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Attorneys for the Industrial Customers of Idaho Power

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A PRUDENCY DETERMINATION OF ENERGY EFFICIENCY RIDER FUNDS SPENT DURING 2008-2009	CASE NO. IPC-E-10-09 COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER

Pursuant to Rule 203 of the Rules of Procedure of the Idaho Public Utilities Commission (the "Commission") and the Commission's Notice of Modified Procedure served July 28, 2010, the Industrial Customers of Idaho Power ("ICIP") respectfully submit the following comments on Idaho Power Company's ("Idaho Power's" or the "Company's") request for a prudency determination as to the $50.7 million in energy efficiency rider funds ("EE rider" or "rider") spent in 2008 and 2009. As set forth in detail below, ICIP requests that the Commission condition any finding of prudency of the expenditure of these funds on the additional requirement that Idaho Power abandon individual programs that fail to meet a total resource cost benefit ratio ("TRC ratio") of 1.25 or greater once mature. ICIP additionally requests that the Commission order Idaho Power to abandon or modify the Holiday Lighting and A/C Cool Credits programs, encourage Idaho Power to use the FlexPeak program as a model for other programs which could be run with third-party aggregators, and order that Idaho Power rely more heavily on third-party evaluations in the future or at least provide criteria establishing when third-party evaluations are appropriate.

I

BACKGROUND

A. The recent EE rider prudency review case (IPC-E-09-09) included a filing of a Memorandum of Understanding that should inform but not replace prudency reviews.

The present application is the second prudency review to be addressed by the Commission this year. In Case No. IPC-E-09-09, the Company sought a prudency determination for expenditure of approximately $14.6 million in EE rider funds spent from 2002 to 2007.[1] *See Application*, Case No. IPC-E-09-09, ¶¶ 2-3 (April 1, 2009). Staff initially concluded the Company provided a lack of documentation regarding that expenditure, and then held private workshops with the three utilities to develop a Memorandum of Understanding ("MOU") regarding future reviews. *See* Direct Testimony of Lynn Anderson, Idaho Public Utilities Commission Staff, Case No. IPC-E-09-09, p. 4 (February 19, 2010).

The utilities agreed in the MOU "to formally evaluate all of their programs on regular, multi-year cycles and to report the results. . . ." *Id.* at pp. 4-5. "In exchange for the utility commitments, Staff agreed that if the evaluation and reporting commitments are fulfilled and if there is no evidence of DSM imprudence, then, when requested by the utilities, Staff would

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1 In the 2008 general rate case, the Company requested approval of approximately $29 million of EE rider fund expenditures from 2002 to 2007. Ultimately, the Commission found prudency as to the expenditure of $14.3 million per stipulation in Order No. 30740, but required the Company to make a separate filing to establish the prudency of the remainder of those expenditures, which resulted in the Company initiating Case No. IPC-E-09-09.

recommend that DSM expenditures be found prudent by the Commission." *Id.* at p. 5. Staff and the Company reached a settlement in Case No. IPC-E-09-09, and attached the MOU between Staff and the three investor-owned-utilities to the settlement stipulation submitted for approval by the Commission. *See Stipulation*, Case No. IPC-E-09-09, ¶¶ 3-4, and Attachment 1 (January 25, 2010). No party to that case challenged the prudency of expenditure of the remaining $14.6 million in Case No. IPC-E-09-09. But ICIP requested the Commission not unconditionally approve the MOU as a basis for future prudency findings by the Commission or as a basis by which Staff would provide its support for a prudency determination. *See* Order No. 31093, at pp. 2-3.[2]

The Commission found expenditure of the remainder of the 2002 to 2007 rider expenditures prudent, but the Commission itself did not approve the MOU. Specifically, the Commission stated, "'even if a utility implements Staff's prudency guidelines and evaluation framework in the Memorandum of Understanding, the utility will still need Commission approval of the expenditures in a formal filing, such as a general rate case.'" Order No. 31039, at p. 3 (quoting *ICIP's Comments and Protest*). The Commission stated that "interested parties will have an opportunity in those proceedings to analyze and challenge the DSM evaluation at issue, regardless whether the utility has evaluated and reported its programs consistent with the

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2 The Stipulation stated, "The obligations of the Parties under this Stipulation are subject to the Commission's approval of this Stipulation." *Stipulation*, Case No. IPC-E-09-09, at ¶ 10; *see also id.* at ¶ 4 and Attachment 1. ICIP's comments opposing the MOU were therefore premised on the assumption that the request for Commission approval of the reasonableness of the stipulation included a request for approval of the reasonableness of the MOU attached to the stipulation as part of the basis for Staff's agreement not challenge the prudency of the remaining EE rider fund expenditures at issue. Staff and Idaho Power both filed reply comments, however, asserting they had no intention of the Commission approving the MOU or of making it binding on other parties.

terms of the MOU." *Id.* The Commission therefore merely "recognize[d] that the MOU has potential in evaluating and reporting Idaho Power's DSM programs." *Id.* Most importantly, the Commission stated, "The Commission's future review of particular DSM programs should be assisted, but will not be replaced by, Idaho Power's compliance with the terms of the MOU." *Id.*

B. The Application in this case requests a prudency finding for rider funds expended in 2008 and 2009.

Although Idaho Power has not had sufficient time to fully comply with the procedural requirements of the MOU in this case, this is the first prudency review assisted by the MOU. *See Application*, ¶ 11. This is also the first case where the Commission is asked to approve the prudency of expenditures collected under the recently-increased EE rider level of 4.75%, which went into effect May 2009 and from which Idaho Power has projected it will collect over $30 million per year. *See* Order No. 30814, at p. 3. In this case, the Company seeks prudency determination as to the expenditure of $18.8 million spent in 2008 and $ 31.8 million spent in 2009. *Application*, at ¶ 6.

In support, the Company asserts that annual energy savings from efficiency activities increased by 62% from 2007 to 2009, representing a savings of 140 Gigawatt hours ("GWh") in 2008 and an additional 148 GWh in 2009. *Application*, at ¶ 5. The Company also reported that its demand-side management (DSM) programs reduced its load by 48 MW in 2007, 61 megawatts ("MW") in 2008, and 218 MW in 2009. *Id.* The Company asserts that all but one of its individual programs – the Holiday Lighting program – produced savings at a benefit/cost ratio of 1.0 or greater when evaluated at a total resource cost perspective ("TRC test"). *Application*, at ¶ 7. The Company has provided its 2008 and 2009 Demand-Side Management ("DSM") Annual Reports, and asserts that the 2009 DSM Annual Report comports with many of the requirements of the MOU from Case No. IPC-E-09-09. *Application*, at ¶ 10-11. Specifically, Idaho Power asserts it has conducted many cost-effectiveness measures, net-to-gross adjustments, and third-party program evaluations. *Id.*

II

COMMENTS

Cost-effectiveness should be the governing factor of Idaho Power's DSM programs to ensure that ratepayer funds achieve the greatest demand-side reductions for ratepayer benefit. Programs should focus on reducing electricity demand, and mature programs that fail to do so with a reasonable assurance of cost-effectiveness should be abandoned. In a prudency review, such as this case, Idaho Power must prove the prudency of its expenditure on its individual programs. Imprudently spent EE rider funds should be subject to a ratepayer refund. And where the program proves to be less than cost-effective, but does not rise to the level of an imprudent expenditure given reasonable expectations at the time of the expenditure, the Commission should order the Company to improve or discontinue that program. In this prudency review, ICIP does not advocate for disallowance of any particular expenditure, but requests the Commission condition its prudency determination by taking the steps described below to improve the Company's overall DSM program and the quality of future prudency reviews.

A. The Commission should set a standard requiring that mature programs that fail to meet a TRC ratio of 1.25 be improved or discontinued.

Idaho Power states that it takes steps to ensure cost-effectiveness, but its tests are not sufficient to guarantee cost-effectiveness of each program. "Idaho Power's goal is that all mature programs have a benefit/cost (B/C) ratio greater than 1.0 for both the total resource cost (TRC), utility cost (UC), and the participant cost (PCT) tests at the program level and the measure level, except in cases where there is interaction between measures." *Idaho Power's 2009 DSM Annual Report*, p. 15.[3] Idaho Power states it will re-examine implementation of programs that fail to meet this minimum level of cost-effectiveness for these three measures. *See id.* But that is not enough to ensure that EE rider funds are prudently spent.

ICIP believes that the most meaningful test for evaluating the programs is the TRC test. That test includes both the costs incurred by the Company and the costs incurred by program participants. It therefore evaluates the true value of the program, considering all relevant costs in analyzing whether the program is a cost effective means of using ratepayers' financial resources to reduce demand. In contrast, the UC test does not consider the costs DSM program participants will incur to bring the program benefits to fruition, and therefore overlooks additional costs of the programs that must be incurred by ratepayers in order to achieve demand reductions on the system. Further, the PCT only analyzes the costs and benefits to an individual participant of a given program. It may be a good "first cut" of the desirability of the program to individual customers from a purely economical standpoint, but it is not a very meaningful tool to evaluate the cost-effectiveness of the program after implementation. The TRC test is therefore the most useful means for comparing the relative value of demand and supply-side options from the ratepayers' perspective.

The Company should be able to achieve a TRC ratio of 1.25 for all programs. A TRC ratio above 1.0 indicates the program has met the bare minimum level of cost-effectiveness to the utility and its ratepayers. But a review of the Company's filing in this case reveals

3 The Company does not appear to have provided the PCT calculation for all programs in this filing. *See id.* at p. 15 and Appendix 4; *see also Idaho Power's 2008 DSM Annual Report*, pp. 11-12 (discussing the TRC and UC tests in more detail, but not discussing use of the PCT test).

that, at least under the current methods of analysis, the successful programs far exceed the bare minimum level of cost-effectiveness. *See, e.g., 2009 DSM Annual Report, Supplement 1: Cost-Effectiveness*, at pp. 27, 43 (April 16, 2010, Revised Edition) (containing the TRC ratio of 3.69 for the Home Improvement program and 3.56 for the Custom Efficiency program). The Commission and the Company should set a higher goal for all programs than the bare minimum of cost-effectiveness when it is obvious programs can far exceed that minimum. Requiring all mature programs to achieve a TRC test of 1.25 will ensure that programs that cannot meet that test will be improved, or replaced, so that beneficial use of DSM funds is maximized.

Additionally, setting a goal of only achieving the bare-minimum level of cost-effectiveness overlooks that many of the assumptions that go into calculation of the TRC ratio are just that – assumptions. And as such they are likely inaccurate. Setting a standard for programs at a score of 1.25 on a TRC basis would therefore allow for some cushion against modeling errors to ensure that all programs that remain in the Company's DSM portfolio are indeed cost-effective.

In a prudency review for funds spent in a given year, therefore, the Commission should require Idaho Power to prove that the funds spent on a program during the review period were spent in a fashion so as to achieve a TRC ratio of 1.25. If the Company cannot make such a showing for a mature program, the Commission should order that the Company abandon the program or demonstrate that the program can be altered such that it will achieve a TRC ratio of 1.25 in the next review period. Continued failure to achieve a TRC ratio of 1.25 for a given program should result in a finding that the expenditures were not prudently incurred.

B. The Commission should require Idaho Power to abandon or improve underperforming programs in this case, such as the Holiday Lighting program and the A/C Cool Credits program.

Although certain programs are clearly cost-effective, some mature DSM programs appear to have failed to meet a TRC ratio of 1.25, or even 1.0, for the review period at issue – 2008 and 2009. The Commission should order Idaho Power to stop funding such programs with EE rider funds, or take substantial steps to improve the programs to a cost-effective level.

For example, the Holiday Lighting program achieved at TRC ratio of only 0.85 in 2009. *See 2009 DSM Annual Report, Supplement 1: Cost-Effectiveness*, at p. 57. This program provides an incentive for commercial customers to replace existing holiday lighting with more efficient LED lights. *See 2009 DSM Annual Report*, at pp. 84-86. In its third year, the program should be mature and achieving greater benefits. Yet the Company appears to have no plans to abandon the program to use the funds on more cost-effective efforts, or to seriously modify the program to render it cost-effective. *See id.* at p. 86 (setting forth no new strategies for 2010, and instead hypothesizing that the program may improve "[a]s the market acceptance of LED lighting increases and if the economy improves").[4]

Another program that appears to be achieving less than a cost-effective result is the A/C Cool Credits program – a peak reduction program on which ratepayers spent almost $3

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4 The Heating and Cooling Efficiency Program also suffered from TRC ratio of less than 1.0. *See 2009 DSM Annual Report*, at p. 38 (stating the program life TRC ratio is 0.91). The Company appears, however, to have eliminated some wasteful elements of this program to succeed in improving its cost-effectiveness in 2009. *See 2009 DSM Annual Report, Supplement 1: Cost-Effectiveness*, at p. 23 (stating the TRC ratio for 2009 was 2.05).

million in 2008 and over $3.4 million in 2009. *See 2009 DSM Annual Report*, at p. 19. For that amount of EE Rider expenditure, Idaho Power "assumed" it achieved a load reduction of 29 MW in 2009. *See id.* at p. 22. But this assumption is based on a detailed analysis of the irrigation and commercial/industrial peak programs, not a detailed analysis of the A/C Cool Credits program. *Id.* And Idaho Power has not conducted a TRC ratio calculation for this program for 2008 and 2009, the period for which it seeks a prudency determination. Rather, the Company has only calculated the cost-effectiveness of this program based on a "20-year model that uses financial and DSM alternative costs assumptions from the 2006 Integrated Resource Plan." *See id.* It is not clear from the Company's filing why the Company cannot calculate the cost-effectiveness of the A/C Cool Credits program in the two years at issue for which it seeks a prudency determination. A model analyzing whether the program will be cost effective over a 20-year period is not an adequate basis upon which to compare its cost-effectiveness to that of other DSM programs.

Nevertheless, even when calculated over 20 years into the future, this program achieves only a TRC ratio of 1.09, less than an ideal level of at least 1.25. *See 2009 DSM Annual Report, Supplement 1: Cost-Effectiveness*, at p. 5. The A/C Cool Credits program is certainly now planned to achieve well below initial expectations. *See* Order No. 29702, at p. 3 (in authorizing expansion of the A/C cycling program, the Commission noted, "the Company performed a benefit-cost analysis that showed a positive benefit-cost ratio of 1.42 over a 30-year period").

Although Idaho Power has not provided a TRC ratio calculation for costs and benefits of the A/C Cool Credits program in 2008 and 2009, further review of the Company's filing reveals that this program may not have achieved even a bare minimum level of cost-effectiveness in 2009. Idaho Power's filing states that the program cost $3,451,988 in 2009, but only reduced peak loads by 38.5 MW which, based on ICIP's calculation, resulted in a cost of $89,662 per MW of peak load reduction. *See 2009 DSM Annual Report*, at p. 19. That is far higher than the cost per MW of peak load reduction for other DSM programs targeting peak. *See id.* at p. 95 (stating the Irrigation Peak Rewards program cost $9,655,283 in 2009, but achieved 160 MW in peak load reduction, which based on ICIP's calculation cost ratepayers only $60,345 per MW).[5]

The third-party evaluation of the program by Paragon Consulting identified a serious free rider problem. The report concluded that "52% of the customers had an average natural duty cycle below the enforced duty cycle of the curtailment at the beginning of the event." *Idaho Power Demand Response Analysis Report, 2009 A/C Cool Credit* Program, prepared by Paragon Consulting Services, at p. 1 (included in the *2009 DSM Annual Report, Supplement 2: Evaluations*). "These customers are therefore free riders." *Id.* In other words, the program did not reduce energy use whatsoever for over half of its participants. But EE rider funds were paid to those free riders in the form of incentive payments, and EE rider funds were used to install equipment at those free riders' residences. The Paragon report also concluded that the average demand reduction per curtailment "was well below the expected demand reduction . . . found in other utility studies." *Id.* The third-party evaluation was far from a ringing endorsement of this program's cost-effectiveness. The

5 Although these calculations ignore customer/participant costs and would be analogous to UC ratio analysis, the participants in the A/C Cool Credits and Irrigation Peak Rewards programs incur no direct participation costs and thus the TRC ratio is the same as the UC ratio.

Company's DSM Report discusses plans to expand the program to reach 40,000 total participants, but perhaps the goal should be to reduce participation to include only those customers whose participation would reduce their energy use. *See 2009 DSM Annual Report*, at p. 22. Or the Company should look to modify this program to target multi-unit residential buildings and implement the program similar to the FlexPeak program, as discussed below.

The pool of DSM funds is limited, and the Company's DSM programs demonstrate that certain programs can achieve far greater than a TRC ratio of 1.0. The Company should therefore abandon programs that are unable to achieve a TRC ratio of 1.25, and direct the funds freed up from those unsuccessful programs to balancing its DSM budget and supporting programs that can achieve a greater TRC ratio of 1.25.

C. ICIP commends Idaho Power for its successful implementation of the FlexPeak program, and submits that the program's success warrants using this model in other programs, such as the forthcoming distributed generation program, and for other customer classes' DSM programs, such as in a multi-unit residential setting.

Although in Case No. IPC-E-09-02 ICIP took issue with some terms of the FlexPeak program, such as transparency of individual EnerNOC contracts with customers and the notice provided prior to curtailments, ICIP remains generally supportive of the FlexPeak program. ICIP submits that the huge success and cost-effectiveness of the program warrants using it as a model the Commission should encourage Idaho Power to follow for other programs.

Idaho Power contracted with a third-party, for-profit entity, EnerNOC, as the FlexPeak program operator. EnerNOC has financial incentive to meet peak demand reduction targets in its contract with Idaho Power and, unlike a utility that also sells electricity, EnerNOC possesses no disincentive to pursue demand reduction that will reduce electricity sales and the future need to build generation resources. Indeed, EnerNOC would pay a penalty under its contract with Idaho Power if it were to fail to hit its target reductions. EnerNOC achieves peak demand reductions in this program by directly contacting large commercial and industrial customers in an effort to locate processes at the customer's facility that can be curtailed during peak hour curtailment events. *See FlexPeak Management Demand Response Program Report*, Case No. IPC-E-09-02, p. 3 (Feb. 26, 2010). In 2009, EnerNOC was contractually committed to 2 MW in demand reduction for the peak season, but the program exceeded that target by over *eight times*, reaching a 17.1 MW reduction in July 2009. *Id.* at p. 4. The program achieved a TRC ratio of 1.60 in its first year, over *three times* the projected TRC ratio of 0.51. *Id.* at p. 11.[6] The program only cost $528,681 to reduce peak demand 17.1 MW. *Id.* at p. 11.

Idaho Power recognizes the reasons this program is successful. "To penetrate the medium to large commercial industry and to achieve moderate demand savings on an individual customer basis is resource intensive in both personnel and technology. Demand response aggregators have refined their marketing messages and have created audits and processes which maximize individual demand reduction potential." Idaho Power Response to Commission Staff's Production Request No. 1. Even Idaho Power recognizes that the requirement that "EnerNOC pays a penalty to Idaho Power" for failure to meet reduction targets is a large factor "enhancing the reliability of its commitments." *Id.* ICIP agrees, and submits that this model should be pursued in other programs.

For example, Idaho Power's 2009 IRP identified a distributed generation program that

6 The TRC ratio provided in the Company's DSM Report is 1.11, but that ratio is based on a 10-year contract life based on assumptions made initially by the Company. *See 2009 DSM Annual Report*, at p. 82; *2009 DSM Annual Report, Supplement 1: Cost-Effectiveness*, at p. 7. But these in initial assumptions underestimated the cost-effectiveness of this program in the initial year, and will likely do so as well for the 10-year contract life.

ICIP believes would be an excellent program for a third-party aggregator to implement and operate. The IRP included a distributed generation program that would use the backup diesel or natural gas generators of large power users as a peaking resource among the Company's "Committed Supply-Side Resources." *See 2009 IRP* at pp. 38-39, 71-75. Although not truly a DSM program, a standby generator distributed generation program is similar to DSM because it replaces the need to build new peaking generation resources. The availability of standby generators provides a basis for obtaining substantial spinning reserves, and thereby saves capital expenditures on peaking plants and offsets the need to purchase reserves elsewhere. The true value of this distributed generation program is its use as a reserve resource, not as a resource that generates substantial amounts of electricity, and although permitted and authorized to generate power up to 400 hours per year, under normal conditions the generators would rarely run. ICIP's position is that Idaho Power's program could easily reach 80 MW of backup peaking reserve requirements in the near future, an amount well within targets that Portland General Electric has set for its backup generator program. Idaho Power disagrees, and calculates the costs as being more expensive than other peaking resources. *See id.* The IRP states the Company has been investigating the merits of this program since before 2006, *see id.* at p. 38, yet Idaho Power still appears to be unable to render it cost-effective.

Given Idaho Power's difficulty in implementing this program, ICIP submits that Idaho Power should release a request for proposals similar to the EnerNOC/FlexPeak RFP to determine if a third-party entity with experience running distributed generation programs could operate Idaho Power's program more cost-effectively than Idaho Power states it could do so in its IRP. ICIP is aware that an EnerNOC affiliate company runs a very similar diesel generator distributed generation program for San Diego Gas and Electric, and the program, in addition to being a cost-effective alternative to new peaking resources, has garnered the support of environmental groups such as the Sierra Club. ICIP has attached (as Attachment 1) the Sierra Club California's letter to the California Public Utility Commission in support of expansion of the program to 50 MW, which explains the benefits well. For many of the same reasons cited by Idaho Power regarding the benefits of a third-party aggregator DSM program, a third-party run distributed generation program is likely to be successful. An aggregator such as EnerNOC will hit the ground running with experience, software, and marketing strategies from running similar programs elsewhere. An RFP would allow Idaho Power to more seriously pursue this peaking resource.

Another potential third-party aggregation program Idaho Power could pursue was recently discussed in the *New York Times*. *See* "To Cut Demand for Electricity, Some Customers Agree to Unplug," *New York Times* (Aug. 12, 2010), http://www.nytimes.com/2010/08/13/nyregion/13peak.html?hpw (Attachment 2 to these Comments). The article discusses the success of a third-party aggregator program directed at apartment buildings, and the parallels to the FlexPeak program are obvious. A third-party aggregator contacts the potential customer participants and helps them curtail non-essential electricity use at pre-determined times in exchange for payment from the utility. The Commission should encourage Idaho Power to implement the FlexPeak model in other customer classes, such as the multi-dwelling residential setting discussed in the *New York Times* article.

D. Idaho Power should rely more heavily on third-party evaluations of its DSM programs.

Third-party evaluations of the Company's programs provide an obvious benefit. Much like contracting with third-party aggregators, a well-chosen, third-party evaluator will have existing software, personnel, and experience in evaluating DSM programs, yet lack any incentive to portray the Company's DSM programs in an unjustifiably favorable light. Yet Idaho Power only uses "third-party evaluators when appropriate for the specific studies or evaluations." *See Application*, at ¶ 11(c). It is not clear what makes one program appropriate for a third-party evaluation from Idaho Power's application. At a minimum, Idaho Power should provide some set of criteria by which it will determine when it engages a third-party evaluator. As discussed above, the third-party evaluations have provided a candid review of the A/C Cool Credits program, and that evaluation should be used to improve the use of EE rider funds. Idaho Power cannot be expected to possess the motivation, let alone the expertise, to produce in-depth reviews of the impact of its DSM programs for use in prudency reviews.

Third-party evaluations are instrumental in determining which programs are succeeding, and which programs are failing and need to be improved or abandoned. The Commission should require Idaho Power to conduct more frequent third-party evaluations for more programs, or at a minimum require Idaho Power to set forth a standard set of criteria by which it will determine a given DSM program is not in need of third-party evaluation.

III

CONCLUSION

ICIP appreciates the opportunity to comment on Idaho Power's request for a prudency determination as to expenditure of EE rider funds spent in 2008 and 2009. ICIP respectfully requests that the Commission condition any finding of prudency of the expenditure of these funds on the additional requirements that Idaho Power abandon individual programs that fail to meet a total resource cost benefit ratio of 1.25 or greater once mature. ICIP additionally requests that the Commission order Idaho Power to abandon or modify the Holiday Lighting and A/C Cool Credits programs, encourage Idaho Power to use the FlexPeak program as a model for other programs which could be run with third-party aggregators, and order that Idaho Power rely more heavily on third-party evaluations in the future or at least provide criteria establishing when third-party evaluations are appropriate.

DATED this 13th day of September 2010.

RICHARDSON AND O'LEARY, PLLC

By: ______________________
for Peter J. Richardson
Gregory M. Adams
Attorneys for the Industrial
Customers of Idaho Power

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 13th day of September, 2010, a true and correct copy of the within and foregoing COMMENTS OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER, was served in the manner shown to:

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Nina M. Curtis

Nina M. Curtis

IPC-E-10-09

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A PRUDENCY DETERMINATION OF ENERGY EFFICIENCY RIDER FUNDS SPENT DURING 2008-2009

Comments of the Industrial Customers of Idaho Power
September 13, 2010

Attachment 1

Letter from Sierra Club California to California Public Utility Commission Supporting Third-Party Distributed Generation Contract

SIERRA CLUB
CALIFORNIA

August 17, 2009

Michael Peevey, Chair
California Public Utilities Commission
5th Floor
505 Van Ness
San Francisco, CA 94102

RE: Proposed Decision in A.08-10-003, Application of San Diego Gas & Electric Company (U902E) for Approval of the Celerity Distributed Generation Supply Contract

Dear Chair Peevey:

Sierra Club California objects to the Proposed Decision which would reject the San Diego Gas & Electric contract with Celerity. The proposal by SDG&E and Celerity is to retrofit diesel back-up generators (BUGs) at customer facilities so that those facilities could be used up to a maximum of 199 hours per year for grid reliability purposes.

It is our understanding that the project would add 25 megawatts (MWs) of new peak capacity, bringing the total San Diego BUGs program up to 50 megawatts. This new 25 megawatts of capacity would help meet the shortfall of 14 megawatts shown in the 2010 CAISO Local Capacity Requirements under operating Category C. (Decision 0906028). This decision noted:

> The San Diego area LCR need increased partly because of load growth and partly because of the new Otay Mesa generating facility becoming the biggest single generation contingency in the area. (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/102755-02.htm)

The Proposed Decision in A.08-10-003 rejects SDG&E's claim regarding need, stating that:

> By SDG&E's own assessment, the J-Power Grove project is expected to be in service in October of 2009, Wellhead Margarita is expected to be on-line in the latter half of 2009, Otay Mesa is expected to be in service in the summer of 2009 and the Lake Hodges pump storage facility will be on-line in early 2010.

However, the statement in this Proposed Decision about reduced need for new generation resource in San Diego due to Otay Mesa coming on line is inconsistent with the adopted final decision of the commission regarding resource adequacy cited above. In fact, as pointed out in that earlier decision Otay Mesa becomes the largest generator, and thus is *discounted in G-1/N-1 resource adequacy counting requirements*. Otay Mesa does not

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contribute toward resource adequacy, but actually helps to create the CAISO projected shortfall under Category C.

In addition, the generators cited above could be delayed, while the backup generators already exist. In fact, rapid and scaled deployment is a major benefit of distributed generation resources. And in particular it avoids the serious waste of capital resource on large central power plants and major new transmission lines that then become "discounted" under G-1/N-1 reliability criteria.

Sierra Club California is concerned that, by rejecting this contract, the Commission is discouraging the use of existing distributed generation resources for the purposes of meeting peak requirements or reliability needs and therefore, encouraging new, central-station peaking resources. Sierra Club California believes that that the alternative of building new central station peaking plants is less efficient, more costly and, ultimately, less beneficial for the environment. Sierra Club California therefore encourages the Commission to reconsider this position, and to reverse the Proposed Decision. Reversing the Proposed Decision will allow SDG&E to use BUGs, such as in the proposed Celerity contract.

Throughout California, over 3000 megawatts of back-up generators exist at customer sites, a valuable resource that is currently not utilized from the perspective of providing reliability and/or peaking benefits to the grid. Sierra Club California strongly supports the emissions restrictions that exist for unimproved back-up diesel generators. However, those BUGs can be retrofitted with particulate filters and re-permitted by the local Air Quality Management District (AQMD) as was done for the first SDG&E – Celerity agreement.

Reversing the Proposed Decision allows the local AQMD to permit increased hours of operation by BUGs with a net annual reduction in the emissions which concern the local AQMD. Specifically for the SDG&E – Celerity agreement, reversing the Proposed Decision, reduces annual particulate emissions, a significant environmental benefit relative to the BUGs current emissions without modern particulate filters. Our analysis is that under the likely range of operating condition, particulate emissions will be reduced compared to running these generators without filters for maintenance and occasional emergency outages. While these plants are permitted to run up to 200 hours per year, running over even 100 hours per year would only happen under very extraordinary circumstance.

The BUGs do not require new siting, construction and disturbance to a Greenfield site; they are distributed so as to provide local benefits that may obviate the need for costly transmission and/or distribution infrastructure. And the new infrastructure would likely only operate at about 1% annual capacity (100 hours/8760 hours), and in no case could operate at more than about 2% (200 hours/8760 hours). For resources that are used so little, far more carbon and other environmental impacts will be attributable to the infrastructure than to the fuel combustion itself. And while it is true that the diesel generators have a higher heat rate than a gas peaker, the marginal difference becomes insignificant when these are operated so few hours per year. Using existing backup generators would encourage more efficient use of existing resources, and would greatly reduce lifecycle emissions relative to the manufacture, transport, and construction of new centralized peakers.

So, while we are sympathetic with the Commission's desire to reduce the use of unimproved, diesel BUGs, the Sierra Club California recommends that BUGs, improved to meet the permit requirements of the local AQMD, be preferred to new central station peaker capacity in California when these would normally operate much less than 100 hours per year, and in no case can operate more than 200 hours per year.

We are also sensitive to the issue of fuel conversion cited in the Proposed Decision. However, we note that conversion to natural gas, while generally a much cleaner fuel than diesel, may not meet the requirements of site owners. However, a failure by the developer to convert fuels as originally proposed does not eliminate the benefits of adding filters to diesel generators. And it is very unlikely that these generators would switch to natural gas if the contract is denied.

The Proposed Decision would create a bias toward long-term commitments to new, fossil fuel, central-station peaking facilities, with associated costs, and environmental degradation. From a larger perspective, the use of existing, retrofitted, distributed generators can provide a better environmental solution. . As such, Sierra Club California requests that the Commission reject the Proposed Decision as written and approve the SDG&E request.

Respectfully,

Jim Metropulos
Sierra Club California

cc: Assigned Commissioner, John Bohn
President Michael Peevey
Commissioner Rachelle Chong
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Commissioner Dian Grueneich
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Karen Shea, Advisor

IPC-E-10-09

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A PRUDENCY DETERMINATION OF ENERGY EFFICIENCY RIDER FUNDS SPENT DURING 2008-2009

Comments of the Industrial Customers of Idaho Power
September 13, 2010

Attachment 2

"To Cut Demand for Electricity, Some Customers Agree to Unplug," *New York Times* (Aug. 12, 2010)

August 12, 2010

To Cut Demand for Electricity, Some Customers Agree to Unplug

By MATTHEW L. WALD

Electricity use is up sharply this summer, but in a windowless room near Albany that is the nerve center of New York State's grid, controllers have noticed that something else is not rising: peak load.

Peak load is the single hour of highest use in the course of the year, a condition for which the electric system is designed and which is the focus of utilities' operating strategies and, sometimes, prayers. Driven by each new air-conditioner, computer and flat-screen television, peak load grew inexorably from the 1980s until the recession.

But it has stopped its climb, and experts say more is at work here than the stalled economy.

Electricity experts compare July 2010 to August 2006, when New York State set its all-time peak demand, 33,939 megawatts. Energy consumption last month was 7.8 percent higher than in August 2006. But the peak demand was 1.4 percent lower.

(Last summer was relatively cool and did not yield high numbers for energy consumption or peak demand.)

There are several small reasons that consumption grows while peak load does not. One is weather patterns, the ratio of very hot days, which drive consumption, to extremely hot days, which drive peak. But another is man-made: "demand-side management," under which customers agree to unplug when controllers need them to.

When balancing electricity supply with demand, demand-side management is a huge weight on the scale on critically hot days.

From the fountain at Lincoln Center to the laundry room and swimming pool at the Gotham condominium building on East 87th Street to the elevators and loading dock lighting at 344 Hudson Street in Manhattan, things are being turned off when supply demands it.

The system controllers in Albany, at the New York Independent System Operator, now count about 37,400 megawatts of generators statewide that can be turned on, and about 2,200 megawatts of consuming devices that can be turned off.

This is not an emergency procedure or an appeal to civic duty — although those can still be invoked on occasion. Rather, it is a commercial transaction with a protocol planned long in advance. On the afternoon before an anticipated surge in demand, e-mails, faxes and phone calls go out alerting those who had already agreed that it is time for them to unplug.

"You get called a day ahead, and all hell breaks loose when they call," said Leo Cutone of Cutone & Company Consultants, which recruits buildings and institutions to participate. Common steps are adjusting air-conditioning thermostats, turning off some elevators, switching off lobby lights or starting up emergency generators.

"If it's nice and sunny enough, then the lobby is bright enough without artificial lighting," said Lewis Kwit of Energy Investment Systems, a company that serves as a "demand response service provider."

Mr. Kwit has lined up about 10 apartment buildings where superintendents will close the laundry room and post signs asking tenants to delay using their dishwashers until the early morning. "You can save 20 to 30 percent," he said.

Companies that recruit buildings or property owners to participate are paid by the New York Independent System Operator or by the local utility. The prices have been running $12 to $13 per kilowatt of reduction.

Alfonse Amore, the senior vice president at Trinity Real Estate, a property management company, said it enrolled 13 office buildings in the program this summer. Building personnel go from door to door asking tenants to turn off nonessential equipment.

“Tenants are fully aware of the problems with electrical distribution,” he said. “They want to continue in business without having a blackout or a brownout.” And they understand immediately when walking through a slightly darkened lobby, he said.

Trinity’s buildings have a collective load of 16 megawatts and can cut that by 2 megawatts, said Alec V. Salticov, the manager of engineering. Next summer, he will try for 3.5 megawatts, he said. The procedure was invoked by the grid operators three times in July, Mr. Salticov said.

Participants have meters with modems or other communications devices that report to a local utility four times an hour. For energy companies, demand-side management may help them avoid building power plants that would be needed only a few hours a year or transmission and distribution lines that would seldom be used to capacity. Trimming the peak load by a few percentage points means getting more use out of existing equipment.

In a place like New York, where getting permission to build a plant or power line is extremely difficult, energy experts say the strategy is especially valuable. And its effects are obvious at Consolidated Edison, said Joseph Oates, vice president of energy management.

Con Ed’s peak load growth had been 1.5 percent a year but will probably be only about 0.35 percent for the next few years, despite the proliferation of cheap air-conditioners and big-screen televisions. “We think it’s a permanent change,” he said.

Apart from the proceeds flowing to the demand response service providers and customers, the technique may also ultimately cut costs for nonparticipants. Electricity is priced in an auction system, and reducing demand reduces the price.