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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND ITS RATE BASE TO RECOVER ITS INVESTMENT IN THE LANGLEY GULCH POWER PLANT.	**CASE NO. IPC-E-12-14** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of Record, Donald L. Howell II, Deputy Attorney General, and submits the following comments in response to Order No. 32523 issued on April 17, 2012.

BACKGROUND

On March 2, 2012, Idaho Power Company filed an Application requesting that it be allowed to increase its rate base and rates upon completion of the Langley Gulch power plant. Langley Gulch is a 330 MW natural gas-fired, combined-cycle combustion turbine currently under construction near New Plymouth, Idaho. Certificate No. 486. The Company proposes that the rate base additions and the resulting rate increases become effective July 1, 2012.

THE 2009 CPCN CASE

On March 6, 2009, Idaho Power Company filed an Application for a Certificate of Public Convenience and Necessity (CPCN) authorizing construction of the Langley Gulch power plant and the ability to ultimately include the costs of the completed Project in the Company's rate base. Under *Idaho Code* § 61-526, an electrical corporation is prohibited from beginning the construction of a generating plant without having first obtained from the Commission a certificate that the present or future public convenience and necessity requires or will require such construction. In its Application, the Company requested that the Commission issue a certificate and authorize cost recovery and ratemaking assurances.

In Order No. 30892 the Commission authorized Idaho Power to construct and operate the Langley Gulch plant. *See* also CPCN No. 486. In its Order, the Commission also provided Idaho Power with the authorization and binding commitment to provide rate base treatment for the Company's capital investment in the Langley Gulch plant and related facilities. At such time as the plant is placed in commercial operation, the Commission authorized an increase in rate base in an amount up to $396,618,473. The Company expects the plant to be placed in commercial operation on July 1, 2012.

OVERVIEW OF THE CURRENT APPLICATION

In the current Application, the Company states that the investment in the Langley Gulch plant for purposes of determining the Company's additional revenue requirement is $390,942,172. Using the Company's overall rate of return of 7.86%, as authorized by the Commission in the Company's last general rate case (Order No. 32426), and including depreciation and the applicable tax rates, the Company calculates an additional annual revenue requirement of $59,869,823 for the Idaho jurisdiction. Included in this revenue calculation are certain expenses related to the investment in the Langley Gulch plant including generation and transmission investments, as well as labor and non-labor operation and maintenance (O&M) expenses, depreciation expenses, ad valorem tax expenses, and income tax expenses.

The Company has proposed a uniform percentage increase in rates of 7.18% to all existing customer classes as measured from current base rate revenues, or a 7.10% increase in total current billed revenues, effective July 1, 2012.

In the most recent Idaho Power general rate case (Case No. IPC-E-11-08), $7,191,606 of Langley Gulch investment has already been included in rate base. These expenditures were included in the Company's original Commitment Estimate of $427,366,769 and were included in the Company's plant balances as of December 31, 2010. These expenditures included the costs associated with: 1) site procurement; 2) water rights; and 3) land for the water line. Because the Company used plant balances through December 31, 2010 as the base year amounts in the last general rate case, the $7.2 million amount is already included in the Company's current rates.

Since this Application was filed, a settlement in Idaho Power's most recent depreciation case (Case No. IPC-E-12-08) has been reached, including a change in depreciation rates for the Langley Gulch plant. Therefore, the depreciation expenses for the Langley Gulch plant will be different than the expenses originally proposed in this Application. The decrease in depreciation expenses will affect the additional revenue requirement and rate increase percentage accordingly.

STAFF REVIEW

To establish costs associated with the construction, transmission and facilities attributable to Langley Gulch, Staff performed a detailed analysis of the Company's Application and workpapers. This analysis included a comprehensive project specific review of actual and estimated transmission and plant expenditures. Staff reviewed major contracts, change orders, invoices and financial transactions of the project to insure reasonableness and accuracy.

PLANT INVESTMENT

Idaho Power received its CPCN authorizing the construction of the Langley Gulch plant in Order No. 30892.[1] In Order No. 30892 Idaho Power was granted "assurance" pursuant to *Idaho Code* § 61-541 that it would be allowed to place $396,618,473 in rate base and to recover the corresponding revenue requirement.

In this Application, Idaho Power is seeking rate recovery for $390,942,172 in capital expenditures related to investment in the Langley Gulch project. This is the amount the Company projects it will spend through June 30, net of $7.2 million in site procurement, water rights, and water line land costs already spent and currently included in base rates. However, the Company expects to spend an additional $3,282,796 after June 30 that it will likely seek for recovery in a future rate case. Thus, the total estimated cost of the project is $401,416,574 ($390,942,172 + $7,191,606 + $3,282,796).

[1] See Case No. IPC-E-09-03.

Staff has focused its review in three primary areas. First, because the pre-approved Commitment Estimate is for the cost of the entire project, any review of budget-to-actual expenditures required an analysis of the total project costs. The Company has projected that the total project investment will be $401,416,574, thereby exceeding the Commission-approved Commitment Estimate by approximately $4.8 million. Staff reviewed the Company's budget spending performance and the prudency of expenditures for the total project, not just the amount the Company is seeking in this case. Second, Staff reviewed estimates for spending through the end of the project. This was to ensure that the total project expenses were accurate and that evaluation of budget performance was reasonable and realistic. Third, Staff reviewed the certainty of estimates used to project total spending through June 30, 2012. This was done to ensure that the amount of capital expenditure sought in this case would be accurate so that ratepayers would not be compensating the Company for expenses not realized during the test period.

As noted above, the Company did not receive full approval for its proposed $427 million[2] Commitment Estimate in the CPCN case. Even with a Commission-approved Commitment Estimate of approximately $397 million (about $30 million lower than the Company's proposed amount), the Company has been able to finish the project within 2.0 percent of the Commission-approved Commitment Estimate.

As expected in a project of this magnitude, there was a mix of cost categories above and below budget based on the pre-approved Commitment Estimate. Although Staff reviewed expenditures in all cost categories, Staff conducted additional review of cost categories that were over budget. In addition, prudency of expenditures was evaluated for any item that did not appear to be part of the pre-authorized Commitment Estimate. As illustrated in Attachment A, Staff concentrated on several cost categories that exceeded their Commitment Estimates: site procurement; NEPA permitting; air permitting; water line construction; gas line construction; miscellaneous equipment; Idaho Power engineering and oversight; RFP pricing components; and transmission.

In its review below, Staff has high-lighted four areas. Details for these and other findings in each cost category (except AFUDC which will be discussed in the Rate Base section) can be found in the sub-sections following the summarized highlights and in Attachment A.

[2] See IPC Application at 11 (Case No. IPC-E-09-03).

- Contingency Reserve: The Company created an approximately $300,000 reserve as a contingency to resolve potential issues after June 30, 2012 for final acceptance of the gas and steam turbine not based on any contractual obligation. This reserve has been included in the Company's estimate of total project costs. If incurred, these costs should be scrutinized before recovery in a future case.
- Development Cost: There is $251,894 related to the cost to develop the Company's benchmark resource proposal that Staff believes should not be allowed. Including this cost in the Commitment Estimate after not including it in the Company's winning bid would unfairly bias or undercut the bidding process.
- Transmission: Upgrading the Langley to Wagoner transmission line from a 138 kV line to a 230 kV line is not necessary for the operation of the Langley Gulch project and is not relevant to this single-issue rate case. The approximately $1.2 million incremental cost of the upgrade should be placed in plant held for future use to be recovered in a future general rate case.
- Fiber Cable: There was $75,000 in cost to perform splicing for the fiber communication line between the Langley Gulch plant and the Caldwell substation that won't be incurred until after June 30, 2012. This cost does not occur in the test period and should not be included for recovery in this single-issue rate case.

Given the sum of the adjustments above, Staff believes the total estimated project costs should be reduced from $401,416,574 to $399,966,742 and the total amount allowed for recovery in this case be reduced from $390,942,172 to $389,417,340.

Gas Turbine

Gas turbine expenditures should finish less than one percent under the Commitment Estimate. The remaining expenditure through June 2012 is based on the last payment to the equipment vendor for contractual obligations to meet equipment performance criteria and facilitate final acceptance by Idaho Power. The Company has reserved $150,000 past June 30, 2012 included in the total project costs for any additional change orders that may be needed for final acceptance. If the Company takes title to the equipment by the end of June, there is a good probability that not all of the $150,000 contingency reserve will be needed.

Steam Turbine

The Company expects steam turbine expenditures to be less than one percent over the authorized Commitment Estimate. Staff reviewed the contract, all of the change orders, and cost estimates that make up the Company's expected project expenditure. All future expenses, except $150,000, are covered by the contract and change orders. The original contract was written for a standard steam turbine. Change orders were required to customize the turbine specific to Langley requirements. Staff believes the turbine change orders reflected in the modifications were reasonable and necessary. The remaining expenses through June are based on a last payment to the equipment vendor for contractual obligations to meet equipment performance criteria and to facilitate final acceptance by the Company. The Company has reserved an additional $150,000 past June 30, 2012 included in the total project costs for any additional change orders that may be needed for final acceptance. If the Company takes title to the equipment by the end of June, it is likely not all of the $150,000 contingency reserve will be needed, thereby allowing the steam turbine expenses to finish under the Commission-approved Commitment Estimate.

EPC Contract

Based on the Company's total project estimate, the engineering, procurement, and construction (EPC) contract is projected to be below the Commitment Estimate budget by 2.57 percent or $5,698,263. Estimates for the remaining expenses through June and for the remaining project was based on a projection of monthly cash flow which totals the difference between the contract amount (with change orders) of $215,655,283 and current actual expenditures of $203,287,526 (through end of January 2012). After reviewing the contract, current change orders, and anticipated change orders, Staff determined these estimates to be reasonable given that anticipated change orders include both additional expenses and credits that net to approximately zero. Staff also believes that the scope of work and cost for both current and anticipated change orders are reasonable and necessary for the completion of the project.

Site Procurement

Idaho Power anticipates the total project costs of $2 million for site procurement to be over the Commitment Estimate by $50,000. Staff reviewed all of the actual expenditures and believes them to be reasonable. The entire budget is targeted to be expended by the end of June 2012.

Landscaping and fencing at an estimated cost of $42,678 is the only expenditure the Company anticipates after construction of the facility is complete.

Water Rights

Water rights necessary for the operation of the facility have been obtained. There is no additional spending required. The total project costs were less than a tenth of a percent over the Commitment Estimate of $2,081,269.

National Environmental Policy Act (NEPA) Permitting

The $150,000 budget for the NEPA permitting costs only applies to permitting related to the power plant site, the gas line, and water line on federal lands. Additional NEPA permitting cost for the transmission line was included in the transmission line budget category. All land use permits have been obtained for the Langley facility and spending related to NEPA environmental permitting has been fully expended. The Company went over the $150,000 original Commitment Estimate by $64,431. Most of this was due to unforeseen incremental cultural and biological assessments, a wetland delineation study, new BLM requirements, and changes to water line routes as a result of initial assessment findings. Given the difficulty in trying to predict the amount of unforeseen constraints found during NEPA permitting, Staff believes that additional expenditures were within a reasonable range of costs.

Air Permitting

The Company anticipates the total project costs for air permitting to be over the Commitment Estimate of $320,000 by 22 percent. Staff reviewed all of the actual expenditures and believes them to be reasonable. There were several unforeseen expenditures that caused the overage related to the construction and operation of the meteorological station, legal support costs, and changes required for air modeling. The Company estimates an additional $14,000 prior to June 30 and $25,000 after June 30 will be needed to obtain final Tier I operating permits. These amounts were an estimate based on work conducted for air shed modeling conducted by the contractor earlier in the project. Staff believes that these figures are reasonable although somewhat conservative.

Water Line Construction

Idaho Power anticipates the total project costs for water line construction to be over the Commitment Estimate of $4.425 million by 3.5 percent. The Company predicts an additional $20,000 in total expenditures with all spending completed by June 30, 2012. The cost will be for labor and material for developing maintenance and operation manuals for the water system and to install security alarms. Staff reviewed all actual expenditures and believes them to be reasonable and needed for the completion of the project.

Gas Line Construction

The gas line is fully constructed and the Company anticipates all payments to be completed by June 30, 2012. The Company has projected that the total project costs will be $1,620,000 over the Commitment Estimate of $1.55 million. Because the original estimate the Company submitted as part of the CPCN case was based on estimates rather than competitive bids, the Commission only allowed 50 percent of the estimated. However, the total project cost is anticipated to be very close to the Company's original estimates which were based on an estimate from Williams Pipeline for the pipeline tap and meter; and an estimate from an engineering cost study for construction of the pipeline. Actual cost for construction of the pipeline came under the original estimate, but cost for the tap and meter was approximately $500,000 over William's original estimate. After reviewing the contract, change orders, and actual costs, Staff believes that the cost to construct the gas pipeline was reasonable.

Miscellaneous Equipment (Idaho Power Supplied)

The miscellaneous equipment cost category includes Company-owned vehicles, office furniture and equipment, and any other piece of equipment directly sourced by the Company. Idaho Power projects the total project costs to be $2.57 million over the authorized Commitment Estimate of $331,150. Although only 50 percent of the costs were authorized in the CPCN case for several of the items that were included in the Company's original budget submission, most of the budget overage is due to unforeseen but necessary purchases. Staff reviewed the prudency of all past and projected purchases and believes them to be reasonable and necessary for the operation of the facility. The Company anticipates that all remaining spending should occur before June 30, 2012. Staff believes the Company's estimate for the remaining amount to be reasonably accurate.

Idaho Power Engineering and Oversight

The Company anticipates the cost of engineering and oversight to be 48 percent over the Commitment Estimate budget of $1.9 million. Staff reviewed actual expenditures of approximately $220,000 for materials and approximately $1.73 million for payroll related expenses. Staff also reviewed the remaining expenditures of approximately $330,000 until the end of June and $81,000 from July 1 until project closeout. Staff believes that these estimates have a sound basis and that the total expenses over the life of the project are reasonable for completion of the project. Staff believes that the original Commitment Estimate was low due to unforeseen circumstances that occurred during project construction, especially given the large overall project scope.

RFP Pricing Components (Including Startup Fuels)

The two main costs included in the RFP pricing cost category were: (1) the cost of all Langley Gulch request for proposal (RFP) development activities ($399,000) including the development of the Company's benchmark resource proposal; and (2) the net cost of fuel and energy used and sold, respectively, for facility startup, and performance and acceptance testing at the facility ($4.7 million). The Company estimates that the total project costs for this category will be $5.074 million over the Commitment Estimate of $500,000.

Staff reviewed all actual and estimated costs and found the main reason for the deviation from budget was due to net fuel cost. The initial Commitment Estimates developed during the CPCN case used a rough estimate of four times the net fuel costs needed for the startup of the Company's Danskin simple-cycle combustion turbine (SCCT) power plant. Although Danskin is a natural gas plant, the characteristics of the plant are much different than Langley and the cost of fuel and energy at that time were much different from current prices. A CCCT plant, such as Langley, is an order of magnitude more complex than an SCCT plant and to use a multiplier related to the capacity of the plant to determine net fuel cost was too simplistic. Staff reviewed the basis used to determine the net fuel cost, including actual and estimated fuel/energy usage and their unit costs, and determined that although the costs are over budget, they were reasonable.

The Company estimates that there will be approximately $500,000 in additional net fuel cost that may be needed for acceptance testing past June 30, 2012. Staff expects that these costs may no longer need to be capitalized and any cost of fuel and energy sold will be rolled into normal operations and maintenance expense and revenue.

Staff believes that the costs associated with the development of the Company's benchmark resource proposal should not be allowed for recovery. First, Order No. 30892 establishes that Staff's methodology be used to determine the Commission-approved Commitment Estimate specifically referencing Confidential Exhibit No. 109 of Staff witness Rick Sterling's direct testimony in the CPCN case. None of the RFP team expenses originally proposed by the Company were included in the Commitment Estimate. Furthermore, the reasons for excluding them are stated in Mr. Sterling's testimony[3]:

> ...this is a cost that should not be included in either the Soft Cap or the Hard Cap. Other bidders would have had to include these costs in their bid amount, so it would be unfair for Idaho Power to exclude them from the Benchmark Resource bid during the evaluation process, but add the costs to its Commitment Estimate after it determined that the Benchmark Resource was the winning bid.

Consequently, Staff recommends that $251,894 in employee-related payroll and benefit costs be excluded for rate recovery that is associated with the development of Idaho Power's benchmark resource proposal. However, Staff believes the Commission should allow for consultant costs to be included, as the bulk of its services were used to oversee the overall bidding process.

Transmission Line

The Company anticipates the cost of constructing the two transmission lines necessary for Langley operation to be 24 percent over the Commitment Estimate budget of $17.86 million. Staff reviewed actual spending, contracts and change orders, and all estimates for the total project costs related to the engineering and construction of two transmission line projects and distribution lines supporting Langley Gulch. Staff also compared all costs against estimates and plans included in the CPCN case. Through this analysis, Staff uncovered two issues.

First, Staff believes that a portion of the transmission upgrades included in the project is not necessary for the operation of Langley in its current configuration. According to the Company's response to Staff's discovery requests, this includes all incremental costs (estimated at $1,197,938) related to upgrading the Langley to Wagner transmission line from 138 kV to 230 kV. These costs were excluded in the authorized CPCN commitment budget because it was acknowledged that upgrade of this transmission line was not required for operation of the Langley

[3] See R. Sterling, Di, p. 69, Case No. IPC-E-09-03.

Gulch plant. Staff has confirmed with Idaho Power that these conditions have not changed and that the line will only be energized at 138 kV. Staff recommends that these costs of $1,197,938 be excluded from the current project and placed in the plant held for future use account.

Second, the Company anticipates that all expenditures related to transmission will be completed by June 30, 2012 with one exception. Idaho Power believes that $75,000 of cost for splicing a fiber communication cable currently included for recovery in this case will not be spent until after July 2012. Staff recommends that this cost of $75,000 be deferred for recovery in this case because it does not occur during the corresponding test period.

DEPRECIATION CASE

On February 16, 2012, Idaho Power Company filed an Application with the Idaho Public Utilities Commission for revised depreciation rates for electric plant in service, Case No. IPC-E-12-08. The Company's Application proposed a 30-year life span for the Langley Gulch plant. However, parties agreed to use a 35-year estimated depreciable life as part of the Settlement Stipulation in the depreciation case. As noted above, the case is scheduled to be decided on the same day these comments are due. Given that all parties have agreed to the Settlement, Staff has chosen to incorporate the Settlement depreciation rates for Langley Gulch as well as additional modifications to the depreciable rates of certain transmission and distribution accounts affecting this case. The effect of the depreciation adjustment is a revenue requirement reduction of $1,561,305.

RATE BASE

Rate base is the capital investment to which a fair rate of return is applied to arrive at the net operating income requirement. In this case, rate base is comprised of electric plant in service (EPIS) less accumulated depreciation and less accumulated deferred income taxes. The Company proposed a total system rate base addition for Langley of $351,994,174. Staff recommends, after adjustments for the depreciation case, plant held for future use, disallowance of RFP costs, and an out-of-period item, a system rate base addition of $351,166,786. The depreciation case (see discussions above and below in these comments) results in an increase in rate base of $522,937 due to the reduction in accumulated depreciation. Because accumulated depreciation is subtracted from plant in service, a reduction in accumulated depreciation increases rate base. The plant held for future use (see plant investment section discussion regarding transmission overbuild above) reduces rate base by $1,033,152. Disallowance of RFP costs (see discussion above) also reduces rate base by $216,268. Finally, the out-of-period adjustment reduces rate base by $64,639.

Plant in Service

Plant in Service is the largest component of the Company's Application. The Company included in its Application $390,942,172 of plant on a system basis. Staff proposes to reduce plant on a system basis by the following adjustments (see plant investment section for further information). One, remove $1,197,938 associated with the overbuilt transmission and place it in plant held for future use. Two, remove $251,894 of RFP costs disallowed by Staff. Three, remove $75,000 of costs that will not be incurred in the test period of the filing (out-of-period adjustment). These adjustments reduce total plant to $389,417,340 on a system basis. The rate base section of these comments identifies the net effect of these adjustments on rate base that includes the accumulated depreciation and accumulated deferred income tax. Each adjustment also changes operating expenses in the following areas: depreciation expense, taxes other than income (property tax), deferred income tax expense, investment tax credit, and federal and state income taxes as discussed in the revenue requirement section of these comments.

Allowance for Funds Used During Construction (AFUDC)

Staff recommends that the Company cease accruing AFUDC on all costs in this case that are allowed for recovery in customer rates to prevent over recovery of costs. AFUDC is an accounting mechanism which recognizes capital costs associated with financing construction. Generally, the capital costs recognized by AFUDC include interest charges on borrowed funds and the cost of equity funds used by a utility for purpose of construction. The main purposes of AFUDC are to capitalize with each project the costs of financing that construction; separate the effects of the construction program from current operations; and to allocate current capital costs to future periods when these capital facilities are in service, useful and producing revenue. AFUDC represents the cost of funds used during the construction period before plant goes into service.

When plant is placed in service, the entire cost of the plant, including AFUDC, is added to rate base, where it earns a rate of return and is depreciated over the life of the plant. Staff reviewed the Company's calculations and process to apply AFUDC to construction work orders. Idaho Power calculates and applies AFUDC to Construction Work In Progress (CWIP) qualifying work orders. When the work order is placed in service, the charges to CWIP are moved to

Account 101 – Electric Plant in Service (EPIS). Costs moved to EPIS are not subject to AFUDC. However, because costs are still being incurred on various work orders after the effective date of the rates in this case, to the extent work orders have not been closed to EPIS the Company would be over recovering costs by earning a rate of return through rates and applying AFUDC to those same costs. Therefore, Staff recommends that AFUDC ceases on all costs that are allowed for recovery in rates and therefore includes a return.

Accumulated Depreciation and Accumulated Deferred Income Taxes

Accumulated depreciation requested by the Company is 50 percent of annual depreciation expense. The Company has used the half-year convention to record accumulated depreciation for Langley Gulch. This convention has historically been accepted by the Commission. Accumulated deferred income taxes requested by the Company is also 50 percent of annual deferred income tax expense due to the half-year convention.

REVENUE REQUIREMENT

The revenue requirement for the Langley Gulch plant is calculated by comparing the return on the Langley Gulch rate base (investment in plant and associated adjustments) to the revenue and expenses attributed to the addition of the Langley Gulch plant. Because the overall operating income (revenue less expenses) for Langley Gulch is negative, this amount is considered with the return on rate base to calculate the revenue deficiency. Revenues must be increased sufficiently so that the net income, after income taxes, is equal to the return on the rate base. The annual revenue increase required to make the Company whole, as calculated with Staff adjustments, is $58,105,578 on an Idaho jurisdictional basis, as shown on Staff Attachment B (Column H, line 39).

Incorporated in Staff's depreciation adjustment, as shown in Column C on Staff Attachment B, is a fine tuning in the calculation of current and deferred income taxes. In an update to Staff's Production Request 35, the Company provided Staff with a Jurisdictional Separation Study (JSS) that incorporated the new depreciation rates agreed to in the Settlement Stipulation in the depreciation case, IPC-E-12-08. Staff, in its review, found that this Company spreadsheet not only updated the depreciation rates, but also fine tuned the income tax and deferred tax calculations. The spreadsheets that calculate federal income tax, state income tax, deferred income tax, and the adjustment to the investment tax credit amortization also include some fine tuning to the spreadsheet that calculates current and deferred income tax. In previous versions of the JSS, the Company spreadsheet calculated bonus depreciation on transmission easements, where there otherwise would be no bonus depreciation on this particular plant account. Staff agrees with this fine tuning in the calculation of current and deferred income tax.

The three Staff plant adjustments discussed above are shown in Attachment B. These adjustments include Column D, the transmission overbuild adjustment; Column E, the out-of-period adjustment; Column F, the RFP cost disallowance.

Staff used the most current JSS with the stipulated depreciation rates, and the fine tuning to the spreadsheet that calculated the current and deferred income tax, to calculate the revenue requirement incorporating all Staff adjustments as shown in Column G and Column H on Staff Attachment B.

The following components contribute to the operating revenues and operating expenses for the Langley Gulch plant:

1. Net Power Supply Expense
2. Labor Operations and Maintenance (O&M) Expense
3. Non-Labor O&M Expense
4. Insurance Expense
5. Depreciation Expense
6. Taxes Other than Income Tax or Ad valorem tax expenses (property tax);
7. Deferred Income Tax Expense
8. Investment Tax Credit
9. Federal Income Taxes
10. State Income Taxes

These revenue and expense components are discussed in greater detail below.

1. Net Power Supply Expenses, which includes System Opportunity Sales Revenues were calculated by the Company using the "AURORA" model and represent the changes to power supply expenses as a result of adding the Langley Gulch plant to the model. Staff agrees with the Company's calculation reducing total net power supply expenses by $8,107,160 on a system basis. The calculation of net power supply expenses includes an increase in revenue of $32,274,040 on a system basis for power sales into the wholesale market. In addition, fuel expenses for coal will decrease due to increased generation from Langley and reduced operation of existing coal plants. The decrease in coal expenses is $525,340 on a system basis. Conversely, fuel expenses for

natural gas will increase as Langley Gulch serves a larger percentage of system load. Natural gas expenses are expected to increase by $45,871,730 on a system basis. Non-firm purchases of electricity in the wholesale market will decrease as a result of adding Langley Gulch to the generation fleet. Because Langley Gulch will be available to serve system load, less power purchases will be required. Power purchases will decrease by $21,179,510 on a system basis.

2. Labor Operation and Maintenance (O&M) Expense included in the Application totals $2,120,436 on a system basis. This amount includes annual payroll, with all the payroll loading for items such as payroll taxes and benefits, for 17 full-time employees. These employees have been hired and are currently working for the Company. Staff reviewed the supporting documentation and finds this amount to be reasonable.

3. Non-Labor Operation and Maintenance Expense included in the Application totals $2,681,152 on a system basis. These expenses include amounts for lubricants, fasteners, filters, paints, safety equipment, testing services, cleaning services, chemicals for water treatment, calibration gases, oil testing, vehicle expenses, training and other miscellaneous charges. The Plant Manager for Langley Gulch provided the estimate for the non-labor O&M expenses, using his expertise at a previous plant to arrive at the normal and routine items and expenses necessary for the normal and ongoing O&M of a CCCT power plant. These estimates do not include expenses other than routine O&M costs, and no expenses for major maintenance are included. Staff reviewed the supporting documentation and finds this amount to be reasonable.

4. Insurance Expense included in the Application totals $229,876 on a system basis. This expense is for property insurance for Langley Gulch and associated transmission and substation property. Staff reviewed the supporting documentation and finds this amount to be reasonable.

5. Depreciation Expense included in the Application totals $13,662,682 on a system basis. Depreciation represents the return of capital to the investor over the life of the investment. Staff has made an adjustment to depreciation expense and a corresponding adjustment to accumulated depreciation in rate base, for the change in depreciation rates as a result of the depreciation settlement discussed earlier. To the extent that Staff has made adjustments to plant in service, Staff has also made a corresponding adjustment to depreciation expense (and the accompanying adjustment to accumulated depreciation in rate base). Staff's adjustments reduce depreciation expense by $1,590,636 for a Staff adjusted total depreciation expense of $12,072,046 on a system basis.

6. Taxes Other than Income Tax included in the Application totals $1,432,047 on a system basis. Ad Valorem taxes, or property taxes, on Langley Gulch have been calculated by the Company based on current property tax rates assessed and the value of the Langley Gulch plant as of January 1, 2012. Staff has reviewed the supporting documentation and finds the calculation to be reasonable. To the extent that Staff has made adjustments to plant in service, Staff also made a corresponding adjustment to the property tax. Staff's adjustments reduce property tax by $5,756 for a Staff-adjusted property tax expense of $1,426,291 on a system basis.

7. Deferred Income Tax Expense included in the Application total $64,251,378 on a system basis. Deferred income taxes arise when income tax amounts provided for book or regulatory purposes differ from the amount of taxes currently due and payable. This tax difference is primary caused by the difference between the straight-line depreciation rates used for rate making purposes versus the accelerated depreciation rates used for federal and state income tax purposes. Under this method, there is higher depreciation expense for tax purposes than for regulatory book purposes, causing the taxes computed for regulatory books (and thus, included in revenue requirement) to be more than the taxes actually payable to the Internal Revenue Service and state taxing entities, in the early years of the asset's life. In later years, the situation reverses itself, such that the revenue requirement will reflect a lesser amount of income tax than that which is actually due and payable. To the extent that Staff has made adjustments to plant in service, Staff also made a corresponding adjustment to the provision for deferred income taxes. Staff's adjustment to deferred income tax expense is $195,748 for a Staff adjusted deferred income tax expense of $64,447,126 on a system basis.

8. The Investment Tax Credit Adjustment included in the Application totals $11,140,104 on a system basis. The investment tax credits are tax benefits the Company has received based on the level of plant investment in various years. The tax credit is normally amortized over the life of the associated plant investment. The amount amortized is based on the amount of the plant investment. To the extent that Staff has made adjustments to plant in service, Staff also made a corresponding adjustment to the investment tax credit adjustment. Staff's adjustments reduce investment tax credit adjustment proposed by the Company by $66,558, resulting in a Staff adjusted investment tax credit adjustment of $11,073,546 on a system basis.

9 and 10. Federal Income Taxes of ($64,153,899) and State Income Taxes of ($12,963,928) are included in the Application. Any adjustment to plant in service will change the amount of federal and state income tax owed due to changes in depreciation expense associated

with the various plant accounts. Staff has proposed changes to plant in service as well as to depreciation rates. All the plant in service adjustments and the change in depreciation rates have an effect on income taxes. To the extent that Staff has made adjustments to plant in service and depreciation expenses, Staff has also made a corresponding adjustment to the federal and state income taxes. Staff's adjustment to federal income taxes is $353,156 resulting in adjusted federal income taxes of ($63,800,743) on a system basis. Staff's adjustment to state income taxes is $55,989 for Staff adjusted state income taxes of ($12,907,939) on a system basis.

The Company has proposed using the overall rate of return of 7.86% currently in effect, as authorized by the Commission in the Company's most recent rate case, Order No. 32426, IPC-E-11-08. Although the Langley Gulch CPCN Order stated that the Company was to use the current Return on Equity in effect, Order No. 32426 did not specify a return on equity. The Company believes that the use of the approved overall rate of return is consistent with the spirit of Order No. 30892 in the CPCN case. Staff concurs with using the overall rate of return of 7.86% currently in effect.

The Net Income (Operating Revenues less Operating Expenses) for the Langley Gulch plant on a system basis is shown on Staff Attachment B, (Column G, line 27) as negative $9,609,762. The return on rate base, calculated by multiplying the dollar amount of the rate base by the Company's authorized rate of return, is $27,585,994 on a system basis. The total earnings deficiency on a system basis is $37,195,756. After applying the net to gross factor, the revenue deficiency or increase needed, as proposed by Commission Staff, is $61,075,432 on a system basis, and $58,105,578 on an Idaho jurisdictional basis.

POWER SUPPLY AND PCA LOAD CHANGE ADJUSTMENT

Idaho Power updated power supply costs by running the AURORA power supply model. The Company added Langley Gulch as a resource to the model most recently accepted by the Commission. No other changes were made in the model. Staff believes that this is the correct way to determine changes in power supply costs in this single-issue rate case. The revised AURORA model run produced a reduction in net power supply expense of $7,732,030 on an Idaho jurisdictional basis. This amount was used in the calculation of the Langley Gulch incremental revenue requirement and in a calculation to update the Load Change Adjustment Rate (LCAR) that is part of Idaho Power's PCA calculations. This update reduced the LCAR from $18.16/MWh to

$17.64/MWh as shown on Company Exhibit No. 4. Staff has reviewed these calculations and accepts them.

REVENUE ALLOCATION AND RATE DESIGN

Idaho Power proposes to allocate the incremental revenue requirement and design rates using forecasted billing determinants for the period June 1, 2012 through May 31, 2013. These billing determinants are the most current information available for revenue allocation/rate design. However, they have not been thoroughly reviewed in a general rate case and approved by the Commission. Staff nevertheless accepts and recommends the use of the Company's proposed billing determinants, just as it has done in its comments to all of the Company's other 2012 rate Applications.

The Company's Application requested that $59,869,823 be spread to customer classes on an equal percent of base revenue basis. The Company further proposed that within each class, all rates except customer service charges be increased on a uniform percentage basis to recover the class revenue requirement. The Company's proposal results in an average increase of 7.10% of billed revenue.

Staff accepts the methodology proposed by the Company for revenue allocation and rate design. For revenue allocation purposes, Staff proposes the use of June 1, 2012 base revenues. The Application of this methodology to the incremental revenue requirement proposed by Staff of $58,105,578 produces an equal percent increase in base revenues to all customer classes of 7.05% as shown on Attachment C, page 1 to these comments. The same increase in incremental revenue requirement produces a near equal percent increase in class revenue requirements that averages 6.97% as shown on Staff Attachment C, page 2.

STAFF RECOMMENDATIONS

- Staff recommends the total plant cost to be included for recovery in this case be reduced from $390,942,172 to $389,417,340.
- Staff recommends that the Commission approve an Idaho incremental revenue requirement associated with adding Idaho Power's Langley Gulch plant to base rates of $58,105,578.

- Staff recommends that the increase be spread to each customer class as an equal percent increase based on June 1, 2012 base revenue and that within each class all rates (other than customer charges) be increased on a uniform percentage basis as proposed by the Company.
- Staff recommends that the new rates become effective July 1, 2012 if the facility is in commercial operation at that time or when the facility begins commercial operation if that date is after July 1, 2012.
- Staff recommends that the Company cease accruing AFUDC on all plant costs that are included in rates to prevent double recovery.
- Staff recommends that the LCAR be updated to $17.64/MWh when new rates become effective.

Respectfully submitted this 30th day of May 2012.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Keith Hessing
Kathy Stockton
Patricia Harms
Shelby Hendrickson
Mike Louis

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Langley Gulch Project Budget Performance Summary

	Approved Commitment Estimate	Estimated Project Spend	Amount over Commitment Estimate
Gas Turbine	$56,281,662	$56,243,839	($37,823)
Steam Turbine	$35,710,905	$35,862,359	$151,454
EPC Contract	$221,421,431	$215,723,168	($5,698,263)
Site Procurement	$1,950,000	$2,000,000	$50,000
Water Rights	$2,081,269	$2,083,419	$2,150
NEPA Permitting	$150,000	$214,431	$64,431
Air Permitting	$320,000	$390,000	$70,000
Water Line Construction	$4,425,000	$4,580,000	$155,000
Gas Line Construction	$1,550,000	$3,170,000	$1,620,000
Misc. Equipment (Idaho Power Supplied)	$331,150	$2,570,632	$2,239,482
Capitalized Property Taxes	$2,881,277	$1,444,431	($1,436,846)
Idaho Power Engineering and Oversight	$1,900,000	$2,820,000	$920,000
RFP Pricing Components (including startup	$500,000	$5,574,298	$5,074,298
Transmission*	$17,856,400	$22,170,060	$4,313,660
AFUDC	$49,259,379	$46,569,937	($2,689,442)
Totals	$396,618,473	$401,416,574	$4,798,101

*AFUDC is included in the Estimated Project Spend but is not included in the Commitment Estimate. AFUDC is approximately $1 million.

Attachment A
Case No. IPC-E-12-14
Staff Comments
5/30/12

IDAHO POWER COMPANY
JURISDICTIONAL SEPARATION STUDY
LANGLEY REVENUE REQUIREMENT
IDAHO PUBLIC UTILITIES COMMISSION STAFF

		A	B	C	D	E	F	G	H
				STAFF ADJUSTMENT	STAFF ADJUSTMENT	STAFF ADJUSTMENT	STAFF ADJUSTMENT		
		COMPANY	COMPANY	DEPRECIATION	TRANSMISSION	OUT-OF-PERIOD	RFP COST	STAFF	STAFF
		TOTAL	IDAHO	TAX FINE TUNING	OVERBUILD	COST	DISALLOWANCE	TOTAL	IDAHO
	DESCRIPTION	SYSTEM	RETAIL	IDAHO RETAIL	IDAHO RETAIL	IDAHO RETAIL	IDAHO RETAIL	SYSTEM	RETAIL
4	***SUMMARY OF RESULTS***								
5	RATE OF RETURN UNDER PRESENT RATES								
6	TOTAL COMBINED RATE BASE	351,994,174	336,701,102	522,937	(1,033,152)	(64,639)	(216,268)	351,166,786	335,909,569
7					0	0	0		
8	OPERATING REVENUES				0	0	0		
9	FIRM JURISDICTIONAL SALES	0	0	0	0	0	0	0	0
10	HOKU 1ST BLOCK ENERGY SALES	0	0	0	0	0	0	0	0
11	SYSTEM OPPORTUNITY SALES	32,274,040	30,780,672	0	0	0	0	32,274,040	30,780,672
12	OTHER OPERATING REVENUES	0	0	0	0	0	0	0	0
13	TOTAL OPERATING REVENUES	32,274,040	30,780,672	0	0	0	0	32,274,040	30,780,672
14	OPERATING EXPENSES			0	0	0	0		
15	OPERATION & MAINTENANCE EXPENSES	28,080,105	27,854,301	0	0	0	0	28,080,105	27,854,301
16	DEPRECIATION EXPENSE	13,662,682	13,069,788	(1,492,644)	(20,736)	(1,435)	(8,169)	12,072,046	11,548,056
17	AMORTIZATION OF LIMITED TERM PLANT	0	0	0	0	0	0	0	0
18	TAXES OTHER THAN INCOME	1,432,047	1,369,989	0	(4,355)	(273)	(878)	1,426,291	1,364,482
19	REGULATORY DEBITS/CREDITS	0	0	0	0	0	0	0	0
20	PROVISION FOR DEFERRED INCOME TAXES	64,251,378	61,475,612	446,770	(205,011)	(12,787)	(41,251)	64,447,126	61,662,903
21	INVESTMENT TAX CREDIT ADJUSTMENT	11,140,104	10,658,833	(20,402)	(34,075)	(2,133)	(7,130)	11,073,546	10,595,151
22	FEDERAL INCOME TAXES	(64,153,899)	(61,268,951)	74,342	207,380	12,983	41,155	(63,800,743)	(60,931,115)
23	STATE INCOME TAXES	(12,963,928)	(12,382,082)	(24)	42,237	2,644	8,319	(12,907,939)	(12,328,524)
24	TOTAL OPERATING EXPENSES	41,448,490	40,777,490	(991,959)	(14,559)	(1,000)	(7,954)	40,390,434	39,765,255
25	OPERATING INCOME	(10,667,818)	(9,996,818)	991,959	14,559	1,000	7,954	(9,609,762)	(8,984,583)
26	ADD: IERCO OPERATING INCOME	0	0		0	0	0	0	0
27	CONSOLIDATED OPERATING INCOME	(10,667,818)	(9,996,818)	991,959	14,559	1,000	7,954	(9,609,762)	(8,984,583)
28	RATE OF RETURN UNDER PRESENT RATES	-3.03%	-2.97%				-3.03%	-2.74%	-2.67%
29									
30	DEVELOPMENT OF REVENUE REQUIREMENTS								
31	RATE OF RETURN @ 10.5% ROE	7.860%	7.860%	7.860%	7.860%	7.860%	7.860%	7.860%	7.860%
32									
33	RETURN	27,650,990	26,464,707	41,103	(81,206)	(5,081)	(16,999)	27,585,994	26,402,492
34	EARNINGS DEFICIENCY	38,318,808	36,461,525	(950,856)	(95,765)	(6,081)	(24,952)	37,195,756	35,387,075
35	ADD: CWIP (HELLS CANYON RELICENSING)	0	0	0	0	0	0	0	0
36	DEFICIENCY WITH CWIP	38,318,808	36,461,525	(950,856)	(95,765)	(6,081)	(24,952)	37,195,756	35,387,075
37									
38	NET-TO-GROSS TAX MULTIPLIER	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642
39	REVENUE DEFICIENCY	62,919,483	59,869,823	(1,561,305)	(157,245)	(9,985)	(40,972)	61,075,432	58,105,578

Attachment B
Case No. IPC-E-12-14
Staff Comments
5/30/12

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
June 1, 2012 Rates to Staff Proposed Langley Increase
Effective July 1, 2012

Summary of Revenue Impact
Current Base Revenue to Proposed Base Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers [1]	Normalized Energy (kWh) [1]	Current Base Revenue	Total Adjustments to Base Revenue	Proposed Base Revenue	Cents Per kWh	Percent Change Base to Base Revenue
	Uniform Tariff Rates:								
1	Residential Service	1	399,329	4,896,272,827	$382,557,620	26,989,202	$409,546,822	8.36	7.05%
2	Master Metered Mobile Home Park	3	23	4,942,681	$365,934	25,816	$391,751	7.93	7.05%
3	Residential Service Energy Watch	4	0	0	$0	-	$0	0.00	0.00
4	Residential Service Time-of-Day	5	0	0	$0	-	$0	0.00	0.00
5	Small General Service	7	28,165	144,888,296	$14,438,119	1,018,600	$15,456,720	10.67	7.05%
6	Large General Service	9	31,614	3,480,101,459	$193,609,530	13,659,032	$207,268,561	5.96	7.05%
7	Dusk to Dawn Lighting	15	0	6,481,376	$1,165,133	82,199	$1,247,332	19.24	7.05%
8	Large Power Service	19	116	1,978,623,647	$84,056,432	5,930,129	$89,986,561	4.55	7.05%
9	Agricultural Irrigation Service	24	16,642	1,720,204,410	$107,859,524	7,609,422	$115,468,947	6.71	7.05%
10	Unmetered General Service	40	2,030	15,807,753	$1,094,576	77,222	$1,171,798	7.41	7.05%
11	Street Lighting	41	361	23,165,568	$2,939,669	207,392	$3,147,061	13.59	7.05%
12	Traffic Control Lighting	42	397	2,981,282	$140,093	9,883	$149,976	5.03	7.05%
13	Total Uniform Tariffs		478,677	12,273,469,299	$788,226,630	55,608,898	843,835,528	6.88	7.05%
14	Special Contracts:								
15	Micron	26	1	451,138,622	$17,298,128	1,220,372	$18,518,500	4.10	7.05%
16	J R Simplot	29	1	203,558,197	$6,787,889	478,881	$7,266,771	3.57	7.05%
17	DOE	30	1	244,266,665	$8,466,979	597,340	$9,064,319	3.71	7.05%
18	Hoku - Retail	32	1	0	$2,836,120	200,087	$3,036,207	0.00	7.05%
19	Total Special Contracts		4	898,963,484	$35,389,117	2,496,680	$37,885,797	4.21	7.05%
20	**Total Idaho Retail Sales**		**478,681**	**13,172,432,783**	**$823,615,747**	**$58,105,578**	**$881,721,325**	**6.69**	**7.05%**

Idaho Power Company
Calculation of Revenue Impact
State of Idaho
June 1, 2012 Rates to July 1, 2012 Rates (Langley Gulch Increase)
Effective July 1, 2012

Summary of Revenue Impact
Current Billed Revenue to Proposed Billed Revenue

Line No	Tariff Description	Rate Sch. No.	Average Number of Customers (1)	Normalized Energy (kWh) (1)	Current Billed Revenue	Total Adjustments to Billed Revenue	Proposed Total Billed Revenue	Cents Per kWh	Percent Change Billed to Billed Revenue
	Uniform Tariff Rates:				w/4 Base	Langley			
1	Residential Service	1	399,329	4,896,272,827	$392,790,830	$26,989,202	$419,780,032	8.57	6.87%
2	Master Metered Mobile Home Park	3	23	4,942,681	$376,264	$25,816	$402,081	8.13	6.86%
3	Residential Service Energy Watch	4	0	0	$0	$0	$0	0	0
4	Residential Service Time-of-Day	5	0	0	$0	$0	$0	0	0
5	Small General Service	7	28,165	144,888,296	$14,845,545	$1,018,600	$15,864,146	10.95	6.86%
6	Large General Service	9	31,614	3,480,101,459	$193,701,774	$13,659,032	$207,360,806	5.96	7.05%
7	Dusk to Dawn Lighting	15	0	6,481,376	$1,174,563	$82,199	$1,256,763	19.39	7.00%
8	Large Power Service	19	116	1,978,623,647	$83,784,476	$5,930,129	$89,714,605	4.53	7.08%
9	Agricultural Irrigation Service	24	16,642	1,720,204,410	$108,055,628	$7,609,422	$115,665,050	6.72	7.04%
10	Unmetered General Service	40	2,030	15,807,753	$1,097,343	$77,222	$1,174,564	7.43	7.04%
11	Street Lighting	41	361	23,165,568	$2,959,058	$207,392	$3,166,450	13.67	7.01%
12	Traffic Control Lighting	42	397	2,981,282	$139,878	$9,883	$149,761	5.02	7.07%
13	Total Uniform Tariffs		478,677	12,273,469,299	$798,925,359	$55,608,898	$854,534,257	6.96	6.96%
14	Special Contracts:								
15	Micron	26	1	451,138,622	$17,204,291	$1,220,372	$18,424,664	4.08	7.09%
16	J R Simplot	29	1	203,558,197	$6,740,257	$478,881	$7,219,138	3.55	7.10%
17	DOE	30	1	244,266,665	$8,408,844	$597,340	$9,006,184	3.69	7.10%
18	Hoku - Retail	32	1	0	$2,836,120	$200,087	$3,036,207	0	7.05%
19	Total Special Contracts		4	898,963,484	$35,189,512	$2,496,680	$37,686,192	4.19	7.09%
20	**Total Idaho Retail Sales**		**478,681**	**13,172,432,783**	**$834,114,871**	**$58,105,578**	**$892,220,449**	**6.77**	**6.97%**

Attachment C
Case No. IPC-E-12-14
Staff Comments
5/30/12 Page 2 of 2

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **30TH** DAY OF MAY 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-12-14, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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