—BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH—

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS.	))))))))	DOCKET NO. 11-035-200 DPU EXHIBIT 2.0DIRECT-REV REQ

PRE-FILED DIRECT TESTIMONY

REVENUE REQUIREMENT

ARTIE POWELL, PHD

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES

JUNE 11, 2012

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- DPU Exhibit 2.4 DIR-REV REQ, Klamath Capital Additions Update
- DPU Exhibit 2.5 DIR-REV REQ, DPU Adjustments Summary

Pre-Filed Direct Testimony

Artie Powell, PhD

Division of Public Utilities

Docket No. 11-035-200

INTRODUCTION

Q: PLEASE STATE YOUR NAME, EMPLOYER, JOB TITLE, AND BUSINESS ADDRESS FOR THE RECORD.

A: My name is Artie Powell; I am employed by the Division of Public Utilities; currently I am the manager of the energy section; my business address is 160 East, 300 South, Salt Lake City, Utah, 84114.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: The Division of Public Utilities (Division).

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A: I hold a doctorate degree in economics from Texas A&M University. Prior to joining the Division, I taught courses in economics, regression analysis, and statistics both for undergraduate and graduate students. I joined the Division in 1996 and have since attended several professional courses or conferences including, the NARUC Annual Regulatory Studies Program (1995) and IPU Advanced Regulatory Studies Program (2005), dealing with a variety of regulatory issues. Since joining the Division, I have testified or presented information on a variety of topics including, electric industry restructuring, incentive-based regulation, revenue decoupling, energy conservation, evaluation of alternative generation projects, and the cost of capital.

SUMMARY OF DIVISION'S CASE

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A: In addition to my own testimony regarding certain expenses and treatment of a settlement agreement, I will introduce the Division's witnesses and summarize the Division's adjustments and recommendations.

Division Witnesses and Adjustments

Q: On what specific topics are you testifying?

A: My testimony covers two topics, generation overhaul expense (GOE) and treatment of the Klamath Hydroelectric Settlement Agreement (KHSA) costs. Specifically, the Division supports and recommends that the Commission adopt the Company's methodology for estimating GOE. This issue has been raised in prior rate cases and in the last rate case, Docket No. 10-035-124, I offered extensive testimony in support of the Company's methodology. The settlement in the prior rate case, however, did not address the GOE issue. Therefore, in this case I again present supporting evidence for the Division's recommendation.

Additionally, the Division supports and recommends that the Commission approve the Company's proposed rate treatment of the KHSA costs including, accounting for or including the Relicensing and Settlement Process costs in rate base, accelerating the depreciation on the Klamath assets, and recovery of Utah's share of the capped removal costs. The Division estimates that this treatment has an approximate $14 million revenue requirement impact on a Utah basis that is included in the Company's case.

Typically, the Division updates the Company's filing with actual plant additions and other information. In response to a Division data request the Company provided actual additions and costs for the Klamath relicensing and process settlement through March 2012. I have included these updates in my testimony. On a Utah basis, this adjustment increases the Company's revenue requirement by approximately $38,000.

Finally, I offer some comments and recommendations regarding the Company's proposal in this case to update its net power costs approximately one month before the deadline for intervener testimony. Briefly, the Division recommends that in the future the update be filed six weeks before the intervener deadline for direct testimony.

Q: WOULD YOU PLEASE INTRODUCE THE DIVISION'S OTHER WITNESSES?

A: Other witnesses for the Division include:

Mr. Chuck Peterson. Mr. Peterson filed testimony as part of this case on May 31, 2012, supporting the Division's recommendations concerning the Company's cost of capital and capital structure. The Division recommends a cost of equity capital of 9.3%, which yields a decrease to the Company's request in this case of approximately $45 million. The weighted cost of capital is approximately 7.35%.

Mr. Richard Hahn. Mr. Hahn, a consultant with La Capra Associates, Inc., was retained in this case by the division to review the Company's capital additions. Mr. Hahn evaluated 98 projects contained in the Company's case. Mr. Hahn's adjustments decrease, on a Utah basis, the Company's revenue requirement by approximately $6.7 million.

Mr. George Evans. Mr. Evans, a consultant with Evans Power Consulting, Inc., has testified previously on behalf of the Division. In this case Mr. Evans supports several adjustments totaling approximately $18 million on a Utah basis to the Company's filed NPC.

Mr. Dave Thompson. Mr. Thompson supports Division adjustments to the Company's distribution, customer account, and property tax expenses, and to the Company's wage and employee benefits proposals.

Mr. Clair Oman. Testimony of Clair Oman will provide overview and discuss his review of the Company's expenses recorded in FERC accounts 930.1 General Advertising Expenses, account 930.2 Miscellaneous General Expenses, account 924 Property Insurance, and account 925 Injuries and Damages. There are adjustments to the test year balances of these accounts that will be described and explained in testimony and exhibits.

Mr. Mathew Croft. Mr. Croft testifies on several matters including the Division's update to the Company's adjustments using actual provided by the Company in response to Division data requests. Mr. Croft also addresses several adjustments dealing with the Company's plant additions, excess depreciation expense, and the lead lag study. These adjustments along with all other Division adjustments were entered into the Company's revenue requirement model (JAM). The Division's JAM is included with Mr. Croft's testimony as DPU Exhibit 5.11.

In addition to these witnesses, the Division will file testimony on the cost of service, rate spread, and rate design on June 22, 2012, according to the schedule in this case.

The Division's adjustments in this phase of the case total approximately $75 million. A summary of the Division's adjustments and overall revenue requirement recommendation can be seen in DPU Exhibit 2.5 DIR-REV REQ. This exhibit includes the Company's adjustment to its filed NPC contained in its updated NPC filings. Given the Division's cost of capital and other adjustments, the Division recommends an overall rate increase of approximately $88 million.

GENERATION OVERHAUL EXPENSE

Q: YOU PREVIOUSLY INDICATED THAT THE DIVISION SUPPORTS THE COMPANY'S METHODOLOGY FOR ESTIMATING GENERATION OVERHAUL EXPENSE (GOE). WOULD YOU EXPLAIN WHAT METHODOLOGY THE COMPANY IS USING?

A: Yes. In his direct testimony, Company witness Mr. McDougal states,

> This adjustment normalizes generation overhaul expenses using a four-year historical average for the years ended June 2008 through 2011. . . . Prior to averaging, annual expenses are restated to June 2011 dollars.[1]

In other words, the Company's methodology escalates or restates the four historical amounts in terms of 2011 dollars and then averages these escalated amounts to estimate the GOE for the test period.

As Mr. McDougal explains, the use of the average of four historical years was approved by the Commission in Docket No. 07-035-93. Subsequent to that order, the Company utilized the method described above. However, in Docket No. 09-035-23, the Commission did not allow the use of escalation prior to averaging.

Q: IF THE COMMISSION DISALLOWED THE USE OF ESCALATION PRIOR TO AVERAGING, WHY DOES THE DIVISION SUPPORT THE COMPANY IN ITS USE OF ESCALATION PRIOR TO AVERAGING IN THIS CASE?

A: As Mr. McDougal points out in his direct testimony, the purpose of averaging is to smooth the volatility in annual GOE; averaging does not account for escalation or inflationary changes from year to year. Failure to account for inflation will

[1] "Direct Testimony of Steven R. McDougal, Revenue Requirement and Test Period," Docket No. 11-035-200, February 2012, p. 22, lines 486-491.

systematically underestimate or understate the Company's test period GOE.[2] The Division agrees with these conclusions.

Additionally, in the Company's last general rate case, Docket No. 10-035-124, the Division presented additional or new evidence and information that was not considered in Docket No. 09-035-23. Based on the conclusions presented above and this new information, the Division recommends adoption of the Company's methodology of escalating the four historical values prior to averaging.

Q: WAS THIS NEW INFORMATION FULLY CONSIDERED IN THE PREVIOUS RATE CASE, DOCKET NO. 10-035-124?

A: No. The settlement in that docket did not address or resolve the GOE estimation issue.

ALTERNATIVE METHODOLOGIES

Q: WOULD YOU PLEASE EXPLAIN THE NATURE OF THE INFORMATION YOU PRESENTED IN THE PREVIOUS RATE CASE?

A: Yes. In past rate cases, parties have advocated one of two methods to forecast GOE. The first method, Method 1, inflates the average of four historical values. For example, if G_1, G_2, G_3, and G_4 are the historical annual GOE, then the fifth or test period GOE, G_5, is estimated as,

$$\hat{G}_5 = \frac{(1 + \pi)}{4}[G_1 + G_2 + G_3 + G_4] = \frac{(1 + \pi)}{4}\sum_{i=1}^{4} G_i \qquad (1)$$

where π is the rate of inflation.[3] The alternative method, Method 2, averages the inflated historical values to estimate the test period value. That is,

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[2] Mr. McDougal, p. 23, lines 500-502.

[3] In previous cases some parties have advocated using the average of the four historical values without any inflation or escalation factors, which is the method specified by the Commission in Docket No. 09-035-23. That

$$\tilde{G}_5 = \frac{1}{4}[G_1(1+\pi)^4 \ + \ G_2(1+\pi)^3 \ + \ G_3(1+\pi)^2 \ + \ G_4(1+\pi)^1] \qquad (2)$$

or simply[4, 5]

$$\tilde{G}_5 = \ \frac{1}{4}\sum_{i=1}^{4} G_i \ (1 \ + \ \pi)^{5-i} \qquad (3)$$

Of these two methods, economic and statistical theory suggests that Method 2 is on average more accurate. That is, on average, the estimator described in Equation 3 will produce better estimates of the GOE than the estimator described in Equation 1.

Economic Considerations

First, economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base. That is, the values should be expressed in real terms, where the effects of inflation are taken into account, as opposed to nominal terms. Comparing values expressed in nominal terms—ignoring inflation—can lead to erroneous conclusions. For example, suppose we bought a particular item in the year 2000, for $30; and another person bought the same item in 2010 for $50. Who paid more for the item? In a nominal sense, the second person paid

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method is a special case of Method 1 and amounts to setting the inflation rate, π, in Equation 1 to zero. The more general model as described Equation 1 is used here for completeness. Its use does not change the qualitative results or conclusions described herein.

[4] One could use different inflation rates in restating or escalating the four historical values. For example, for G_i, an inflation rate of π_i could be used to restate that value to a common base, e.g., $G_i(1 + \pi_i)^{5-i}$. Alternatively, different inflation rates for each period could be applied to bring each value to a common base. Using either method would complicate the presentation but would not change the qualitative results. Therefore, for simplicity, the following presentation assumes a single or common inflation rate. It is important to note that in its filing the Company did use specific annual inflation rates in its formulation.

[5] Method 2 differs slightly from the Company's proposed method. In the Company's method the historical values are brought to a common base short of the test period or period 5 described in Equation 2: the Company only escalates the historical values to the base year, the 12 months ending June 2012 (i.e., set the power in Equation 3 to (4 - i)). As with the differences from past proposals and Method 1 (see discussion in footnotes 3 and 4), for purposes of this presentation the more general specifications in Equations 1 and 2 are inclusive of these other proposals. Again, these differences would not affect the qualitative conclusions or results presented herein.

more: \$50 is greater than \$30. However, a nominal comparison such as this ignores the effect of inflation on the purchasing power of the dollar between the two periods and can lead to erroneous conclusions. The proper comparison would take into account the effects of inflation using a price index—such as the Consumer Price Index—to either deflate the 2010 value to 2000 dollars; or, inflate the 2000 value to 2010 dollars. Suppose the price index in 2000 was 1.00 and in 2010 the price index was 1.75. Then, the \$30 price paid in 2000 would be equivalent to \$52.50 (=1.75*\$30) in 2010. Thus, in this example, the person buying the item for \$50 in 2010 actually paid less in real terms than the person paying \$30 in 2000.

By inflating each of the historical values to a common base Method 2 properly takes into account the effects of inflation before making a comparison (or forecast) to the test year.

STATISTICAL CONSIDERATIONS

Statistical theory also supports the use of Method 2 over Method 1. To demonstrate this, consider the following specification of the annual generation overhaul expense. Let the generation overhaul expense, G, for year "i" be specified as,

$$G_i = H_i + \varepsilon_i \qquad (4)$$

where

G_i = the actual or observed generation overhaul expense for period "i";

H_i = the base or unobserved (unknown) generation overhaul expense for period "i";

ε_i = a random error (shock) term with a mean zero and standard deviation σ_ε; and

$H_i = H_{i-1} (1 + \pi)$.[6]

On average, under this specification, Method 1, $\hat{G}_5$, will underestimate the GOE in the test period, whereas, Method 2, $\tilde{G}_5$, the Company's method, will on average equal the test period value. That is,

$$E(\hat{G}_5) = \theta * H_5 \leq H_5 \tag{5}$$

where E(•) is the linear expectation operator, and θ is a constant between zero and one[7]:

$$\theta = \frac{1}{4}\left[1 + (1+\pi)^{-1} + (1+\pi)^{-2} + (1+\pi)^{-3}\right] \tag{6}$$

The Expectation operator, E(•), can be read as "on average." Thus, Equation 5 indicates that Method 1 will on average underestimate the test period value H_5. Whereas,

$$E(\tilde{G}_5) = H_5 \tag{7}$$

That is, Method 2 on average will equal the test period value. DPU Exhibit 2.1 DIR-REV REQ provides a derivation or demonstration of Equations 5 through 7.

Therefore, Method 2 will on average yield a more accurate result and, thus, is the preferred method for forecasting the GOE for the test year. Therefore, the Division recommends that the Commission adopt the Company's methodology for forecasting the GOE.

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[6] In this specification the observed GOE, G_i, includes the volatility while the base value, H_i, is a trend variable where the trend is the rate of inflation. The error term, in other words, represents the volatility which averaging smoothes: $E(\varepsilon_i) = 0$, where E(•) is the linear expectation operator; that is, on average, $\varepsilon_i = 0$. In other words, by averaging the historical values, G_1, G_2, G_3, and G_4, the volatility is smoothed or removed because $\sum_{i=1}^{4} \frac{\varepsilon_i}{4} = 0$ approximately. Averaging, however, does not address the trend or inflation inherent in the problem.

[7] Assuming that π is greater than or equal to zero.

GOE Model Simulation

Q: Do you have any other evidence that Method 2 is likely to provide a better estimate of the test year level of generation overhaul expense?

A: Yes. I have simulated the two estimation methods for the model previously defined in Equation 4. Since the simulation is relatively large—10,000 replications—I provide the full simulation only in electronic form as part of my pre-filed testimony. However, a summary of the simulation is provided in DPU Exhibit 2.2 DIR-REV REQ attached to my testimony.

To perform the simulation I chose a value for year 1's base or unobserved value, H_1, of 1,000 and an inflation rate of three percent. Given the model specified herein, these assumptions yield a fifth year base value, H_5, of 1,126, which is the value to estimate using the first four values. To generate the observed values, G_i, for the four historic years, I used the RAND() function in EXCEL© to generate random deviates, which were added to the four historic values.

Under these conditions, Method 1 underestimates the fifth year value 95% of the time; whereas, Method 2 underestimates the fifth year value as expected approximately 50% of the time. The root mean squared error, RMSE,[8] of the estimates from the two methods also indicate that Method 2 provides a better estimate on average—the RMSE for Method 1 is approximately two times as large as the RMSE for Method 2.

[8] The RMSE is a common statistical measure of the accuracy or precision of an estimator and is defined as the square root of the average squared deviation of the estimates around the true value being estimated. The RMSE is similar to the sample standard deviation: RMSE = $\sqrt{\frac{1}{n}\sum_{i=1}^{n}\left(\hat{\beta}_i - \beta\right)^2}$, where $\hat{\beta}_i$ is the ith estimate of the true value β. The smaller the RMSE the more accurate the estimate, that is, the smaller is the variation of the estimate around the true value.

The simulation confirms the conclusions drawn from the statistical modeling (and economic reasoning), namely, Method 2 provides a better estimate of the test year value. See Table 1 for a summary of the simulation results.

Table 1: GOE Model Simulation (10,000 Replications)

	Average Estimate	Minimum Estimate	Maximum Estimate	RMSE	Number Under Estimated	Percent Under Estimated
Method 1	1,078	987	1,166	56	9,496	94.96%
Method 2	1,126	1,031	1,218	31	5,046	50.46%

Klamath Dam

Recommendation

Q: Would you please summarize the Company's proposed treatment of the costs associated with the Klamath Hydroelectric Settlement Agreement or KHSA?

A: The Company's witness Mr. Steven McDougal provides details on the adjustment in his direct testimony and in attached exhibits. As Mr. McDougal explains, "The KHSA impacts the Test Period in three main areas: depreciation and amortization expense associated with the Klamath-related assets, inclusion of the relicensing and process costs in rate base, and allocation of the KHSA dam removal surcharge."[9] The Company proposed a similar treatment in the last rate case. That case, however, was settled with the KHSA issues being reserved for a future proceeding. The Company's proposed treatment in this case, therefore, includes the impact of the settlement agreement from that prior case, namely, "the accrual of additional AFUDC on the balance of relicensing and settlement process costs."[10]

[9] See, McDougal Direct, p. 37, lines 830-833.

[10] McDougal Direct, p. 38, lines 851-852.

In summary, the Company is asking for three things. First, that the relicensing and process settlement costs be included in rate base in this case. As of December 31, 2010, these costs were approximately $74 million and projected to be approximately $82 million as of May 30, 2012, on a system basis. The difference, approximately $8 million represents the additional accrued AFUDC. On a Utah basis as of May 2012 the total relicensing costs, including the AFUDC, are approximately $35 million.

Second, the Company is asking that the relicensing costs be amortized on a straight-line basis through December when the Company expects the Klamath facilities to be decommissioned.[11] This treatment also includes accelerated depreciation of the remaining Klamath assets at rates sufficient to fully depreciate the assets over the same period.[12]

Third, the Company is asking to recover in Utah rates, Utah's allocated share of the capped removal costs. On a system basis the removal costs are $17.2 million. On a Utah basis, the removal costs are approximately $7.4 million.

Q: WOULD YOU PLEASE SUMMARIZE THE DIVISION'S RECOMMENDATION REGARDING THE COMPANY'S KLAMATH PROPOSAL IN THIS CASE?

A: Yes. The Division recommends that the Commission adopt the Company's proposal in this case to include the relicensing costs in rate base and the proposed amortization schedule and the accelerated depreciation of the remaining assets, and the recovery of Utah's share of the removal costs.

I think it is important to note that the Company's analysis demonstrates that the Company's decision to enter to the KHSA leaves rate payers slightly better off than if the

[11] See, Direct Testimony of Andrea Kelly," Docket No. 11-035-200, p. 4, lines 74-82.

[12] McDougal Direct, p. 38, lines 859-861.

Company had pursued successful relicensing of the Klamath facilities.[13] Additionally, approving rate making treatment in this case as opposed to some future date avoids further accrual of AFUDC.

Q: DO YOU HAVE AN ESTIMATE OF THE REVENUE REQUIREMENT IMPACT FOR THE COMPANY'S PROPOSED TREATMENT OF THE KLAMATH COSTS?

A: Yes. I estimated the Klamath impact by turning the Klamath adjustment off in the model provided by the Commission in this docket. The result was to decrease, on a Utah basis, the Company's request by approximately $14 million.

IN SUPPORT OF THE RATE MAKING TREATMENT OF KLAMATH

Q: WOULD YOU EXPLAIN THE REASONS WHY THE DIVISION SUPPORTS THE COMPANY'S PROPOSED TREATMENT OF THE KLAMATH COSTS?

A: Yes. First, the Division supports the recovery of these costs at this time to terminate the accrual of AFUDC. As I previously indicated, the Company is asking to amortize approximately $82 million in relicensing and process costs, which includes approximately $7.8 million in AFUDC that accrued from January 2011 through May 2012. If amortization begins June 2012 coinciding with the test year in this case as the Company proposes, the accrual of AFUDC will cease. If the amortization is postponed to a future case, then through the end of the test year, May 2013, another $5.9 million will potentially accrue in AFUDC. Looking at it in a different light, as of December 2010, AFUDC was approximately 34.5% of the total relicensing and process costs. If AFUDC is allowed to accrue unabated through the end of the test year, AFUDC will be approximately 45% of the total costs; and that percentage will continue to grow, possibly substantially, depending on the timing of the next rate case. (See CONFIDENTIAL DPU Exhibit 2.3 DIR-REV REQ)

[13] See Confidential Exhibit RMP_(ALK-4), attached to Ms. Kelly's Direct Testimony.

Second, the Company's analysis shows that ratepayers are slightly better off under the KHSA relative to relicensing and continued operation of the Klamath facilities. (See Confidential Exhibit RMP_(ALK-4))

Third, it appears that all of the costs included in the relicensing costs are costs that the Company would incur whether Klamath was relicensed or removed. In response to a data request, OCS 21.15, from the Office of Consumer Services in Docket No. 10-035-124, the Company provided confidentially a description and annual breakout of the relicensing costs that the Company proposes to recover. In response to DPU data request 34.1 (in the present case) the Company provided clarification on several cost items. The Company's clarification included an explanation of the relationship between the costs and the relicensing process. The Division concludes that the cost were part of and necessary for the FERC relicensing process.

For these reasons, the Division recommends that the Commission approve the Company's proposed rate treatment of the Klamath relicensing costs.

KLAMATH UPDATE AND ADJUSTMENT

Q: WOULD YOU PLEASE EXPLAIN THE DIVISION'S ADJUSTMENT RELATED TO THE KLAMATH FACILITIES?

A: The Company's first supplemental response to DPU 2.14 updated the capital additions and the AFUDC calculations through March 2012. I have included these updates in my testimony and they are reflected in the Division's case summarized in DPU Exhibit 2.5 DIR-REV REQ. A summary of this adjustment is provided in DPU Exhibit 2.4 DIR-REV REQ.

The Company's update indicates an increase in the capital additions of approximately $366,506 on a system basis. Accrued AFUDC increases by approximately $93,585 on a system basis. Including the impact on depreciation expense and reserves, this adjustment increases revenue requirement by approximately $38,000 on a Utah basis.

NET POWER COST UPDATE

Q: IN HIS DIRECT TESTIMONY COMPANY WITNESS MR. DUVALL PROPOSES A PROCESS TO UPDATE NPC DURING THIS AND FUTURE GENERAL RATE CASE PROCEEDINGS. WOULD YOU EXPLAIN THE COMPANY'S PROPOSAL?

A: Yes. As set forth in his testimony, Mr. Duval proposes that "the Commission establish a fixed schedule of when NPC updates will occur over the course of a rate case proceeding and what particular NPC items will be updated."[14] Specifically, Mr. Duval recommends that the Company be allowed to update its NPC one month prior to the deadline for intervener direct testimony.

Q: DID THE COMPANY FILE AN UPDATE TO ITS NPC IN THIS CASE?

A: Yes, the Company filed updates on April 10, April 30, and May 11, 2012. The May 11th date was approximately one month before the deadline for intervener direct testimony.

According to the cover letters accompanying the two April filings, the updates contained in the April filings were updates the Company intended to include as part of the final May update. The cover letter accompanying the May filing indicates updates in 15 areas, including the Company's official forward price curve.

Q: DO YOU HAVE ANY CONCERNS WITH THE COMPANY BEING ALLOWED TO UPDATE ITS NPC ONE MONTH PRIOR TO THE DEADLINE FOR DIRECT TESTIMONY?

A: Yes. In his direct testimony on behalf of the Division, Mr. Evans points out that the Company's update is complex, extensive, and has an impact on nearly every aspect of

[14] "Direct Testimony of Gregory N. Duval," Docket No. 11-035-200, February 2012, p. 15, lines 287-289.

the Company's NPC. Filing such an extensive update one month prior to the deadline for direct testimony does not allow adequate time for intervening parties to analyze the Company's updates and receive responses to data requests.

Q: WHAT IS THE DIVISION'S RECOMMENDATION WITH RESPECT TO THE COMPANY UPDATING ITS NPC?

A: If the Commission allows the Company to update its NPC, the Division recommends that the Company be required to do so six weeks prior to the deadline for intervener direct testimony.

Q: DOES THE DIVISION BELIEVE THAT IT IS REASONABLE FOR THE COMPANY TO UPDATE ITS NPC PRIOR TO INTERVENING PARTIES FILING DIRECT TESTIMONY?

A: Yes. If the intent is to reflect in rates the actual conditions the Company is likely to experience in the rate effective period, the Division believes it is reasonable for the Company to update its NPC, as long as intervening parties are provided adequate time to review any updates. As I indicated previously, the Division typically updates other aspects of the Company's filing using actual data provided by the Company in response to data requests. In this case, however, the Division's consultant, Mr. Evans, has advised the Division four weeks is not sufficient time in all circumstances to review a complex update such as NPC. Therefore, the Division recommends that the Company file its NPC update at least six weeks prior to testimony deadlines.

CONCLUSION

Q: WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A: In addition to summarizing the Division's case, I provide testimony on two issues, and one adjustment. First, I provide testimony in support of the Company's methodology for estimating generation overhaul expense. Second, I provide evidence in support of the Company's proposed ratemaking treatment of the Relicensing and Settlement

Process costs associated with the Klamath Hydroelectric Settlement Agreement or KHSA. Adopting this ratemaking treatment at this time will terminate continued accrual of AFUDC. Third, based on actual capital additions through March 2012, I increased the Klamath costs on a Utah basis by approximately $38,000.

The Division's witnesses support a variety of adjustments to the Company's filed case. The Division's adjustments include a 9.3% return on equity capital with an overall cost of capital of 7.35%. Given the Division's cost of capital and other adjustments, the Division recommends an overall increase in the Company's revenue requirement of approximately $88 Million.

Finally, if the Company is allowed to update its NPC during the course of the case, the Division recommends that the Commission direct the Company to do so at least six weeks prior to the deadline for intervener direct testimony.

Q: DOES THAT CONCLUDE YOUR DIRECT REVENUE REQUIREMENT TESTIMONY?

A: Yes.