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## BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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| **IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A DETERMINATION OF 2011 DEMAND-SIDE MANAGEMENT EXPENDITURES AS PRUDENTLY INCURRED** | ) | **CASE NO. IPC-E-12-15**<br><br>**COMMENTS OF THE COMMISSION STAFF** |

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's March 15, 2012 Application for an Order establishing that it prudently incurred \$42,641,706 in demand-side management ("DSM) expenses in 2011.

**BACKGROUND**

On March 15, 2012, Idaho Power Company (Idaho Power, or the Company) applied for an Order establishing that it prudently incurred \$42,641,706 in DSM expenses in 2011. Application at 1. The Company asks the Commission to process the Application under Modified Procedure. *Id.* at 7.

The Company says it has implemented or manages a wide range of opportunities for all customer classes to participate in DSM activities, consistent with the Commission's direction that the Company pursue all cost-effective DSM programs to promote energy efficiency. The Company says it uses DSM programs to (1) provide customers with programs and information to help them manage their energy usage, and (2) achieve prudent cost-effective energy efficiency and demand response resources to meet the Company's electrical system's energy and demand needs. Idaho Power consults with an Energy Efficiency Advisory Group (EEAG) that provides a broad range of recommendations, including input on new program proposals, modifications to existing programs, and overall expenditures of DSM funds. *Id.* at 2.

In this case, Idaho Power seeks a determination that it prudently incurred $35,623,321 in Idaho Energy Efficiency Rider (Rider) expenses and $7,018,385 in custom efficiency incentive expenses, for a total of $42,641,706 in DSM-related expenses. The Company notes that since the Rider was implemented in 2002, Idaho Power has steadily increased the breadth and funding level of its DSM activities. The Commission found the Company had prudently incurred cost-effective DSM-related Rider expenses of $29 million from 2002 and 2007. *Id., citing* Order Nos. 30740 and 31039. Additionally, the Commission approved DSM-related Rider expenses of $50.7 million from 2008 and 2009. *Id., citing* Order No. 32113. Further, the Commission found the Company prudently incurred cost-effective DSM-related Rider expenses of $41.9 million in 2010. *Id., citing* Order No. 32331.

The Application says that in 2011, the Company continued its DSM programs to increase participation and facilitate energy savings. The Company currently offers 17 energy efficiency programs (16 of which are cost-effective; the Home Improvement Program was not for 2011), three demand response programs (all of which are cost-effective from a long-term perspective; the A/C Cool Credit program was not cost-effective for 2011), and several educational initiatives. It also offers savings to customers through market transformation programs. *Id.* at 3-4. The Company notes that overall, energy savings from Idaho Power's efficiency activities in 2011 totaled 179,424 MWh. *Id.* at 3.

The Application attaches the Company's 2011 DSM Annual Report (the 2011 DSM Report). The 2011 DSM Report provides detailed cost-effectiveness information by program and energy savings measures as well as detailed financial information separated by expense category and jurisdiction. *Id.* at 5. The Company uses four cost/benefit analyses to determine cost-effectiveness of the programs: the total resource cost perspective (TRC), the utility cost perspective (UCT), the participant cost perspective (PCT), and the ratepayer impact measure (RIM). *Id.* The 2011 DSM Report also contains an evaluation section that includes the Company's evaluation plans, copies of completed program evaluation reports, research reports, and reports completed by the Company or third parties. *Id.* The 2011 DSM Report contains specific information for each program, including its 2011 activities, a section on customer satisfaction and evaluations providing an overview of process, impact, and market effect evaluations. *Id.* at 6.

The Application says that independent, third-party consultants provide impact and process evaluations to verify that program specifications are met, recommend improvements to the programs, and validate program-related energy savings. *Id.* at 7. During 2011, impact evaluations were completed on eight programs and process evaluations were completed on two programs. Third-party consultants conducted eight of the evaluations. *Id.*

Based on the information provided with its Application, Idaho Power requests that the Commission issue an Order designating the Company's expenditure of $42,641,706 in 2011 as prudently incurred DSM expenses. *Id.* at 8.

**STAFF ANALYSIS**

The Rider funds about 83% of Idaho Power's DSM programs. The Company has requested a prudency determination of $42.6 million, an amount that increased slightly from the 2010 prudency determination of $41.9 million. Staff notes that the Company continues to generally meet the DSM reporting guidelines established in the 2009 DSM Memorandum of Understanding (DSM MOU).[1]

Staff Attachment A compares Idaho Power's reported utility costs of $24.1 million for its 15 energy efficiency programs in 2011 to the estimated present value of utility benefits of $103 million over the projected lives of the installed measures. This analysis yields a 4.27 benefit/cost ratio. Idaho Power's three demand response programs are projected to have average annual utility cost of $15.3 million, which compares favorably with the reported average annual benefits of $23.8 million for a benefit/cost ratio of 1.55. Net benefits to the utility indicate that future rates paid by the utility's customers will be lower than they would be without the investment.

The Company claims a system-wide energy efficiency savings of 179,424 MWh, including Northwest Energy Efficiency Alliance (NEEA) savings. The Company further claims

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[1] The DSM MOU is a document signed by all Idaho three IOU's that outlines guidelines for a DSM prudency determination. The document incorporates sections on management, planning, cost-effectiveness, evaluation and reporting.

its demand response programs provide 403 MW of demand reduction capacity. Much of the demand response capacity was not dispatched during 2011. The energy savings have dipped slightly from 2010. However, the demand response capacity has continually increased over the years since demand response was initiated.

**Expenditures**

Staff reviewed all expenditures charged to the Rider for 2011 and calculated the Rider account balance as follows:

| | |
|---|---|
| 2010 Year End Balance | $(17,595,938) |
| 2011 Balance Transfer to PCA[2] | 10,000,000 |
| 2011 Funding plus Accrued Interest | 37,367,481 |
| 2011 Expenses[3] | (35,096,540) |
| Transfer to Oregon Rider | 345 |
| Adjustment to AC Cool Credit | 165,711 |
| 2011 Year End Balance | $( 5,155,941) |

While preparing responses to Staff's production requests, Idaho Power discovered two customer incentives for Oregon customers, paid through the Home Improvement Program, that were inadvertently charged to the Idaho Rider. After filing this Application, Idaho Power removed payments of $210 and $135 from the Idaho Rider and transferred these amounts to the Oregon Rider as shown in the table above. Additionally, an adjustment to the A/C Cool Credit program of $165,711 is discussed in further detail under the Demand Response section of this analysis.

**2011 DSM Changes**

Significant changes have been applied to the Company's 2011 DSM portfolio. Consistent with the 2009 DSM MOU's reporting objectives, the Company has reported current and future changes to DSM generally and to each program specifically. Pertinent changes include:

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[2] In Order No. 32217, dated April 1, 2011, the Commission authorized Idaho power to recover $10 million from the Rider deferral balance through a Power Cost Adjustment (PCA) surcharge during the 2011 PCA year.

[3] The Company's Application requests a prudency determination of $35,623,321, which is $526,781 more than the net expenses included in this table. The $526,781 represents the incentive payments made to Oregon customers that were inadvertently booked to the Idaho Rider in 2010, but corrected in 2011. The 2011 DSM net expenses are $35,096,540.

1. Custom Efficiency incentive payments are now paid through a regulatory asset account beginning January 1, 2011. Order No. 32245. The Commission authorized an amortization period to be determined when the Company seeks recovery of the deferral balance. Idaho Power reports a regulatory asset balance of $7,230,724 ($7,018,385 of incentive payments and $212,339 in accrued interest). The Company is not asking to recover this amount now.

In the Stipulation filed in Case No. IPC-E-10-27, the signing parties agreed to a carrying charge on the regulatory asset at a rate equal to the Company's approved overall rate of return. However not all parties to that case signed the Stipulation and, in Order No. 32217, the Commission ultimately rejected it. Discussion of the appropriate carrying charge was absent from both orders in that case. Staff believes valid arguments exist for a carrying charge less than that of the Company's rate of return. This issue can be more thoroughly vetted by all parties when the Company seeks recovery and an amortization period is established in a general rate case.

Idaho Power reports a Utility Benefit/Cost Ratio of 7.27 for this program, and a Total Resource Benefit/Cost Ratio of 3.09. A 2011, independent impact evaluation confirms the program's success and effectiveness. Staff recommends that the Commission approve the incentives paid under the Custom Efficiency program as prudent expenditures, that the balance of the Custom Efficiency regulatory asset account as of December 31, 2011 be set at $7,018,385, and that the carrying charge and the amount of accrued interest be established when the Company applies for recovery.

2. The avoided capacity cost for demand response increased from $63 to $94/kW as a result of the Commission-accepted, 2011 Idaho Power Integrated Resource Plan (IRP). Order No. 32425.

3. The Company applies an effective load carrying capacity (ELCC) of 93.4% to the avoided capacity cost ($94) of its three demand response programs. The avoided capacity cost for the Company's three demand response programs changed to $87.80 (93.4% of $94 yields $87.80). Since demand response is viewed as a capacity resource, the ELCC is used to measure the capacity of demand response against a thermal resource.

To obtain an ELCC of 93.4%, the Company analyzed the top 100 load hours in each of the past 5 years. Of the top 500 hours, the number of hours that fell between the operating parameters of demand response was used to calculate the ELCC. The Company maintains that, because demand response programs cannot perfectly match the reliability of a generation resource (due to the programs' limited availability), the Company should not claim the full avoided capacity cost benefit of that supply-side resource. Staff finds this methodology reasonable.

4. The Company altered the discount rate used to calculate the net present value (NPV) of the benefits for the program participants. Formerly, the Company used a 6.98% weighted average cost of capital (WACC) as the discount rate for participant costs and benefits. Now, a 3.88% discount rate is used. The Company says the new discount rate benefits participant bill-savings and non-electric benefits. While Staff notes that multiple discount rates exist that can be applied to the costs/benefits, Staff believes that the rate used is reasonable.

5. A one-time, $10 million deferral balance was transferred to the PCA mechanism effective June 1, 2011 through May 21, 2012. Order No. 32217.

Several Commission decisions in 2011 will impact the DSM prudency determination for the impending 2012 DSM review. First, the Commission adjusted the Rider from 4.75% to 4.0%, effective 2012. Order No. 32426. Second, a base level of $11.2 million in demand response payments will be funded through base rates beginning January 1, 2012. Order No. 32426. Finally, the Company will recover all demand response incentive payments through base rates and the PCA as power supply expenses.

While the Company will now recover demand response incentive payments through base rates and the PCA, Staff recommends that the Company continue detailing its demand response activities for prudency in the Company's DSM prudency determination. Staff believes it is more appropriate for Staff to review and analyze demand response in the DSM prudency determination than in a general rate case or PCA proceeding. The Rider will continue to fund a substantial amount of expenditures for each demand response program, such as labor and administrative expenses, materials and equipment, purchased services, and miscellaneous expenses. For example, the 2011 A/C Cool Credit program spent about 73% of its total program budget on expenditures that excluded customer incentive payments. Staff is opposed to fragmenting demand response programs into multiple proceedings. Therefore, Staff considers the DSM prudency determination to be the most appropriate venue for Staff analysis.

**Cost-Effectiveness**

The DSM MOU recognizes the cost-effective tests primarily from the perspective of the UCT, TRC and PCT. Staff recognizes that the RIM perspective allows for a wider conceptual context of the program. The Company's programs and measures were generally cost-effective from a UCT and TRC one-year perspective. However, there were some exceptions.

1. The A/C Cool Credit program was not cost-effective for 2011 due to paging and automated metering infrastructure (AMI) switches not functioning and a Company oversight on software upgrades. The A/C Cool Credit program is discusses in greater detail later in Staff comments.

2. The Home Improvement Program was not cost-effective for 2011 (TRC, RIM, PCT) due to a change in the Regional Technical Forum's deemed savings for weatherization by heating type and climate zone resulting in a large decrease in savings estimated with attic insulation. Additionally, the 2011 third-party impact evaluation discovered the programs savings estimates incorrectly included new windows in addition to insulation. Finally, of the 2,275 incentives offers, 40 incentives were paid to customers who submitted non-qualifying applications. This was captured in the cost-effectiveness of the program, thus decreasing the amount. The Company states that it has implemented a more rigorous participant review process. Staff notes that 34 measures will be discontinued and three measures will be reviewed for non-electric benefits. Staff has reviewed the Company's Home Improvement Program analysis and finds the alterations to be reasonable and within the guidelines set forth in the DSM MOU.

3. A total of 51 measures within various programs were not cost-effective from a UCT or TRC perspective. Most of these measures will be discontinued and some will be reviewed for non-electric benefits. The Holiday Lighting program was completely discontinued in 2011.

The Company continues to work within the cost-effectiveness guidelines[4] established in the DSM MOU. Staff encourages the Company to continue updating the cost-effectiveness assumptions with the most recent and correctly referenced sources. Staff expects the Company

[4] The DSM MOU calls for a cost-effectiveness section that lists programs and measures and includes the basis for the cost-effective estimate, formulas, data inputs and assumptions, the source or rationale for each assumption, and the corresponding date of the source referenced.

to include the correct status of the Regional Technical Forum measure (i.e. under review, active, out of compliance).

**Labor Expenses**

Staff continues to have concerns with the escalating labor costs charged to the Rider account. In 2011, Idaho Power charged approximately $2.64 million, or 7.5% of the total Rider budget, in labor expenses to the Rider account. In 2010, labor expenses were approximately 6% of the total DSM budget. Wage and Salary increases for Rider-funded employees continue to be automatically passed on to customers without the level of scrutiny and evaluation that occurs during a general rate case. The following table illustrates the increases in direct labor expenses and labor loadings paid out of the Rider for 2005-2011:

| Year | Labor Total | FTE Equivalents | Average Per FTE Equivalent | Average % Increase |
|---|---|---|---|---|
| 2005 | $ 434,301 | 5.6 | $ 77,554 | N/A |
| 2006 | $ 736,519 | 9 | $ 81,835 | 5.52% |
| 2007 | $ 1,399,692 | 17.1 | $ 81,853 | 0.02% |
| 2008 | $ 1,965,698 | 24.3 | $ 80,893 | -1.17% |
| 2009 | $ 2,293,136 | 25.7 | $ 89,227 | 10.30% |
| 2010 | $ 2,577,080 | 26.7 | $ 96,520 | 8.17% |
| 2011 | $ 2,637,729 | 26.4 | $ 99,914 | 3.52% |

Throughout several rate cases in 2011, Staff continually proposed adjustments for wage increases during the tough economic times customers were facing. The table above illustrates that the on average, Full Time Employee Equivalents (FTE) were seeing wage increases during the recent recessionary period while many Idaho families were facing income reductions. Staff continues to proposes that all wage increases for Rider-funded employees be excluded from the Rider until the Commission has approved the wage increases in a general rate proceeding.

## DEMAND RESPONSE PROGRAMS

### A/C Cool Credit

Funding increased in 2011 by 44%, from $2 million to $2,781,553. Participation increased 22%, from 30,391 participants to 37,728. The program was dispatched 14 times. Comparatively, the program was dispatched three times in 2010. In 2011, an independent impact evaluation was conducted on the A/C Cool Credit program, which indicated that the program was not cost-effective in 2011 and will not be cost-effective until 2014. The program life cost-effectiveness dropped from 1.11 to 1.10. The one-year TRC was not cost-effective at 0.74.

The cost-effectiveness decrease occurred because about 30% of A/C units or about 11,000 program participants were not cycled throughout the summer.[5] The Company did not discover the problem until well after the summer cycling season. To facilitate A/C unit cycling, the Company may install four different types of switches that communicate with the A/C unit. Two switches are AMI compatible and two are paging compatible. When an event is dispatched, the Company will send a signal to communicate with AMI-compatible switches. For A/C units with paging switches, a third-party paging provider is required.

A/C units were not cycled due to two problems. First, without Idaho Power noticing, a paging company discontinued service to a large portion of the Company's service territory.

The second issue causing the decrease in the cost effectiveness of the program was with the newest version of AMI-compatible switches. The Company used two different types of AMI-compatible switches, and each switch required its own software and firmware. Rather than running two separate operating systems for the switches, Aclara, the AMI switch manufacturer, developed a code change that would allow both versions of the switch to be dispatched through the same software. The software change was tested successfully in a controlled environment in fall 2010. However, following the successful testing of the new software code, the Company failed to update its software throughout its system. This oversight caused 7,891 A/C units in the Twin Falls, Idaho Falls and Boise area to not be cycled (February 22, 2012 EEAG).

[5] Production Response #7. The Company claims that some of the paging switches did receive the signal intermittently throughout the summer, but the Company did not quantify that number.

This is the second consecutive year that participants in eastern Idaho were not cycled. In 2010, Twin Falls and Pocatello were not cycled because the two available paging companies "discontinued their service" and no alternative paging providers "were available for that area" (2010 DSM annual report, pg. 21). The Company brought this to the EEAG's attention and it was determined that crediting the affected customers on their bills using non-Rider funds would be appropriate. The paging equipment was subsequently changed out to new, AMI-compatible switches in 2010/2011.

Remediation

The software affecting the AMI switches was upgraded in February 2012. The Company says it will replace most paging switches with AMI-compatible switches in 2012 and 2013 (about 24,000 switches) at an approximate cost of $6 million. All financial inputs have been updated to reflect the A/C Cool Credit issues in the 2011 DSM Report. The Company projects that the A/C Cool Credit program will continue to be cost-effective from a program-life perspective. However, the program will not be cost-effective from a one-year perspective until 2014. Mountain Home Air Force base (MHAFB)[6] is unable to upgrade to the AMI switches and may not be cycled during the 2012 season due to a lack of a paging service providers. Staff does not believe that ratepayer money should be used to pay A/C Cool Credit incentive payments to customers who are unable to provide any additional capacity to the system.

The Company says it will modify the program, conduct a process evaluation in 2012 and an impact evaluation in 2013, and develop an enhanced measurement and verification plan for 2012. Staff expects the Company to adhere to its planned evaluation schedule for the A/C Cool Credit program and implement modifications that enhance the program's cost-effectiveness. A third independent analysis should provide the Commission and Staff the proper foundation and information to determine how to modify or proceed with the program.

Staff finds the Company's impact analyses in the 2011 DSM Report to be excellent. Staff also appreciates the Company's full disclosure about the A/C Cool Credit issue to Staff

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[6] MHAFB contributes 803 participants that ARE NOT individually metered. MHAFB can only be cycled by a pager provider due to the technology of the MHAFB substation.

and the EEAG. However, Staff must ensure ratepayer funds are prudently spent. While the program life cost-effectiveness yields a UCT and TRC greater than 1.0, at this point, Staff views the Company's failure to properly manage the A/C Cool Credit program as an imprudent use of ratepayer funds. The Company's failure to cycle 7,891 AMI compatible switches was an avoidable error. Staff recommends the Commission deny the Company's request to fund from the Rider $165,711 — the amount of incentives paid to the 7,891 participants affected by the Company's failure to upgrade its software. Staff declines to recommend any adjustment for failure to cycle due to pager problems.

Staff's recommendation to deny funding for only the amount of A/C units not cycled by the AMI-compatible switches has been tempered by the Company's thorough evaluation and clear disclosure. Denying the use of ratepayer funding for the 7,891customer incentives is consistent with prior Company actions. As stated earlier, the Company in 2010 did not fund from the Rider the amount of incentives paid to eastern Idaho customers who were not cycled. Further, a 2009 analysis performed by a third party evaluator, Paragon, found that the program's cost-effectiveness was inconclusive and that some A/C units may not have received the paging signal. If the Company has not resolved the paging issues for the 2012 cooling season, Staff believes the Company should use non-ratepayer funds to pay any customers who are not cycled. Staff will expect the Company's 2012 DSM Report to quantify how many switches the Company could not cycle.

**Irrigation Peak Rewards**

Significant financial changes to the Irrigation Peak Rewards program occurred in 2011. Formerly, the program paid participants a 100% fixed incentive structure with the ability to call upon as many events as needed. As authorized in Order No. 32200, the program now offers a 75% fixed/25% variable structure. The Company now compares the cost of market energy prices with the program's variable costs. The program was not dispatched in 2011.

The expenditures for the Irrigation Peak Rewards decreased by about 9% to $11.7 million, primarily due to the new fixed/variable incentive structure recently approved. Program participation increased by about 15%, to 2,342 participants. Due to the increase in participants, the available capacity increased from 250 MW in 2010 to 320 MW.

Irrigation Peak Rewards was cost-prohibitive to dispatch in 2011 due to the new fixed/variable incentive structure and a combination of low system demand, low energy prices and a lack of system emergencies. Furthermore, the Company says the program has an approximate dispatch price of $200/MWh (totaling about $270,000 per event). To provide a brief historical snapshot, the program in 2009 (100% fixed structure) was dispatched on seven days and in 2010 the program was dispatched on three days. Regardless of the participation increase and the funding decrease, the $11.7 million program was not dispatched in 2011, providing limited system benefits. Staff is concerned that the new incentive structure will have lasting implications for the program's viability. If the cost to dispatch the program continues to outpace the cost of market-energy prices, the program will rarely be dispatched and may need to be refined.

**FlexPeak**

The FlexPeak Management Program continues to increase its expenditures, participation, cost effectiveness, and energy savings. The Company is requesting a prudency determination of $2,057,730 — a slight increase from 2010 ($1,902,680). The program life cost-effectiveness increased from 1.14 to 1.19. Additionally, the Company claims 58.8 MW of demand reduction, an increase from 47.5[7] MW in 2010. The program participation has grown by 85% to 111 in 2011, primarily due to a change in the reporting structure between Idaho Power and EnerNOC. (Customer sites were formerly reported by location. Now, customers are counted by the number of meters.)

The FlexPeak contract with EnerNOC will expire in 2014. EnerNOC is responsible for marketing, procuring participants, determining incentive levels, installing and maintaining equipment, and running the program. The Company notifies EnerNOC of an impending event and EnerNOC is responsible for meeting an agreed-upon weekly demand obligation. Over the course of five years, EnerNOC's reduction capacity is required to incrementally increase.

For 2011, EnerNOC was contractually obligated to provide 35 MW of reduction each week with an actual reduction ranging from 33 to 41.4 MW. The highest hourly reduction EnerNOC achieved was 58.8 MW. EnerNOC met the agreed-upon demand reduction for most

[7] This represents the highest hourly reduction.

of the events. EnerNOC did not meet its required demand reduction target for 5 of the 14 events and thus received a financial penalty.

Fourteen events were called in 2011, with each event lasting about four hours. In 2010, four events were called. EnerNOC committed to deliver 25 MW of reduction each week. The highest hourly reduction EnerNOC achieved in 2010 was 34.2 MW.

The Company pays EnerNOC a monthly lump sum from June through August that consists of unknown amounts of participant incentives, marketing costs, equipment costs, EnerNOC administrative costs, capacity payments (amount of reduction EnerNOC can secure), and energy payments (the measured reduction achieved during each event). Staff notes that the Company categorizes all its EnerNOC payments as "incentive" payments in the 2011 DSM report. Furthermore, the Company is unaware of the customer incentive structure and amount negotiated with EnerNOC (Production Request 10). To be consistent with the Company's DSM expenditure reporting, Staff believes it important for the Company and Staff to be aware of the amount of incentives paid to FlexPeak participants. Staff recommends that the Company detail the amount of incentives paid to its customers in future DSM annual reports.

Staff notes that the Company's demand response programs are not being used to their full potential. There appears to be significant load-shaping potential that is not dispatched due to a combination of low market prices, low demand, and cooler weather. For example, the Irrigation Peak Rewards program (the powerhouse of Idaho Power's demand response portfolio) sat idle due to a new incentive structure that made it cost-prohibitive to dispatch with such low energy prices. With the addition of the Langley Gulch natural gas plant this year, Staff is concerned that a combination of existing resources, and current market and load conditions make demand response cost-prohibitive in the near term. Staff does not advocate that these programs be discontinued now, but notes that further evaluation is necessary and future refinements may be warranted.

## ENERGY EFFICIENCY

### Irrigation Efficiency

While reviewing the 2011 DSM Report, Staff noticed several omissions in the Company's Irrigation Efficiency program discussion. First, the Company estimated 100% net-to-gross (NTG) energy savings for both its Custom and Menu, or prescriptive, incentive options in the program, even though the Regional Technical Forum estimates, which include NTG assumptions, are only applied to the Menu option. In its discovery response, the Company corrected this error and will apply a 75% NTG value to Custom energy savings in the future. Applying a 75% NTG value reduced the UCT from 4.71 to 4.22 and provides an increase in the TRC, from 1.55 to 1.90.

Second, Idaho Power wrote that the Regional Technical Forum savings cited for the program's Menu option are "under review" by the Regional Technical Forum. Actually, the Regional Technical Forum has deemed these savings to be "out of compliance" since February 2011. While it may be acceptable to cite savings estimates that are "out of compliance" if new savings are being actively pursued, the 2011 DSM Report appears to mischaracterize the status of the Company's savings estimates.

Third, Idaho Power reports that the non-electric benefits[8] produced by this program increased about 357% between 2010 and 2011, while electric savings increased by 35% and the program budget increased by 7%. In response to discovery, Idaho Power wrote that it had "improved its tracking of non-electric benefits with the implementation of a new more comprehensive database," but did not provide sources, values, or any methodology for these subjective, non-electric benefit estimates. Further, the Company's 2011 DSM Report fails to mention this new database. Staff points out that even with the massive addition of non-electric benefits, this program's TRC only increased from 1.52 in 2010 to 1.55 in 2011. After discovery, the Company held a telephone conference with Staff and explained the methodologies used to estimate non-electric benefits, which include yield benefits, labor savings, maintenance savings, and water savings. None of these estimates come from verifiable sources — they are all estimated by a project engineer on an individual project basis based on his or her judgment.

Fourth, the impact evaluation scheduled for Irrigation Efficiency in 2011–2012 was removed from the evaluation schedule. In response to discovery, Idaho Power said that the impact evaluation was modified to become a research project that would generate updated energy savings estimates. While this may be a reasonable approach to the problem posed by

[8] The DSM MOU recognizes the validity of incorporating non-energy benefits. However, the DSM MOU does not discuss the appropriate amount of non-energy benefits.

"out of compliance" Regional Technical Forum savings, the Company's 2011 DSM Report should have clearly explained the evaluation schedule change.

The sum of these missteps is a serious concern for a program that cost ratepayers $2.1 million in 2011. Even more concerning is the Company's decision not to disclose these issues in the 2011 DSM Report. Lastly, Staff believes that a 357% increase in non-electric benefits, which rests on the unevaluated estimations of program engineers, creates an artificially high TRC. Staff believes that this program might not pass the TRC when energy savings are verified by an impact evaluation and if non-electric benefits are removed.

Staff recommends that the Company include in its program cost-effectiveness the TRC value with and without non-electric benefits.

**Home Improvement Program**

Idaho Power's 2011 Home Improvement program created an incentive for residential customers with electric heat or central air conditioning to professionally install additional attic insulation in their homes. During the 2011 impact evaluation of this program, Idaho Power discovered that the energy savings estimates used for this program assumed that high-efficiency windows had been installed along with additional attic insulation. This faulty assumption caused the Company to overstate the program's energy savings. When the impact evaluation calculated the accurate savings, only attic insulation incentives for customers with electric heat remained cost-effective. In addition, the Company paid incentives to 40 non-qualifying program applicants.

Staff appreciates that the Company is revising its program to only include cost-effective measures and tightening its applicant review process. Staff is concerned, however, that the Company has failed to detect its faulty inclusion of energy savings from high-efficiency windows since 2008. Combined, these problems indicate inadequate oversight of the residential programs.

**Energy Efficient Lighting**

The Company's residential Energy Efficient Lighting program experienced a slight reduction in its cost-effectiveness, but it continues to pull in a strong program life UCT of 4.2 and a TRC of 3.07. The decrease in cost-effectiveness is due to the Regional Technical Forum's updated savings assumptions. The recent change in baseline assumptions is due to compliance with the federal Energy Independence and Security Act of 2007 (EISA).

Staff notes the variety of energy efficient lighting promotions detailed in the 2011 DSM Report. Staff suggests the Company expand its marketing efforts to include mobile applications like the Light Bulb Finder. Staff notes that federal policies will continue to change the lighting industry and market, and will most likely impact the Company's Energy Efficient Lighting program in the future.

**Energy Efficiency Advisory Group**

The EEAG met three times last year. Staff believes the dialogue between invited stakeholders and the Company could be greatly improved by more frequent EEAG meetings and more in-depth discussions. Discussion quality is currently hindered in two ways. First, Idaho Power only lets EEAG members comment or ask questions at EEAG meetings. Since several Staff members regularly attend EEAG meetings but only one Staff member is an EEAG member, the Company's policy precludes most Staff members not from providing feedback or asking for clarification on Company presentations.

Second, the EEAG has become a forum for Idaho Power's presentations on its DSM activities rather than a discussion where the Company actively seeks input. Idaho Power's ratepayers would be better served by an advisory group that contributes to the Company's decisions rather than merely receives updates on the Company programs.

Staff notes that Avista and Rocky Mountain Power's DSM advisory committees met either in person or by webinar approximately once a month in 2011 and that there committees did not censor attendees. In fact, the other utilities encouraged everyone to participate. Since this is the first year in which Idaho Power experienced declining energy savings and published its first impact evaluations, Staff believes there is no shortage of topics that warrant EEAG attention. Further, the publication of Idaho Power's next DSM potential study in 2013 will raise questions about which DSM resources the Company should expand, initiate, or reduce. These decisions would certainly benefit from the EEAG's frequent consideration.

## STAFF RECOMMENDATIONS

With a few exceptions, Staff believes Idaho Power's DSM efforts were generally prudent and cost-effective. The Company continues to make significant efforts to meet the objectives and goals outlined in the DSM MOU. Staff recommends:

- That the Commission approve Rider-funded expenditures of $35,728,206 as prudently incurred, and establish the ending balance of the Rider account as of December 31, 2011 at $(5,155,941);
- That the Commission deem the incentives paid under the Custom Efficiency program ($7,018,385) as prudently incurred;
- That the Commission deny Rider funding for $165,711 of A/C Cool Credit customer incentives;
- That the Commission prohibit the Company from accruing a carrying charge on the Custom Efficiency program's deferral balance until the Company seeks recovery of that balance in a general rate proceeding. At that point, the Company should be able to apply the Commission-approved carrying charge retroactively to the balance;
- That the Company continue to detail its demand response incentives, activities, evaluations and cost-effective benefits/costs for prudency in the Company's DSM prudency determination;
- That the Company detail the amount of incentives paid to its FlexPeak Management participants in future DSM annual reports;
- That the Company increase the number and depth of the EEAG meetings and encourage questions and feedback from <u>all</u> attending stakeholders;
- That the Company not fund any additional wage increases through the Rider until the increases can be properly vetted through a general rate proceeding, and
- That the Company include in its program cost-effectiveness the TRC value with and without non-electric benefits.

Respectfully submitted this 25th day of June 2012.

Karl T. Klein
Deputy Attorney General

Technical Staff: Nikki Karpavich
Donn English
Stacey Donohue

i:umisc/comments/ipce12.15kkdesdnk comments

Attachment A

| Idaho Power's 2011 Annual Demand-Side Management Utility Benefits and Costs | | | | | |
|---|---|---|---|---|---|
| **Energy Efficiency Programs** | **Measure Life** | **Utility Benefit (net present value of avoided costs)** | **Utility Cost** | **Net Benefit (Benefit-Cost)** | **2011 Utility B/C Ratio** |
| Ductless Heat Pumps | 20 | 591,603 | 191,183 | 400,420 | 3.09 |
| Energy Efficient Lighting | 5 | 6,850,821 | 1,719,133 | 5,131,688 | 3.99 |
| Energy House Calls | 20 | 1,178,997 | 483,375 | 695,622 | 2.44 |
| Energy Star Homes Northwest | 32 | 967,191 | 259,762 | 707,429 | 3.72 |
| Heating & Cooling Efficiency | 20 | 946,314 | 195,770 | 750,544 | 4.83 |
| Home Improvement | 45 | 1,772,738 | 666,041 | 1,106,697 | 2.66 |
| Home Products | 15 | 1,304,940 | 638,323 | 666,617 | 2.04 |
| Rebate Advantage | 25 | 183,939 | 63,469 | 120,470 | 2.90 |
| See Ya Later, Refrigerator | 8 | 994,718 | 654,393 | 340,325 | 1.52 |
| Weatherization Assistance | 25 | 3,531,604 | 1,324,415 | 2,207,189 | 2.67 |
| Weatherization Solutions | 25 | 1,447,829 | 788,148 | 659,681 | 1.84 |
| Building Efficiency, Commerical | 12 | 7,627,364 | 1,291,425 | 6,335,939 | 5.91 |
| Easy Upgrades, Commercial | 12 | 25,650,385 | 4,719,466 | 20,930,919 | 5.44 |
| Custom Efficiency, Comm/Indust. | 12 | 38,838,187 | 8,783,811 | 30,054,376 | 4.42 |
| Irrigation Efficiency, Irrigation | 8 | 11,123,018 | 2,360,304 | 8,762,714 | 4.71 |
| **Total Energy Efficiency** | | **103,009,648** | **24,139,018** | **78,870,630** | **4.27** |

| Peak Demand Programs | Utility Benefit | Utility Cost | Net Benefits (Benefits - Cost) | 2011 Utility B/C Ratio |
|---|---|---|---|---|
| AC Cool Credit (20 year projected) | 37,186,165 | 33,948,331 | 3,237,834 | 1.10 |
| FlexPeak Management (10 year projected) | 36,551,819 | 30,629,291 | 5,922,528 | 1.19 |
| Irrigation Peak Rewards (20 year projected) | 365,066,962 | 211,898,973 | 153,167,989 | 1.72 |
| **Average Annual Peak Demand, Projected** | **23,767,838** | **15,355,294** | **8,412,544** | **1.55** |

# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 25TH DAY OF JUNE 2012, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-12-15, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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