BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 233

In the Matter of	)
IDAHO POWER COMPANY	)
Request for a general rate revision	)

OPENING TESTIMONY OF THE
CITIZENS' UTILITY BOARD OF OREGON

December 7, 2011

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IDAHO POWER COMPANY	)	
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Our names are Gordon Feighner and Bob Jenks, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

CUB submits its Opening Testimony in this docket with the knowledge that all issues presented by Idaho Power Company (hereafter, "Idaho Power" or "the Company") in its initial filing are on the table. The first round of settlement negotiations on November 21 and 22 ended without the parties reaching even a partial settlement of the issues.

CUB's testimony in this docket will focus on several topics. Section II will address the general upward trend of Idaho Power's rates and the negative impact that these increases are having on Oregon ratepayers. Section III will discuss the Company's proposed rate spread and rate design and CUB's opposition to Idaho Power's proposed seasonal rate structure. Section IV will address CUB's proposed adjustments, including the Company's proposed increase in its rate of return; the Company's allocation methodology for its distribution system; the Company's treatment of capital investments in clean air compliance at its coal plants; the Company's director and officer insurance; the Company's structure for wages and salaries; and the Company's methodology for allocating expenses and benefits related to Advanced Metering Infrastructure (AMI). Section V concludes the testimony and includes a summary of CUB's adjustments.

II. Idaho Power's Rates Are Increasingly Unaffordable

Idaho Power provides electric service in a relatively poor part of Oregon. The median household income in Ontario is $35,661, well below the state median household income of $50,166.[1] Nevertheless, Idaho Power's residential customers in Oregon have been subjected to significant rate increases the past few years. CUB Exhibit 102 shows that the Company's average residential customer in Oregon has seen a cumulative rate increase of over 36% since 2008. In 2010 alone residential rates increased by 27.53%. Oregon rates are now higher than those in Idaho, even though load growth in Idaho has been the driver of the Company's costs for years (this will be addressed further in Section III, below). It would be extremely difficult for customers to swallow yet another significant increase such as the one proposed in this docket.

The most dire consequence of Idaho Power's continually increasing rates has been the marked increase in the number of customers who have had their electricity service disconnected due to nonpayment. CUB Exhibit 103 shows the number of customer disconnections each month in Idaho Power's Oregon and Idaho service territories from 2008 to 2011. In 2011, the monthly average so far in Oregon is 85

[1] http://www.city-data.com/city/Ontario-Oregon.html.

disconnections, which is an increase from an average of 58 in 2008.[2] Disconnections in Idaho, meanwhile, have remained relatively stable. Even given the limited sample size, an increase of more than 30% in disconnections in Idaho Power's relatively small Oregon service territory indicates that a considerably higher number of customers are having difficulty paying their electric bills this year. Even more alarming is the fact that as shutoffs in Oregon have increased, the number of Oregon customers receiving energy assistance through Project Shares has decreased and is now approximately half of what it was in 2007-08.[3]

The amount of customer arrearage is also increasing, meaning customers are finding it more difficult to keep up with payments. CUB Exhibit 103 shows that the average amount owed by Oregon customers at the time a disconnection notice was issued was $175 in 2008.[4] That number has climbed steadily over the past few years, and the average amount owed in 2011 is $247, an increase of over 41%. It is clear that Idaho Power's rate hikes are outpacing the rate of inflation and are becoming increasingly difficult to manage for the Company's Oregon customers.

III. Residential Rate Design

Idaho Power is proposing several changes to rate design in Oregon. First, the Company is proposing an increase in the customer charge from $8/month to $10/month.[5] Second, it is proposing to increase the amount of usage available in the first tier of usage from 300 to 1,000 kWh/month.[6] Third, it is proposing to impose a seasonal rate structure that will result in higher summer rates for residential customers in the months of June,

[2] CUB Exhibit 103, page 3-4.
[3] See CUB Exhibit 104.
[4] CUB Exhibit 103, pages 13-15.
[5] Idaho Power / 1100 / Nemnich / 5.
[6] *Ibid*., page 6.

July and August.[7] CUB will address the seasonal rate issue first, since its views on the other issue grow out of concerns over seasonal rates.

A. Seasonal Rates

Idaho Power makes two justifications for a significant increase in summer rates. The Company claims that seasonal rates will both send a correct price signal and encourage customers to use energy more efficiently:

> My proposal supports the continuation of tiered rates and the implementation of seasonal rates, both of which encourage customers to use energy more efficiently in response to the appropriate price signals.[8]

And:

> The current residential rate design, which does not include a seasonal component, does not provide customers with any indication that the costs incurred by the Company to provide them energy service during the three summer months are significantly greater than the nine non-summer months.[9]

i. UM 1415

Earlier this year, the PUC opened up a new phase of UM 1415 to investigate how to evaluate proposals for mandatory time-varying rates, such as seasonal rates. The proposal from the Commission listed a series of factors to be used to create an analytical framework for considering such rates, as well as a series of directives to utilities to ensure that such programs are being considered:

> The factors in the straw proposal are intended to create a broad analytical framework for approving or rejecting a mandatory time-varying rate proposed by a party in a general rate case or other tariff filing. The directives are distinct from the factors. They are intended to create a process by which the Commission is assured that electric utilities, with input from Staff and stakeholders, are systematically evaluating promising time-varying rate designs or programs, and the costs and benefits of those

[7] *Ibid*., pages 7-8.
[8] *Ibid*., page 3.
[9] *Ibid*., page 8.

> rates and programs. Just because a rate is evaluated does not mean it will be proposed by a party or approved by the Commission. The Commission also clarified that this evaluation process does not necessarily need to occur as part of the Integrated Resource Planning (IRP) process. Moreover, the evaluation of time-varying rates need not be limited to mandatory rates.[10]

In that proceeding, Idaho Power, CUB, Staff, and many other parties weighed in on how the Commission should consider time-varying rates. A decision has not been reached in that docket, and CUB believes that it is premature to move forward with a seasonal rate proposal before the Commission has ruled on the factors it would like to consider.

CUB believes that Idaho Power has failed to address the correct factors in its proposal for seasonal rates. In the first Straw Proposal, the Commission identified the following factors for consideration:

> F-l. The amount of demand-side resource and system benefits that can be tapped through a time-varying rate.
>
> F-2. The extent to which an optional rate or alternative program can achieve that resource.
>
> F -3. The impact on customers of the proposed rate (*e.g.* rate shock, bill impacts on vulnerable populations) and the ability of customers to respond to those impacts.
>
> F-4. The means available to mitigate impacts on customers (*e.g.* phasing in of rate differentials, opt-in and opt-out provisions, providing programmable equipment or software to enable customers to respond more easily).
>
> F-5. The direct costs of implementing time-varying rates (*e.g.* IT costs, accounting).
>
> F-6. The ability to explain and communicate the rate to customers.

[10] UM 1415, Memorandum, September 30,2011, page 1.

F -7. The cost differential between the relevant time periods, how robust the cost studies are, and whether customer response to the time-varying rate is expected to affect the cost differential over time.[11]

Parties also suggested other factors in the proceeding. CUB suggested the following factors should be considered:

- **Arrearages.** Arrearages are the measure of how far customers are behind on their bills. Looking at whether arrearages are growing on an annual basis, and how they change each month, can help provide an indication about affordability. Arrearages that are growing from year to year indicate that customers are generally having trouble keeping up with the rates charged by the utility. Increases that are associated with particular months indicate which bills create the largest affordability problems.
- **Shutoffs.** Shutoffs ultimately grow out of arrearages, but they provide a different metric. When shutoffs are growing (as they currently are across all three electric utilities), it is a sign that care must be taken before raising the cost of monthly bills.
- **Relationship of median household income to electric bills.** How much are the costs at issue rising as compared to incomes? This is a classic way to assess the affordability of rates. The best metric for this, in CUB's opinion, is to look at the percentage of household income which would go to electricity if the house had median income and average usage.
- **Correlation between forecasted peak costs and actual peak costs.** As discussed in CUB's opening comments and at the Commission workshop, hydro conditions have a large effect of summer energy costs in the region. Since costs are set on a forecasted basis and it is difficult to forecast the variability of hydro conditions, there should be an assessment of how often and how close the forecasts are to reality. While the goal may be to set price signals that reflect costs, the evidence might suggest a forecasted rate will only reflect actual costs on a random basis.
- **Load shape of Customer class.** Residential customers are winter peaking for all three electric utilities. As mandatory time-varying pricing is considered the Commission should examine load shapes to determine whether the problem being addressed is significant or not, and whether the proposed solution will have an effect.
- **Customer growth**. Customer growth is a very real driver of higher energy costs and a large part of what is causing rates to increase faster than incomes. The Commission should look at how customer growth is driving the costs of the utility before raising the bills of customers who

[11] UM 1415, OPUC Order No: 11-255, Attached Straw Proposal, page 1.

> are paying significantly higher rates due to this load growth, but are not themselves contributing to the load growth. [12]

Idaho Power has made no attempt in its filing to systematically address the factors listed in the straw proposal by the Commission or the factors proposed by CUB and other parties in their comments on the straw proposal. Instead, Idaho Power essentially claims that because its marginal cost study shows higher summer costs, that fact alone justifies seasonal rates. The other factors are ignored.

ii. Higher Summer Costs

Idaho Power claims that its seasonal rate proposal simply reflects higher costs in the summer months:

> Idaho Power continues to be a summer peaking utility with its highest system peak occurring during the summer months. The unit costs resulting from the Company's proposed cost-of-service study indicate that the residential kilowatt-hour unit cost is approximately 61percent higher in the summer than for the non-summer months. In fact, the unit cost differential for the generation function alone, as provided by the marginal cost allocation methodology described by Mr. Larkin, results in a summer differential of more than 127 percent over the non-summer months.[13]

And:

> As shown in Mr. Larkin's Exhibit 1006 on page 2, and discussed on page 7 above, the summer season cost-of-service unit costs for energy are much higher than the non-summer seasonal cost-of-service unit costs for energy.[14]

But page 2 of Mr. Larkin's Exhibit 1006 is not so clear cut. First, it shows that the Company's per-unit energy costs are ***lower*** in the summer than the winter. Energy in the summer has a unit cost of $.02309, where energy in the non-summer months has a unit cost of $0.2457. This is not surprising, since Idaho Power is a hydro utility and there is a great deal of low-cost hydro power being produced during the summer months. It is the

[12] UM 1415, Reply Comments of Bob Jenks on Behalf of CUB, page 10-11.
[13] Idaho Power /1100 / Nemnich / 7.
[14] Idaho Power / 1100 / Nemnich / 10.

capacity (or demand) costs where the Company claims higher costs. Demand in the summer has a unit cost of $.05264 versus $0.00870 in the non-summer months.

a. Summer Energy Costs

Idaho Power is a hydro utility and has a great deal of hydro generation that is available in the summer, resulting in lower generation costs during those months in most years. CUB Exhibit 105 shows Idaho Power's hydro generation over the last five years. In four of those years, hydro production peaked in June. In three of the five years, July was the third most productive month for hydro power. Hydropower is Idaho Power's least cost resource and, as shown in CUB Exhibit 105, is readily available in the summer months. Customers have paid for the rate base associated with this generation, and to the degree it is being produced in the summer, it should be available for customers to use.

b. Summer Capacity Costs

Idaho Power also claims to have higher capacity costs in the summer months.[15] These costs, however, reflect the resource decisions that Idaho Power has made to serve growing load in Idaho, not the cost of serving Oregon's winter-peaking residential load.

CUB Exhibit 106 shows mid-C high load hour prices for 2010 and 2011. In both cases August is the higher cost month, but June and July are lower than September in both years. In 2011 July prices were also lower than November prices. The difference between these costs and the demand costs listed in Idaho Power's case is the difference between the short-run marginal costs of demand and the long-run marginal costs of demand.

Idaho Power's IRP makes clear that the long-run cost of capacity is driven by load growth, which has occurred almost completely in Idaho. Since 1990, Idaho Power's retail

[15] Idaho Power / 1100 / Nemnich / 8.

customers have grown by 68%, from 292,000 to 492,000.[16] Each new residential customer requires a capital investment of $1,800 in energy and $4,000 in capacity.[17] Of these 200,000 new customers added since 1990, only 1,625 – less than 1%[18] – were added in Oregon.[19] This means that while Oregon makes up a little under 4% of Idaho Power's total customer count,[20] it has accounted for less than 1% of the load growth over the last 20 years, and thus less than 1% of these extraordinary capacity costs. Load growth over this period has caused the need for expensive capacity resources. Idaho Power charges higher rates to its Oregon residential customers, even though it is load growth in Idaho that is driving costs. Instead of summer rates, Oregon should be asking Idaho Power to allocate the cost of load growth to the jurisdictions that are growing. It is time for Oregon customers to stop subsidizing Idaho.

iii. No Evidence Seasonal Rates Will Reduce Demand

The first factor proposed by the Commission in UM 1415 is related to demand response: "[t]he amount of demand-side resource and system benefits that can be tapped through a time-varying rate."[21] Idaho Power already has seasonal rates for residential customers in Idaho.[22] CUB Exhibit 107 is Idaho Power's response to CUB Data Request 20. CUB requested "any evidence" that seasonal rates were reducing peak loads in Idaho. The Company's answer was that it has no evidence that seasonal rates reduce load.

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[16] LC 53, Idaho Power 2011 IRP, page 23.
[17] *Ibid*, page 25.
[18] Oregon is the 1%, Idaho is the 99%.
[19] Oregon Utility Statistics, OPUC, 2010 and 1990.
[20] In 2010, there were 18,455 customers in Oregon divided by 492,000 total customers.
[21] UM 1415, OPUC Order No: 11-255, Attached Straw Proposal, page 1.
[22] Idaho Power / 1100 / Nemnich / 8.

iv. Evidence That Seasonal Rates Will Harm Customers

CUB believes there are two big questions regarding time-varying rates. The first question is whether such rates bring benefits to the system. CUB finds that in this case, there is no evidence to support such a finding. The second question is whether such rates are likely to harm customers. There is a great deal of evidence to support the notion that seasonal rates are harmful to customers, some of which has already been shown in this testimony. Residential rates have been increasing and shutoffs and arrearages have surged. But there is also evidence that points to problems with seasonal rates, not just rates in general.

CUB Exhibit 103 contains a wealth of data that demonstrates the level at which Idaho Power's Oregon customers are struggling. It is clear from this Exhibit that customers are having trouble paying summer cooling bills. Shutoff notices and disconnections for nonpayment typically increase through the winter and peak just after the winter in the March and April period. This is due to the time lag it takes before customers fall 60 or more days behind on their bill. In 2008 and 2010, there is clearly a second peak of disconnection notices in the September and October period, which follows the summer cooling season.[23] In 2008, October was the peak month for disconnection notices. In 2010, September and October were the top two months for disconnection notices. This trend follows into disconnections. In October 2010, 104 Oregon customers were disconnected in October. This year, 109 Oregon customers were disconnected in August.[24]

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[23] CUB Exhibit 103, pages 1-3.
[24] *Ibid*., pages 3-4.

These numbers clearly show that higher summer rates will cause harm to customers. Customers are already struggling to pay for the cost of cooling their homes in the summer, and increasing that cost by a significant amount will only increase the problem.

v. Air Conditioning Customers

Staff has argued that customers with air conditioning need to be charged more for electricity out of a principle of fairness and equity:

> Staff was mindful of this principle when advocating summer-seasonal rates for Idaho Power's Oregon residential customers in Docket UE 213. Staff assumes a high correlation of natural-gas-heating central air-conditioned customers with higher income customers and of swamp-cooling, electric-resistance-heating customers with lower income customers.[25]

But the data concerning shutoff notices and disconnections suggests that Staff's assumption might not be correct. CUB argued in UE 213 that there was not a great deal of natural gas service in Idaho Power's service territory and that much of the air conditioning load was in fact not high income customers but customers who live in manufactured homes.[26] According to Consumers Union, "[A]lmost all mobile homes have forced-air heating and air conditioning."[27]

CUB asked Idaho Power about the number of manufactured homes in its Oregon service territory, and even we were surprised by the answer: 21% of the Company's Oregon customers live in a manufactured or mobile home.[28] Most of these manufactured homes are not new – there has been little new customer growth in Oregon for 20 years. This means that most of these manufactured homes are likely not very efficient.

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[25] *Ibid*, page 3.
[26] UE 213 / CUB / 100 / Jenks / 3.
[27] http://www.consumersunion.org/other/mh/brochure.htm.
[28] See CUB Exhibit 108.

B. Customer Charge

CUB opposes Idaho Power's proposal to increase the monthly residential customer charge from $8 to $10. This proposal would increase costs on low use customers and runs counter to Idaho Power's claimed need to reflect higher costs in energy prices and encourage more efficient use of electricity. CUB believes that keeping the focus on cost recovery through volumetric rates and rejecting seasonal rates is the approach that strikes the best balance between volumetric price signals and helping customers manage bills. CUB therefore respectfully requests that the Commission leave the monthly customer charge unchanged at $8/month.

C. Tiered Rates

CUB generally supports moving the tiers between residential rate levels from 300 kWh/month to 1000 kWh/month. Such a move would better reflect a difference between basic electricity use and electricity use that includes heating and cooling. However, CUB recognizes that with shutoffs and arrearages on the increase, such a move can only be made if it does not create rate shock for a significant number of customers. Recognizing that Staff will likely weigh in with a different rate design and the revenue requirement will likely be lower than Idaho Power requested, it is difficult to know whether such a change will cause rate shock to customers at some usage levels.

CUB recommends that the tier between rate levels for residential customers be increased from 300 to 1000 kWh/month. This recommendation is contingent upon the assumption that the Commission will find that, based on the revenue requirement and other rate design elements, such a change in the tier levels can be accomplished without causing rate shock to customers with some usage levels.

IV. CUB's Proposed Adjustments

CUB proposes a number of adjustments to Idaho Power's revenue requirement based on a review of the Company's initial filing and its responses to data requests from intervenors.

A. Rate of Return

Idaho Power certainly cannot be accused of a lack of audacity in its proposal to increase its rate of return in this docket. Idaho Power witness Steven Keen argues at length in his testimony that the Company's allowed Return on Equity (ROE) should be increased to 10.5%.[29] Keep in mind that this request follows on the heels of an allowed ROE of 10.175% that was set in Docket UE 213 and became effective on March 1, 2010.[30] Given that the Company's initial filing in this docket was dated July 29, 2011, this means that after little more than one year of operation under a 10.175% ROE Idaho Power feels it is appropriate to seek another increase that will result in increased profits for the Company with a corresponding increase in rates for its already struggling customers. Surely even Idaho Power has noticed that its customers cannot afford another rate increase.

Idaho Power claims a number of issues are combining in the current economic climate that increase its operational risks. While times may arguably be difficult for the Company, there is no denying that times are worse for many of its customers. Idaho Power's Oregon service territory is one of the poorest parts of the state, and there has been little in the way of economic development in recent years. The fact that electricity

[29] Idaho Power / 500 / Keen / 4.
[30] Order No. 10-064, page 3.

rates for the average residential customer have increased by over 36% since 2008[31] continues to make things harder for the people who live in the Company's Oregon service territory. Further increasing rates to fund an increase in the Company's allowed ROE will exacerbate the already existing level of rate shock.

The Company also cannot have failed to notice that other utilities in other states are not obtaining ROEs greater than 10% any more. PacifiCorp's most recent general rate case in the state of Washington resulted in that company receiving an allowed ROE of 9.8%.[32] This has been true of other utilities in other states, too. CUB Exhibit 109 contains a table summarizing a number of recent Commission decisions from around the country that ordered ROEs below 10%. These decisions affect utility operations in 11 states. The bottom line here is that many Commissions are recognizing that the cost of capital for utilities has decreased during this economic downturn, thereby justifying lower utility ROEs.

CUB respectfully requests that the Commission also recognize the effect that the economic climate is having on the cost of capital and not approve Idaho Power's proposed increase in ROE and instead adopt a reasonable level, commensurate with current economic conditions, based on Staff's recommendations.

B. Allocation of Distribution Costs

Idaho Power's methodology for allocating the cost of line transformers results in Oregon customers subsidizing load growth in Idaho. CUB Exhibit 110 shows that the Company has been allocating the cost of line transformers in Account 368 based on the number of underground and overhead line miles, which places approximately 9.1% of the

[31] See CUB Exhibit 102.
[32] Washington Utilities and Transportation Commission, Docket UE-100749, Order No. 06.

cost of transformers on to Oregon customers. This makes little sense. Distribution plant should be directly assigned to the state where the distribution plant is located. There is no reason to allocate distribution plant because such plant is not shared between the states.

There are several reasons to believe that allocating the cost of line transformers based on conductor miles assigns Oregon an unfair share of the total costs.

- Idaho Power's service territory in Oregon is growing much more slowly than its territory in Idaho. Since 1990, Oregon represents less than 1% of the customer growth of the system.[33] Customer growth is the biggest driver of investment in the distribution system, including line transformers. With Oregon representing less than 1% of the growth, it is safe to assume that not many new transformers are being installed in Oregon.

- Oregon's land use planning laws and rules place restrictions on building outside of urban growth boundaries. By limiting the number of buildings that may be developed in farm and forest lands, Oregon limits the need for additional line transformers.

- While Idaho Power's service territory in Oregon is rural, much of the housing is located in relatively dense enclaves within that area. More than 20% of the Company's Oregon customers live in mobile and manufactured housing.[34] When housing is compact, one line transformer can serve several homes.

CUB recommends that until the Company can demonstrate that it is directly assigning the cost of line transformers to the state where the transformer is located, the Commission should limit the assigned Oregon costs to no more than 1% of the total cost of line transformers, which is a little greater than Oregon's share of system load growth.

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[33] LC 53, Idaho Power 2011 IRP, page 23.
[34] CUB Exhibit 108.

C. Clean Air Compliance Costs

CUB had been under the impression that the total cost of emission control technology placed into service during the test period was limited to a few thousand dollars. However, Idaho Power's Errata Exhibit 901 (filed on December 2, 2011) indicates that over $8 million in investments in emission control upgrades at the Jim Bridger coal plant went into service in July 2011.[35] The Company's initial filing indicated an in-service date for this investment of July 2008, so CUB did not previously feel the need to thoroughly investigate this expenditure.

This error is troubling to CUB. For such a large adjustment to be made evident only a few days before the deadline for intervenor testimony places CUB in the position of not being able to fully review the prudency of the investment. As such, CUB has no choice but to request that the Commission disallow Idaho Power's investments in emission control upgrades at the Jim Bridger plant for the Company's failure to demonstrate prudence. The total investments placed into service in 2011 in the project (Project ID B00900447) amount to $8.2 million on a system basis. Assuming a 4.88% capital allocation factor, CUB recommends an Oregon adjustment of $402,000 to rate base.

D. Director and Officer Insurance

Idaho Power purchases three tiers of insurance for directors and officers. This insurance is primarily used to shield directors and officers from lawsuits filed against the Company's management by shareholders. It is reasonable for the Company to provide a standard, primary insurance policy for these executives that is assessed to customers, as

[35] Idaho Power / 901 / Noe / 2, line 42 (Errata).

this policy helps to protect customers from the risk of having to pay for legal settlements. Idaho Power, however, also provides two additional (excess) tiers of insurance for executives. CUB contends that the expense of these two layers should be shared equally between customers and shareholders, as shareholders both benefit from protection from lawsuits and are more than likely to be the recipient of any payout from this insurance. Since half of the expenses for the first and second layers of executive insurance should be disallowed, CUB recommends an adjustment of $350,000 on a system basis. Applying a 4.58% labor allocation factor results in an Oregon adjustment of $16,000.[36]

E. Wages and Salaries

Idaho Power's wage and salary expenses continued to grow in 2011, despite a relative lack of growth in customer base and load. CUB Exhibit 112 is Idaho Power's response to Staff Data Request 94. This response details the Company's annual actual wage and salary expenses for the years 2007-2011. CUB notes a few disconcerting trends in this data. First and foremost, total wage and salary expenditures increased more than 16% from 2007 to 2011, while the total number of FTEs increased by only around 2%. Furthermore, the Company had claimed that its investment in AMI would result in lower payroll expenses and a smaller staff. Instead, the number of FTEs has increased by nearly 100 from 2009 to 2011, again during a period of very low load growth. For the above reasons, CUB proposes a significant adjustment related to meter reading labor costs in Section E below.

Another aspect of Idaho Power's wage and salary expenses that is of concern to CUB is the relatively high number of executive officers retained by the Company. CUB

[36] See CUB Confidential Exhibit 111.

Exhibit 113 details CUB's calculations on this issue. This filing indicates that Idaho Power has 16 executive officers on its payroll in 2011, up two from previous years. PGE and PacifiCorp, for comparison, have significantly fewer officer positions, even though those companies are larger and serve more customers. Given the above, CUB recommends that the Commission disallow 25% of the wage and salary costs for Idaho Power's officers so as to effectively reduce the number of officers at Idaho Power to that of PGE (a reduction from 16 to 12). CUB thinks this is generous given that Idaho Power is a smaller utility. This adjustment totals $1 million on a system basis, and $49,000 on an Oregon allocation basis after accounting for the division of executive salaries between O&M and Capital.[37]

F. AMI System Operations Benefits

Idaho Power recently completed the upgrade of its meters in Oregon to AMI. The new infrastructure should realize significant savings in costs associated with labor, transportation, and O&M. The Company estimates that AMI enabled it to achieve significant savings in operational costs for 2011.[38] Upon review of documents provided by the Company, CUB finds additional savings that should be able to be achieved in meter reading operations.

CUB Exhibit 114 contains part of Idaho Power's response to Staff Data Request 343. The Company's Third Supplemental Response included the spreadsheet that contained the data in this exhibit. Idaho Power continues to model significant costs related to meter reading and transportation, even though the installation of AMI is largely complete and these costs should have been nearly eliminated. Nevertheless, annualized,

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[37] See CUB Exhibit 113.
[38] Idaho Power / 300 / Kline / 5.

levelized costs from these two expenditures remain and are expected to increase in future years. CUB respectfully recommends that the Commission remove the entirety of Idaho Power's labor and transportation costs related to meter reading. The levelized costs are $5.6 million for labor and $1.1 million for transportation. Using allocation factors for labor and O&M for Oregon, the total requested adjustment is $309,000.

V. Conclusion

CUB is concerned about the impact of yet another rate increase on Idaho Power's Oregon customers. In a time when economic difficulties are lowering the cost of capital, it is difficult to justify awarding the Company a higher ROE. When Oregon residential customers are winter-peaking and do not drive Idaho Power's summer peak, it is also difficult to justify adopting a new seasonal rate structure. And it is difficult to justify increasing the monthly customer charge when energy conservation is a stated goal of the utility. In addition to opposing these proposals from the Company, CUB also recommends that the Commission make the following adjustments to Idaho Power's Oregon revenue requirement:

- Remove $402,000 from clean air capital expenditures
- Remove $16,000 from director and officer insurance expenses
- Remove $49,000 from executive compensation
- Remove $309,000 from meter-reading expenses due to savings from AMI

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, and UM 1355. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

WITNESS QUALIFICATION STATEMENT

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EDUCATION:	Master of Environmental Management, 2005 Duke University, Durham, NC Bachelor of Arts, Economics, 2002 Reed College, Portland, OR
WORK EXPERIENCE:	I have previously provided testimony in dockets including UE 196, UE 204, UE 207, UE 208, UE 210, UE 213, UE 214, UE 216, UE 217, UE 219, UE 227, UE 228, UM 1355, UM 1431, and UM 1484. I have also completed the Annual Regulatory Studies Program at the Institute of Public Utilities at Michigan State University in 2010. Between 2004 and 2008, I worked for the US Environmental Protection Agency and the City of Portland Bureau of Environmental Services, conducting economic and environmental analyses on a number of projects. In November 2008 I joined the Citizens' Utility Board of Oregon as a Utility Analyst and began conducting research and analysis on behalf of CUB.

CUB'S DATA REQUEST NO. 12:

Refer to Idaho Power / 200 / Anderson / 18. Please provide the top graph on the page with the addition of lines charting the growth in Idaho Power's Oregon rates and the growth of average annual income for Oregon residents.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 12:

The table below reflects the average annual mills/kWh and percent change for an Oregon residential customer using 1,240 kWh per month. Idaho Power is not in possession of the average annual income for Oregon residents.

Year	Average Mills/kWh	Percent Change
2005	48.39	
2006	49.02	1.30%
2007	49.02	0.00%
2008	52.07	6.23%
2009	55.56	6.70%
2010	70.85	27.53%

CUB'S DATA REQUEST NO. 27:

Please provide the following information by month and annual average for residential customers for the calendar years 2008, 2009, 2010, and 2011 to date, separately for both Oregon and Idaho:

a. Number of disconnection notices issued;

b. Number of actual disconnections for nonpayment;

c. Number of payment plans entered into with installment payments of the arrears balance plus the current bill;

d. Number of payment plans entered into with equal monthly payments, including budget payment plans;

e. Number of residential customers receiving federal or state bill paying assistance;

f. Average dollar amount of overdue balance for customers who receive a disconnection notice;

g. Average dollar amount owed at time of disconnection for nonpayment;

h. Average amount owed at time of reconnection of service following disconnection for nonpayment;

i. Information on f, g, and h for identified low-income customers;

j. Total cumulative arrearage for residential customers.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 27:

a. The following data details the number of 5-day, or final, disconnection notices issued:

2008	Idaho Disconnect Notices	Oregon Disconnect Notices
January	15,020	596
February	15,619	540
March	20,510	757
April	18,227	788
May	19,004	757
June	19,624	789
July	17,296	674
August	19,095	643
September	22,314	731
October	24,515	826

November	16,688	642
December	18,132	682
Average	18,837	702
2009	**Idaho Disconnect Notices**	**Oregon Disconnect Notices**
January	16,620	754
February	14,753	645
March	22,644	809
April	20,902	884
May	20,772	853
June	21,758	926
July	20,296	852
August	21,489	748
September	22,644	724
October	24,190	776
November	19,749	710
December	19,154	649
Average	20,414	777
2010	**Idaho Disconnect Notices**	**Oregon Disconnect Notices**
January	16,359	679
February	17,095	669
March	24,589	773
April	21,945	767
May	20,934	780
June	21,891	833
July	21,107	841
August	21,646	776
September	23,455	861
October	22,847	900
November	20,767	740
December	18,074	776
Average	20,892	783
2011	**Idaho Disconnect Notices**	**Oregon Disconnect Notices**
January	16,792	682
February	16,360	570
March	19,246	719
April	20,185	776

May	13,168	705
June	15,010	748
July	12,434	688
August	13,761	613
September	14,362	606
Average	15,702	679

b. The following table provides the actual disconnections for nonpayment:

2008	**Idaho Disconnections for Nonpayment**	**Oregon Disconnections for Nonpayment**
January	1,065	25
February	1,124	53
March	1,838	69
April	2,520	113
May	2,075	96
June	2,051	76
July	1,924	58
August	1,891	45
September	1,801	51
October	2,068	27
November	1,479	61
December	1,025	22
Average	1,738	58
2009	**Idaho Disconnections for Nonpayment**	**Oregon Disconnections for Nonpayment**
January	1,062	1
February	1,255	18
March	2,258	43
April	2,253	36
May	1,966	40
June	2,043	47
July	1,817	158
August	1,692	118
September	2,293	78
October	1,917	97
November	1,316	61
December	883	32
Average	1,729	60

2010	Idaho Disconnections for Nonpayment	Oregon Disconnections for Nonpayment
January	1,140	27
February	1,283	47
March	1,599	72
April	2,053	104
May	1,691	69
June	1,934	68
July	1,389	100
August	2,012	63
September	1,958	63
October	1,781	104
November	1,169	54
December	963	24
Average	1,581	66
2011	**Idaho Disconnections for Nonpayment**	**Oregon Disconnections for Nonpayment**
January	1,444	54
February	1,562	58
March	1,831	84
April	2,148	100
May	2,049	90
June	1,845	124
July	1,460	76
August	1,539	109
September	1,673	74
Average	1,728	85

c. The following table provides the number of payment plans entered into with installment payments of the arrears balance plus the current bill:

2008	**Idaho Payment Plans Balance + Current Bill**	**Oregon Payment Plans Balance + Current Bill**
January	2,483	46
February	2,799	42
March	3,434	73
April	2,882	53
May	2,455	40
June	2,642	53
July	2,447	32
August	2,961	31
September	3,710	35
October	3,270	45
November	1,973	33
December	2,235	30
Average	2,774	42

2009	**Idaho Payment Plans Balance + Current Bill**	**Oregon Payment Plans Balance + Current Bill**
January	2,525	35
February	3,284	35
March	5,004	75
April	3,455	58
May	3,325	49
June	3,210	54
July	2,953	50
August	3,716	58
September	3,899	40
October	3,877	48
November	2,633	52
December	2,562	48
Average	3,370	50

2010	Idaho Payment Plans Balance + Current Bill	Oregon Payment Plans Balance + Current Bill
January	2,796	46
February	3,030	56
March	4,600	94
April	3,675	77
May	3,514	62
June	3,695	48
July	3,281	75
August	3,802	48
September	4,215	53
October	4,035	57
November	2,764	41
December	2,587	43
Average	3,499	58
2011	**Idaho Payment Plans Balance + Current Bill**	**Oregon Payment Plans Balance + Current Bill**
January	3,108	57
February	3,299	87
March	4,504	113
April	3,623	56
May	3,259	68
June	3,571	77
July	3,236	53
August	3,779	55
September	3,940	74
Average	3,591	71

d. Equal monthly payments for the years 2008, 2009, 2010, and 2011 are detailed in the table below:

2008	**Idaho Payment Plans with Equal Monthly Payments**	**Oregon Payment Plans with Equal Monthly Payments**
January	180	65
February	860	92
March	1,683	153
April	845	110
May	473	78
June	353	65
July	244	43
August	311	56
September	362	49
October	301	70
November	148	45
December	176	37
Average	494	71
2009	**Idaho Payment Plans with Equal Monthly Payments**	**Oregon Payment Plans with Equal Monthly Payments**
January	272	65
February	1,168	106
March	2,383	177
April	1,444	118
May	914	97
June	616	70
July	502	82
August	555	62
September	623	65
October	532	58
November	305	64
December	254	65
Average	797	85

2010	Idaho Payment Plans with Equal Monthly Payments	Oregon Payment Plans with Equal Monthly Payments
January	539	85
February	1,699	119
March	3,381	149
April	1,578	118
May	978	87
June	734	80
July	624	78
August	642	64
September	724	84
October	620	79
November	434	73
December	323	98
Average	1,023	92
2011	**Idaho Payment Plans with Equal Monthly Payments**	**Oregon Payment Plans with Equal Monthly Payments**
January	778	132
February	2,194	188
March	4,550	208
April	1,943	123
May	1,232	90
June	867	86
July	698	71
August	801	69
September	989	78
Average	1,561	116

Budget Pay Program data for the years 2008, 2009, 2010, and 2011 is detailed below:

2008	Idaho Budget Pay Program	Oregon Budget Pay Program
January	43,584	1,083
February	44,005	1,107
March	44,263	1,121
April	44,419	1,128
May	44,436	1,122
June	44,258	1,116
July	44,282	1,112
August	44,242	1,105
September	44,391	1,109
October	44,948	1,119
November	45,066	1,119
December	44,963	1,124
Average	44,405	1,114
2009	**Idaho Budget Pay Program**	**Oregon Budget Pay Program**
January	45,226	1,135
February	45,562	1,149
March	45,911	1,148
April	46,105	1,151
May	46,034	1,149
June	45,730	1,137
July	45,497	1,137
August	45,574	1,137
September	45,594	1,131
October	46,115	1,132
November	46,175	1,145
December	46,280	1,148
Average	45,817	1,142

2010	**Idaho Budget Pay Program**	**Oregon Budget Pay Program**
January	46,820	1,167
February	46,915	1,172
March	46,912	1,172
April	46,689	1,172
May	46,453	1,170
June	46,127	1,158
July	45,913	1,156
August	45,954	1,154
September	45,980	1,146
October	46,251	1,164
November	46,383	1,167
December	46,573	1,195
Average	46,414	1,166
2011	**Idaho Budget Pay Program**	**Oregon Budget Pay Program**
January	47,166	1,242
February	47,369	1,262
March	47,538	1,246
April	47,552	1,239
May	47,304	1,230
June	46,919	1,213
July	46,800	1,212
August	46,857	1,201
September	47,062	1,208
Average	47,174	1,228

e. Idaho Power does not track the number of customers who receive federal or state bill paying assistance. The following information details the number of assistance payments that have been applied to customer accounts:

2008		Idaho Payments	Oregon Payments
200801		2,024	99
200802		1,576	195
200803		1,674	64
200804		1,076	168
200805		129	67
200806		76	4
200807		44	1
200808		31	0
200809		79	0
200810		129	7
200811		2,007	8
200812		3,362	58
	Average	1,017	56
200901		3,640	223
200902		2,751	153
200903		2,225	268
200904		1,182	178
200905		161	45
200906		215	101
200907		328	47
200908		285	7
200909		278	70
200910		204	42
200911		1,785	95
200912		5,702	177
	Average	1,563	117
201001		3,677	209
201002		4,137	211
201003		2,629	401
201004		514	169
201005		290	93
201006		290	41
201007		204	39
201008		229	77
201009		340	47

201010		478	15
201011		1,188	15
201012		5,198	154
	Average	1,598	123
201101		4,777	224
201102		3,782	338
201103		3,184	336
201104		1,221	132
201105		611	106
201106		12,098	27
201107		201	4
201108		266	1
201109		17,360	195
2011	Average	4,833	151

f. The following data details the average dollar amount of overdue balances owed at the time the 5-day, or final, disconnection notice is issued:

Month	Idaho Average Amount	Oregon Average Amount
01/2008	201.16	188.54
02/2008	223.56	203.64
03/2008	267.69	229.02
04/2008	230.66	210.49
05/2008	220.60	182.78
06/2008	191.29	151.41
07/2008	199.66	145.11
08/2008	202.47	156.67
09/2008	209.23	164.69
10/2008	194.80	160.76
11/2008	177.91	149.68
12/2008	190.29	162.81
2008	209.42	175.47
01/2009	219.34	194.12
02/2009	247.14	237.28
03/2009	293.67	260.01
04/2009	264.53	228.74

05/2009	238.74	212.67
06/2009	207.53	180.35
07/2009	209.57	176.24
08/2009	225.71	162.66
09/2009	235.94	165.92
10/2009	229.96	175.07
11/2009	211.55	162.37
12/2009	232.47	172.13
2009	235.07	194.55
01/2010	272.87	227.18
02/2010	277.27	247.92
03/2010	324.05	264.79
04/2010	292.92	221.69
05/2010	254.79	212.91
06/2010	241.04	190.22
07/2010	209.10	180.09
08/2010	219.50	169.07
09/2010	241.04	214.31
10/2010	215.74	191.19
11/2010	199.05	165.36
12/2010	206.14	191.71
2010	246.57	246.28
01/2011	264.01	262.63
02/2011	274.15	285.73
03/2011	286.52	275.53
04/2011	309.89	270.90
05/2011	351.10	257.08
06/2011	286.80	236.62
07/2011	273.76	212.47
08/2011	280.10	210.43
09/2011	284.46	216.01
2011	290.09	247.49

g. The average dollar amount owed at time of disconnection for nonpayment is detailed in the table below.

Month	**Idaho Average Amount**	**Oregon Average Amount**
01/2008	201.86	310.22
02/2008	227.57	259.12

03/2008	304.13	330.29
04/2008	309.60	301.51
05/2008	284.04	297.71
06/2008	225.66	292.83
07/2008	215.04	355.88
08/2008	222.18	206.34
09/2008	225.87	315.55
10/2008	230.40	360.88
11/2008	216.10	204.72
12/2008	192.84	400.01
2008	244.31	296.32
01/2009	216.79	1,089.72
02/2009	238.84	442.22
03/2009	321.27	398.02
04/2009	328.99	498.02
05/2009	312.35	461.89
06/2009	286.76	447.36
07/2009	246.32	288.60
08/2009	300.13	263.12
09/2009	268.95	268.92
10/2009	265.87	249.10
11/2009	282.31	221.61
12/2009	250.14	235.06
2009	282.86	310.59
01/2010	280.72	282.58
02/2010	289.57	296.87
03/2010	388.09	407.68
04/2010	443.31	324.79
05/2010	389.19	335.49
06/2010	360.36	335.02
07/2010	323.07	265.91
08/2010	306.15	282.19
09/2010	283.57	326.44
10/2010	306.82	277.06
11/2010	288.44	292.75
12/2010	225.63	287.11
2010	331.97	310.81
01/2011	229.11	286.72
02/2011	272.46	344.54
03/2011	323.28	327.24
04/2011	440.91	362.49
05/2011	411.60	604.86
06/2011	369.86	460.20

07/2011	359.98	364.69
08/2011	318.78	399.68
09/2011	298.14	331.46
2011	336.01	386.88

h. This information is not available.

i. Idaho Power does not track income status; therefore, information for low-income customers is not available.

j. Total cumulative arrearage information for residential customers is included on the attached Excel file.

CUB'S DATA REQUEST NO. 14:

How many Oregon customers have received energy assistance through Project Share in each of the past five years for which data is available?

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 14:

Project Share energy assistance is tracked on an October 1 – September 30 basis. The information detailed below identifies the number of Project Share grants issued to Idaho Power customers in Oregon.

October 1 - September 30	# of Grants
2006-2007	71
2007-2008	76
2008-2009	56
2009-2010	39
2010-2011	39

ATTACHMENT - RESPONSE TO CUB'S DR 24

IDAHO POWER COMPANY
HYDRO GENERATION - NET MWH

YEAR	MONTH	MWH
2007	Jan	714,191
2007	Feb	531,892
2007	Mar	600,341
2007	Apr	458,224
2007	May	566,152
2007	Jun	514,504
2007	Jul	587,278
2007	Aug	461,773
2007	Sep	449,419
2007	Oct	432,843
2007	Nov	376,952
2007	Dec	487,753
TOTAL MWH		6,181,322

YEAR	MONTH	MWH
2008	Jan	602,108
2008	Feb	492,466
2008	Mar	568,567
2008	Apr	611,329
2008	May	675,910
2008	Jun	789,417
2008	Jul	669,822
2008	Aug	640,051
2008	Sep	516,503
2008	Oct	474,239
2008	Nov	405,673
2008	Dec	462,126
TOTAL MWH		6,908,211

YEAR	MONTH	MWH
2009	Jan	578,825
2009	Feb	447,989
2009	Mar	558,690
2009	Apr	947,154
2009	May	982,964
2009	Jun	1,045,627
2009	Jul	915,047
2009	Aug	548,526
2009	Sep	548,854
2009	Oct	547,069
2009	Nov	422,037
2009	Dec	553,583
TOTAL MWH		8,096,365

YEAR	MONTH	MWH
2010	Jan	690,441
2010	Feb	616,830
2010	Mar	594,601
2010	Apr	567,553
2010	May	846,758
2010	Jun	883,646
2010	Jul	637,134
2010	Aug	518,153
2010	Sep	531,542
2010	Oct	483,784
2010	Nov	408,892
2010	Dec	565,099
TOTAL MWH		7,344,433

YEAR	MONTH	MWH
2011	Jan	873,250
2011	Feb	851,186
2011	Mar	974,414
2011	Apr	1,002,983
2011	May	1,074,497
2011	Jun	1,116,612
2011	Jul	1,046,032
2011	Aug	781,257
2011	Sep	962,553
2011	Oct	-
2011	Nov	-
2011	Dec	-
TOTAL MWH		8,682,784

POWER SYSTEM DATA
Week ending November 4, 2011

STREAMFLOW CONDITIONS	July	Aug	Sept	Oct	Nov
Natural Streamflow at The Dalles (as percent of 71-year average)	152.1%	115%	96%	104%[1]	94%
Critical Year Natural Streamflow at The Dalles	81.6%	85.5%	90.8%	71.6%	57.2%
FEDERAL HYDRO GENERATION	**July**	**Aug**	**Sept**	**Oct**	**Nov**
2010/2011 Federal Hydro Generation	12166	9236	7019	6547	
2009/2010 Federal Hydro Generation	7965	5674	5017	5603	
2007-2011 Average Federal Hydro Generation	8981	6641	5405	5548	
RESERVOIR CONTENT (Libby, Hungry Horse, Grand Coulee & Dworshak)	**July**	**Aug**	**Sept**	**Oct**	**Nov**
2010/2011 Reservoir Content (% full)	96%	85%	83%	86%	
2009/2010 Reservoir Content (% full)	90%	80%	82%	83%	
5 Year Average (% full)	91%	81%	82%	83%	
HISTORIC PRICES (Dow Jones HLH month average)	**July**	**Aug**	**Sept**	**Oct**	**Nov**
2011 Mid-C Prices in $/megawatt-hour	31.37	34.12	33.81	26.87	33.62[2]
2010 Mid-C Prices in $/megawatt-hour	36.65	40.01	36.76	31.52	34.88
Dow Jones HLH firm Mid-C Prices					
For week ending November 4 $/megawatt-hour	$28.12 - $36.25				
PRECIPITATION AND TEMPERATURES	**July**	**Aug**	**Sept**	**Oct**	**Nov**
Precipitation above The Dalles as % of Avg.	85%	32%	45%	143%[1]	
Load Center temperature departures in °F	-1.6	+1.3	+4.2	+.02[3]	
VOLUME FORECAST (as percent of average)	**July**	**Aug**	**Sept**	**Oct**	**Nov**
2011 Snowpack as % of average as of first of month (Jan-May ONLY)					
Observed January – July runoff and (%) of average at The Dalles	**142.6 MAF (133%)**				
Monthly Final Forecast at The Dalles in MAF and as a (%) of average (RFC Jan-Jul final forecast)	141.0 131%	142.0 132%			
– average Jan.-Jul. vol. used by NWS is 107.3 MAF – lowest Jan.-Jul. vol. on record is 53.8 MAF in 1977 – critical Jan.-Jul. vol. is 69.4 MAF					

[1] Observed through October 31st (preliminary)

[2] Observed through November 3rd

[3] Observed through October 31st (final)

RESERVOIR ELEVATIONS

DATE:	2400 hours 10/30/2011	2400 hours 10/30/2011	2400 hours 10/23/2011
PROJECT	CURRENT ELEV. (ft)	PERCENT FULL	PREVIOUS ELEV. (ft)
Libby	2448.2	90.2	2448.2
Horse	3548.7	91.2	3548.8
Coulee	1288.7	97.9	1288.0
Dworshak	1519.0	38.3	1518.9

CUB'S DATA REQUEST NO. 20:

Please provide any and all evidence showing that the Company's seasonal rate structure is reducing peak loads in Idaho.

IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 20:

Idaho Power has not conducted a study examining, in isolation, seasonal rate impacts in part because all current rate designs have other components.

Idaho Power's primary reason for proposing seasonal rates is to send the appropriate price signals to customers. These seasonal rates better reflect the higher cost of providing energy in the summer season than during the non-summer months.

<u>CUB'S DATA REQUEST NO. 21</u>:

Please provide, to the best of the Company's ability, an estimate of the number of Oregon residential customers that live in manufactured housing.

<u>IDAHO POWER COMPANY'S RESPONSE TO CUB'S DATA REQUEST NO. 21</u>:

The percentage of Oregon residents living in mobile or manufactured homes can be estimated using Idaho Power's *2010 Residential End-Use Survey* that was published as part of the *Demand-Side Management 2010 Report, Supplement 2: Evaluation*. Ten percent of Oregon survey respondents reported their type of residence as a mobile home while an additional 11 percent reported their type of residence as a manufactured home. Using the average daily residential customer count of 13,432 for December 2010, it is estimated that 2,820 Oregon customers reside in mobile or manufactured homes. A copy of Idaho Power's *Demand-Side Management 2010 Report* is provided in the Company's response to CUB's Data Request No. 10 above.

Utilities with less than 10% ROE

Utility	State	ROE	Proceeding	Date of Order
Central Illinois Light Company	IL	9.90%	Docket No. 09-0306	4/29/2010
Baltimore Gas and Electric	MD	9.85%	Docket No. 9230; Order No. 83907	3/9/2011
Vermont Public Service Company	VT	9.45%	Docket No. 7694	4/26/2011
Connecticut Light and Power	CT	9.40%	Docket No. 09-12-05	6/30/2010
Fitchburg Gas and Electric Company	MA	9.20%	Docket No. DPU 11-01; 11-02	8/1/2011
Green Mountain Power	VT	9.69%	Docket No. 7585	4/16/2010
National Grid	RI	9.80%	Docket No. 4065	4/29/2010
Niagara Mohawk	NY	9.10%*	Docket No. 08-E-0827	1/24/2011
Northern Indiana Public Servcice Company	IN	9.90%	Docket No. 43526	8/25/2010
Orange and Rockland Utilities	NY	9.20%	Docket No. 10-E-0362	6/17/2011
Rocky Mountain Power	ID	9.90%	Docket No. PAC-E-10-07; Order No. 32196	2/28/2011
PacifiCorp	WA	9.80%	Docket No. UE 100749; Order No. 06	3/25/2011
Public Service Company of New Hampshire	NH	9.67%**	Docket No. DE-09-035; Order No. 25,123	6/28/2010
Unitil Energy Systems	NH	9.67%**	Docket No. DE-10-055; Order No. 25,214	4/26/2011
Wester Massachusetts Electric Company	MA	9.60%	Docket No. DPU 10-70	1/31/2011

*In this docket, the State of New York Public Service Commission approved a 9.1% ROE for a single year case or a 9.3% ROE in the event of an additional stay-out year.

**Pursuant to a Settlement Agreement

Idaho Power Company
Distribution Line Account 368
By State and County
December 31, 2010

		Overhead & UGD Miles	368 Account
Oregon			
	Baker	1,051.42	6,884,983.87
	Grant	1.34	8,774.68
	Harney	263.54	1,725,731.53
	Malheur	4,444.36	29,102,876.94
	Wallowa	0.63	4,125.41
		5,761.29	37,726,492.43
Idaho			
	Ada	8,098.78	53,033,012.12
	Adams	932.96	6,109,275.59
	Bannock	1,941.36	12,712,552.80
	Bingham	4,787.25	31,348,213.84
	Blaine	1,781.35	11,664,763.85
	Boise	1,238.05	8,107,087.81
	Camas	731.71	4,791,435.91
	Canyon	7,138.39	46,744,117.43
	Cassia	1,610.10	10,543,372.31
	Elmore	3,089.86	20,233,242.89
	Gem	1,410.35	9,235,355.03
	Gooding	2,382.85	15,603,549.29
	Idaho	188.48	1,234,218.26
	Jerome	2,809.11	18,394,815.60
	Lemhi	1,384.97	9,069,159.90
	Lincoln	1,245.43	8,155,414.06
	Minidoka	1,532.27	10,033,720.32
	Oneida	105.12	688,354.32
	Owyhee	2,737.25	17,924,256.79
	Payette	1,742.81	11,412,393.45
	Power	2,209.83	14,470,567.32
	Twin Falls	5,161.79	33,800,803.53
	Valley	1,763.89	11,550,431.02
	Washington	1,556.98	10,195,528.12
		57,580.94	377,055,641.56
Total		63,342.23	414,782,133.99

Check Figures		368 Account
	Oregon	37,726,492.44
	Idaho	377,055,641.56
	Total	414,782,134.00
		(0.01)
	Idaho %	**90.90%**

CUB EXHIBIT 111 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 11-288

IDAHO POWER®
An IDACORP Company

August 30, 2011

Subject: Docket No. UE 233
Idaho Power Company's **Corrected** Response to Staff's Master Data Request 94

STAFF'S DATA REQUEST NO. 94:

WAGE AND SALARY DATA

For the test year and the preceding 4 calendar years, please provide (on a total company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX		Actual (unadjusted) Paid Cash Compensation			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
**Exclude FTE created by Overtime					

IDAHO POWER COMPANY'S *CORRECTED* RESPONSE TO STAFF'S DATA REQUEST NO. 94:

Please see the information on the following page. Please note the following:

- Salary data includes regular earnings, paid time off, and holidays.
- Headcount is as of December 30 of each year reported.
- Compensation figures include employees who terminated during the year.
- Employees retiring during the year are broken out separately. Any incentive payments to employees retiring in one year are paid in the following year.
- 2011 FTE figures include headcount expected through year-end 2011.
- 2011 Salary data includes forecast dollars for all employees on payroll as of June 30 through year-end; it does not include forecast dollars for employees that may be hired later in the year.

2007		Actual (unadjusted) Paid Cash Compensation			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	14	$3,457,885.42	$0.00	$1,661,197.00	$5,119,082.42
Exempt	725	$55,724,268.90	$94,058.06	$4,317,417.73	$60,135,744.69
Nonexempt	1319	$68,459,759.46	$8,405,141.95	$4,757,080.01	$81,621,981.42
Union	0	$0.00	$0.00	$0.00	$0.00
Retirees	52	$2,655,787.38	$143,625.73	$713,054.08	$3,512,467.19
Total	2058	$130,297,701.16	$8,642,825.74	$11,448,748.82	$150,389,275.72
	**Exclude FTE created by Overtime				

2008		Actual (unadjusted) Paid Cash Compensation			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	14	$3,696,827.25	$0.00	$1,006,916.00	$4,703,743.25
Exempt	768	$62,309,268.12	$69,582.39	$3,408,651.91	$65,787,502.42
Nonexempt	1301	$71,437,961.40	$7,516,203.32	$3,792,344.27	$82,746,508.99
Union	0	$0.00	$0.00	$0.00	$0.00
Retirees	47	$2,640,506.21	$80,481.07	$499,938.12	$3,220,925.40
Total	2083	$140,084,562.98	$7,666,266.78	$8,707,850.30	$156,458,680.06
	**Exclude FTE created by Overtime				

2009		Actual (unadjusted) Paid Cash Compensation			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	14	$3,641,519.60	$0.00	$2,212,270.00	$5,853,789.60
Exempt	782	$68,601,731.85	$50,023.54	$5,691,265.91	$74,343,021.30
Nonexempt	1212	$74,838,842.22	$6,163,113.07	$5,714,187.74	$86,716,143.03
Union	0	$0.00	$0.00	$0.00	$0.00
Retirees	52	$3,049,909.08	$39,704.24	$877,898.68	$3,967,512.00
Total	2008	$150,132,002.75	$6,252,840.85	$14,495,622.33	$170,880,465.93
	**Exclude FTE created by Overtime				

2010		Actual (unadjusted) Paid Cash Compensation			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	16	$3,900,692.32	$0.00	$2,579,961.00	$6,480,653.32
Exempt	837	$70,602,117.18	$65,906.96	$5,884,938.06	$76,552,962.20
Nonexempt	1190	$71,529,265.18	$7,133,071.31	$5,607,588.41	$84,269,924.90
Union	0	$0.00	$0.00	$0.00	$0.00
Retirees	36	$2,277,076.21	$105,520.55	$860,532.20	$3,243,128.96
Total	2043	$148,309,150.89	$7,304,498.82	$14,933,019.67	$170,546,669.38
	**Exclude FTE created by Overtime				

2011*		Actual (unadjusted) Paid Cash Compensation*			
Category	Total Co FTE**	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	16	$4,035,456.99	$0.00	$2,498,547.00	$6,534,003.99
Exempt	849	$75,099,008.53	$37,552.84	$6,195,273.25	$81,331,834.62
Nonexempt	1239	$73,462,772.37	$6,146,108.41	$6,042,992.27	$85,651,873.05
Union	0	$0.00	$0.00	$0.00	$0.00
Retirees	30 (YTD)	$712,735.33	$8,037.82	$513,964.90	$1,234,738.05
Total	2104	$153,309,973.22	$6,191,699.07	$15,250,777.42	$174,752,449.71
**Exclude FTE created by Overtime		*Employee headcount includes forecast through year-end; Compensation includes data for current employees through 6/30, with remainder of year forecasted			

IDAHO POWER -UE 233
CUB WORK PAPER
Customer Count to Officer Analysis

Company	2008 Number of Executive Officers	2008 Average Number of Customers	2009 Number of Executive Officers	2009 Average Number of Customers	2009 Customer Change Comparison	2010 Number of Executive Officers	2010 Average Number of Customers	2010 Customer Change Comparison	2011 Number of Executive Officers	2011 Average Number of Customers	2011 Customer Change Comparison
Idaho Power	14	484,535	14	488,175	0.7512%	14	490,705	0.5183%	16	498,393	1.5667%
PacifiCorp	8	1,706,127	8	1,718,485	0.7243%	8	1,732,815	0.8339%	5	1,741,000	0.4724%
PGE	11	811,315	11	815,869	0.5613%	11	820,266	0.5389%	12	824,526	0.5193%

	2008 Number of Executive Officers	2008 # of Customers per Officer	2009 Number of Executive Officers	2009 # of Customers per Officer	2009 Change from prior period	2010 Number of Executive Officers	2010 # of Customers per Officer	2010 Change from prior period	2011 Number of Executive Officers	2011 # of Customers per Officer	2011 Change from prior period
Idaho Power	14	34,610	14	34,870	0.7512%	14	35,050	0.5183%	16	31,150	-11.1291%
PacifiCorp	8	213,266	8	214,811	0.7243%	8	216,602	0.8339%	5	348,200	60.7558%
PGE	11	73,756	11	74,170	0.5613%	11	74,570	0.5389%	12	68,711	-7.8573%

Proposed Salary/Officer

2011 Officer	# of Officers	Salary/Officer
4,205,333	16	262,833

Range of Cust/Officer

Officers	#/Cust
15	33,226
14	35,600
13	38,338
12	41,533

Staff Proposal

			Line No.
Officer	Allowable	Variance	
16	12	-4	1
	Salary	262,833	
% of Salary		(1,051,333)	2
O&M			3
		70%	4
		(735,933)	5
	OR. Alloc.	4.64%	6
		(34,147)	7
Capital			
Adjustment		(1,051,333)	8
% of Salary		30%	9
		(315,400)	10
	OR. Alloc.	4.88%	11
		(15,392)	12

Total Adjustment	(1,051,333)
Total Oregon Adjustment	(49,539)

Officers/Customer	2008	2009	2010
Idaho Power	34,610	34,870	35,050
PacifiCorp	213,266	214,811	216,602
PGE	73,756	74,170	74,570

Executive Officers	2008	2009	2010
Idaho Power	14	14	14
PacifiCorp	8	8	8
PGE	11	11	11

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	**Idaho Power Company**																			
2	**Analysis: Pworth of Automated Meter Infrastructure**											**Table 9: Automated Meters**								
4	**12/7/11 2:07 PM**																			
5	**Table 9: Automated Meters**																			
6	**CIS Plus Area: Total, , , , ,,**																			
7																				
8																				
9								Station Electronic						Accumulated						
10								Equipment Software						Deferred	Income		Income			
11				O&M		Bus Transformer		and Hardware			Automated Meters		Accumulated	Taxes and	Statement		Statement			
12	Assumptions			Escalation			Book		Book		Book	Deferred	Deferred		Earnings		Earnings			
13	Description	Amount	Year	Factor		Year	Depr	Year	Depr	Year	Depr	Taxes	Taxes	Book Depreciation	Base	Interest	Base	Interest	Preferred	Common
14	Financing:		2009	3.67%		1	0	1	435,479	1	1,211,585	386,317	386,317	2,033,381	22,672,581	647,507	22,672,581	647,507	0	1,951,916
15	Composition		2010	1.64%		2	0	2	931,116	2	2,286,447	1,514,849	1,901,166	6,765,794	41,497,663	916,320	41,497,663	916,320	0	2,762,256
16	Debt	50.538%	2011	1.99%		3	0	3	2,118,095	3	3,209,592	2,360,193	4,261,359	14,453,673	58,328,175	1,425,464	58,328,175	1,425,464	0	4,297,078
17	Preferred	0.000%	2012	2.46%		4	0	4	2,118,095	4	3,352,727	2,482,609	6,743,968	22,407,104	52,521,766	1,582,883	52,521,766	1,582,883	0	4,771,619
18	Common	49.462%	2013	2.67%		5	0	5	2,118,095	5	3,440,509	1,319,227	8,063,194	29,284,934	46,960,665	1,420,561	46,960,665	1,420,561	0	4,282,296
19	Total	100.000%	2014	2.58%		6	0	6	2,118,095	6	3,529,150	647,941	8,711,135	35,580,120	41,995,106	1,270,245	41,995,106	1,270,245	0	3,829,168
20	Cost		2015	2.46%		7	0	7	2,118,095	7	3,617,828	213,375	8,924,510	41,529,417	37,375,974	1,133,380	37,375,974	1,133,380	0	3,416,587
21	Debt	5.651%	2016	2.53%		8	0	8	1,404,750	8	3,707,517	230,559	9,155,069	46,872,242	29,811,750	959,408	29,811,750	959,408	0	2,892,146
22	Preferred	0.000%	2017	2.50%		9	0	9	1,404,750	9	3,798,732	-27,612	9,127,457	52,048,112	26,004,113	797,023	26,004,113	797,023	0	2,402,636
23	Common	10.600%	2018	2.50%		10	0	10	1,404,750	10	3,889,524	-256,438	8,871,019	57,085,947	22,328,151	690,161	22,328,151	690,161	0	2,080,498
24	Total	8.099%	2019	2.50%		11	0	11	1,404,750	11	3,981,819	-575,031	8,295,988	61,897,485	18,901,042	588,733	18,901,042	588,733	0	1,774,741
25	Pretax	11.465%	2020	2.50%		12	0	12	1,404,750	12	4,076,335	-967,508	7,328,480	66,411,062	15,805,208	495,588	15,805,208	495,588	0	1,493,956
26	Discount Rate	6.982%	2021	2.55%		13	0	13	1,404,750	13	4,172,195	-1,309,351	6,019,129	70,678,655	12,975,510	410,975	12,975,510	410,975	0	1,238,887
27	Discount Delay	0.500	2022	2.55%		14	0	14	1,404,750	14	4,269,695	-1,491,067	4,528,062	74,862,032	10,254,629	331,715	10,254,629	331,715	0	999,959
28			2023	2.55%		15	0	15	1,404,750	15	4,368,804	-1,528,789	2,999,273	79,106,797	7,496,512	253,478	7,496,512	253,478	0	764,111
29			2024	2.55%		16	0	1	1,404,750	0	4,470,123	-594,183	2,405,090	59,681,525	28,441,560	513,178	28,441,560	513,178	0	1,546,981
30	Taxes		2025	2.55%		17	0	2	1,404,750	0	4,573,118	1,055,913	3,461,003	43,157,810	46,510,200	1,070,275	46,510,200	1,070,275	0	3,226,355
31	Month (RI Prop)	6	2026	2.60%		18	0	3	1,404,750	0	4,677,020	2,195,209	5,656,213	30,483,124	60,743,418	1,531,529	60,743,418	1,531,529	0	4,616,812
32	DRDB Rate	1.5	2027	2.60%		19	0	4	1,404,750	0	4,781,435	2,199,365	7,855,578	36,721,651	56,071,117	1,668,055	56,071,117	1,668,055	0	5,028,369
33	Composite Rate	0.391	2028	2.60%		20	0	5	1,404,750	0	4,887,675	1,406,604	9,262,182	43,103,952	51,282,419	1,532,956	51,282,419	1,532,956	0	4,621,113
34	Gross up on Tax	1.642	2029	2.60%		21	0	6	1,404,750	1	4,996,199	828,867	10,091,049	49,004,140	47,010,089	1,403,569	47,010,089	1,403,569	0	4,231,074
35	Deferred Rate - .327	0.35	2030	2.60%		22	0	7	1,404,750	2	5,106,576	487,841	10,578,889	54,673,141	42,996,746	1,285,254	42,996,746	1,285,254	0	3,874,411
36	Investment Tax Credit	0.03	2031	2.60%		23	0	8	1,404,750	3	5,217,930	256,150	10,835,039	60,206,643	39,133,548	1,172,781	39,133,548	1,172,781	0	3,535,360
37			2032	2.70%		24	0	9	1,404,750	4	5,327,465	-2,115	10,832,925	65,568,510	35,414,706	1,064,513	35,414,706	1,064,513	0	3,208,985
38	Facility		2033	2.70%		25	0	10	1,404,750	5	5,432,197	-234,287	10,598,637	70,809,296	31,744,907	959,006	31,744,907	959,006	0	2,890,936
39	Book Life	25	2034	2.70%		1	0	11	1,404,750	6	5,538,965	-558,345	10,040,292	75,810,237	28,345,477	858,061	28,345,477	858,061	0	2,586,635
40	Tax Life	15	2035	2.70%		2	0	12	1,404,750	7	5,647,809	-954,175	9,086,117	80,490,878	25,297,504	765,996	25,297,504	765,996	0	2,309,102
41	Tax Basis	100%	2036	2.70%		3	0	13	1,404,750	8	5,758,774	-1,297,714	7,788,404	84,918,793	22,534,063	683,011	22,534,063	683,011	0	2,058,946
42	Investment - Transformer w/Installation - All Years	$ -	2037	2.70%		4	0	14	1,404,750	9	5,870,039	-1,479,838	6,308,566	89,251,247	19,870,577	605,518	19,870,577	605,518	0	1,825,339
43			2038	2.70%		5	0	15	1,404,750	10	5,981,603	-1,518,044	4,790,522	93,632,908	17,162,377	528,813	17,162,377	528,813	0	1,594,111
44	Facility		2039																	
45	Book Life	15	2040																	
46	Tax Life	7	2041																	
47	Tax Basis	100%	2042																	
48	Investment - Station Electronic Equipment - All Years	**$ 63,213,732**	2043																	
49			2044																	
50	Facility		2045																	
51	Book Life	15	2046																	
52	Tax Life	10	2047																	
53	Tax Basis	100%	2048																	
54	Investment - Automated Meters - All Years	**$ 179,448,081**																		
55																				
56	Facility																			
57	Book Life	5																		
58	Tax Life	3																		
59	Tax Basis	100%																		
60	Investment - Hardware and Software - All Years	**$ 3,566,726**																		
61																				
62	Total, , , , Counties	0.60%																		
63	Insurance	0.047%																		
64						**TOTAL**	0		44,266,310		131,179,385	4,790,522	214,906,631	1,598,530,612	997,487,552	28,565,954	997,487,552	28,565,954	0	86,112,385
66	Customer Count	457,824				P.V.	0		18,700,095		47,121,978	5,844,251	80,489,759	529,631,600	432,131,743	12,210,924	432,131,743	12,210,924	0	36,809,965
68	Number of Years Analized(Used in Levelized Calculation)	30				Levelized	0		1,504,249		3,790,527	470,116	6,474,656	42,603,956	34,760,996	982,256	34,760,996	982,256	0	2,961,021
69																				
70																				
71																				
72																				
73																				

Table 9: Automated Meters Contin

Row	C Year	U State Tax Savings on Accelerated Depreciation Passed through to Rate Payers	V Total Cost of Capital	W Bus Transformer Tax Depr	X Station Electronic Eq. Software and Hardware Tax Depr	Y Automated Meters Tax Depr	Z Accumulated Tax Depreciation	AA Total Revenue Reqmt for Asset	AB
14	2009	-74,309	2,525,114	0	933,449	1,817,378	2,750,827	4,172,178	
15	2010	-291,385	3,387,190	0	2,662,131	4,883,573	10,296,531	6,604,754	
16	2011	-453,990	5,268,552	0	5,167,226	6,903,869	22,367,625	10,596,239	
17	2012	-477,537	5,876,965	0	5,441,476	7,122,514	34,931,615	11,347,786	
18	2013	-253,757	5,449,099	0	3,282,710	6,045,113	44,259,438	11,007,703	
19	2014	-124,633	4,974,779	0	2,398,223	5,100,281	51,757,942	10,622,025	
20	2015	-41,043	4,508,924	0	1,880,919	4,464,647	58,103,507	10,244,847	
21	2016	-44,349	3,807,205	0	1,588,963	4,182,042	63,874,512	8,919,471	
22	2017	5,311	3,204,970	0	966,013	4,158,578	62,466,920	8,408,452	
23	2018	49,327	2,819,986	0	316,861	4,244,732	67,028,513	8,114,259	
24	2019	110,609	2,474,083	0	0	3,743,624	70,772,137	7,860,651	
25	2020	186,103	2,175,648	0	0	2,716,777	73,488,913	7,656,732	
26	2021	251,857	1,901,719	0	0	1,835,941	75,324,854	7,478,664	
27	2022	286,811	1,618,485	0	0	1,414,252	76,739,106	7,292,929	
28	2023	294,067	1,311,656	0	0	1,405,586	78,144,692	7,085,210	
29	2024	114,293	2,174,452	0	933,449	3,243,758	67,782,839	8,049,324	
30	2025	-203,108	4,093,521	0	2,662,131	6,332,631	76,777,601	10,071,389	
31	2026	-422,255	5,726,087	0	3,978,436	8,375,360	89,131,397	11,807,856	
32	2027	-423,054	6,273,369	0	3,856,066	8,614,018	101,601,481	12,459,554	
33	2028	-270,564	5,883,505	0	2,754,478	7,556,816	111,912,775	12,175,930	
34	2029	-159,435	5,475,209	0	2,133,929	6,635,210	102,508,136	11,876,157	
35	2030	-93,837	5,065,828	0	1,880,919	6,024,237	94,290,359	11,577,153	
36	2031	-49,271	4,658,869	0	1,588,963	5,765,574	87,797,729	11,281,549	
37	2032	407	4,273,905	0	966,013	5,760,160	85,844,696	11,006,119	
38	2033	45,066	3,895,008	0	316,861	5,850,694	90,695,522	10,731,955	
39	2034	107,399	3,552,096	0	0	5,348,442	94,714,337	10,495,810	
40	2035	183,538	3,258,636	0	0	4,326,345	97,710,517	10,311,195	
41	2036	249,619	2,991,576	0	0	3,455,771	99,820,960	10,155,100	
42	2037	284,651	2,715,508	0	0	3,046,679	101,499,407	9,990,296	
43	2038	292,000	2,414,924	0	0	3,049,084	103,186,617	9,801,276	
44	2039								
45	2040								
46	2041								
47	2042								
48	2043								
49	2044								
50	2045								
51	2046								
52	2047								
53	2048								
64		-921,470	113,756,868	0	45,709,214	143,423,686	2,197,581,506	289,202,563	0
66		-1,124,158	47,896,731	0	23,957,582	58,562,349	724,998,579	113,718,803	0
68		-90,428	3,852,848	0	1,927,166	4,710,799	58,319,420	9,147,624	0

Row	C Year	AC Remaining Meter Reading Function; fied - Updated with Act; Post ARM Labor Dollars Remaining Meter Readers	AD Updated with Ac; Post AMI Transportation Dollars Required	AE - Updated with Actua; Post AMI Phone Bills on Lines O&M	AF - Updated with Actu; Annual Softwarre Maintenance Licensing Expense O&M	AG Verified - Updated with Actual Costs; Post AMI Purchase and Other Expenses Services O&M	AI Verified - Updated with Actual Costs; Post AMI Severence Packages O&M	AJ Meter ITC Amortization Expense O&M	AK Electronic Eq. Software and Hardware ITC Amortization Expense O&M	AL Bus Transformer ITC Amortization Expense O&M	AN Vefified; Customer Service Efficiency Benefit O&M
14	2009	7,155,699	1,309,336	36,646	40,126	856,141	0	-36,348	-13,064	0	0
15	2010	5,761,908	1,391,625	81,616	52,219	825,426	2,888	-68,593	-27,933	0	0
16	2011	4,563,846	1,311,280	164,572	159,137	344,502	118,711	-96,288	-63,543	0	0
17	2012	4,165,214	813,211	168,614	190,919	372,005	0	-100,582	-63,543	0	0
18	2013	4,290,170	833,185	173,121	195,834	381,949	0	-103,215	-63,543	0	-257,814
19	2014	4,418,876	855,456	177,581	201,027	391,790	0	-105,875	-63,543	0	-265,548
20	2015	4,551,442	877,497	181,949	206,507	401,426	0	-108,535	-63,543	0	-273,514
21	2016	4,687,985	899,078	186,549	212,285	411,574	0	-111,225	-42,142	0	-281,720
22	2017	4,828,625	921,808	191,212	218,372	421,863	0	-113,962	-42,142	0	-290,171
23	2018	4,973,483	944,853	195,993	224,779	432,410	0	-116,686	-42,142	0	-298,877
24	2019	5,122,688	968,474	200,892	231,519	443,220	0	-119,455	-42,142	0	-307,843
25	2020	5,276,369	992,686	205,915	238,607	454,301	0	-122,290	-42,142	0	-317,078
26	2021	5,434,660	1,017,503	211,166	246,059	465,885	0	-125,166	-42,142	0	-326,590
27	2022	5,597,699	1,043,449	216,550	253,891	477,765	0	-128,091	-42,142	0	-336,388
28	2023	5,765,630	1,070,057	222,072	262,121	489,948	0	-131,064	-42,142	0	-346,480
29	2024	5,938,599	1,097,344	227,735	270,768	502,442	0	-134,104	-42,142	0	-356,874
30	2025	6,116,757	1,125,326	233,542	279,851	515,254	0	-137,194	-42,142	0	-367,580
31	2026	6,300,260	1,154,022	239,615	289,391	528,651	0	-140,311	-42,142	0	-378,608
32	2027	6,489,268	1,184,026	245,845	299,405	542,396	0	-143,443	-42,142	0	-389,966
33	2028	6,683,946	1,214,811	252,237	309,919	556,498	0	-146,630	-42,142	0	-401,665
34	2029	6,884,464	1,246,396	258,795	320,955	570,967	0	-149,886	-42,142	0	-413,715
35	2030	7,090,998	1,278,803	265,523	332,541	585,812	0	-153,197	-42,142	0	-426,127
36	2031	7,303,728	1,312,051	272,427	344,702	601,043	0	-156,538	-42,142	0	-438,910
37	2032	7,522,840	1,346,165	279,782	357,460	617,271	0	-159,824	-42,142	0	-452,078
38	2033	7,748,525	1,382,511	287,337	370,833	633,938	0	-162,966	-42,142	0	-465,640
39	2034	7,980,981	1,419,839	295,095	384,853	651,054	0	-166,169	-42,142	0	-479,609
40	2035	8,220,410	1,458,175	303,062	399,551	668,633	0	-169,434	-42,142	0	-493,997
41	2036	8,467,023	1,497,545	311,245	414,964	686,686	0	-172,763	-42,142	0	-508,817
42	2037	8,721,033	1,537,979	319,649	431,123	705,226	0	-176,101	-42,142	0	-524,082
43	2038	8,982,664	1,579,505	328,279	448,066	724,267	0	-179,448	-42,142	0	-539,804
44	2039										
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48	2043										
49	2044										
50	2045										
51	2046										
52	2047										
53	2048										
62				5647071.774	1103038.876						
64		187,045,791	35,083,997	6,734,614	8,187,785	16,260,343	121,600	-3,935,382	-1,327,989	0	-9,939,496
66		70,201,641	13,712,441	2,357,602	2,740,711	6,474,858	99,476	-1,413,659	-561,003	0	-3,099,137
68		5,647,072	1,103,039	189,647	220,465	520,842	8,002	-113,716	-45,127	0	-249,297

Oregon Alloation Factor	4.58%	4.64%
	258,635.89	51,181.00
Total Oregon Adjustment		309,816.89

	C	AO	AP	AQ	AR	AS	AU	BJ	BK	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW
1																				CIS Plus Area: Total, , , , ,,
2		ued																		
4																				
5																				
6																				Automated
7													Existing meters							
8											Rate Case 2008,		32,972,436						WACC	
9		Verified	Verified	Verified	Verified	Verified	Verified												on Current	
10									Total Revenue										Investment	
11								Escalated	Requirement		Additional Rev			Accumulated				Gross up on	Piece Only	
12		Regional Operations Benefit on Detecting Overloaded Distribution Transformers	Regional Operations Benefit in Confirming Equipment Outage to prevent Crew Dispatch.	Regional Operations Benefit in Confirming Service Restored to Prevent Prolonged Crew Time in Area.	Load Research Load Sampling Meter Installation Savings	Irrigation Peak Rewards Program	T&D Development Outage Management	Property Taxes	With		though Meter		Depreciation & Remaining Amortization on Existing Meters currently in Rate	Amort on Current				Common &	In Standard	Total Revenue Requirement with Auto Meters including Existing
13	Year	O&M	O&M	O&M	O&M	O&M	O&M	and Insurance	Expenses		Expansion		Base	Standard Meters	Interest	Preferred	Common	Preferred	Meters	meters
14	2009	0	0	0	0	0	0	148,352	13,669,065		13,732,448		$ 7,034,067	7,034,067	757,697	0	1,391,008	2,284,085	3,041,781	23,744,914
15	2010	0	0	0	0	0	0	289,808	14,913,717		14,072,056		$ 10,990,812	18,024,879	443,810	0	814,762	1,337,869	1,781,679	27,686,208
16	2011	0	0	0	0	0	0	437,033	17,535,489		14,723,723		$ 10,551,216	28,576,096	142,477	0	261,565	429,499	571,976	28,658,682
17	2012	0	0	0	0	-16,590	0	449,925	17,326,961		15,295,054		$ 4,396,340	32,972,436	16,922	0	31,066	51,012	67,934	21,791,235
18	2013	0	0	0	0	-17,087	0	457,832	16,898,135		15,667,808		$ -	32,972,436	16,922	0	31,066	51,012	67,934	16,966,068
19	2014	-28,239	-525,559	-40,615	0	-17,600	-186,469	465,816	15,899,123		16,037,496		$ -	32,972,436	16,922	0	31,066	51,012	67,934	15,967,057
20	2015	-29,745	-553,592	-42,781	0	-18,128	-190,694	473,803	15,656,938		16,410,236		$ -	32,972,436	16,922	0	31,066	51,012	67,934	15,724,872
21	2016	-31,323	-582,964	-45,051	0	-18,672	-194,962	460,464	14,469,346		15,656,938		$ -	32,972,436	16,922	0	31,066	51,012	67,934	14,537,280
22	2017	-32,981	-613,819	-47,436	0	-19,232	-199,302	468,680	14,099,966		16,007,415		$ -	32,972,436	16,922	0	31,066	51,012	67,934	14,167,900
23	2018	-34,704	-645,888	-49,914	0	-19,809	-203,607	476,858	13,951,009		16,363,748		$ -	32,972,436	16,922	0	31,066	51,012	67,934	14,018,943
24	2019	-36,513	-679,557	-52,516	0	-20,403	-207,981	485,171	13,846,205		16,717,150		$ -	32,972,436	16,922	0	31,066	51,012	67,934	13,914,139
25	2020	-38,419	-715,031	-55,257	0	-21,015	-212,464	493,684	13,794,595		17,076,301		$ -	32,972,436	16,922	0	31,066	51,012	67,934	13,862,529
26	2021	-40,418	-752,230	-58,132	0	-21,646	-217,007	502,318	13,772,922		13,794,595		$ -	32,972,436	16,922	0	31,066	51,012	67,934	13,840,856
27	2022	-42,517	-791,292	-61,151	0	-22,295	-221,627	511,100	13,747,881		14,089,566		$ -	32,972,436	16,922	0	31,066	51,012	67,934	13,815,815
28	2023	-44,720	-832,296	-64,320	0	-22,964	-226,322	520,027	13,704,758		14,389,528		$ -	32,972,436	16,922	0	31,066	51,012	67,934	13,772,691
29	2024	-47,039	-875,454	-67,655	0	-23,653	-231,124	529,153	14,837,321		14,694,352		$ -	32,972,436	16,922	0	31,066	51,012	67,934	14,905,254
30	2025	-49,473	-920,755	-71,156	0	-24,363	-236,004	538,430	17,031,884		15,006,121		$ -	32,972,436	16,922	0	31,066	51,012	67,934	17,099,818
31	2026	-52,018	-968,130	-74,817	0	-25,093	-240,919	547,788	18,945,544		17,031,884		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,013,478
32	2027	-54,675	-1,017,576	-78,638	0	-25,846	-245,848	557,193	19,779,551		17,386,617		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,847,484
33	2028	-57,464	-1,069,483	-82,649	0	-26,622	-250,863	566,762	19,682,582		17,742,361		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,750,516
34	2029	-60,397	-1,124,073	-86,868	0	-27,420	-255,988	576,537	19,573,780		18,104,272		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,641,714
35	2030	-63,476	-1,181,366	-91,296	0	-28,243	-261,200	586,478	19,470,263		18,474,154		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,538,197
36	2031	-66,694	-1,241,265	-95,925	0	-29,090	-266,450	596,508	19,374,995		19,470,263		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,442,928
37	2032	-70,015	-1,303,070	-100,701	0	-29,963	-271,570	606,374	19,306,649		19,861,615		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,374,582
38	2033	-73,392	-1,365,927	-105,558	0	-30,862	-276,379	615,807	19,248,040		20,243,279		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,315,973
39	2034	-76,935	-1,431,861	-110,654	0	-31,788	-281,281	625,424	19,232,616		20,601,709		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,300,550
40	2035	-80,651	-1,501,025	-115,999	0	-32,741	-286,280	635,227	19,273,983		20,967,149		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,341,917
41	2036	-84,550	-1,573,579	-121,606	0	-33,723	-291,376	645,222	19,349,227		19,273,983		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,417,161
42	2037	-88,610	-1,649,138	-127,445	0	-34,735	-296,473	655,244	19,421,825		19,617,102		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,489,759
43	2038	-92,837	-1,727,816	-133,525	0	-35,777	-301,570	665,292	19,476,428		19,960,252		$ -	32,972,436	16,922	0	31,066	51,012	67,934	19,544,362
44	2039																			
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64		-1,377,806	-25,642,743	-1,981,665	0	-675,361	-6,053,759	15,588,310	507,290,801	0	508,469,179	0	32,972,436	943,890,810	1,800,878	0	3,306,120	5,428,768	7,229,646	547,492,883
66		-386,994	-7,202,466	-556,605	0	-218,070	-1,882,656	5,775,100	199,760,044	0	198,993,836	0	28,151,521	369,000,988	1,378,323	0	2,530,377	4,154,971	5,533,295	233,444,859
68		-31,130	-579,372	-44,774	0	-17,542	-151,442	464,553	16,068,845	0	16,007,211	0	2,264,529	29,682,712	110,873	0	203,545	334,229	445,102	18,778,477
69																				
70																				
71																				
72																				
73																				