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January 26, 2010

**VIA ELECTRONIC AND U.S. MAIL**

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

**Re: UE 213 - In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service in the State of Oregon**

Attention Filing Center:

Enclosed in the above-referenced docket are an original and five (5) copies of the following:

1. Testimony of Mike Youngblood, Courtney Waites, Jim Hovda, and Perry Van Patten on behalf of Idaho Power Company; and
2. Testimony of George Compton and Lisa Gorsuch on behalf of Oregon Public Utility Commission Staff.

A copy of this filing was served on all parties to this proceeding as indicated on the attached certificate of service.

Please contact me with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo

cc: Service List

## CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents on the parties of record in Docket UE 213, on the date indicated below, by email and U.S. first class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: January 26, 2010

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UE 213**

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| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON. | ) ) ) ) ) ) |

**IDAHO POWER COMPANY**

**REPLY TESTIMONY**

**OF**

**MICHAEL J. YOUNGBLOOD**

**January 26, 2010**

**Q. Please state your name, business address, and present occupation?**

A. My name is Michael J. Youngblood and my business address is 1221 West Idaho Street in Boise, Idaho.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Manager of Rate Design in the Pricing and Regulatory Services Department.

**Q. Are you the same Michael J. Youngblood who previously submitted direct testimony in this docket, UE 213?**

A. Yes, I am.

**Q. What is the purpose of your reply testimony?**

A. This testimony replies to certain arguments made by Citizens' Utility Board of Oregon ("CUB") witnesses Bob Jenks and Gordon Feighner.

In particular, I will address three specific areas of Company policy as they relate to the testimony submitted by Mr. Jenks and Mr. Feighner. In addition, Idaho Power witness Courtney Waites will respond to the testimonies of Mr. Jenks and Mr. Feighner as these relate to the specifics of the stipulated residential rate design and the Company's residential energy efficiency programs.

**Q. Before addressing the specific issues, do you have any general observations about the CUB testimony?**

A. Yes. It appears to me that much of the testimony submitted by Messrs. Jenks and Feighner is outside the scope of the issues identified by CUB to be addressed separately from the Stipulation and supporting testimony. On page 1 of the Stipulation, lines 17 through 19, "CUB objects only to the Residential Rate Design portions of this Stipulation and will file, on January 19, 2010, testimony only in opposition to the Residential Rate Design portion of the Stipulation." However, much of Mr. Jenks' response testimony goes far beyond this issue, to include long discussions on CUB's historic opposition to various time and season-related pricing programs and advanced metering infrastructure ("AMI"), CUB's dissatisfaction with the scope and direction of the UM 1415 proceeding and workshops, and CUB's disappointment that it has no intervenor funding for its hoped-for expert witness, Ms. Alexander. Indeed, a significant portion of Mr. Jenks' testimony appears to have been tailored to position CUB in *future* dockets, rather than to respond to the narrow issues presented by the residential rate design issue presented in *this* docket. In addition, both Mr. Jenks and Mr. Feighner devote a significant amount of testimony arguing about portions of the Stipulation to which they agreed—such as revenue allocation and certain rule changes.

**Q. Has CUB already agreed to the revenue allocation between classes and the specific rule changes specified in the Stipulation?**

A. Yes. For that reason, it is puzzling that both Mr. Jenks and Mr. Feighner discuss the "irrigation subsidy" issue as if it has an effect on rate design. It does not. The revenue requirement allocated to the residential class is set and agreed to by all Parties to the Stipulation. In addition, Mr. Feighner brings up changes in definitions in Rule B and contends that Rule B should remain unchanged, even though CUB did not oppose in the Stipulation any rule changes proposed by the Company.

**Q. How does the Company propose to address these extraneous issues put forth by CUB?**

A. The Rule B issue will be discussed in Ms. Waites' reply testimony to correct CUB's apparent misunderstanding of the effect of the Company's change to the definition of Billing Period. With regard to CUB's revenue allocation between classes or inter-class subsidies, the Company does not plan to address these issues at this time. However, in future dockets where these items are at issue, the Company will give each issue its proper review and consideration. In my reply testimony presented here, I will just address three policy issues as they relate to the contested topic of rate design.

**Q. What is the first policy issue related to rate design?**

A. The first policy issue is the Company's support for—and CUB's opposition to—the stipulated seasonal rates that are a component of the stipulated Residential Rate Design. It does not appear that the CUB objects to the current tiered rate structure, which the Company has had in place in Oregon since 1986, although CUB may suggest a difference in the exact kilowatt-hour break between the blocks. CUB objects to the seasonal rates arguing that they would not reduce consumption and would confuse residential customers.

**Q. Please reiterate the Company's objectives for rate design.**

A. The Company's objectives in its original rate design in this docket were to (1) establish prices that primarily reflect the costs of the services provided, (2) have cost-based rate proposals designed to align with and encourage energy efficiency, and (3) provide consistency and continuity through the Company's service territory. While the stipulated Residential Rate Design departs in some ways from the Company's original proposal, it does adhere to these fundamental objectives.

**Q. Does the CUB proposal, to establish residential rates based solely on annual rather than seasonal costs, send the correct price signals and encourage energy efficiency?**

A. No. CUB's proposal to rely solely on annual as opposed to seasonal rates conflicts with the Company's first two objectives of establishing prices that reflect the costs of the services provided and to have cost-based rate proposals designed to align with and encourage energy efficiency. To encourage the efficient use of energy, it is important for residential customers to be aware of seasonal costs that the Company experiences. Prices that reflect seasonal costs provide better and more accurate cost signals than prices that reflect annual costs. CUB's proposal suggests a rate design that would not meet either of these fundamental rate design principals and promotes short-term goals at the expense of long-term thinking.

**Q. What do you mean by short-term rather than long-term thinking?**

A. The unit cost per kilowatt-hour to provide Residential Service is significantly higher during the summer months than it is during the non-summer season. As a result, it costs the Company more to serve the residential customer during the summer months. The Staff and Company agree with economic theory that rational and informed consumers respond to appropriate price signals. A seasonal rate structure with higher prices for the summer months better reflects the costs to serve this class during the summer months. With this appropriate price signal, customers can make choices to reduce their consumption and to use energy more efficiently. By doing so, this action helps delay future need for additional peaking or base load resources. Long-term thinking looks into the future, and tries to enable changes in habits or consumptive patterns now, which can help reduce the need or cost of resources in the future. Short-term thinking would focus on mitigating the immediate price today, without consideration of how the current consumptive behavior on a flat rate or non-seasonal rate may drive the need for more and larger resources sooner, requiring additional revenue recovery and higher rates later.

**Q. What is the next Company policy issue you would like to discuss?**

A. I would like to discuss the Company's policy addressing low-income customers or customers who may have other special needs. Mr. Jenks argues that rate design should consider the price response of "elderly couples dealing with dementia, young families dealing with sick children, families dealing with grief, households dealing with unemployment, and individuals dealing with mental illness." Idaho Power is not indifferent to the plight of customers who may have special needs. Indeed, since 2004, the Company has employed a program manager to work in the communities we serve to identify and provide critical services to our customers with special needs. This program manager works with regional social service and Oregon State agencies to provide energy assistance and home weatherization services for qualified customers and coordinates symposiums bringing local agency offices together to improve services for our special needs customers. The program manager coordinates Project Share, the Company's voluntary fuel fund with the Salvation Army and administers the Gatekeeper program that utilizes Company field staff to support and assist vulnerable elderly people who need help but may be unable to seek assistance on their own. Through this community work, the Company is better able to understand the needs of our most vulnerable customers, incorporates this understanding into our planning process, and ultimately serves those customers better. However, with regard to rate design, the Company's policy is that proper rate design should be structured according to principles that benefit the greatest number of customers, while special needs customers can and should be assisted through additional programs established to provide assistance targeted specifically for those customers. It would not make sense for the Commission to reject a rate design that produces the most benefits for customers as a whole in order to benefit a small subset of a class of customers.

**Q. What types of assistance are available to Idaho Power's customers with special needs?**

A. Through the Weatherization Assistance for Qualified Customers ("WAQC") program, Idaho Power provides financial assistance to Idaho and Oregon Community Action Partnership ("CAP") agencies to help cover the cost for weatherization of electrically heated homes of qualified customers. Energy Assistance can be provided through Low Income Home Energy Assistance ("LIHEAP"), a federally funded program for qualified households. The Company has a number of energy efficiency programs designed to help all customers save on their monthly bill, reducing energy consumption and helping offset the growing need to build new resources. Ms. Waites will discuss these further in her testimony. In addition, the Company's Budget Pay plan is a convenient payment plan designed to help customers keep their electricity bills manageable all year long.

**Q. Is the Company's Budget Pay plan consistent with the Company's policy to provide effective price signals through its rate design?**

A. Yes. The stipulated Residential Rate design is the rate structure that determines how electric service is priced. The Company's Budget Pay plan is a payment option for customers to help them predict and budget utility payments. Seasonal rates do not undermine these goals because the Budget Pay plan only addresses the payment schedule, not the underlying rates.

**Q. Will a residential customer who participates in the Company's Budget Pay plan still receive the same price signal encouraging the efficient use of energy?**

A. Yes. Budget Pay customers' bills look just like all other residential customers' bills, with the additional line items of "Budget Pay" and "Budget Balance" included. The monthly usage and the determination of the monthly charges will still be shown on the customer's bill; however, the monthly payment amount will be the same month to month. It is incumbent on the customer to monitor their monthly usage and use energy efficiently so that a large annual adjustment in their Budget Pay plan will not be necessary.

**Q. What is the third Company policy you would like to discuss?**

A. The third Company policy has to do with CUB's proposal for the Commission to order that the PCAM (Power Cost Adjustment Mechanism) be used to bring irrigation customers closer to their cost of service. Again, please note that CUB has already accepted the Stipulation containing an agreed-upon class allocation of revenue requirement. Nevertheless, what is the appropriate forum to address cost allocation issues and inter-class subsidies is the question at hand. The Company asserts that the appropriate forum is a general rate case filing, when a full and current cost-of-service analysis, marginal cost analysis, and final revenue requirement allocation is performed. This process is well vetted and allows all parties to comment and intervene. The Company's current Annual Power Cost Update ("APCU"), which the Company assumes was the intent of CUB's proposal since the PCAM is an automatic adjustment clause as defined in ORS 757.210, is specifically for the annual rate revisions due to changes in the Company's projected Net Power Supply Expense. It is focused on a single issue with a prescriptive process for the variable to be considered as part of the update. The APCU adjustment rate is subject to increases or decreases, and may be made without prior hearing to reflect increases or decreases, or both, in the Net Power Supply Expense.

**Q. Why do you believe CUB proposes to address revenue requirement allocation issues through an automatic adjustment clause?**

A. While the Company's APCU and PCAM have been in effect for only a little over a year, the Staff has held one workshop to discuss the allocation of the APCU to different classes. Currently the rate adjustment is an equal cents-per-kilowatt-hour. Large power users with high load factors have expressed a concern that this methodology unfairly allocates the revenue adjustment. CUB was present at this workshop; however, the irrigation customers were not represented. During the conversation, a side issue was discussed–that of the "irrigation subsidy" that was stipulated to in the Company's general rate case. There was great interest by both the industrial customers and CUB that they could remedy this apparent inequity through the APCU. However, the Company does not support this concept. The Company maintains that the APCU and the PCAM are single issue, automatic adjustment clause mechanisms, and should not be used to address other, unrelated issues.

**Q. Does this conclude your reply testimony?**

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
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**UE 213**

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**IDAHO POWER COMPANY**

**SUPPLEMENTAL DIRECT TESTIMONY**

**OF**

**COURTNEY WAITES**

**January 26, 2010**

**Q. Please state your name.**

A. My name is Courtney Waites.

**Q. Are you the same Courtney Waites who has previously presented direct testimony in this case?**

A. Yes, I am.

**Q. Have you had the opportunity to review the Response Testimony objecting to the Stipulation of the Citizens' Utility Board of Oregon ("CUB") filed by witnesses Bob Jenks and Gordon Feighner?**

A. Yes, I have.

**Q. What is the scope of your testimony in this proceeding?**

A. My testimony will respond to issues raised by Mr. Jenks and Mr. Feighner regarding the residential rate design proposal contained in the Stipulation. It should be noted that any omission on my part in addressing issues raised by the parties does not indicate my concurrence with those issues.

**Q. What is the Company's current Oregon residential rate structure?**

A. Currently, Oregon residential customers have a two-tier inclining block rate year-round. Oregon residential customers pay a base energy charge for the first 300 kWh of energy used per month (the first block) and an energy charge that is approximately 25 percent higher per kWh for all energy used over 300 kWh (the second block).

**Q. The Parties, with the exception of CUB, agreed to the residential rate structure contained in the Stipulation. Please describe the agreed-upon rate structure.**

A. The Parties, with the exception of CUB, agreed to a seasonal two-tier inclining block rate with a new first block level of 1000 kWh; the first block rate would apply to energy usage from 0-1000 kWh and the second block rate would apply to all energy usage over 1000 kWh.

**Q. How is a seasonal two-tier inclining block rate different from the existing two-tier inclining block rate?**

A. Currently, the rate Oregon residential customers pay for energy usage in the first block is the same rate year round. The rate Oregon customers pay for the energy usage in the second block, which is approximately 25 percent per kWh higher than that of the first block, is also the same year round. The seasonal two-tier inclining block rate agreed to in the Stipulation includes an energy charge for the first block that stays the same throughout the year, just like the current rate structure. However, the energy charge for the second block varies by season. The proposed seasons are Summer, which includes the months June, July, and August, and Non-summer, which includes the months September through May.

**Q. So the only difference between the current rate structure and the one agreed to in the Stipulation is the block level and the rate charged for the second block of energy use?**

A. Yes. The new residential rate structure contained in the Stipulation is a block level that breaks at 1000 kWh rather than 300 kWh and a rate for the second block of energy that changes each season rather than staying constant year round.

**Q. Please restate the Company's overall objectives for residential rate design.**

A. As explained in the direct testimony, the Company's overall objectives with regard to rate spread and rate design are to (1) establish prices which primarily reflect the costs of the services provided, (2) have cost-based rate proposals designed to align with and encourage energy efficiency, and (3) provide consistency and continuity throughout the Company's service territory.

**Q. Does the Stipulation's rate design meet the Company's overall objectives?**

A. Yes, it does. The Stipulated residential rate design (a) establishes prices that primarily reflect the costs of the service provided, (b) has cost-based rates that align with and encourage energy efficiency, and (c) provides a little more consistency and continuity throughout the Company's service territory. Ren Orans' summary of inclining block rates in his article "Inclining for the Climate" in Public Utilities Fortnightly (May 2009), attached as Exhibit 1501, explains why utilities use this rate design to meet objectives:

> "An inclining block rate is consistent with accepted criteria for utility ratemaking. It promotes efficient consumption. Since the per-kWh charge rises with consumption, it has the correct price signal in a rising marginal-cost environment. Plus it fairly apportions the costs of service. In a rising marginal-cost environment, it assigns a higher proportion of costs to large customers, who bear greater responsibility for the increasing costs."

**Q. CUB Witness Mr. Jenks states the sole purpose of a summer seasonal rate is to discourage residential air-conditioning usage. Is this a correct statement?**

A. No. It is true that a higher summer rate should encourage energy efficiency during the summer months. However, the primary reason the Company is promoting seasonal rates is to meet the main objective for rate design, which is to establish prices that reflect the costs of the services provided. As shown in Exhibit 1502 (an updated version of Mr. Tatum's Exhibit Idaho Power/803 which has been adjusted to reflect the agreed-upon cost-of-service methodology and stipulated revenue requirement) at line 24, columns D and E, the unit cost for Residential Service is $0.08768 per kWh and $0.05254 per kWh for the summer and non-summer seasons, respectively. It costs the Company more to serve residential customers during the summer months. A seasonal rate structure with higher prices for the summer months better reflects the costs to serve this class during those summer months.

**Q. CUB Witness Mr. Feighner states that "[r]esidential customers do not drive the summer peak." Do you agree?**

A. No. The statement is not correct for the Idaho Power system. As I stated in my direct testimony, while the Oregon residential customer class' annual peak demand is forecasted to occur in January, the Oregon residential class represents 30 percent of the Oregon jurisdictional contribution to the annual system peak, which is forecasted to occur in July. The Oregon residential class is the second highest contributor to the Oregon jurisdictional share of the annual system peak behind only the industrial customer class, which contributes 32 percent. Furthermore, the residential class contribution to the monthly peak demand levels during the other two summer months is a significant driver of the Company's summer monthly system peaks, approximately 32 percent in June and 35 percent in August on an Oregon jurisdictional basis. The residential customer class is the single largest contributor to the Company's June and August monthly peaks on an Oregon jurisdictional basis.

**Q. At line 9 on page 2 of Mr. Jenks' testimony he states "the rate increase is not in fact related to the actual costs incurred by Idaho Power during the months when bills would be affected." Is his statement accurate?**

A. No. The summer season rate proposal contained in the Stipulation attempts to match seasonal revenues to seasonal costs. Based upon the Stipulated cost-of-service study, 64 percent of the Company's revenue requirement is comprised of costs and revenues that vary by season. Of the revenue requirement that is identified as seasonal in nature, 85 percent is generation-related. According to the same cost-of-service study, approximately 58 percent of the generation-related revenue requirement allocated to the residential class is attributed to the months of June through August. The Stipulated residential rate design does indeed align that class' rate increase with actual costs incurred by the Company during the summer months (CUB/100, Jenks/2).

**Q. Mr. Feighner asserts that there is a lack of a direct correlation between the tail block price assessed and the marginal cost of service. Do you agree?**

A. No. Mr. Feighner reasons that "it is difficult to support Idaho Power's position that seasonal rates are meant to reflect the Company's higher energy costs in the summer months when June marginal energy costs are below the annual average and below several other months." However, Mr. Feighner failed to look at the marginal energy costs during all 12 months of the year. While June's marginal costs are below the annual average, there are several months where the energy marginal costs are *above* the annual average. For example, September falls during the Company's lower priced, non-summer season. Seasonal pricing is not exact. The most appropriate way to reflect the marginal energy costs signal would be to have an inclining block rate that adjusted rates according to the marginal cost of energy each month. However, that approach would be too confusing for customers. Seasonal rates are an alternative; higher priced months can be grouped together in commonly referred to categories, such as summer, and lower priced months can be categorized as non-summer.

When grouped in the Stipulation's proposed seasons, summer containing the months June through August and non-summer containing September through May, the average marginal cost of energy per season is $0.08427 per kWh and $0.05232 cents per kWh, respectively. This value does not include the marginal costs of capacity which also drives prices. According to the Company's marginal cost study, the marginal costs of generation and transmission capacity is at the highest level during June and July, which is an important factor that Mr. Feighner fails to include in his analysis.

**Q. Both CUB witnesses Mr. Jenks and Mr. Feighner indicate residential customers' rates are being structured to subsidize the rates of others (primarily the irrigation customers). Is this true?**

A. No. The class revenue requirement is part of the cost allocation process. Any subsidies created through that process were agreed upon by all parties, including CUB, as part of the Stipulation. In addition, any subsidies produced do not impact rate design.

The rate design proposed simply takes the agreed upon revenue requirement for the residential class and spreads it to the various rate components.

**Q. CUB witness Mr. Jenks states that many customers prefer simplicity in pricing. Do you agree?**

A. I do agree that many customers prefer simplicity in pricing. However, I disagree that the Stipulated rate design is hard to understand. In his article "Inclining for the Climate" in Public Utilities Fortnightly (May 2009), Ren Orans describes an inclining block rate as fair and functional. He states "the inclining block rate is non-discriminatory and easy to understand. The rate applies to all customers in the residential class, with bill differences reflecting consumption differences. Though more complicated than a flat rate, an inclining block rate remains easy to understand."

**Q. How long has an inclining block rate been in place for Oregon residential customers?**

A. The inclining block rate structure in effect now, with a break point at 300 kWh, was put in place for residential customers in Oregon in 1986.

**Q. Will adding a seasonal component to an inclining block rate make the design too complicated?**

A. No, not in my opinion. As I stated earlier, the rate for the first block of energy use will remain constant throughout the year. The only seasonal change will be the rate for the second block of energy use.

**Q. Are seasonal block rates common?**

A. The Company has had seasonal rates in its Idaho jurisdiction since 2004. Likewise, as Orans points out "summer inclining block rates are well established in the West Coast and Southwest states, where in most cases at least one of the two largest utilities has inclining block residential rates. They are also prevalent in the Southeast and, to a lesser extent, in the Northeast and around the Great Lakes. Further, "in the West, Southeast, and Great Lakes regions, inclining block rates also are widely used in non-summer seasons."

**Q. You stated that residential customers in your Idaho jurisdiction have had seasonal rates since 2004. Does the Company make any attempt to notify your Idaho residential customers of the higher seasonal rates?**

A. Yes. As shown in Idaho Power Company's Response to CUB's Data Request No. 41, each May, prior to the beginning of the summer seasonal rates, Idaho customers receive a bill message on their electric bills indicating higher summer rates are in effect each year during the months of June, July, and August to reflect the increased costs of meeting summer energy demands. In addition, the previous two issues of the June/July Customer Connection brochures have included an article with suggestions to help customers reduce their summer electricity bills and an article reminding customers of the summer rate effective data as well as describing the Company's tiered rate structure.

**Q. Does the seasonal rate structure meet other Company objectives with regard to rate design?**

A. Yes. A seasonal rate structure also meets the Company's objective of having cost-based rates that align with and encourage energy efficiency. As Mr. Youngblood states in his supplemental direct testimony, the proposed seasonal rate structure, coupled with the tiered block design proposal, does just that. With higher rates in the summer, along with higher rates for all energy consumed over 1000 kWh a month, customers are given the price signals to encourage the efficient use of energy. Customers are encouraged to conserve and use less energy during the summer months when it costs the Company the most to provide that energy.

**Q. How does the Stipulated rate design proposal encourage energy efficiency?**

A. As I pointed out earlier, inclining block rates, like those currently in effect for Oregon residential customers, provide an incentive to customers to conserve energy. By charging customers a higher rate for energy as the amount of energy usage increases, customers are given a price signal to encourage energy efficiency. Furthermore, by adding seasonality to the second block energy rate, customers are sent a price signal more reflective of current costs. CUB witness Mr. Jenks agrees that when combined with good energy efficiency programs, tiered rates can have an important role to play in encouraging load reduction.

**Q. But Mr. Jenks states that "CUB's examination of Idaho Power Company's energy efficiency program suggests that the residential energy efficiency programs available to customers may not be robust enough to support tiered rates in Oregon." Do you agree with this statement?**

A. No, I do not. As shown in Idaho Power Company's Response to CUB's Data Request No. 37, the Company offers sixteen energy efficiency programs, education and outreach initiatives, and market transformation efforts to residential customers throughout its service territory:

1. A/C Cool Credit
2. Home Improvement Program
3. Ductless Heat Pump Pilot
4. Energy Efficient Lighting
5. Energy House Calls
6. ENERGY STAR® Homes Northwest
7. Heating and Cooling Efficiency
8. Home Products Program
9. Home Weatherization Pilot
10. Oregon Residential Weatherization

11. Rebate Advantage
12. Weatherization Assistance for Qualified Customers
13. See Ya Later Refrigerator
14. Residential Education Initiative
15. Northwest Energy Efficiency Alliance
16. Local Energy Efficiency Funds

Of these 16 programs, only two are not offered to our Oregon customers. One is the Home Weatherization Pilot, which is a pilot tested by a Community Action Partnership agency in the eastern Idaho area and the other is the Home Improvement Program. The Home Improvement Program provides a cash incentive for professional installation of attic insulation. This specific program has not been offered to our Oregon customers because incentives are available for attic insulation through the Residential Energy Conservation Program.

These 14 programs offer Oregon customers a wide range of options to encourage energy conservation, as well as options that require little or no investment on the customer's part. Additionally, even as I was preparing this testimony, Idaho Power was featured in the New York Times for its efforts in energy efficiency (see Exhibit 1503). The rate structure provides the Oregon residential customer the economic incentive to take other actions that influence customer consumption unrelated to a specific utility program.

**Q. CUB Witness Mr. Jenks expresses his concern for Oregon residential customers not able to afford capital investments in energy efficiency products. What are some of the energy efficiency programs offered to residential customers in Oregon that require little or no investment on the customer's part?**

A. Through the Company's Residential Education Initiative, the Company offers information or special presentations educating customers about wise and responsible energy use. For as little as $1 per bulb, customers can purchase an energy efficient compact fluorescent light ("CFL"). Energy House Calls is a program designed for residents of manufactured homes heated by an electric furnace or heat pump, that provides testing and sealing of ductwork, installation of CFLs, air filter replacement, and checking of hot water temperature, all free of charge. Weatherization Assistance for Qualified Customers provides free weatherization measures for electrically-heated homes. Finally, the A/C Cool Credit program provides a $7 per month *credit* for customers who permit the Company to install a load control device on their air conditioner, allowing the Company to cycle it on a few June, July, and August afternoons during periods of high electric demand.

**Q. Witness Mr. Feighner argues that "Idaho Power appears to have had a decent amount of success in implementing energy efficiency programs in its Idaho service territory, but has achieved poor results in its Oregon service territory" and that "these results indicate a lack of Company effort." Do you agree?**

A. No. As I have shown above, other than the two exceptions, the Company's energy efficiency offerings in Oregon mirror those in Idaho. Moreover, efforts to market energy efficiency offerings in Oregon also mirror those in Idaho. While it is true that Oregon participation in some programs is very small when compared to Idaho participation, it is also true that Oregon participation in other programs is very strong – in the neighborhood of 10 and even 20 percent. Overall, when estimating program participation during program planning, the Company generally assumes 5 percent of total program participants to be Oregon residents.

**Q. Mr. Jenks states that there is lack of evidence to show that imposing the proposed price signals on winter-peaking residential customers will be effective in reducing peak energy consumption. Do you agree?**

A. No. The Company has data supporting the fact that price increases will result in reduced usage. Mr. Jenks explicitly acknowledges this fact when he says "historically, we can see that weather-normalized usage declines after large bill increases." A higher second tail block rate will have a greater impact on the higher use customers. The price signals sent through the rate design coupled with the 26.3 percent overall increase for the residential class will be a strong energy efficiency message to customers. Mr. Jenks agrees: "Because bills are going up so significantly, customers are receiving strong price signals that encourage conservation."

**Q. CUB Witness Mr. Jenks points out that electric service is an essential service that is provided by a monopoly and that customers do not have the ability to shop elsewhere if they do not like the cost or pricing plans offered. How does the Stipulated rate design address this concern?**

A. It is important to note that while electric service is an essential and is necessary, not all electric *use* is. The rate design agreed upon by the Parties, with the exception of CUB, takes this into account. As I mentioned in my direct testimony, increasing the block level of the first block of energy from the current 300 kWh level allows for more energy use to be priced at the lowest rate. A block level of 1000 kWh, which is the level set in the Stipulation, will cover what the Company considers as basic electric usage, estimated at approximately 500-850 kWh (Idaho Power/900, Waites/7). The second block rate, for usage above 1000 kWh, is intended to encourage more efficient discretionary consumption, such as for radios, televisions, clothes washers and dryers. The Stipulated rate design will generally have the greatest impact on higher use customers; customers whose usage falls around 1000 kWh will see an average increase of approximately 21 percent, while customers who use 3000 kWh will see an increase of approximately 30 percent.

**Q. CUB Witness Mr. Jenks states Idaho Power Company is asking to extend billing cycles to as long as 36 days. Is this correct?**

A. No. Mr. Jenks is confused about the Company's proposed change to a definition in Rule B. Billing cycles are the Company's schedules for meter reading and billing. The Company has 21 billing cycles that encompass each revenue month and is not changing any of the billing cycles. However, the Company is proposing to change the definition of “Billing Period” in Rule B to state that a normal billing period is considered to be 27 to 36 days. As stated in Company witness Mr. Youngblood’s direct testimony (Idaho Power/1200 Youngblood/6), the change is being made to minimize the number of bills that include prorated billing components.

**Q. Why is this change being made?**

A. As part of the Company’s billing process, meter reading lists are prepared three days in advance of the read date. If a meter is installed for a customer, either due to a new service or as part of meter maintenance, three days or less before the scheduled read date for the route, the customer’s meter will not be included on the meter reading list for that month’s reading. When this situation occurs, the period of time between when the meter was installed and when it is read can exceed 33 days. When the number of days in the billing period exceeds the current upper limit of 33 days, the Service Charge, Basic Charge, and Demand Charge are prorated to recognize the longer billing cycle. If the definition of a normal billing period is changed to 27 to 36 days, proration of the Service Charge, Basic Charge, and Demand Charge will not be required in these circumstances.

**Q. CUB witness Mr. Feighner states “this rule change would have the potential to be harmful to customers in all months” because it would extend the 30-day billing cycle an additional six days. Is the Company proposing to also change the number of days in a billing cycle?**

A. No. As shown in Idaho Power Company’s Response to CUB‘s Data Request No. 44, the average number of days in the billing cycles of 2007, 2008, and 2009 are 29-32 days. In fact, those combined years had 2 months with an average of 29 days, 15 months with an average of 30 days, 15 months with an average of 31 days, and 4 months with an average of 32 days.

**Q. Is the Company's normal billing period in the Idaho jurisdiction defined as 27 to 36 days?**

A. Yes. The normal billing period was extended to 36 days in the Company's Idaho jurisdiction in 2008.

**Q. Are you able to quantify the impact this change had to your Idaho customers?**

A. In 2009, less than .22 percent (22/100th of 1 percent) of *all* customers' bills included a billing cycle that was 34-36 days, of which almost all were due to a starting bill or an ending bill.

**Q. Mr. Feighner indicates a concern of billing cycle timing and seasonal rates. He states that "very few customers will have their billing cycles perfectly coincide with the June 1 through August 31 period that constitutes the summer seasonal rate period" and that the "vast majority of customers will have this period spread across four billing cycles – May-June, June-July, July-August, and August-September." Is this correct?**

A. Yes it is.

**Q. CUB believes issues may arise during overlapping billing cycles. For example, customers' energy use during a heat wave that runs from May 28 - 31 may be billed at the higher summer rate because of the Company's prorating formula.**

A. Due to current meter data and the Company's billing system constraints, energy usage during season changes is prorated based on the number of days in the billing cycle that fall in each season. However, it is important to note that the same holds true for a heat wave that runs from August 28-31. Energy usage during this time may in fact be billed at the *lower*, non-summer rate.

**Q. Does CUB raise any other concerns you would like to address?**

A. Yes. CUB witness Mr. Jenks voices his concern about minimizing rate changes and states in his testimony that "minimizing rate changes is a clear and long-standing policy in Oregon." He states that NW Natural includes a variety of rate changes that are timed to coincide with the Company's Purchased Gas Adjustment to avoid having several rate changes in a single year. The Company has proposed a summer season that runs from June 1 through August 31. The June 1 rate change to summer rates would coincide with Idaho Power's Annual Power Cost Update ("APCU") and Power Cost Adjustment Mechanism ("PCAM") – both of which will change customers' rates. As I mentioned above, the Company has numerous methods of notifying its Idaho customers about seasonal rate changes.

**Q. Do you acknowledge, however, that there are no existing rate changes that coincide with the non-summer seasonal rate change?**

A. Yes I do. However, I would point out that, while it is generally desirable to minimize rate changes, there is an advantage to rate changes as well. Whether they are increases because customers are entering the summer season or decreases because customers are entering the non-summer season, these changes help get customers focused on their energy use, even if only temporarily. Being aware of energy use and using this energy wisely and efficiently, is the best way for customers to keep their monthly energy bill low.

**Q. Does this conclude your testimony?**

A. Yes, it does.

Idaho Power/1501
Witness: Courtney Waites

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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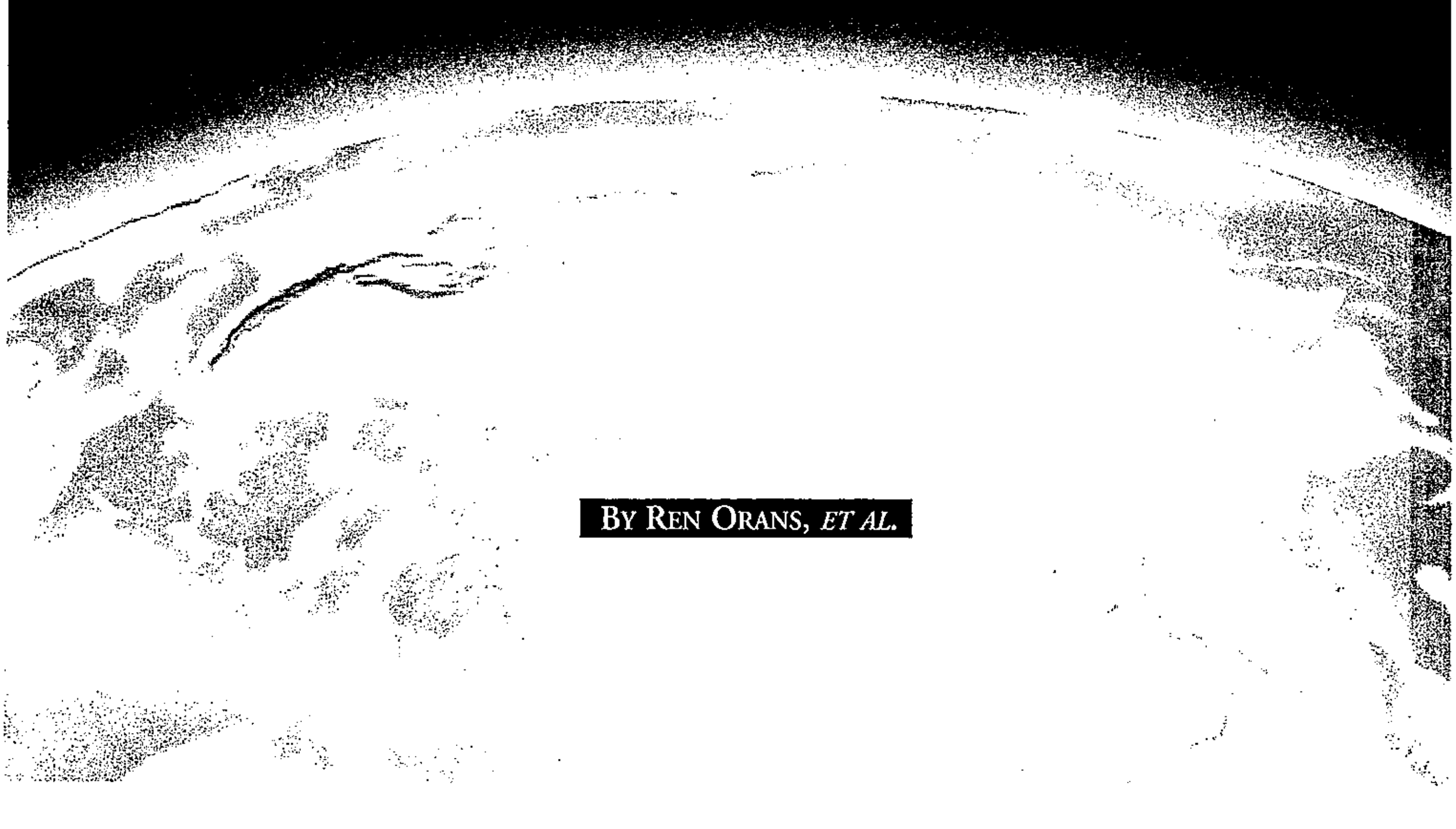
Exhibit Accompanying Reply Testimony of Courtney Waites
Ren Oran's Article – *Inclining for the Climate*

January 26, 2010

# Inclining for the Climate

GHG reduction via residential electricity ratemaking.



BY REN ORANS, *ET AL.*

On the campaign trail, then-Senator Obama made ambitious statements regarding renewable energy investment and greenhouse-gas (GHG) reduction goals. For example, in October 2007, Senator Obama announced plans to, if elected president, reduce emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050.[1] Achieving such ambitious goals will require major changes on many fronts. In the electric power sector, an essential component of significant GHG reduction is energy efficiency.

In the arena of electricity efficiency, much attention has been given to building codes and weatherization, efficient lighting and appliance standards, and other measures that can be undertaken by businesses and households, often with incentives from the local electric utility. Rate design has received less attention. However, building on a survey the authors performed for BC Hydro in its 2008 residential rate-design application,[2] a study by the authors suggests that rate design—in particular residential inclining block rates—can help achieve GHG-reduction goals. The same opportunity does not exist for time-varying rates.

**Many utilities are missing an easy opportunity to boost the effectiveness of their DSM programs.**

Admittedly rough and based on simplifying assumptions, the study's calculation suggests rate redesign could reduce GHG emissions by one to two percent. While seemingly negligible, this GHG reduction easily could be obtained at low cost and in short time. Thus, both regulators and electric utilities should consider residential inclining block rate design as part of their efforts in complying with the forthcoming GHG-reduction targets.

**Fair and Functional**

An inclining block rate has a per-kilowatt hour charge that increases with a consumer's monthly kWh consumption. Most inclining block rates use a two-tier design, though three- or more tier designs do exist. The consumption and price levels set for each tier depend on the specific goals of the utility and the characteristics of its residential customer class. To collect the same revenue as an otherwise applicable flat rate, a revenue-neutral inclining block rate's lowest tier charge must be below, and the highest tier charge above, the flat rate. For example, a hypothetical two-tier inclining block rate might provide an original flat rate of 10-cents per kWh, with a tier-1 rate 15-percent lower, and a tier-2 rate 25-percent higher (*see Figure 1*).

To see how such an inclining block-rate design can be revenue-neutral, while still providing a strong incentive to conserve, consider the simplified case of two hypothetical customers with monthly consumption of 667 kWh and 2,000 kWh, respectively. Under the flat rate, utility revenue is given by total consumption multiplied by the flat rate, or (667 kWh + 2,000 kWh) * $0.10/kWh = $267. Under the new rate, if the tier-1 quantity is set at 1,000 kWh, then 1,667 kWh will be billed at the tier-1 rate (all 667 kWh of the small customer's consumption plus the first 1,000 kWh of the large customer's consumption) and the remainder (1,000 kWh) will be billed at the tier-2 rate.[3] Revenue under the new rate is equal to the quantity times the price in each tier: (1,667 kWh * $0.085/kWh) + (1,000 kWh * $0.125/kWh), or $267, identical to the revenue collected under the original flat rate.

Although the rate is revenue-neutral, the majority of the kWh sales (75 percent = 2,000 kWh ÷2,667 kWh) will see the tier-2 rate as the marginal rate, providing a strong conservation incentive. Higher prices lead to lower electricity demand. A 2004 meta-analysis of residential price elasticity studies reports 123 short-run estimates between -0.004 and -2.01, with an average of -0.35, and 125 long-run estimates between -0.04 and -2.25, with an average of -0.85.[4]

An inclining block rate is consistent with accepted criteria for utility ratemaking:[5] It promotes efficient consumption. Since the per-kWh charge rises with consumption, it has the correct price signal in a rising marginal-cost environment. Plus it fairly apportions the costs of service. In a rising marginal-cost environment, it assigns a higher proportion of costs to large customers, who bear greater responsibility for the increasing costs.

Additionally, the inclining block rate maintains universal affordability. Low-income customers, who tend to consume less energy than other customers, enjoy the lower tier-1 rate. To be fair, an inclining block rate may result in less stable bills than the flat rate. But large bill spikes can be mitigated by an optional payment plan that aims to partly smooth large bill fluctuations.

The inclining block rate is non-discriminatory and easy to understand. The rate applies to all customers in the residential class, with bill differences reflecting consumption differences. Though more complicated than a flat rate, an inclining block

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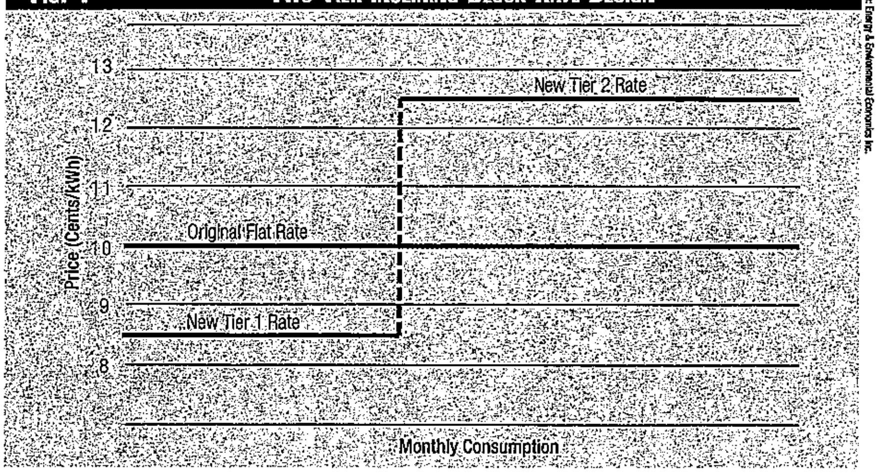
**FIG. 1 TWO-TIER INCLINING BLOCK RATE DESIGN**




rate remains easy to understand.

Finally, unlike time-varying or dynamic pricing rates, an inclining block rate can be implemented quickly and at very low cost using an electric utility's existing billing and metering system.

One possible objection to residential inclining block rates in some jurisdictions is the need to maintain affordable electric space and water heating, particularly for low-income customers. This can be addressed, however, through the use of a design that offers a large tier-1 quantity for customers who have electric heating and no access to natural gas.

### Rates in the States

Inclining block rates already are used throughout the United States.[6]

Utility rates fall into four categories: inclining, flat, declining, and mixed. Flat rates provide a single price for all consumption, while declining block rates have per-kWh charges that decrease with consumption. Mixed rates vary by season (*see Figures 2 and 3*).

Summer inclining block rates are well established in the West Coast and Southwest states, where in most cases at least one of the two largest utilities has inclining block residential rates. They also are prevalent in the Southeast and, to a lesser extent in the Northeast and around the Great Lakes.

However, a significant portion of the country employs flat rates. This category includes Maine and Texas, where the two largest residential providers are competitive energy providers rather than regulated utilities. In these cases, rate structure is not readily apparent, but the small amount of published rate data available shows flat rates are used.

In the West, Southeast, and Great Lakes regions, inclining block rates also are widely used in non-summer seasons. Much of the country, however, employs declining block rates in non-summer seasons, particularly a central swath of the country and much of the Northeast. In seven states—Iowa, Indiana, Mississippi, North Dakota, Ohio, Pennsylvania, and West Virginia—at least one of the two largest utilities uses declining block rates year-round.

**Making time-varying rate designs mandatory doesn't alter their inability to induce conservation.**

### Green Inclination

Utilities that emphasize demand-side management (DSM) programs might be expected also to use inclining block rates, which provide a strong incentive to conserve and shorten the payback period for energy-efficiency measures. However, this is not entirely the case for the sample of utilities studied in the authors' review of rate designs, as shown by a comparison of rate structures and DSM expenditures reported on EIA Form 861.[7]

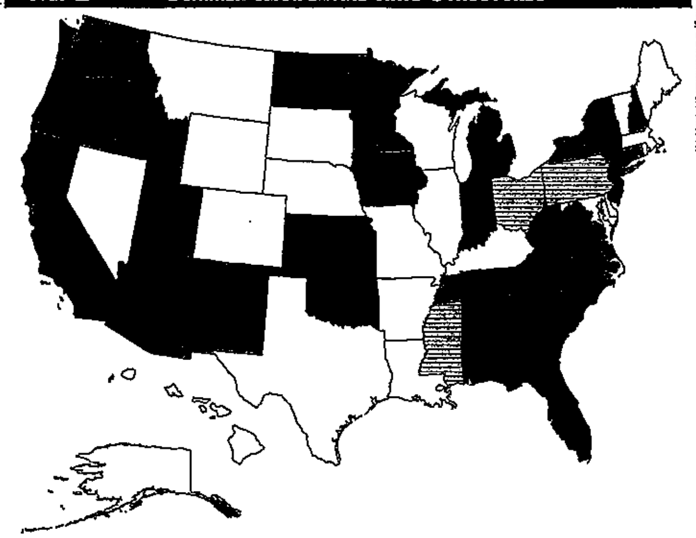
To be sure, utilities with higher DSM expenditures are more likely to employ inclining block-rate structures. The energy providers in the survey with relatively higher DSM expenditures were more than twice as likely as others to use year-round residential inclining block rates—28 percent vs. 12 percent, respectively.[8] Nevertheless, the comparison also reveals room for improvement. Many utilities with higher DSM expenditures don't yet employ residential inclining block rates (56 percent), or employ them during summer only (16 percent); several employ declining block rates for part or all of the year. These utilities miss an easy opportunity to boost the effectiveness of their DSM programs.

They also miss an opportunity to reduce their aggregate GHG emissions as estimated under the following assumptions.

According to EIA data, the jurisdictions in the study sample with flat or declining block rates serve approximately 350 TWh of residential load per year. This sales assumption excludes: A) sales by utilities in the sample that use inclining block rates in any portion of the year; and B) sales by utilities not in the sample. Including A) or B) magnifies the sales assumption and the savings opportunity.

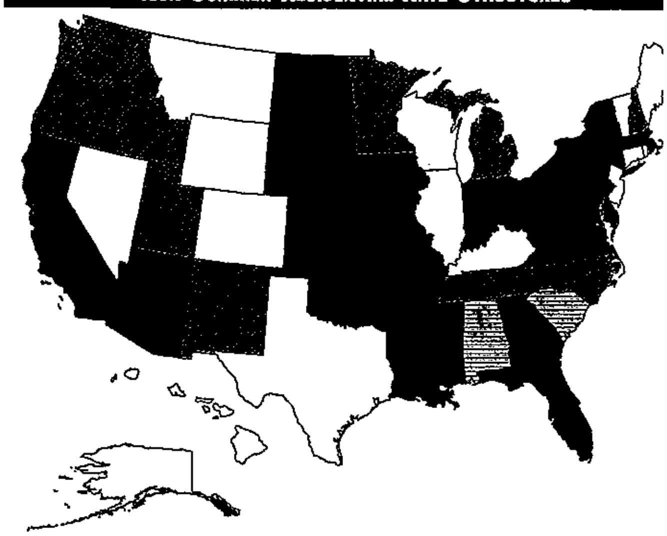
These jurisdictions with flat or declining block rate structures adopt simple two-tier inclining block residential rates that are 15-percent lower than the original rate in the first tier, and 25-percent higher than the original rate »

**Fig. 2 Summer Residential Rate Structures**



Source: Energy & Environmental Economics Inc.

**Fig. 3 Non-Summer Residential Rate Structures**



- Both Utilities have Flat Rates
- Both Utilities have Inclining Rates
- Both Utilities have Declining Rates
- One Utility has Inclining Rates, the Other has Flat Rates
- One Utility has Declining Rates, the Other has Flat Rates
- One Utility has Inclining Rates, the Other has Declining Rates

This rate design map is based on the authors' review of the residential tariffs of the two largest ene providers, in terms of residential sales, in each of the 50 states, plus Potomac Electric Power in the I trict of Columbia. The top two providers of residential energy in each state are based on the data fi the U.S. Department of Energy, Energy Information Administration (EIA). This review is not exhaust but in many cases the top two providers of residential energy in a state serve a significant portioi that state's residential load. The utilities reviewed account for 57 percent of total U.S. residential el tricity consumption. Moreover, other providers in the state often have residential rate structures sim to those of the top two providers. Thus, the review provides a reasonable representation of the g graphical dispersion of residential rate structures in the United States.

in the second tier, in keeping with the example presented earlier.

Also in keeping with the earlier example, 75 percent of the 350 TWh sees the tier-2 rate as the marginal price, while the remainder sees the tier-1 rate as the marginal price.

Small users (1,000 kWh and below) facing the tier-1 rate as the marginal price have an average short-term price elasticity of -0.05; larger users facing the tier-2 rate as the marginal price have a moderately higher average short-term price elasticity of -0.1. These elasticities are conservatively low, given the meta-analysis of other studies, and are applied under the assumption that users respond to marginal price changes.[9] The percentage in consumption by user group is estimated as the percentage change in price times the elasticity value.

GHG-emission rates among the affected utilities are equal to the U.S. average.

Using the above simplifying assumptions, the percentage change in total sales is 1.7 percent,[10] or 5.9 TWh of energy savings. Assuming $CO_2$ emissions intensity of 0.67 metric tons per MWh,[11] this amounts to 3.96 million metric tons of $CO_2$ savings, about one percent of what would be required to reduce the electric sector's total $CO_2$ emissions to the 1990 level.[12] This number would be roughly doubled if the calculation were expanded to encompass utilities not in our review and those with inclining rates in other seasons.

While a one to two percent $CO_2$ reduction might seem negligible, it's significant when one considers the ease of implementing the rate redesign. Further, where marginal cost is high, upper-tier rates might be increased beyond the modest levels considered in this study, spurring even greater reductions. California's large IOUs for example, have upper tiers that are multiples of lower tiers, nearly 30 cents/kWh in the case of PG&E.

Finally, the calculation does not account for long-term customer price response that entails energy-efficient purchase decisions, nor does it attempt to measure the enhanced value to existing DSM programs.

## TOU Alternatives

Time-varying pricing encompasses time-of-use (TOU) rates, real-time pricing (RTP), and critical-peak pricing (CPP).[13] Peak-shaving benefits notwithstanding, there is little GHG reduction potential for alternative rate designs based on time-varying pricing.

To achieve meaningful GHG reduction, a rate redesign must induce a reduction in a customer's overall kWh consumption. Time-varying rates, in contrast, mainly result in load shifting. To understand this point, consider the case of optional time-varying pricing. A customer likely joins a time-varying rate option, whether TOU, RTP or CPP, if he or she can achieve bill savings with relative ease. The bill savings can be obtained by shifting consumption from the high-price peak hours to low-price off-peak hours.[14] While the participating customer may achieve the desired reduction in the per-kWh charge, there is little or no conservation incentive.

Making the time-varying rate designs mandatory doesn't alter their inability to induce significant conservation. For example, a revenue-neutral two-period TOU rate design necessarily has a peak rate above, and an off-peak rate below, an existing flat rate. While the peak rate reduces peak kWh consumption, the off-peak rate increases off-peak kWh consumption. Thus, the total kWh effect of the TOU design is small. The same line of reasoning applies to an RTP that has hourly rates above and below the existing flat rate. It also applies to a CPP that has high rates during critical peak hours but low rates in non-critical-peak hours.

### GHG Solution

Inclining block rates offer a low-cost and timely opportunity to achieve electricity conservation and efficiency improvements, and resulting GHG-emissions reductions. Residential inclining block rates are easy to implement and to understand. Unlike time-varying and dynamic pricing rates, they don't require new billing and metering infrastructure. Moreover, inclining block rates can spur residential customers to make long-term consumption decisions that incorporate investments in energy efficiency. Efforts to reduce national GHG emissions should include this easy-to-implement and low-cost measure.

### Endnotes:

1. Jeff Zeleny, "Obama Proposes Capping Greenhouse Gas Emissions and Making Polluters Pay," *The New York Times*, Oct. 9, 2007, at: *http://www.nytimes.com/2007/10/09/us/politics/09obama.html#*.
2. Filed in February 2008, BC Hydro's Residential Inclining Block Rate Application is available at: *http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/info_2008_residential_inclining_block_application.Par.0001.File.info_2008_residential_inclining_block_application.pdf*.
3. Revenue-neutrality is calculated prior to any consideration of price-induced changes in consumption.
4. James A. Espey and Molly Espey, "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities," *Journal of Agricultural and Applied Economics*, April 2004, Vol. 36, No.1, pp.65-81. See also: Ahmad Faruqui, "Inclining Toward Efficiency: Is Electricity Price-Elastic Enough for Rate Designs to Matter?" *Public Utilities Fortnightly*, August 2008, Vol. 146, No. 8, pp.22-27
5. Charles F. Phillips. *The Regulation of Public Utilities*, Public Utilities Reports, Arlington, Virginia, 1993, p.434.
6. DOE EIA-0348, 2007. *http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html*.
7. DOE EIA Form 861. EIA-861 does not provide DSM expenditures by customer class; we assume that utilities with high overall DSM expenditures include residential programs in their portfolio.
8. We defined "high" DSM expenditures as $0.75/MWh or greater, which results in a "high" label for energy providers with DSM expenditures in roughly the upper quartile of our sample. Where utilities did not report a value for DSM expenditures on EIA-861, we assume expenditures were, in fact, zero.
9. Applied microeconomics typically models customer responsiveness based on marginal price changes, see Jerry A. Hausman, "The Econometrics of Nonlinear Budget Sets," *Econometrica*, Vol.53, No.6, pp.1255-1282.
10. Percentage change in total sales = (share of sales with marginal rate at tier-1 rate * price elasticity for small users * percentage of tier-1 rate change) + (share of sales with marginal rate at tier-2 rate * price elasticity for large users * percentage of tier-2 rate change). Thus, (25 percent * -0.05 * -15 percent) + (75 percent * -0.10 * +25 percent) = 1.7 percent. Changing the tier-1 sales share assumption to 50 percent would result in a total sales change of -0.9 percent.
11. The U.S. average based on EIA 2006 sales and emissions data.
12. The total emissions reduction requirement is estimated based on EIA and EPA sources: *http://www.eia.doe.gov/cneaf/electricity/epa/epat5p1.html*; EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2006*, Apr. 15, 2008, pp.2-4.
13. For a discussion of time-varying pricing options, see C.K. Woo, Eli Kollman, Ren Orans, Snuller Price and Brian Horii, "Now that California Has AMI, What Can the State Do with It?" *Energy Policy*, April, 2008, Vol. 36, pp.1366-74.
14. For empirical evidence on customer response to time-varying pricing, see: Chris King and Dan Delurey, "Efficiency and demand response: twins, siblings, or cousins?" *Public Utilities Fortnightly*, March 2005, 58-61; and DOE (2006) "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," Department of Energy, Washington D.C. (Available at: *http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf*).

Idaho Power/1502
Witness: Courtney Waites

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Courtney Waites
Updated Version of Mr. Tatum's Exhibit Idaho Power/803

January 26, 2010

**IDAHO POWER COMPANY**
**Marginal Cost Analysis 2009**
**Marginal Cost By Class - OREGON JURISDICTION**
**(2009 Dollars)**

| Line | Description | (A) TOTAL SYSTEM | (B) RESIDENTIAL (1) | (C) GEN SRV (7) | (D) GEN SRV SECONDARY (9-S) | (E) GEN SRV PRIMARY (9-P) | (G) AREA LIGHTING (15) | (I) LG POWER PRIMARY (19-P) | (J) LG POWER TRANS (19-T) | (K) IRRIGATION SECONDARY (24-S) | (L) UNMETERED GEN SERVICE (40) | (M) MUNICIPAL ST LIGHT (41) | (N) TRAFFIC CONTROL (42) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | *Normalized Sales (kWh)* | 740,533,031 | 220,362,881 | 19,087,766 | 129,779,060 | 17,340,865 | 470,308 | 195,081,276 | 90,310,412 | 67,154,213 | 14,306 | 912,800 | 19,144 |
| 2 | Current Revenue | $32,433,692 | $11,262,377 | $1,176,138 | $6,331,332 | $654,786 | $98,625 | $6,712,141 | $3,243,600 | $2,846,148 | $772 | $106,979 | $794 |
| 3 | | | | | | | | | | | | | |
| 4 | Generation Marginal Cost | | | | | | | | | | | | |
| 5 | Generation Demand-Related | $5,368,907 | $1,681,622 | $160,628 | $942,951 | $119,727 | $519 | $1,078,999 | $563,709 | $819,581 | $75 | $995 | $100 |
| 6 | Generation Energy-Related | $46,251,305 | $13,587,114 | $1,187,823 | $7,954,222 | $1,055,870 | $28,374 | $11,838,944 | $5,800,384 | $4,741,513 | $863 | $55,044 | $1,155 |
| 7 | Generation Total | $51,620,212 | $15,268,735 | $1,348,451 | $8,897,174 | $1,175,597 | $28,893 | $12,917,943 | $6,364,093 | $5,561,094 | $938 | $56,039 | $1,255 |
| 8 | Transmission Marginal Cost | | | | | | | | | | | | |
| 9 | Transmission Demand-Related (75%) | $14,714,881 | $4,912,854 | $433,698 | $2,725,422 | $348,347 | $2,358 | $3,117,028 | $1,404,982 | $1,765,148 | $216 | $4,540 | $289 |
| 10 | Transmission Energy-Related (25%) | $4,904,960 | $1,459,585 | $126,429 | $859,599 | $114,858 | $3,115 | $1,292,131 | $598,176 | $444,800 | $95 | $6,046 | $127 |
| 11 | Transmission Total | $19,619,842 | $6,372,439 | $560,127 | $3,585,021 | $463,205 | $5,473 | $4,409,159 | $2,003,158 | $2,209,948 | $311 | $10,586 | $416 |
| 12 | Distribution Marginal Cost | | | | | | | | | | | | |
| 13 | Demand-Related | $9,658,948 | $4,441,166 | $280,793 | $1,812,158 | $171,415 | $5,820 | $1,102,323 | $0 | $1,833,817 | $156 | $11,191 | $110 |
| 14 | Customer-Related | $2,877,137 | $1,831,719 | $489,644 | $230,216 | $7,279 | $0 | $18,994 | $6,595 | $289,732 | $261 | $1,857 | $838 |
| 15 | | | | | | | | | | | | | |
| 16 | Total Functionized Revenue Requirement | | | | | | | | | | | | |
| 17 | Generation | $20,407,194 | $6,036,241 | $533,088 | $3,517,350 | $464,753 | $11,422 | $5,106,895 | $2,515,939 | $2,198,486 | $371 | $22,154 | $496 |
| 18 | Demand-Related | $7,997,569 | $2,365,600 | $208,917 | $1,378,448 | $182,136 | $4,476 | $2,001,389 | $985,995 | $861,586 | $145 | $8,682 | $194 |
| 19 | Energy-Related | $12,409,625 | $3,670,641 | $324,171 | $2,138,902 | $282,616 | $6,946 | $3,105,505 | $1,529,943 | $1,336,901 | $225 | $13,472 | $302 |
| 20 | Transmission | $3,694,492 | $1,199,955 | $105,474 | $675,073 | $87,223 | $1,031 | $830,262 | $377,202 | $416,142 | $58 | $1,993 | $78 |
| 21 | Distribution | | | | | | | | | | | | |
| 22 | Demand-Related | $10,306,242 | $4,738,791 | $299,610 | $1,933,600 | $182,902 | $6,210 | $1,176,195 | $0 | $1,956,711 | $166 | $11,941 | $117 |
| 23 | Customer-Related | | | | | | | | | | | | |
| 24 | Allocated | $2,611,035 | $1,662,306 | $444,358 | $208,924 | $6,606 | $0 | $17,238 | $5,985 | $262,935 | $237 | $1,686 | $760 |
| 25 | Direct Assignment** | $414,826 | $190,712 | $42,634 | $18,964 | $71 | $58,699 | $85 | $30 | $21,595 | $43 | $81,908 | $85 |
| 26 | | | | | | | | | | | | | |
| 27 | Total | $37,433,790 | $13,828,005 | $1,425,163 | $6,353,911 | $741,555 | $77,361 | $7,130,674 | $2,899,156 | $4,855,869 | $876 | $119,683 | $1,537 |
| 28 | Revenue Difficiency | $5,000,098 | $2,565,628 | $249,025 | $22,579 | $86,769 | ($21,264) | $418,533 | ($344,444) | $2,009,721 | $104 | $12,704 | $743 |
| 29 | % Increase Required | 15.42% | 22.78% | 21.17% | 0.36% | 13.25% | -21.56% | 6.24% | -10.62% | 70.61% | 13.41% | 11.88% | 93.60% |
| 30 | | | | | | | | | | | | | |
| 31 | Proposed Revenue Spread | $37,434,662 | $14,224,869 | $1,466,066 | $6,536,268 | $762,838 | $98,625 | $7,335,324 | $3,243,600 | $3,641,901 | $901 | $123,118 | $1,153 |
| 32 | % Increase Required | 15.42% | 26.30% | 24.65% | 3.24% | 16.50% | 0.00% | 9.28% | 0.00% | 27.96% | 16.67% | 15.09% | 45.20% |
| 33 | Cost of Service Index | | 102.87% | 102.87% | 102.87% | 102.87% | 127.49% | 102.87% | 111.88% | 75.00% | 102.87% | 102.87% | 75.00% |
| 34 | Average Mills Per kWh | 50.55 | 64.55 | 76.81 | 50.36 | 43.99 | 209.70 | 37.60 | 35.92 | 54.23 | 62.96 | 134.88 | 60.22 |

Idaho Power Company
Marginal Cost Analysis 2009
2009 TY Revenue Requirement per Billing Component - OREGON JURISDICTION

**** * * RESIDENTIAL SERVICE - SCHEDULE 1 * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KWH) | (E) NON-SUMMER ($/KWH) | (F) SERVICE ($/CUST/MO) |
|---|---|---|---|---|---|---|
| GENERATION | | | | | | |
| DEMAND - Summer | $1,364,368.86 | 43,876,537 | 0.03110 | 0.03110 | | |
| DEMAND - Non-Summer | $1,001,231.07 | 154,682,385 | 0.00647 | | 0.00647 | |
| ENERGY - Summer | $1,170,605.38 | 43,876,537 | 0.02668 | 0.02668 | | |
| ENERGY - Non-Summer | $2,500,035.82 | 154,682,385 | 0.01616 | | 0.01616 | |
| TRANSMISSION | | | | | | |
| DEMAND | $1,199,954.96 | 198,558,922 | 0.00604 | 0.00604 | 0.00604 | |
| DISTRIBUTION | $4,738,790.60 | 198,558,922 | 0.02387 | 0.02387 | 0.02387 | |
| CUSTOMERS (BILLINGS) | $1,853,018.40 | 160,983 | 11.51064 | | | 11.51064 |
| TOTALS | $13,828,005.11 | | | 0.08768 | 0.05254 | 11.51064 |

**** * * SMALL GENERAL SERVICE - SCHEDULE 7 * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KWH) | (E) NON-SUMMER ($/KWH) | (F) SERVICE ($/CUST/MO) |
|---|---|---|---|---|---|---|
| GENERATION | | | | | | |
| DEMAND - Summer | $133,413.97 | 4,280,444 | 0.03117 | 0.03117 | | |
| DEMAND - Non-Summer | $75,502.86 | 12,920,608 | 0.00584 | | 0.00584 | |
| ENERGY - Summer | $114,881.48 | 4,280,444 | 0.02684 | 0.02684 | | |
| ENERGY - Non-Summer | $209,289.45 | 12,920,608 | 0.01620 | | 0.01620 | |
| TRANSMISSION | | | | | | |
| DEMAND | $105,474.04 | 17,201,052 | 0.00613 | 0.00613 | 0.00613 | |
| DISTRIBUTION | $299,610.31 | 17,201,052 | 0.01742 | 0.01742 | 0.01742 | |
| CUSTOMERS (BILLINGS) | $486,991.28 | 35,988 | 13.53212 | | | 13.53212 |
| TOTALS | $1,425,163.38 | | | 0.08156 | 0.04559 | 13.53212 |

**** * * LARGE GENERAL SERVICE - SCHEDULE 9 SECONDARY * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KW) | (E) NON-SUMMER ($/KW) | (F) SUMMER ($/KWH) | (G) NON-SUMMER ($/KWH) | (I) SERVICE ($/CUST/MO) | (H) BASIC ($/KW) |
|---|---|---|---|---|---|---|---|---|---|
| GENERATION | | | | | | | | | |
| DEMAND - Summer | $804,686.38 | 87,373 | 9.20982 | 9.20982 | | | | | |
| DEMAND - Non-Summer | $573,761.34 | 290,238 | 1.97686 | | 1.97686 | | | | |
| ENERGY - Summer | $693,291.64 | 26,659,239 | 0.02601 | | | 0.02601 | | | |
| ENERGY - Non-Summer | $1,445,610.61 | 90,297,619 | 0.01601 | | | | 0.01601 | | |
| TRANSMISSION | | | | | | | | | |
| DEMAND | $675,073.31 | 377,611 | 1.78775 | 1.78775 | 1.78775 | | | | |
| DISTRIBUTION | $1,933,599.65 | 530,106 | 3.64757 | | | | | | 3.64757 |
| CUSTOMERS (BILLINGS) | $227,887.85 | 16,008 | 14.23623 | | | | | 14.23623 | |
| TOTALS | $6,353,910.79 | | | 10.99757 | 3.76461 | 0.02601 | 0.01601 | 14.23623 | 3.64757 |

**** * * LARGE GENERAL SERVICE - SCHEDULE 9 PRIMARY * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KW) | (E) NON-SUMMER ($/KW) | (F) SUMMER ($/KWH) | (G) NON-SUMMER ($/KWH) | (I) SERVICE ($/CUST/MO) | (H) BASIC ($/KW) |
|---|---|---|---|---|---|---|---|---|---|
| GENERATION | | | | | | | | | |
| DEMAND - Summer | $105,199.31 | 9,271 | 11.34741 | 11.34741 | | | | | |
| DEMAND - Non-Summer | $76,937.14 | 27,854 | 2.76211 | | 2.76211 | | | | |
| ENERGY - Summer | $96,772.14 | 3,855,826 | 0.02510 | | | 0.02510 | | | |
| ENERGY - Non-Summer | $185,844.35 | 12,321,447 | 0.01508 | | | | 0.01508 | | |
| TRANSMISSION | | | | | | | | | |
| DEMAND | $87,223.29 | 37,125 | 2.34944 | 2.34944 | 2.34944 | | | | |
| DISTRIBUTION | $182,902.00 | 46,987 | 3.89264 | | | | | | 3.89264 |
| CUSTOMERS (BILLINGS) | $6,677.27 | 60 | 111.28775 | | | | | 111.28775 | |
| TOTALS | $741,555.50 | | | 13.69685 | 5.11155 | 0.02510 | 0.01508 | 111.28775 | 3.89264 |

**** * * LARGE POWER - SCHEDULE 19 PRIMARY * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KW) | (E) NON-SUMMER ($/KW) | (F) SUMMER ($/KWH) | (G) NON-SUMMER ($/KWH) | (I) SERVICE ($/CUST/MO) | (H) BASIC ($/KW) |
|---|---|---|---|---|---|---|---|---|---|
| GENERATION | | | | | | | | | |
| DEMAND - Summer | $978,215.67 | 88,078 | 11.10621 | 11.10621 | | | | | |
| DEMAND - Non-Summer | $1,023,173.78 | 243,179 | 4.20749 | | 4.20749 | | | | |
| ENERGY - Summer | $1,146,022.72 | 48,330,793 | 0.02371 | | | 0.02371 | | | |
| ENERGY - Non-Summer | $1,959,482.34 | 133,133,212 | 0.01472 | | | | 0.01472 | | |
| TRANSMISSION | | | | | | | | | |
| DEMAND | $830,261.70 | 331,257 | 2.50640 | 2.50640 | 2.50640 | | | | |
| DISTRIBUTION | $1,176,194.68 | 358,534 | 3.28057 | | | | | | 3.28057 |
| CUSTOMERS (BILLINGS) | $17,322.97 | 72 | 240.59680 | | | | | 240.59680 | |
| TOTALS | $7,130,673.86 | | | 13.61261 | 6.71389 | 0.02371 | 0.01472 | 240.59680 | 3.28057 |

**** * * LARGE POWER - SCHEDULE 19 TRANSMISSION * * ****

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) SUMMER ($/KW) | (E) NON-SUMMER ($/KW) | (F) SUMMER ($/KWH) | (G) NON-SUMMER ($/KWH) | (I) SERVICE ($/CUST/MO) |
|---|---|---|---|---|---|---|---|---|
| GENERATION | | | | | | | | |
| DEMAND - Summer | $635,787.61 | 50,057 | 12.70115 | 12.70115 | | | | |
| DEMAND - Non-Summer | $350,207.47 | 125,452 | 2.79156 | | 2.79156 | | | |
| ENERGY - Summer | $682,919.89 | 27,981,572 | 0.02441 | | | 0.02441 | | |
| ENERGY - Non-Summer | $847,023.57 | 59,131,043 | 0.01432 | | | | 0.01432 | |
| TRANSMISSION | | | | | | | | |
| DEMAND | $377,202.37 | 175,510 | 2.14918 | 2.14918 | 2.14918 | | | |
| CUSTOMERS (BILLINGS) | $6,014.92 | 25 | 240.59680 | | | | | 240.59680 |
| TOTALS | $2,899,155.83 | | | 14.85033 | 4.94074 | 0.02441 | 0.01432 | 240.59680 |

***** IRRIGATION - SCHEDULE 24 SECONDARY *****

(Production-related revenue and billing units are for June - September)

| FUNCTION | (A) REVENUE | (B) BILLING UNITS | (C) UNIT COSTS ($/EACH) | (D) IN-SEASON ($/KW) | (E) OUT-SEASON ($/KW) | (F) IN-SEASON ($/KWH) | (G) OUT-SEASON ($/KWH) | (H) SERVICE ($/CUST/MO) |
|---|---|---|---|---|---|---|---|---|
| GENERATION | | | | | | | | |
| DEMAND - In-Season | $648,723.26 | 111,758 | 5.80473 | 5.80473 | | | | |
| DEMAND - Out-Season | $212,862.42 | 67,570 | 3.15027 | | 3.15027 | | | |
| ENERGY - In-Season | $1,146,974.25 | 44,510,145 | 0.02577 | | | 0.02577 | | |
| ENERGY - Out-Season | $189,926.31 | 16,043,665 | 0.01184 | | | | 0.01184 | |
| TRANSMISSION | | | | | | | | |
| DEMAND | $416,141.72 | 179,327 | 2.32057 | 2.32057 | 2.32057 | | | |
| DISTRIBUTION | $1,956,710.72 | 179,327 | 10.91139 | 10.91139 | 10.91139 | | | |
| CUSTOMERS (BILLINGS) | $284,529.88 | 18,229 | 15.60881 | | | | | 15.60881 |
| TOTALS | $4,855,868.57 | | | 19.03668 | 16.38223 | 0.02577 | 0.01184 | 15.60881 |

Idaho Power/1503
Witness: Courtney Waites

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Courtney Waites
New York Times Article about Idaho Power

January 26, 2010

The New York Times





**January 24, 2010**

# Why Is a Utility Paying Customers?

**By KATE GALBRAITH**

BOISE, Idaho

FOUR decades ago, when Sid Erwin began his career as an inspector at the Idaho Power Company, a string of new hydroelectric plants was pumping out power faster than locals could buy it. Soon enough, Mr. Erwin recalls, the utility began sending representatives to rural areas, urging farmers to use more electricity when irrigating their crops.

These days, Idaho's farmers are being paid to stop using power.

Sitting at a cluttered kitchen table in his home, Mr. Erwin — now a farmer himself — waved a bill showing that last July he received a credit of more than $700 from Idaho Power for turning off his power-guzzling pumps on some summer afternoons.

"It's a total turnabout," says Mr. Erwin, who lives in Bruneau, about 60 miles southeast of here. "I'm almost 70 years old and this has been a lifelong education to me."

As saving energy becomes a rallying cry for utilities and the government, Idaho Power is in the vanguard. Since 2004, it has been paying farmers like Mr. Erwin to cut power use at crucial times, resulting in drop-offs of as much as 5.6 percent of peak power demand.

In a related program, it pays homeowners to turn off their air-conditioners briefly at times of high demand.

Other efficiency initiatives by the utility, including one promoting attic insulation, have saved about 500,000 megawatt-hours of power since 2002, according to the company — roughly equal to the amount used by 5,000 gadget-filled homes over eight years.

To pay for these and other energy-saving measures, Idaho customers — individuals and companies — are charged a 4.75 percent "energy efficiency" rider on their electric bills, one of the highest percentage charges of this kind in the country.

"It's clearly iconic in terms of a utility that's turned the corner," says Tom Eckman, the manager of conservation resources with the Northwest Power and Conservation Council, a planning group created by Congress. "They have gone from pretty much ground zero to a fairly aggressive program level."

The company's efforts are especially striking given that the push for energy efficiency is generally associated with coastal states like California and Massachusetts, not with a state whose electric rates are among the lowest in the country.

But the concept has rung true for Idaho's farmers, anglers and snowbirds — outdoor types who have helped keep the state nearly free of coal plants. They have been largely receptive to the utility's arguments that it is cheaper to save energy than to build new power plants.

"Every time they would build a plant, it would raise our rates," says Terry Ketterling, a farmer in Mountain Home, Idaho, who grows sugar beets, corn, wheat and alfalfa and who, like Mr. Erwin, participates in the irrigation payment program.

Energy experts say Idaho Power's efforts can be replicated by other power companies across the country. Steve Nadel, executive director of the American Council for an Energy-Efficient Economy, an advocacy group, estimates that about half of utilities now run programs that pay customers to cut use during peak periods. And companies like Enernoc, based in Boston, have sprung up that help utilities by outfitting stores and other businesses with devices to turn off lights or reduce power in other ways during a power squeeze.

But most utilities spend a much lower proportion of their revenue on saving energy than Idaho Power, says Ralph Cavanagh, a senior lawyer at the Natural Resources Defense Council, an environmental group.

LaMont Keen, the C.E.O. of Idaho Power, acknowledges that the company, with its large cohort of farmers, has a different customer base than most other power companies. Still, he argues that the success of his programs shows that even utilities with large industrial loads can adapt.

"With the right incentives, people can and will modify their behavior in ways that are beneficial," he says.

The utility also has its share of critics: Big businesses sometimes wince at paying the efficiency charge. And some say the utility has dragged its feet when it comes to renewable energy — other than that generated by huge dams. Some detractors refer to Idaho as the "hole in the doughnut" on wind power — because most of its neighbors, like Oregon, Washington and Wyoming, have built far more wind farms.

"Very little has been developed in Idaho in the past six or seven years, whereas all the states around us have blossomed," says Kiki Tidwell, a self-described "Republican soccer mom" near Hailey, Idaho. Ms. Tidwell helped push through a shareholders' resolution to urge Idaho Power to plan for a low-carbon future.

To the surprise of even Ms. Tidwell, it passed last May, with 52 percent of the votes.

Mr. Keen notes that hydro is a clean resource and says Idaho Power — a subsidiary of the publicly listed Idacorp that serves parts of Oregon as well as most of Idaho — is working to ramp up wind production and reduce the carbon intensity of its operations.

IDAHO POWER has been used to getting its way: it's an old joke around Boise that Idaho is the only state named for a power company.

Until recently, getting its way meant adding power, which was cheap and plentiful, thanks in part to several new dams completed in the late 1950s and '60s. (One of them, called Hells Canyon, was where Mr. Erwin spent his younger days checking on cables and fittings during construction.)

A nasty shock arrived in 2000 and 2001, when peak-time energy prices on the open market rose about tenfold — not counting steeper, temporary spikes. The Western energy crisis was under way, with market manipulation woes in California compounded by a dry stretch for Idaho's dams.

"Everything turned a full 180," Ric Gale, the utility's vice president for regulatory affairs, said in an interview in Idaho Power's blocklike Boise headquarters, which is itself undergoing a floor-by-floor green retrofit.

Idaho Power and regulators held emergency meetings, and customers were soon hit with a temporary rate increase of about 44 percent. The utility paid big irrigators to shut down their electric pumps for the summer of 2001, figuring it would be cheaper than buying the power at high prices. An enormous phosphate plant in Pocatello was also in effect paid to temporarily shut down one of its energy-guzzling furnaces. The move hurt sales, and the company, FMC, decided later that year to close the plant permanently.

To avoid being caught short again, Idaho Power decided to give energy-saving measures a try. Another push came from the state's Public Utilities Commission, which ordered Idaho Power in 2001 to refocus on energy efficiency — something the utility had dabbled in during the 1990s.

PERHAPS more than any other group, Idaho's farmers have experienced at first hand the effects of the utility's transformation. Though Idaho's economy has diversified in recent years, more than a fifth of its land is devoted to farming — not only to grow Idaho's world-famous potatoes, but also crops like alfalfa, triticale and oat hay, all of which Mr. Erwin grows.

Vast amounts of energy are required to pump water up to the state's plains from the Snake River or from wells. The largest farms can use as much electricity as several thousand homes. During the summer, big farms keep their pumps on nearly 24 hours a day, seven days a week.

Until the 1970s, many farmers used gas-powered engines to force water uphill, according to Mr. Erwin. But by offering steep discounts, Idaho Power convinced many of them to put in electric pumps and use them to move water up even taller slopes; the discounts are still in effect. Irrigation accounts for 12 percent of Idaho Power's electricity load over all — and 23 percent during peak periods.

That's why, in recent years, Idaho Power decided that farmers could help it reduce the load on sunny summer days, when air-conditioners and other gadgets are on, by turning off their pumps for up to 15 hours a week.

This concept, called demand response, has gained traction in utility circles. In essence, it involves paying users to make small sacrifices when there is an urgent need for extra power (the "peak"). The utility can then rely on cutting some demand on its system at crucial times — and, in theory, avoid the cost of building a new plant just to meet those peak needs.

Over the course of the day, Mr. Gale says, "you can actually see the peak drop off when the program kicks in."

For farmers, however, this process isn't easy. Workers must be dispatched to turn the pumps on and off, and there is a risk of crop damage. "I may save on power, but it may cost me some on crop," says Mr. Ketterling, who pumps water up more than 600 feet from the Snake River. He spends about $1.8 million a year on electricity and estimates he shaved more than 30 percent off his bill over a six-week period last year by participating in the program.

Ordinary consumers have also been called upon to help with efficiency. These days, most utilities enclose fliers with monthly bills that offer energy-saving tips for appliances and light bulbs, but Idaho Power seems to have taken the campaign to an extreme.

Just before Christmas, the utility bought ads in newspapers flagging "naughty or nice" holiday gifts: an electric charger for a mobile device, for example, was "naughty," but a solar charger was "nice." Last October, Idaho Power offered free classes to Boise residents featuring energy-saving tips for cooking (ever tried a solar oven?) and demonstrations on sealing ducts.

Another program, begun last June after a yearlong pilot version, pays individuals 15 cents for each square foot of insulation they put in their attics. "That was a no-brainer," said Courtney Washburn, a Boise resident who works for the Idaho Conservation League and who received a letter from Idaho Power promoting the insulation rebate.

Ms. Washburn also participates in the utility's "demand response" program for air-conditioners. More than 32,000 Idaho Power households (out of nearly 407,000 total) have allowed the utility to control their air-conditioners at crucial times.

On a hot summer day, Idaho Power can in essence push a switch that causes devices installed on participating air-conditioning units, like Ms. Washburn's, to cycle on and off for intervals as long as 15 minutes. Ms. Washburn says she has noticed no difference in temperature, even though a sweltering day is exactly when people want their air-conditioning most. Executives say the program lowers use during peak periods by about 1 percent. Participants are paid $7 a month during the summer.

Ms. Washburn says her electric bill has dropped by about 30 percent as a result of the attic insulation and the $7 credit.

FACED with a fast-growing population, Idaho Power has been unable to avoid building new power plants altogether; a new natural gas plant is in the works. But executives are pressing ahead with efficiency measures. The utility is asking regulators to make permanent a pilot program started in 2007 that allows Idaho Power to raise rates to make up for selling less power.

(This concept is known as decoupling and is celebrated by energy-efficiency advocates; Idaho was one of the first states to adopt it, after California, though Idaho Power's large industrial customers are so far exempt from the rate adjustments.)

But the aggressive pursuit of efficiency has prompted concerns in some quarters. Ray Stark, senior vice president of the Boise Metro Chamber of Commerce, says that not long ago a few companies, including a chemical producer, that had been considering operations in the state were told by Idaho Power that there was insufficient capacity to accommodate their power needs.

"That concerns us a great deal because we want to be competitive for economic development projects," said Mr. Stark, adding that he supports the efficiency push.

Mr. Gale said that capacity constraints were unrelated to the drive to save energy and that utilities can't always quickly accommodate a big new customer.

The rising efficiency charges have also raised corporate eyebrows. Don Sturtevant, the energy manager for the J. R. Simplot Company, the potato processor, said he cringed when Idaho Power raised the charge last June to 4.75 percent from 2.5 percent, though he said the company benefited from the program.

If the utility raises the charge again, Mr. Sturtevant said, "it's going to be a challenge."

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UE 213**

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|---|---|
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON. | )<br>)<br>)<br>)<br>)<br>) |

**IDAHO POWER COMPANY**

**REPLY TESTIMONY**

**OF**

**JIM HOVDA**

**January 26, 2010**

**Q. Please state your name and business address?**

A. My name is Jim Hovda. My business address is 2420 Chacartegui Lane in Nampa, Idaho 83687.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Major Account Representative.

**Q. Please describe your educational background.**

A. I have a Bachelor of Science degree in Business from Eastern Oregon State College in La Grande, Oregon.

**Q. Please describe your work experience with Idaho Power.**

A. I have 35 years of experience with Idaho Power Company. I have worked in different capacities for Idaho Power from eastern Idaho to and including eastern Oregon. My first position in 1974 was on a line crew that installed and maintained both overhead and underground distribution systems. Between 1976 and 1985, my work experience included being a customer service representative working with commercial customers both in Pocatello and in Boise, Idaho.

My work experience also includes management positions with Idaho Power employed as a District Manager in Nyssa, Oregon, from 1985 to 1988 as well as a District Manager in Emmett, Idaho, from 1988 to 1996. As a District Manager, I was responsible for all activities within the district. My duties included supervision of line crews, local engineering personnel, meter reading, and accounting personnel. I also supervised non-Idaho Power contract crews assigned to the district. This included additional line construction crews, pole treatment, and tree trimming crews.

As a District Manager, I interacted with community organizations and community leaders as the representative for Idaho Power. In addition, for the past 10 years, I have served Idaho Power as a Major Account Representative. Currently, I am based in Nampa, Idaho, with a satellite work station in Payette, Idaho. I work with large commercial and industrial customers in southwest Idaho and eastern Oregon.

**Q. What is the scope of the testimony you are presenting in this case?**

A. I will provide testimony regarding the customer service and communication efforts that Idaho Power puts forth with regard to its large industrial customers generally, and with regard to the Heinz facility in Ontario specifically. I will also address the contention put forth by Heinz's witnesses that a restart from a "forced shutdown" results in higher monthly demand charges than Heinz would normally incur.

**Q. Please describe your role in providing customer service and communication efforts related to industrial customers of Idaho Power.**

A. As a Major Account Representative, I am responsible for providing customer service and communicating with the Company's industrial customers. In general, I am a "point of contact" for Heinz and other large, industrial customers.

I respond to customer service inquiries, perform general account maintenance activities, advise customers regarding applicable rules and regulations, and coordinate Idaho Power programs. Additionally, with Idaho Power owned facilities serving industrial customers, I assume the role of project manager.

As the "point of contact," every industrial customer has my work, cell, and home phone numbers. I make myself available to the Company's customers whether it be in person, by phone, or e-mail; this communication can be as often as daily for on-going projects or, for any purpose, on an "as-needed" basis.

**Q. Please describe your specific duties and experiences in relation to the Heinz facility in Ontario.**

A. The Heinz facility is an important customer to Idaho Power. It is one of the Company's larger accounts in Oregon. I am a liaison between the Company and Heinz. I am available to any Heinz employee regardless of the position or department. I also work in cooperation with other departments and employees of Idaho Power. In that capacity, I act as an advocate on behalf of Heinz in its discussions with the Company.

It has been my experience that Heinz and Idaho Power work well together. After the initial presentation of energy conservation program materials to Heinz management, Idaho Power, to date, has reviewed seven lighting proposals and provided a $100,000 incentive to Heinz for refrigeration upgrades. In addition, a large-compressed air project is nearing completion. This project alone will provide approximately $180,000 in incentives. Idaho Power is continually providing support for Heinz with funds for energy audits from outside engineering firms.

As a result of a meeting between me and the Heinz plant controller in 2007, Idaho Power, on a monthly basis, started compiling and evaluating an estimated power bill that is provided to Heinz two to three weeks in advance of receiving their formal billing. This assists Heinz in its cash flow management. Idaho Power has provided this estimated billing and other billing information on a monthly basis from 2007 to the present.

Idaho Power has entered into a technical service agreement with Heinz where the Company has and will continue to respond to emergency outage calls concerning Heinz-owned distribution system facilities on the Heinz side of the meter. Heinz is provided direct access to Idaho Power dispatch 24 hours a day, 7 days a week so that it can receive information that may affect Heinz's service.

Idaho Power has also worked with Heinz to improve the reliability of Heinz-owned distribution equipment. Idaho Power provided local personnel with help interpreting oil sample results and made available, on short notice, a replacement transformer when the Heinz-owned transformer failed. Idaho Power has provided Harmonic monitoring and has participated in other facility improvements.

**Q. Could you explain any steps or actions that you are aware of that Idaho Power has taken to provide documentation and or communications regarding power quality issues with relation to Heinz.**

A. After the 2005 Oregon general rate case, Idaho Power and Heinz met to discuss ways to reduce the number of times the Heinz plant trips out. As a result of that meeting, the two companies decided to make some changes in communications. Prior to this meeting, after the plant tripped out, the Heinz electrical supervisor would immediately call Idaho Power dispatch for information. However, Idaho Power dispatch was unable to immediately provide detailed information. This procedure was frustrating to both parties. It was agreed upon that Heinz would still contact Idaho Power dispatch for outage and restoration information; however, in addition, a different communication process was agreed upon where the Heinz electrical supervisor would e-mail me directly for information regarding an event. This would allow Idaho Power's engineers to research Idaho Power supply system databases and provide Heinz with more information. This information was documented and communicated to Heinz in a format that would help both companies evaluate the economics of different solutions that could improve performance either on the supply system or within the customer's facility. Since 2005, each request for information from Heinz has been evaluated and an e-mail response has been communicated back to Heinz.

**Q. Heinz's consultants Ratcliffe and Bickford both suggest communication could be improved with quarterly meetings between Idaho Power and Heinz. Could you elaborate on your current availability to address the needs of Heinz?**

A. I have been and continue to be available to Heinz on a twenty-four hour, seven days a week basis, and am willing to explore and accommodate a quarterly meeting should Heinz so desire. I view Heinz's willingness to consider a quarterly meeting schedule in a very positive light. Quarterly meetings with Heinz personnel would augment the existing communication efforts.

**Q. As Heinz's customer representative please describe any activities that you do with regard to Heinz's monthly billing.**

A. Heinz's usage is billed on a calendar month basis. The usage and demand is read remotely in 15 minute intervals. A formal bill is prepared and sent to Heinz approximately mid-month.

In addition, for the past 2 years, Idaho Power's Major Customer Segment Coordinator has prepared an estimated power bill on the first business day of each calendar month. This billing is based on metering data from the on-site revenue meter. The Segment Coordinator shares this estimated billing with me, and together, we review the bill prior to mailing it to Heinz. Initially, at Heinz's request, I e-mailed the estimate to Heinz's Accounting and Energy employees. Currently, I e-mail each monthly estimate to one person at Heinz who routes it internally.

The estimated bill format provides better insight to how Heinz's power bill is calculated than the formal bill format they receive later in the month. The billing estimate shows where all of the charges come from, all rates, the quantity used, and total amounts for each component. Also provided are charts showing the monthly demand and usage for each of the last 4 years compared to their current demand and usage. In addition, the actual 15-minute usage data is included for Heinz's review and analysis.

**Q. Have you reviewed Heinz's monthly billing data to evaluate their claim that a restart of the plant from a "forced shutdown" results in higher monthly demand charges than Heinz would incur?**

A. Yes. The monthly reviews and evaluations from the estimated billings that have been prepared for the past 2 years have given no indication of a higher monthly demand charge due to "forced shutdowns" of the Heinz plant.

In addition, please see Exhibit 1601, which is a monthly comparison of actual billing demand that includes the date and time for each month in the year 2009 where Heinz's monthly billing demand was set. This is compared with the forced shutdown dates and times that Heinz reported to Idaho Power. This comparison shows no correlation between a "forced shutdown" and Idaho Power actual billing demand.

For example, Exhibit 1601 shows a June billing demand was established on June 16 at 11:30, compared to a reported event 2 days later on June 18. In July, billing demand occurred on July 30 at 10:30 compared to events reported by Heinz on July 22 and July 23.

**Q. Heinz analyzes "forced shutdowns" in their testimony for the last 24 months. How many times has Heinz contacted you regarding these "forced shutdowns" in the last 24 months?**

A. During the last 24 months, I have received fewer requests than I did in 2005 and 2006 prior to the retirement of the Heinz employee who requested such information during 2005 and 2006. In the last 24 months, I have been contacted 4 times.

**Q. What action was taken on the part of Idaho Power in response to these communications initiated by Heinz?**

A. As I explained above, an evaluation of each event was undertaken by Idaho Power power quality engineers. A report was produced for each event and e-mailed to Heinz. In addition, at the time of each plant trip, I have offered to have the Company's power quality engineers answer any questions Heinz may have.

**Q. Heinz's consultant Bickford implies on page 8, lines 15 through 22 and page 8, lines 1 through 3, that Idaho Power does not make efforts to know its industrial customers or their needs and wants? Is this accurate?**

A. I do not believe that Mr. Bickford's implications are an accurate assessment of Idaho Power's relationship with its industrial customers. First of all, Idaho Power has dedicated customer representatives for all of its large industrial class customers. In the case of Heinz, I am their dedicated customer representative and am available to them any time, seven days a week. Also whenever Heinz notifies the Company of a sag or outage event at their facility, Idaho Power engineers prepare the data and analysis that I described above and this is communicated back to Heinz. Additionally, Idaho Power senior management represented by the Vice President of Regulatory Affairs and the Western Regional Manager has visited the Heinz plant for discussion with Heinz management. Idaho Power Energy Engineers have worked with Heinz in evaluating several energy conservation measures and programs, some of which have been implemented and some of which continue to be evaluated on a going forward basis. Idaho Power has provided funding for outside engineering companies to do scoping audits that further identify energy conservation measures for Heinz to consider. Idaho Power Planning Engineers have attended meetings with contract engineering firms on new capital projects offering information and advice to Heinz. Idaho Power's power quality engineers have met with Heinz on more than one occasion and they are willing to follow up with additional meetings.

While I have attended several of the above mentioned meetings, I have been fortunate enough to work with a number of Heinz employees. In addition to the tours of the facility and PowerPoint presentations regarding their business, it is the follow-up and on-going discussions with its employees that are beneficial to both companies.

Although some of the people at Heinz have changed positions or workplace, I am pleased that I have been able to interact and learn about Heinz from its employees. This list of Heinz employees I have interacted with would include but is not limited to: Plant Manager, Environmental/Energy Supervisor, Electrical Supervisor, Plant Controller, Business Planning/Cost Accounting Supervisor, and Maintenance Superintendent. Additional communications from time to time include fielding inquiries from outside engineers or Heinz's internal engineering personnel. Idaho Power's efforts to know the needs and wants of Heinz have been extensive and across the board with regard to Heinz personnel.

**Q. Witness Ratcliffe testifies on page 3 lines 17 through 22 that Heinz annual power bill has increased from 3.3747 cents per kWh in 2005 to 4.5235 cents per kWh in 2009. Have Heinz's base rates – which include recovery of distribution and transmission related costs – increased since 2005?**

A. No. Mr. Ratcliffe may not understand Idaho Power's rate structure with Heinz. The only variability that has occurred in Heinz rates since 2005 is due to the pass through costs of power supply expenses. There have been no base rate increases during this time.

**Q. Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Jim Hovda
Monthly Comparison of Actual Billing Demand

January 26, 2010

Comparison of billing demand days and event days

| Billing Demand Date | Billing Demand Time | Billing Demand kW | Event Date and time in month |
|---|---|---|---|
| 01/20/09 | 12:15 | 15,229.44 | |
| 02/24/09 | 10:45 | 15,148.80 | |
| 03/20/09 | 15:30 | 15,189.12 | |
| 04/22/09 | 17:00 | 15,886.08 | |
| 05/19/09 | 15:30 | 16,485.12 | |
| 06/16/09 | 11:30 | 16,398.72 | 06/18/09 7:34 am, 06/18/09 10:59 pm |
| 07/30/09 | 10:30 | 15,984.00 | 07/22/09 4:29 am, 07/23/09 3:01 am |
| 08/29/09 | 18:00 | 16,513.92 | |
| 09/12/09 | 14:45 | 16,663.68 | |
| 10/14/09 | 20:00 | 16,030.08 | |
| 11/06/09 | 09:45 | 16,191.36 | |
| 12/03/09 | 14:45 | 16,346.88 | |

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

**UE 213**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OREGON. | ) ) ) ) ) ) |

**IDAHO POWER COMPANY**

**REPLY TESTIMONY**

**OF**

**PERRY VAN PATTEN, PE**

**January 26, 2010**

**Q. Please state your name, business address, and present occupation?**

A. My name is Perry E. Van Patten. My business address is Idaho Power Company, 1111 West Jefferson Street (4th Floor), Boise, Idaho 83702

**Q. By whom are you employed and in what capacity?**

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") and I am the Senior Manager of Delivery Distribution Reliability.

**Q. Please describe your educational background.**

A. I have a Bachelor of Science degree in Electrical Engineering from the University of Idaho.

**Q. Please describe your work experience with Idaho Power.**

A. I have over 21 years of experience at Idaho Power. I was a summer engineering intern in the Southern Division and in Idaho Power's Transmission Department from May 1982 to September 1982, May 1983 to September 1983, and May 1984 to September 1984. I spent time in various departments and learned about electric utility operations, including hydro-power generation, transmission line design and maintenance, substation apparatus, system protection and communications, distribution line design, distribution line construction, distribution line maintenance, customer service operations, and metering operations.

From October 1989 to November 1992, I was an Engineer I/II in the Western Division. I provided distribution system protection design, distribution line design, distribution line planning, and engineering expertise for distribution operations.

From November 1992 to March 1996, I was an Engineer II in the Transmission and Distribution Engineering Department. I reviewed existing and new transmission and distribution lines located over waterways for proper clearances. I completed designs and documented improvements as necessary. I also provided power quality engineering support for Idaho Power's Divisions Engineers and completed financial analysis of operating procedures.

From March 1996 to January 1999, I was Engineering Leader of the Distribution Methods and Materials Department. I was responsible for the distribution system design and construction guidelines for the Company as well as process owner for various distribution processes designed to provide new service to customers and maintain existing service to existing customers.

From January 1999 to March 2007, I was Regional Senior Manager for the Southern Region. I was responsible for all distribution and transmission operations in the region. I worked directly with regional and local state, county, and city officials as well as all classes of customers.

From March 2007 to the present, I have been Senior Manager of Delivery Distribution Reliability. I am responsible for the processes required to manage existing transmission, station apparatus, and distribution infrastructure. This includes: aging assets, maintenance procedures, operating voltage support, distribution system protection, and power quality.

**Q. Please describe any other work experience relevant to power quality or maintenance of utility electrical facilities.**

A. In addition to my employment at Idaho Power, I was employed for 4 years by Pacific Gas and Electric Company in San Francisco. I was responsible for electrical distribution planning, design, and system protection for certain circuits serving the City of San Francisco.

**Q. What is the scope of the testimony you are presenting in this case?**

A. I will provide testimony in response to the concerns regarding power quality voiced by the Oregon Industrial Customers of Idaho Power ("OICIP") on behalf of one of their members, the H.J. Heinz Company ("Heinz"), in relation to their Heinz Ontario, Oregon, facility. I will describe the facilities utilized to provide service to Heinz. I will describe how Idaho Power measures power quality, and relate this to the facilities that serve Heinz. I will also discuss several issues raised by OICIP in its testimony and, in particular, many of the statement and/or conclusions of Heinz witnesses Schneider and Bickford.

**Q. What are the power quality concerns of Heinz as you understand them?**

A. Idaho Power is aware that Heinz has been and continues to be concerned about electrical conditions that cause operational problems at its Ontario facility. The varying terminology their consultants and witnesses have used in their testimonies has caused some confusion. It is Idaho Power's belief that Heinz is concerned with "voltage sags" that inconsistently affect their operations and not "power interruptions." The Heinz facility is served by the OIDA-012 feeder that is supplied by Ore-Ida Substation via the Ontario-Ore-Ida-Emmett 69KV transmission line. When faults occur on these or other Idaho Power lines, the voltage drops briefly on 1 to 3 phases and is sometimes perceptible at the Heinz facility. No interruption to the OIDA-012 feeder occurs but the associated voltage sag, depending upon a combination of sag depth and duration, may disrupt the operation of some of the Heinz facility's electrical equipment.

**Q. OICIP's witness Schneider describes Idaho Power's 69 KV electrical system in the City of Ontario. Is his description accurate?**

A. No. The description he gives is incorrect.

**Q. Could you please describe Idaho Power's 69 kV electrical system in the Ontario, Oregon area?**

A. Yes. [redacted]

[redacted]

**Q. Witnesses Schneider and Bickford state that they observed and inspected certain portions of Idaho Power's electrical system in Oregon stating in their testimony that the system is poorly designed, poorly maintained, and is generally old. What is your response to their statements?**

A. Idaho Power's electrical infrastructure in Oregon is designed and maintained in such a manner as to meet and, in many instances, exceed accepted industry practices and parameters. The system has performed exceptionally well, as has been documented in the reliability records disclosed as part of this proceeding, and my testimony. Additionally, contrary to Mr. Schneider's testimony, the age of the pole plant (1980 vintage) is not at all considered old in the electric utility business. In general, most utilities consider wood poles to have an effective service life of 40 years; however, there is an increasing body of evidence that average service lives may extend to 80 to 150 years where poles are properly specified and maintained. See, Dr. J.J. Morrell, Department of Forest Products, Oregon State University, EPRI Workshop: *Manufactured Distribution and Transmission Pole Structures*, July 25, 1996. The Oregon facilities are not old compared with many facilities in the industry (particularly overhead wood pole constructed facilities) and have operated and continue to operate satisfactorily. Furthermore, the design and maintenance practices for these facilities are carried out in accordance with the National Electrical Safety Code and both the Idaho and Oregon Public Utility Commission's requirements. In fact, the Staff of the Oregon Public Utility Commission has conducted inspections of these facilities and has concluded their general approval of them.

**Q. Witness Schneider states that the design of the Ontario substation is non-typical and quite complex. In your experience is the Ontario substation non-typical and complex?**

A. No. The electrical design of the Ontario substation is a very typical, highly reliable, cost-effective, and a simple design. [redacted]

**Q. What is an advantage of operating the 69 KV system as a "looped" system?**

A. A "looped" electrical system is one that is interconnected such that there are multiple sources to electrical loads. If any one line is opened (taken out of service), all of the load, besides the tapped load associated with the open line, can continue to be served reliably. This contingency design, N-1, is very typical and provides for very cost-effective and reliable service for customers. Idaho Power operates much of its system in an electrically interconnected or "looped" design in an effort to provide reliable service for our customers.

**Q. Are there any trade-offs made in designing and operating an electrical system as "looped"?**

A. An undesirable effect of operating the 69 kV system as "looped" is the fact that voltage sags/swells resulting from events anywhere on the system are "visible" to all customers served by the system. This does in no way imply that all customers realize a negative impact by the sag/swell. Depending upon the fault magnitude and duration and very importantly the customer's tolerance for sags/swells, there may or may not be a negative impact caused by a sag/swell. The Company must balance between minimizing customer outage frequency and duration, and minimizing the impact of voltage sags.

**Q. How is the Heinz facility served from Idaho Power's electrical system?**

A. [redacted]

**Q. Given that the Ore-Ida substation is served as a tapped load with 2.5 miles of 69 kV transmission line exposure, is there a reliability deficiency due to the transmission source at Ore-Ida substation?**

A. No. The problems identified at Ore-Ida substation, and in particular, the Heinz plant, are associated almost exclusively with voltage sags, and are rarely caused by actual service interruptions. Idaho Power typically does not expose more than 80 MW of load to a single event. In the case of the Ontario 69 kV system, loss of any one line will not disconnect more than 25 MW. Although the load at risk is much less than 80 MW, 69 kV lines tend to be fairly long; therefore, exposure to an outage is quite high. In order to mitigate for this exposure, Idaho Power has installed many line sectionalizing devices to automatically sectionalize and restore load within seconds after an event. [redacted]

**Q. Witness Schneider suggests that part of the transmission system is protected by fuses tying in certain substations. Is this a correct analysis of the system?**

A. No. The transmission system is not protected by fuses. Looking at the higher voltages first, all 230 kV and 138 kV transmission lines out of Ontario are breaker protected with communication-aided protection schemes, resulting in standard fault clearing times of less than 10 cycles. Communication-aided protection is required for these 230 kV and 138 kV lines due to grid system stability concerns for long-duration faults. These communication-aided schemes tend to be costly, requiring more sophisticated relaying and a communications medium such as a fiber-optics wire or microwave path between the substations with circuit breakers. Faults on the 69 kV system, in general, do not affect grid stability and, therefore, do not require costly communications-aided protection. The 69 kV lines are protected with simple time-overcurrent and/or distance relays. Fault clearing times can vary between 10 cycles for close-in faults to 30 cycles for remote faults (60 cycles per second; 30 cycles = .5 seconds).

**Q. Thirty Cycles to clear a fault seems like a long time; will you please elaborate on this?**

A. I will elaborate by providing an example. [redacted]

**Q. Witness Schneider states that there should be a greater number of power circuit breakers installed in the 69 kV system to improve the 69 kV system reliability. Would the addition of more 69 kV transmission line power circuit breakers help the problem at Heinz?**

A. No. Additional 69 kV power circuit breakers are exactly what Heinz does *not* need. A fault on any 69 kV line in the Ontario 69 kV system will result in a 10-30 cycle voltage sag. The impact of voltage sags at Heinz is the problem. Mr. Schneider suggests adding additional 69 kV line breakers would improve reliability; however, additional line breakers would do nothing to prevent these sags from occurring. In fact, additional breakers without communication-aided protection would *increase* the percentage of long-duration sags. Non-communication-aided time-overcurrent and distance relays are much more effective in protecting longer lines because there is less risk of tripping for faults beyond the relays zone of protection. In the case of short lines, often the only thing a protection engineer can do is add a time delay to ensure that the relay makes the proper decision.

**Q. Mr. Bickford suggests that fault duty of 7,103 amperes at 12.47 kV at Ore-Ida substation seems low considering the size of the substation and the load it servers. Could you discuss fault duty and typical industry standards?**

A. The fault duty at Ore-Ida substation is not problematic and is in accordance with typical industry standards (fault duty is the amount of current that flows through the system in a faulted condition). Mr. Bickford likely mentions this because very low source impedance, directly related to high fault current, would minimize voltage sags for faults on the adjacent OIDA-011 feeder.

Generally, and this is true in the case of the Ore-Ida substation, the impedance of the substation 69/12.47 kV transformer is the biggest contributor to the magnitude of fault duty of a 12.47 kV bus. In the electrical utility industry, unless the utility requires a special transformer, the impedance of a distribution transformer is generally 6-9 percent of the transformer name plate OA rating. In the case of Ore-Ida substation, the transformer has an OA rating of 15 MVA, and an impedance of 6.92 percent; the transformer can be operated up to 28 MVA due to the addition of forced oil and air cooling. Assuming no source impedance besides the distribution transformer, a 15 MVA transformer with 6 percent impedance would have 11,500 amperes of fault current and a 15 MVA transformer with 9 percent impedance would have 7,700 amperes of fault current. If some source impedance is assumed to include the effects of the 69 kV line, the 138/69 kV transformers, the 230/138 kV transformer, and the 230 kV system between Ontario and the generation, it is obvious to conclude the fault duty of the 12.47 kV bus at Ore-Ida could be 7,103 amperes. Mr. Bickford is likely familiar with higher fault currents due to his experience working in the generation-saturated state of Washington where higher voltage 500 kV transmission, and a larger amount of generation lead to much smaller source impedances, and higher fault currents.

In comparison to other 12.47 kV busses connected to the Idaho Power 69 kV system, the Ore-Ida substation's fault duty is much higher than average.

**Q. Witness Schneider suggests that it is unusual to serve a load as large as the one at Heinz by a substation transformer that is not dedicated to a single customer. Is this an unusual service design?**

A. No. An electrical load the size of the Heinz facilities will typically be fed from a multiple customer transformer, and this includes industrial food processing facilities. [redacted]

**Q. OICIP witness Ratcliffe uses various terms in his testimony including "sags," "delivery disturbances," "forced shut down," and "outages." What is the definition of a sag, a momentary outage, and a sustained outage?**

A. A <u>sag</u> is a short duration Root Mean Square ("RMS") voltage variation resulting in a decrease in voltage to between 10 percent and 90 percent of normal voltage for a time duration from .008 seconds to 1 minute.

A <u>momentary outage</u> (brief interruption) is a total loss of voltage for a time not exceeding 5 minutes.

A <u>sustained outage</u> is a total loss of voltage for a time period greater than 5 minutes. Idaho Power has found its terminology to be inconsistent with Heinz's. It would be helpful in future communication to clearly indicate a utility supply side outage, sag, or an internal production shutdown.

**Q. What causes sags, momentary outages, and sustained outages on an electrical system?**

A. Outages (momentary and sustained) and sags are caused by short circuits on the Idaho Power system and other connected utility systems. Outages are due to the opening of circuit protection devices operating to remove a short circuit. When a short circuit occurs and immediately prior to the opening of circuit protection devices, a sag in voltage will occur throughout the entire system in varying magnitudes. The magnitude of sag at any customer's facility is dependent on system electrical parameters including the amount of current flowing during the short circuit and the location of the short circuit. The sag will end when the short circuit is cleared from the system. For example, a short circuit in eastern Idaho will cause a sag in some magnitude to voltage supplied to our Oregon customers. As another example and more directly related to Heinz, a fault anywhere on the approximately 900 miles of 69kV system to which Heinz is connected will cause a sag at Heinz. However, whether or not the sag actually has a negative impact at the plant depends upon the magnitude, duration, and, very importantly, on how Heinz designed the plant to tolerate reasonable sags.

The remediation of sags and outages (momentary and sustained) is accomplished by minimizing the number of faults on all Idaho Power and other connected systems. This is part of our ongoing work to improve system reliability and reduce customer outages.

**Q. How does Idaho Power measure momentary and sustained outages?**

A. Sustained outages are measured by System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). Momentary outages are measured by Momentary Average Interruption Event Frequency Index ("MAIFIe"). These are defined as follows:

<u>SAIFI - System Average Interruption Frequency Index</u>. The average number of times that an average customer experiences a service interruption during a year. SAIFI is an indicator of utility network performance.

<u>SAIDI - System Average Interruption Duration Index</u>. The average total amount of time that an average customer does not have power during a year. SAIDI generally measures the operating performance of the utility in restoring customer service after interruptions.

<u>MAIFIe - Momentary Average Interruption Event Frequency Index</u>. The average number of times that an average customer experiences momentary interruption events during a year. This does not include events immediately preceding a sustained interruption.

**Q. When considering the reliability indices mentioned above as noted in *Idaho Power Company's 2008 Electric Service Reliability Annual Report* to the Oregon Public Utility Commission, reproduced in OICIP Exhibit 403, Mr. Bickford states that, "The Idaho Power Company numbers seem to be worse than the national averages," p. 7, l. 6-7. What has been the performance of Idaho Power's Oregon system?**

A. The SAIDI, SAIFI, and MAIFIe values for the Oregon system have been charted for the years 2004 through 2008. The 2009 performance indices are currently being compiled and will be filed with the Oregon Public Utility Commission by April 2010 in Idaho Power's *Annual Electric Service Reliability Report*. Idaho Power Company's numbers DO NOT exclude major events. The system, overall, has performed exceptionally well and is improving. See Exhibit 1701.

The Oregon SAIFI performance of the system as indicated in the chart has been below the Company's historically calculated threshold performance since 2005. As noted, Idaho Power's Oregon customers on average only experienced 1.5432 sustained interruptions in 2008.

The Oregon SAIDI performance of the system as indicated in the chart has been below the Company's historically calculated threshold performance since 2005 with the exception of 2006. As noted, Idaho Power's Oregon customers on average were only out of power an average of 2.2381 hours during 2008.

The Oregon MAIFI performance of the system as indicated in the chart has been below the Company's historically calculated threshold performance since 2005. As noted, Idaho Power's Oregon customers on average only experienced 3.57 momentary interruptions during 2008.

**Q. How does Idaho Power's performance in Oregon compare to other utilities across the nation?**

A. According to the Institute of Electrical and Electronics Engineers ("IEEE") Benchmarking 2008 Results provided September 2009 by the Distribution Reliability Working Group, Idaho Power's Oregon service territory performance is in the first quartile in both SAIFI (1.5432) and SAIDI (2.2381 hrs/134 mins). This national study does not include MAIFIe results. See Exhibit 1702. As indicated in Exhibit 1702, first quartile performance is the best performance of the surveyed companies with fourth quartile performance being the worst.

**Q. What is Idaho Power's reliability performance regarding outages (momentary and sustained) with respect to Heinz?**

A. The SAIDI, SAIFI, and MAIFIe values for the OIDA-12 feeder that provides service to Heinz have been charted for the years 2004 through 2008. The 2009 performance indices are currently being compiled and will be filed with the Oregon Public Utility Commission by April 2010 in Idaho Power's *Annual Electric Service Reliability Report*. Idaho Power Company's numbers DO NOT exclude major events. The reliability performance provided to Heinz by Idaho Power has been excellent over the last 5 years. See Exhibit 1703.

The Oregon SAIFI, SAIDI, and MAIFI performance of the system serving Heinz as indicated in the exhibit have all been below our historically calculated threshold performances since 2005. In fact, 2008 recorded zero interruptions (sustained or momentary).

**Q. The SAIDI, SAIFI, and MAIFIe measure momentary and sustained outages. How does Idaho Power measure sags?**

A. As with most utilities, Idaho Power has not adopted formal indices to quantify sags. The Company is currently researching several of the IEEE standards and benchmarking methods and studies from organizations such as Electric Power Research Institute ("EPRI"), the Edison Electrical Institute ("EEI"), and the International Electrotechnical Commission ("IEC"). At this time Idaho Power is providing customers, as requested, with sag summaries in an Information Technology Industry Council ("ITIC") curve format. Please see Exhibit 1704 for a graphical representation of the ITIC curve. Also please see Exhibit 1707 for Heinz's ITIC graphs from 2006, 2007, 2008, and 2009 demonstrating that the vast majority of "events" are within the parameters of the ITIC curve and indicates that these issues should be addressed first at the affected equipment level.

The ITIC curve was derived by the Information Technology Industry Council. This derivation was developed in collaboration with EPRI's Power Electronics Application Center ("PEAC"). The intent was to develop a curve that accurately reflects the performance of typical single-phase, 60-Hz computers and their peripherals, and other information technology items like copiers, fax machines, and point-of-sales terminals. While specifically applicable to computer-type equipment, the ITIC curve is generally applicable to other equipment containing solid-state devices.

The curve is a susceptibility profile, with the vertical axis representing the percent of voltage applied to the power circuit and the horizontal axis representing the time factor involved, measured from microseconds to seconds. In the center of the plot is a bounded acceptable area where equipment is expected to perform satisfactorily

Outside of the bounds at the top involves tolerance of equipment to overvoltage levels, while the zone at the bottom sets the tolerance of equipment to a loss or reduction in applied power. If the voltage supply stays within the acceptable area, electrical equipment will operate well.

Currently, three-phase motor controls and other industrial plant automation controls are typical electronic devices expected to operate satisfactorily when operated within the bounds of the ITIC curve.

Most reliability projects undertaken by Idaho Power aim to decrease the number of interruptions, or decrease the time associated with an interruption. Reliability projects to improve the voltage sag characteristics of a system are considered if Idaho Power believes that an event has or will result in voltage deviations outside of the ITIC curve and ANSI C84.1 “Electric Power Systems and Equipment Voltage Ratings (60 Hertz).

**Q. What is Idaho Power doing to measure power quality (sags) on its electrical system?**

A. We have an ongoing effort to install the monitors and communication systems to measure power quality events such as sags. [redacted]

It is common practice for these customers to request data as events affect them. In all cases, the data is provided in the format of the customer’s choosing. Typically, this information is sent to the customer through e-mails or it may be presented in person by either the Regional Power Quality Engineer or the Company's Regional Industrial Customer Representatives. In the case of Heinz, Mr. Jim Hovda is the Major Account Representative for Heinz, and has also provided testimony in this matter.

**Q. Does Idaho Power typically communicate such information with its large industrial customers such as Heinz?**

A. Yes. To assist with customer power quality issues Idaho Power employs a Commercial/Industrial Representative to coordinate any business issues that the customer may be having in relation to their power service. Additionally, a regional Power Quality engineer is available to assist the Representative and customer with related technical issues. For local operational issues, a Regional Distribution Field Engineer is available to lend any needed assistance. Also available to assist customers are the Power Quality Support Engineers in the corporate headquarters in Boise. Idaho Power, on at least two occasions, has presented educational material on how Heinz may address issues related to process interruption at their facility, in addition to several other communications and analysis regarding events that Heinz notifies the Company about.

**Q. Heinz states in its testimony that its Ontario facility had 22 "disruptive events" in the last 2 years. Is this consistent with Idaho Power's notifications from Heinz during the years 2008 and 2009?**

A. No. Heinz has indicated in this proceeding that it has had 22 "disruptive events" in the last 2 years including 8 in 2008 and 14 in 2009. However, during the course of 2008 and 2009, Heinz informed Idaho Power of only 4 events in 2009 and none in 2008.

**Q. Has Idaho Power's subsequently conducted any analysis regarding the 22 disturbances reported by Heinz?**

A. Yes. Idaho Power performed a sag analysis regarding the 22 events that Heinz stated had caused their process to shut down. A summary of this analysis is included as Exhibit 1705. Plotting all 22 events on an ITIC chart indicated that 16 of these events should not have caused any process interruption at their facility. See Exhibit 1705. The other 6 events that were outside of the ITIC curve may not have caused interruption had the plant been using sag tolerant equipment. It is interesting to note that the four 2009 events reported to us during the course of the year were a part of the detailed sag analysis and all resided inside the ITIC curve and should not have caused a process interruption at the facility, even with its current equipment. It is this type of inconsistency that has made assisting Heinz in determining a viable solution of their process interruptions very difficult.

**Q. Witness Bickford concludes that Idaho Power Company's system is not properly maintained. Do you agree?**

A. No. Idaho Power complies with industry standard maintenance and inspection of its electrical system, and the system is well maintained.

**Q. Can you describe Idaho Power's transmission maintenance program?**

A. Yes, I can. Idaho Power adheres to its Transmission Maintenance and Inspection Plan ("TMIP"), see Exhibit 1706, in compliance with the Western Electric Coordinating Council ("WECC") Reliability Standards. In accordance with the TMIP, an Idaho Power Transmission Line Patrolman routinely inspects all transmission lines once or twice a year depending upon line voltage and if the lines are defined as WECC path facilities. All WECC path facilities are also inspected by a Line Clearing Specialist, a certified Arborist, for proper clearances from vegetation on an annual basis. Identified line defects and or hazards are prioritized for proper replacement, repair, or removal as noted in the TMIP. In addition to routine annual inspections and maintenance, Idaho Power also completes comprehensive 10-year maintenance, as described in the TMIP, on all its transmission lines. The 10-year detail inspection includes the visual and internal inspection of wood poles at ground-line as well as treatment of all wood poles in the line. In addition, a comprehensive detailed visual inspection of all components of the transmission line is completed. The data collected from the wood pole inspection report and visual inspection report are compiled, evaluated, and defects prioritized for a general maintenance projects on the lines.

Since 2005, Idaho Power has expended nearly $50 million dollars maintaining and upgrading its transmission system. Specific expenses are: $7,980,003 in 2005; $8,964,715 in 2006; $11,227,898 in 2007; $11,100,924 in 2008; and $9,554,837 in 2009.

**Q. What maintenance improvements have been completed on the Ontario-Ore-Ida-Emmett 69 kV transmission line since 2005?**

A. Since 2005, the Ontario-Ore-Ida-Emmett 69 kV line was patrolled on 6 different scheduled occasions (3/17/05, 2/27/06, 6/27/07, 5/12/08 and 3/23/09). Defects identified during these patrols were corrected at a cost of $568,217. This maintenance improvement work included, in part, the replacement of 17 poles, 235 cross arms, and 919 insulators (including the removal of wooden insulator pins). The 2009 maintenance improvement work is currently scheduled during 2010 and includes the replacement of 23 structures at a cost of $112,404.

**Q. Has maintenance on the Ontario-Ore-Ida-Emmett 69 kV line been a significant contributor to the voltage sags reported by Heinz since 2005?**

A. No. Only 2 of the 22 events reported by Heinz could be attributed to maintenance items. As stated in the data response documents provided by Idaho Power, one event was caused by broken wooden insulator pin (2/4/2006) and the second event has an unknown cause (4/4/2005).

**Q. Can you describe Idaho Power's distribution maintenance program?**

A. Yes, I can. In Oregon, Idaho Power completes a biannual public safety inspection and a detailed 10-year inspection of its distribution lines. The biannual visual inspection is designed to identify obvious defects that may endanger the public. The 10-year detailed inspection involves conducting very thorough visual inspections. The information collected from these inspections results in the planning, scheduling, and completion of maintenance work. In addition to these inspections, a wood pole inspection and ground-line treatment is performed on all poles on the feeder once every 10 to 12 years. The data collected from the wood pole inspection is used to either steel stub or replace the reject poles the following year.

Since 2005, in Oregon, Idaho Power has expended nearly $10 million dollars maintaining and upgrading its distribution system. Specific expenses area include: $1,373,973 in 2005; $2,217,586 in 2006; $2,858,597 in 2007; $2,104,290 in 2008; and $1,328,279 in 2009.

**Q. What maintenance improvements have been completed on the OIDA-011 distribution feeder line since 2005?**

A. The OIDA-011 12.47 kV feeder serves customers in the immediate vicinity of the City of Ontario. Since 2005, the line was patrolled 3 times (2005, 2007, and 2008). Since 2005, defect corrections and other maintenance and upgrade work expense on this feeder are $216,694.

**Q. Has maintenance on the OIDA-011 distribution feeder line been a significant contributor to the voltage sags reported by Heinz since 2005?**

A. No. Only 2 of the 22 events reported by Heinz could be attributed to maintenance items. As stated in the documents provided to Heinz by Idaho Power, one event was caused by an overhead switch failure (3/30/2006) and the second event was caused by a failed lightning arrestor (1/17/2007).

**Q. Witness Ratcliffe states that Idaho Power sent a consultant to analyze Heinz's system and the consultant did not look at Idaho Power's side of the meter. Did Idaho Power hire a consultant and what were the findings?**

A. Idaho Power did hire an independent Power Quality consultant, PowerCET, to review the facilities of *both* Idaho Power and Heinz and to analyze the data on the number and magnitude of the sags and provide recommendations to Idaho Power and Ore-Ida about how to minimize the number and effect of the sags on the system. PowerCET has been performing power quality audits on large industrial plants and in the semi-conductor industry for 25 years and is an expert in studying the effects of adverse power quality, and the means to identify and correct sources of interference.

In their findings, see Exhibit 1708, PowerCET stated that the voltage sag activity for the site, while problematic for the facility, is pretty much in accordance with fault clearing activities that one would expect for a utility system covering hundreds to thousands of square miles of rough terrain. Electric Power Research Institute-Power Electronics Applications Center ("EPRI-PEAC") found in a comprehensive multi-state study of power delivery to semiconductor manufacturing plants that the average rate of sags experienced by facilities included in the study was 12 sags per year outside the ITIC curve.

Their conclusion was that the sag rate incidence at Heinz is below the average sag rate reported by EPRI-PEAC. The consultant recommended the best solution was for Heinz to improve the PLC power supplies, drives, and other critical equipment so it can at least ride though sag events within ITIC limits. Idaho Power fully funded this work of the consultant, as Ore-Ida chose not to participate. The results were presented to Heinz in April 2006.

**Q. Has the Company communicated and cooperated with Heinz in the investigation/resolution of their concerns beyond the PowerCET study mentioned above?**

A. Yes. Idaho Power has routinely communicated with and cooperated with Heinz. At Heinz's request, Idaho Power has consistently provided information about events on the Idaho Power system that may have correlated with negative impact events at their facilities. Idaho Power had in service a high speed power quality recorder at Heinz beginning in 1998. The information from the recorder provides an event and steady state power quality record at the customer's point of delivery. Furthermore, Idaho Power personnel analyzed the data and graphed the data in an event summary along with the expected end use equipment performance as plotted on an Information Technology Industry Council ("ITIC") curve. Typically, this information was sent to Heinz through e-mails and in some instances presented in person by representatives of Idaho Power Company. Please see OICIP's Exhibit No. 402 for an example of the correspondence documents.

Mike Whatley, Jim Hovda, and Jared Ellsworth met with Heinz (Scott Patterson in particular) in late 2007 to discuss moving Heinz off of the 69 kV and onto the 138 kV system via a single end-user (Heinz) transmission line and a new 138 kV transformer at Ore-Ida Substation. As an additional option, it was suggested to leave Heinz on the 69 kV system, but provide it with its own 69kV transformer at Ore-Ida Substation.

**Q.** [redacted]

A. [redacted]

**Q. In the testimony of Witness Ratcliffe, he gives examples of equipment that has been damaged by past "outages" including variable frequency drives, MOVs (metal oxide varisters), shaker drives, heat transmitters, touch screens, ADR**

**computers, sorter cameras, Tegra touch screen and Tegra computer. Do you agree with his damage assessment?**

A. No. Damage due to sags typically occurs in the front-end power supply of an electronic device. Some of the devices listed can also be easily damaged due to transients, inadequate grounding, wiring issues, ground loops, communication failures, or various other conditions. For example, sags do not damage MOVs. MOVs are damaged by sustained over-voltages (swells) or transients. Capacitor switching transients are a well documented source of variable speed drive failures specifically, failing the drives' DC bus capacitors.

**Q. What is Idaho Power's position regarding the sag tolerance of the Heinz facility**?

A. Many of the power quality events that impact the customers fall within the bounds of the ITIC curve. The events outside the bounds of the ITIC curve typically originate from circuit breaker operations that occur from short circuit events across Idaho Power's system. When these events occur, a protective device will sense the condition and open the power line. These events naturally produce voltage sags for every customer on Idaho Power's system. These events are considered normal within the operation of Idaho Power's system.

Heinz has informed the Company that these normal disturbances are affecting some of the more sensitive equipment within their plants. Because these events will continue to occur in the normal course of operating the system, the Company has offered to assist Heinz in the implementation of a number of actions to help them minimize the impact of these disturbances. First, the Company has recommended that Heinz enhance the precision of their record keeping with regards to the time a disruptive event occurs so that Idaho Power may determine the specific sag and duration levels to which the facility is most sensitive. Further, Heinz should endeavor to provide, to the best of their ability, what equipment, manufacturer, models, and processes, etc., are being affected so that specific recommendations for changes may be made within the plant. With this data in hand, Idaho Power may be able to determine better protection settings that will allow them to minimize or even eliminate the impact of these events. While Idaho Power is not aware that any of these recommendations have been adopted, the Company is willing to continue working with these customers to resolve their issues.

[redacted]

Also, the Company is committed to continue to patrol and maintain the transmission and distribution circuits that serve the Heinz facility to minimize the outage impacts. A safety patrol is performed every 2 years and a detailed patrol is performed every 10 years on all Oregon distribution feeders. The Heinz facility is served by the OIDA-012 Feeder from the Ore-Ida Substation. The Ore-Ida Substation is served by the Ontario-Emmett 69 kV line (Line 204). Since 2003, various maintenance projects have been performed on the line at a cost of $568,217. The majority of OIDA-012, except for 5 spans (6 poles) from the substation to the plant, is owned by Heinz.

**Q. What could be done to reduce Heinz's exposure to voltage sags?**

A. Idaho Power has met and talked with Heinz on numerous occasions to discuss ways Heinz can decrease their exposure to voltage sags. As has also been pointed out, Heinz would be responsible for the costs associated with a change in connectivity.

Several options exist. One option is to install a new 138/12.47 kV transformer at the Ore-Ida substation and build a new 138 kV transmission line to the station from Ontario substation. This would connect the plant to the 138 kV system. However, voltage sags can still occur on the 138 kV system. Another option is to install an additional 69/12.47 kV transformer at the Ore-Ida substation and the plant, or the adjacent feeder, could be moved to this new transformer. This option would decrease adjacent feeder sag exposure, but would do nothing about 69 kV sags. A third option is to install fast acting power electronics, such as a large UPS, to assist in sag ride through capability.

The electrical connectivity of the system serving the Heinz plant has not changed significantly for a very long time. It is apparent, however, that the Heinz plant has grown over time and power quality has begun to play a much larger role. Idaho Power is willing to make changes to the Idaho Power system in an effort to improve the quality of power to the Heinz facility; however, changes should not be made at the expense of Idaho Power's ratepayers.

**Q. Do you have any concluding remarks?**

A. Yes, I do. Idaho Power is concerned about the fact that the Heinz facility is unable to operate to the financial and operating satisfaction of its management because of electricity related issues. It is imperative that technical and operational people at both companies work cooperatively to address this issue. Voltage sags are inherent to the successful and safe operation of any utility electrical system and the utility and customers must learn to be successful despite their presence. Understanding the magnitude, duration, location, and cause of events on Idaho Power's system is very important. Likewise, understanding the time and impact of events (such as what specific equipment, manufacturer, models, and processes) that affect the Heinz plant is very important.

Idaho Power very much appreciates Heinz as a customer. I agree with Mr. Ratcliffe's goal to work together as partners so that both companies can be as successful as possible. I welcome the opportunity to meet on a quarterly basis, as recommended by Mr. Ratcliffe, in an effort to work on electrical issues concerning the facilities, both on facilities owned by Heinz and those owned by Idaho Power. In fact, Mr. Jim Hovda, Idaho Power's Customer Representative for Heinz is available and has access to me and others at Idaho Power at anytime Heinz wishes to contact him. I am positive that we can work together in a constructive fashion and improve this situation to the satisfaction of both Companies. However, I believe that Heinz must realize that the solution to their problems may not lie with Idaho Power system improvements funded by the general body of its customers and may involve solutions whereby they upgrade their own equipment in what appears to be a critical, high volume facility, and/or purchase the necessary system upgrades for their own dedicated service, or other reconfiguration of Idaho Power's facilities.

**Q. Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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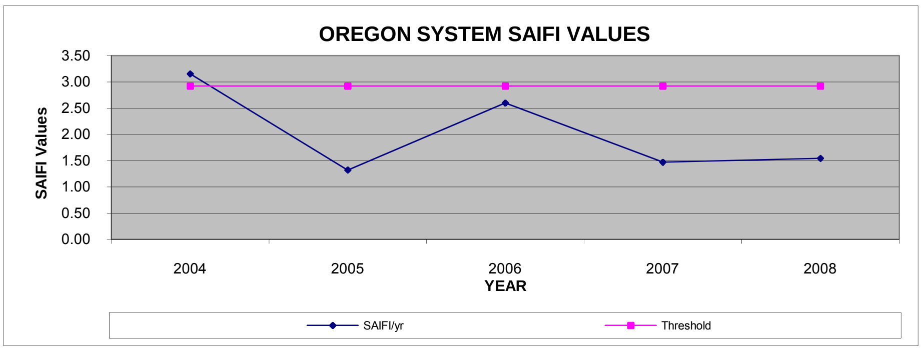
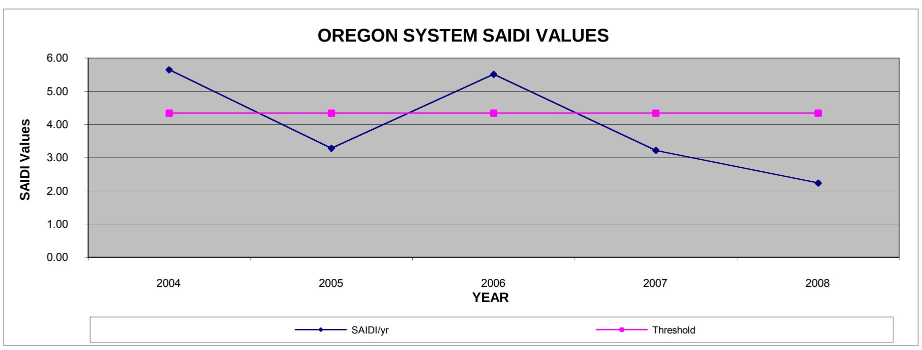
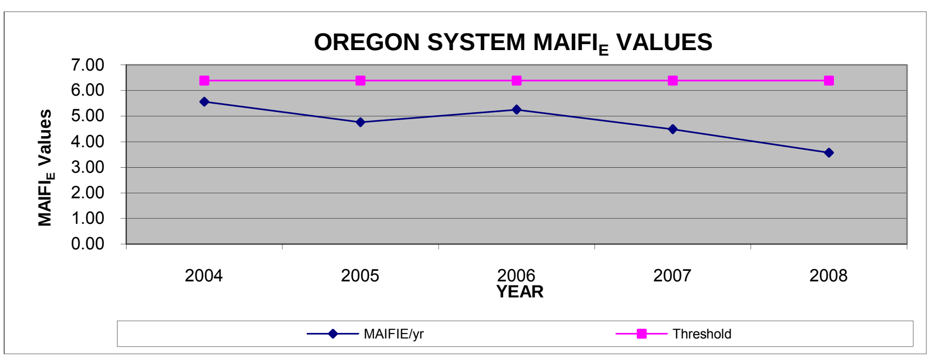
Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
2004-2008 SAIDI, SAIFI, and MAIFIe for Oregon System

January 26, 2010

The 2009 performance indices are currently being compiled and are due at the Oregon Public Utilities Commission in April, 2010.



BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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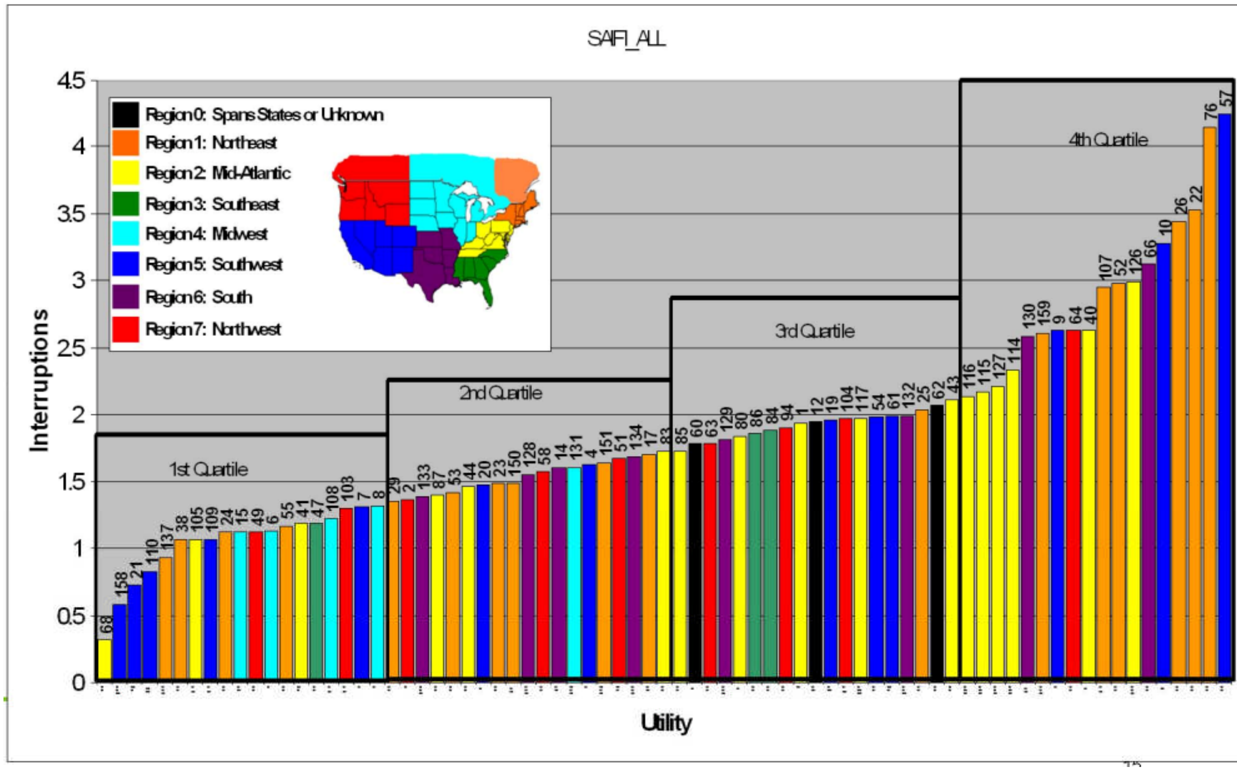
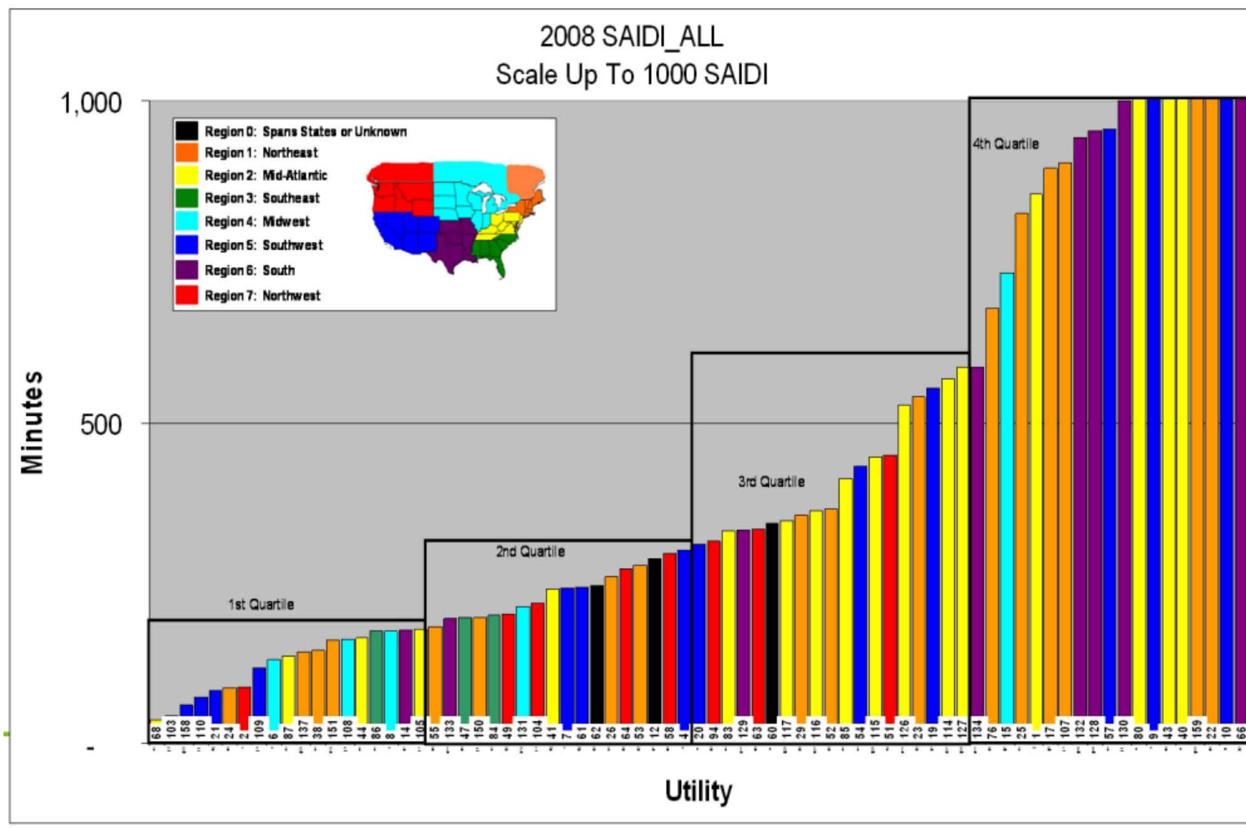
Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
2008 IEEE National SAIDI and SAIFI Study

January 26, 2010


SAIFI_ALL
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest
1st Quartile
2nd Quartile
3rd Quartile
4th Quartile
Interruptions
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
68 158 21 110 137 38 105 109 24 15 49 6 55 41 47 108 103 7 8 29 2 133 87 53 44 20 23 150 128 58 14 131 4 151 51 134 17 83 85 60 63 129 80 86 84 94 1 12 19 104 117 54 61 132 25 62 43 116 115 127 114 130 159 9 64 40 107 52 126 66 10 26 22 76 57
Utility


2008 SAIDI_ALL
Scale Up To 1000 SAIDI
Region 0: Spans States or Unknown
Region 1: Northeast
Region 2: Mid-Atlantic
Region 3: Southeast
Region 4: Midwest
Region 5: Southwest
Region 6: South
Region 7: Northwest
1st Quartile
2nd Quartile
3rd Quartile
4th Quartile
Minutes
1,000
500
-
68 103 158 110 21 24 2 109 6 87 137 38 151 108 44 86 8 14 105 55 133 47 150 84 49 131 104 41 7 61 62 26 64 53 12 58 4 20 94 83 129 63 60 117 29 116 52 85 54 115 51 126 23 19 114 127 134 76 15 25 1 17 107 132 128 57 130 80 9 43 40 159 22 10 66
Utility

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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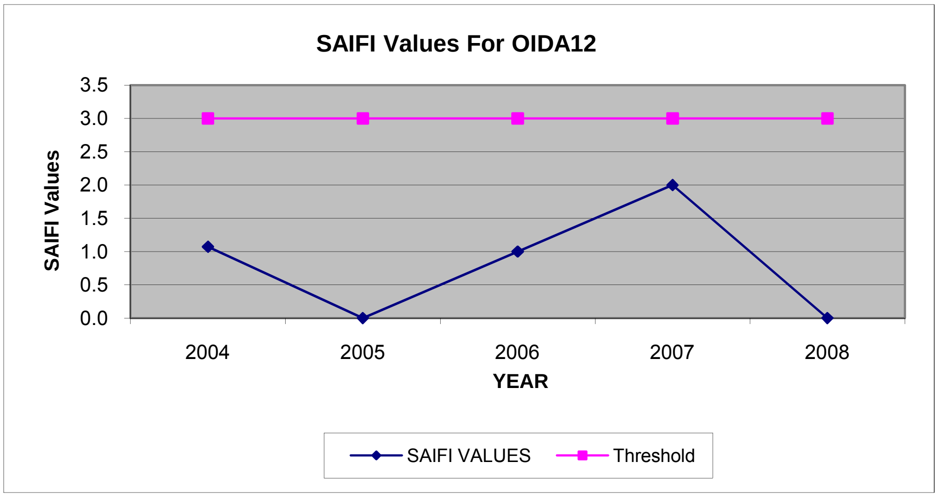
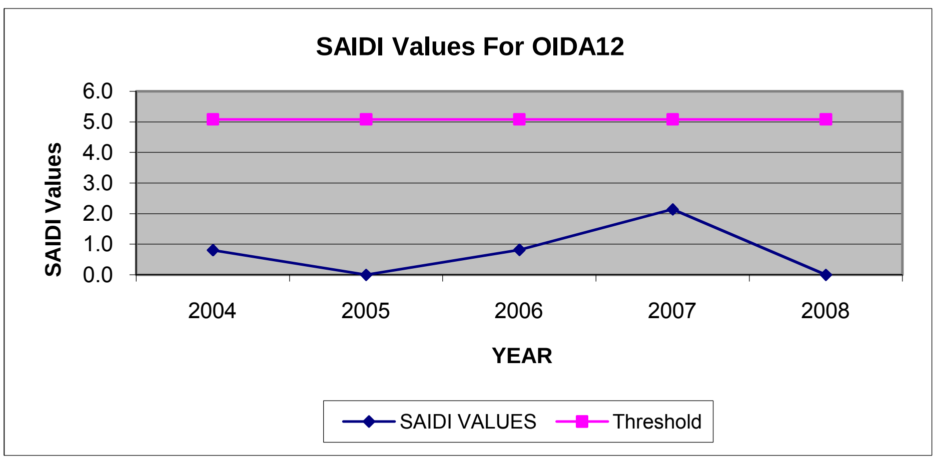
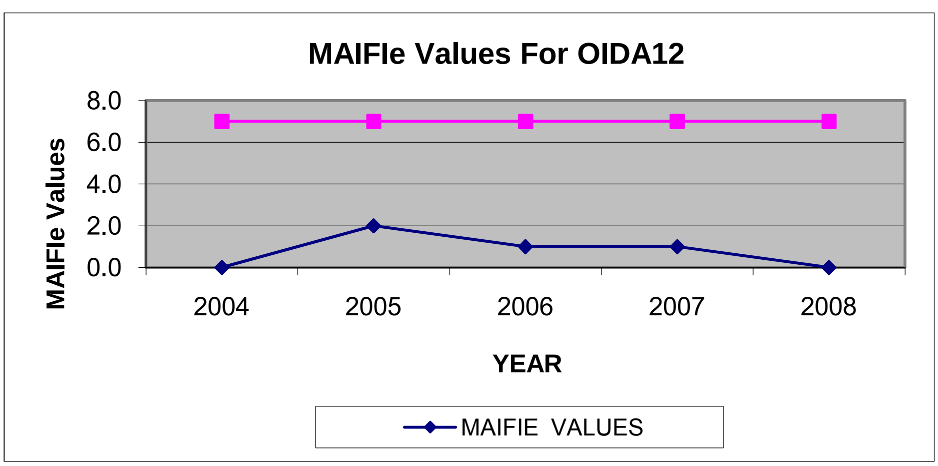
Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
2004-2008 SAIDI, SAIFI, MAIFIe for OIDA-12 Feeder

January 26, 2010


SAIFI Values For OIDA12
SAIFI Values
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2004
2005
2006
2007
2008
YEAR
SAIFI VALUES
Threshold


SAIDI Values For OIDA12
SAIDI Values
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2004
2005
2006
2007
2008
YEAR
SAIDI VALUES
Threshold


MAIFIe Values For OIDA12
MAIFIe Values
8.0
6.0
4.0
2.0
0.0
2004
2005
2006
2007
2008
YEAR
MAIFIE VALUES

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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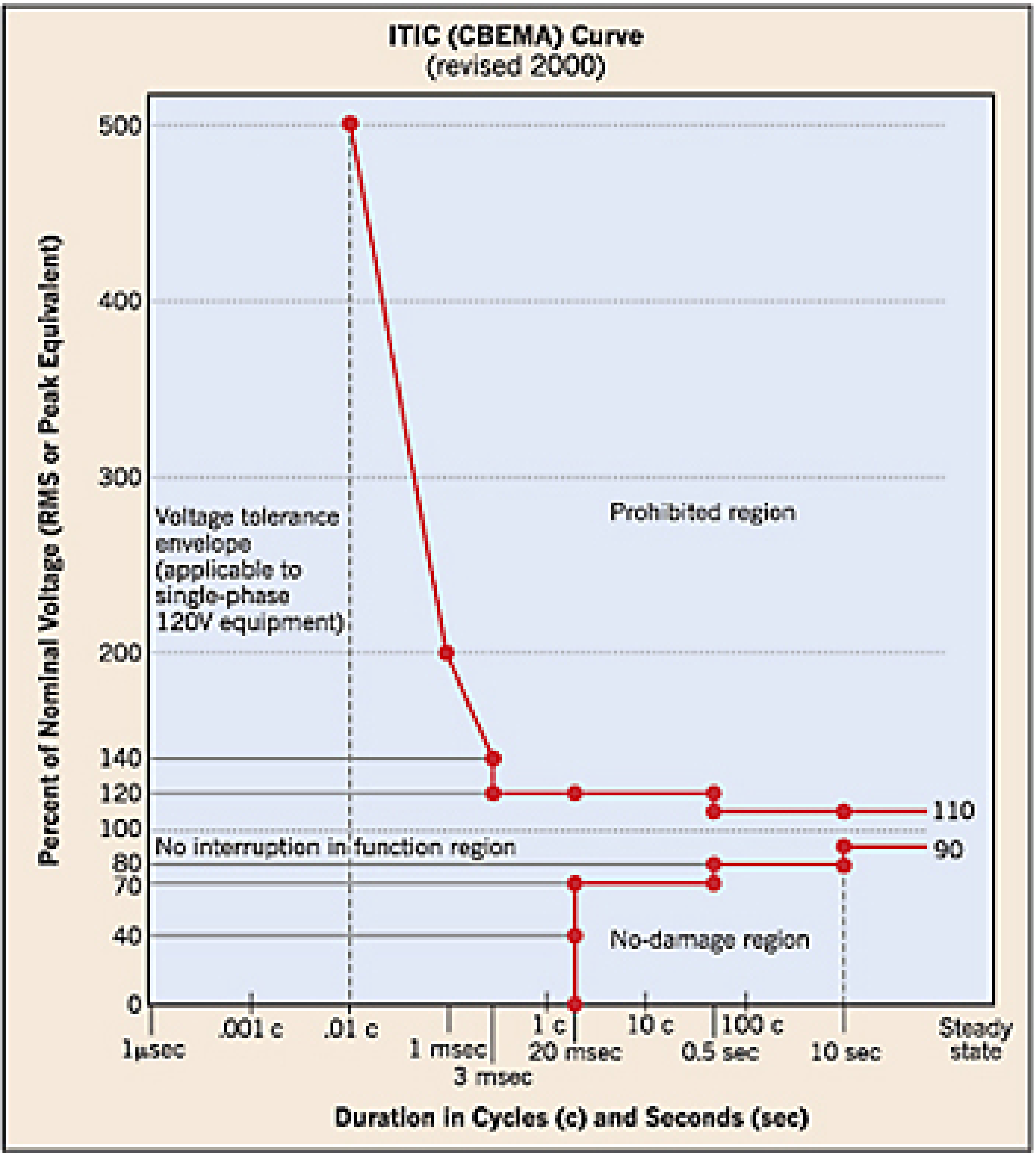
Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
Information Technology Industry Council ("ITIC") Curve

January 26, 2010


ITIC (CBEMA) Curve
(revised 2000)
Percent of Nominal Voltage (RMS or Peak Equivalent)
500
400
300
200
140
120
100
80
70
40
0
Voltage tolerance envelope (applicable to single-phase 120V equipment)
Prohibited region
No interruption in function region
No-damage region
110
90
1μsec
.001 c
.01 c
1 msec
3 msec
1 c
20 msec
10 c
100 c
0.5 sec
10 sec
Steady state
Duration in Cycles (c) and Seconds (sec)

Idaho Power/1705
Witness: Perry Van Patten, PE

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
Heinz Sag Event Analysis

**CONFIDENTIAL**

January 26, 2010

**IDAHO POWER EXHIBIT 1705 IS CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
Transmission Maintenance and Inspection Plan

**CONFIDENTIAL**

January 26, 2010

**IDAHO POWER EXHIBIT 1706 IS CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
Heinz's ITIC Graphs

**CONFIDENTIAL**

January 26, 2010

**IDAHO POWER EXHIBIT 1707 IS CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

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Exhibit Accompanying Reply Testimony of Perry Van Patten, PE
PowerCET Report

**CONFIDENTIAL**

January 26, 2010

**IDAHO POWER EXHIBIT 1708 IS CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**