendix K.1.8 we state that demand-side management programs are modeled as supply resources. That is a common and well established modeling methodology.

Comment: Explain why two discount rates used.

Response: The 1.4% discount rate is specified in OMB circular A-94, Appendix C. This is a real discount rate as opposed to an administratively determined one. In the final EIS, we direct the reader to the section of Appendix K where the discount rates are discussed in more detail; namely, K.1.9 and K.1.10.

Comment: Page 4-9, lines 25 and 26: Explain how Glen Canyon Dam capacity cost changes relate to costs incurred to purchase power.

Response: Section K.3.1.2 titled: "Incorporation of Power Systems Analysis and Capital Recovery Factors" discusses in detail how capacity costs changes are converted to grid costs which are the major component of grid power costs incurred by the individual systems. The explanation extends for a few pages and is considered sufficient after further review.

Comment: Page 4-8, line 24: Show interrelationships among the four steps of estimation.

Response: The four steps in estimation flow from the first step of gathering data, to the fourth step of presenting the retail rate impact results. This logical flow is described on the second page of Appendix K.3. Further, the four steps of the retail rate impact analysis are explained in detail in Section K.3.1 where each of the four steps of the estimation is described in a separate sub-section. Explaining that the four steps introduced in Chapter 4 are described in detail in Appendix K.3 will be considered for the final EIS.

Comment: Page 4-8, lines 3 to 40: Consider using bench-mark rates and bills from investor-owned electric utilities in neighboring geographic areas and regions (Utah, Colorado).

Response: The objective of the retail rate analysis is to compare overall retail rates and residential bills under different LTEMP alternatives. As such, comparison to retail rates for utilities that do not receive preference power would not be directly relevant to the ultimate policy decision. However the comment is appreciated and to the extent possible a comparison may be included in discussion of the No Action Alternative in Appendix K. Finally, investor-owned retail rates are the basis for some of the contracts between Western and tribal authorities and are described in the regional economic impacts section of the EIS that describes the rate impacts on Tribal Authorities.

Comment: Page 4-8, lines 3 to 38: Consider presenting electricity bill impacts and change relative to residential household income.

Response: The relationship between income and rates was not an objective of the retail rate impact analysis and to the extent it is relevant to the ultimate policy would be part of the regional economic analysis. It is noted that the rate impacts are generally so small that they would be minor even for low income consumers. For example, Figure K.3.9 shows the impact from Alternative D relative to the No Action Alternative is 15 cents per month.

Comment: Discuss rationale for selecting and using Alternatives A through G.

Response: This was discussed in Chapter 2 of the EIS which the peer reviewers did not see.

Comment: Page 4-15, line 30: Redefine economic impacts to be power systems economic impacts.

Response: In the final EIS we may change the title of this section to "Power System Economic Impacts" to be sure it is clear that we are only studying power system economic impacts and not impacts on other sectors of the economy. However, there are other sections of the EIS that studied socioeconomic impacts (4.14) and recreational economic impacts (4.10).

Comment: Page 4-17, lines 39 thru page 4-18, line 6: Clarify if the basis for rate impacts and associated costs are either marginal costs or accounting (embedded) costs or a combination of marginal and accounting costs.

Response: The basis for allocation of cost changes under different LTEMP alternatives to different retail systems is the current SLCA/IP energy allocations. These allocations are the result of the historical decisions with respect to which entities should receive the benefits of hydro power built by the Federal government. As such the primary allocations are not derived from either marginal cost or embedded cost. The mechanism to allocate costs is based on the wholesale power tariffs developed by Western. These tariffs include capacity charges and energy charges and ultimate represent purchased power costs for each system. It is true that the costs must then be allocated to different classes of consumers. From the perspective of the ultimate distribution system, the costs are both embedded costs and long-run marginal costs for purposes of allocation (i.e. the marginal cost equals the embedded cost). It would not make a difference in cost allocation whether the costs are embedded costs or long-term marginal costs. As explained in Appendix K.3, the changes in costs resulting from LTEMP alternatives are allocated among customer classes on the basis of the amount of energy sold.

Comment: Page 4-18, lines 12-13: Explain the type of detailed analysis of retail rates and residential bills that are provided in Appendix K; and add more results of analysis in this section of the report.

Response: This comment will be considered for the final EIS.

Comment: Page 4-18, lines 15-22: Present a clear conclusion concerning the relatively small bill increases for residential customers.

Response: The relatively small magnitude of rate impacts is discussed at length in Appendix K.3. For example in Section K-3 states "Figure K.3-9 demonstrates that even the most extreme LTEMP alternative in terms of changing dam operations (Alternative F) results in relatively minor rate changes for retail consumers. Under Alternative F, there is an average rate increase of 0.75% relative to Alternative A. Figure K.3-10 shows that the highest average residential bill impact is 69 cents per month. Alternatives E *and D have much lower retail rate impacts that are approximately 20% of the rate impact under Alternative F." However, given the comment by Reviewer 4, including a discussion of limited rate impacts in Chapter 4 will be considered for the final EIS.*

Comment: Other than Alternative A thru Alternative G, explain if there are other important business risk conditions that could impact the costs of electricity generated at Glen Canyon Dam.

Response: We think the reviewer is referring to "economic value" and/or "change in economic value" among alternatives. There are many factors, one of the most important being the market price of energy and Western's ability to participate in bilateral energy markets. Western is concerned that the Western Interconnection may change in the future if other utilities join formal marketplaces (e.g., energy imbalance markets like the CAISO EIM, or form new regional transmission organizations or independent system operators).

Comment: Present major conclusions at the end of chapter 4.

Response: Major conclusions are presented in Chapter 2, Alternatives.

Comment: Page K-127, lines 14-29: Explain if these costs are a mixture of marginal (incremental) costs and accounting (embedded costs).

Response: See discussion of marginal and embedded costs in response to comment on page 4-17. Given that the primary allocation does not relate to either marginal or embedded costs as described in Appendix K.3, the discussion is considered sufficient.

Comment: Page K-128. Discuss any important assumptions about the profile of the average residential customer and related usage characteristics.

Response: Discussion of the No-Action case in terms of residential bills was intended to address customer characteristics in Section K.3.3.1. Further, usage characteristics were directly addressed in Section K.3.3.3 as follows: "One of the reasons for differences in ranking is due to residential use variation among individual systems. Systems with lower residential use have a higher bill impact because grid costs are spread over a smaller base, all else being equal. Differences in residential usage are evidenced by the fact that the median average usage across the different systems is 730 kWh per month, while the maximum use for a single system is 1,680 kWh per month, and the system with the lowest annual residential usage is 391 kWh per month." All residential rate impacts are derived from average residential use as demonstrated by the equations. Consideration will be given to further explanation in the final EIS that all residential rate impacts are computed on the basis of average usage and data on the variation in residential usage was not available.

Comment: Table K 3-1: Specify the time period for the data on this table.

Response: This comment is appreciated and revisions to the document for the final EIS will be considered for the final EIS. To clarify, the data in Table 3-1 are the latest data available for the systems from the EIA 861 database that contained 2012, 2011 and 2010 data. Further, in response to comments made by Reviewer 4, the LTEMP period is defined in Appendix K.3 as 2015 through 2035. Virtually every table refers to the LTEMP period.

Comment: Page K-138, lines 14-38. Discuss average residential customer profiles relating to usage levels and patterns.

Response: See response to comment on page K-128.

Comment: Page K-138, lines 38 thru page K-139, line 23. Explain the generalizations that can be concluded from this case study to other utility systems getting power from the Glen Canyon Dam.

Response: The case study is used to demonstrate that using Western wholesale rates should produce the same results as the grid cost method used in the retail rate analysis. This issue was discussed at length with cooperating agencies in developing the retail rate analysis. It is intended to be self-evident that the equivalence of the grid cost method with the direct wholesale rate method would apply to all systems. As this was apparently not clear, including language to explain this equivalence between use of grid costs and wholesale rates will be considered for the final EIS.

Comment: Figures K 3-5 and K 3-6. Explain the meaning and implications of the scatter plots.

Response: Appendix K.3 explains that "The relationship between the preference ratio and rate changes for individual systems is demonstrated by scatter plots of the percentage retail rate change and the preference ratio." The implication of the scatter plots is also described: "The scatter plots shown in Figure K.3-6 demonstrate that much of the rate impact on individual systems is driven by the preference ratio…The upper end of the y-axis therefore represents the absolute maximum retail rate percent increase for the LTEMP alternative across systems. Finally, regression equations are presented in each panel of Figure K.3-6 that shows the relationship between the preference ratio and the percent retail rate change in the year with the maximum change for each LTEMP alternative. These regression equations can be used to approximate rate impacts for systems that are not included in the database." The scatter plots were presented to cooperating agencies and were mentioned as an effective manner to present ranges in retail rate (business and residential) impacts. The explanation of scatter plots is considered adequate in Appendix K.3.

Comment: Cite any previous relevant research that uses "preference ratios" relating to the electric utility industry.

Response: The term "preference ratio" was specifically defined for purposes of the rate impact analysis. It is doubtful that this term has been used in other instances because the issue of different allocations of preference power is not a common issue in the electric utility industry.

Comment: Page K-143, line 14. Does the term "retail rate impacts" mean changes (increases or decreases) in retail electricity rates?

Response: Yes. On numerous occasions in the report, the notion that retail rates include both residential and non-residential rates is mentioned. Additional statements that clarify this in Appendix K.3 include: "…recall that retail rates include rates to residential, business, and other consumers served by the utility system" and "Retail rates are computed by dividing retail revenues collected from residential, business and other consumers by retail sales for the consumers." No further clarification is deemed necessary.

Comment: Page K-143, line 14: Does the term "residential bill impacts" mean changes (increases or decreases) in residential electricity bills?

Response: Yes. Residential bill impacts measure the effects of different LTEMP alternatives relative to Alternative A, in 2015 dollars. This is described on multiple occasions in Appendix K.3 and described in terms on an equation as follows: "Calculation of residential bills involves two steps. The first step is to allocate a portion of the total retail increase for the system to residential consumers. This allocation is made with the ratio of residential revenues to total retail revenues for each system. Using the residential *revenue percent, the dollar amount of change in residential revenue under LTEMP alternatives relative to Alternative A can be represented by the following equation:*

Residential Revenue Change $\$_{t,i}$ = *Change in Grid Cost*$_{t,i}$ × *Residential Percent*$_{i}$.

The second step is computing the monthly residential bill change from residential revenue change. The change in monthly residential bill relative to Alternative A is computed by dividing the total residential revenue change by projected residential consumers and then by 12." No further clarification is deemed necessary.

Comment: Page K-144, lines 5-11: Use a diagram/flow chart to present and integrate the four parts of rate and bill impact analysis.

Response: The reviewer suggestions including flow charts from his earlier comments were appreciated and incorporated in Figure K.3-1 and Figure K.3-3. It is deemed that these figures adequately integrate various sections of the rate impact analysis.

Comment: In addition to Alternative A, as a bench-mark, consider using rate and bill impacts from a representative investor-owned electric utility in the region (Utah, Colorado).

Response: See the response to comment on page 4-8.

Comment: Present any clear "policy" conclusions from the analysis.

Response: Policy conclusions are not presented in the EIS.

Comment: Page K-150, lines 14 thru page K-157, line 22: Consider conducting a detailed case study for a municipal utility, such as Bountiful or Meadow, with a relatively high "preference ratio". This case study would show actual rates/tariffs and information concerning business and residential customers.

Response: Systems with high rate impacts are frequently Tribal Authorities. These systems were earlier targeted to receive 50% of their resources from Federal Preference Power in the SLCA/IP allocations. Given the importance of these systems and the potential for disproportionate impacts, the regional economic impacts section discusses the impacts on various Tribal Authorities in detail.

Comment: Page K-158, lines 1 thru page K-162, line 9: Present any clear "policy" conclusions from the analysis.

Response: Policy conclusions are not presented in the EIS.

Comment: Page K-162: Add published reports from state regulatory commissions (such as Wisconsin PSC) concerning system planning and consumer impacts analysis associated with regulated investor-owned utilities.

Response: This comment will be considered for the final EIS.

Comment: The author needs to link more clearly and specifically the references from Appendix K to Chapter 4.

Response: This comment will be considered for the final EIS.