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December 22, 2010

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IDAHO PUBLIC
UTILITIES COMMISSION

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Case No. GNR-E-10-04
IN THE MATTER OF THE JOINT PETITION OF IDAHO POWER COMPANY, AVISTA CORPORATION, AND PACIFICORP DBA ROCKY MOUNTAIN POWER TO ADDRESS AVOIDED COST ISSUES AND TO ADJUST THE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP

Dear Ms. Jewell:

Enclosed for filing please find an original and seven (7) copies of the Comments of Idaho Power Company in the above matter.

Very truly yours,

Donovan E. Walker

DEW:csb
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE JOINT PETITION OF IDAHO POWER COMPANY, AVISTA CORPORATION, AND PACIFICORP DBA ROCKY MOUNTAIN POWER TO ADDRESS AVOIDED COST ISSUES AND TO ADJUST THE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP.	CASE NO. GNR-E-10-04 COMMENTS OF IDAHO POWER COMPANY

Idaho Power Company ("Idaho Power" or "Company"), by and through its attorney of record, Donovan E. Walker, and in response to the Notice of Modified Procedure issued in Order No. 32131 on December 3, 2010, respectfully submits the following comments.

I. INTRODUCTION

On November 5, 2010, Idaho Power Company, Avista Corporation, and PacifiCorp d/b/a Rocky Mountain Power ("the Utilities") filed a Joint Petition requesting the Idaho Public Utilities Commission ("Commission") to initiate an investigation into various avoided cost issues regarding the Public Utility Regulatory Policies Act of 1978 ("PURPA") Qualifying Facilities ("QF"). Additionally, the Utilities requested that the Commission issue an Interlocutory Order adjusting the published avoided cost rate eligibility cap for QFs from 10 average megawatts ("aMW") to 100 kilowatts ("kW") effective immediately.

On December 3, 2010, the Commission issued Notice of the Joint Petition and Notice of Modified Procedure, Intervention Deadline, and Oral Argument setting a Modified Procedure comment schedule with which to develop a record for its decision regarding the Joint Petition and Motion's request to lower the published avoided cost rate eligibility cap. Order No. 32131, Case No. GNR-E-10-04. Comments are due on December 22, 2010; Reply Comments are due January 19, 2011; and Oral Argument is scheduled for January 27, 2011. The Commission also ordered that its decision regarding whether to reduce the published avoided cost rate eligibility cap become effective on December 14, 2010. *Id.*, at 6-7. In that Notice, the Commission stated that it "will first take up the request to reduce the eligibility cap." *Id.*, at 5. The Commission set out three specific topics that it is interested in receiving comments upon:

> (1) the advisability of reducing the published avoided cost eligibility cap; (2) if the eligibility cap is reduced, the appropriateness of exempting non-wind QF projects from the reduced eligibility cap; and (3) the consequences of dividing larger wind projects into 10 aMW projects to utilize the published rate.

Id.

In these Comments, Idaho Power will address these three topics by submitting comments supporting the initial request to reduce the published avoided rate eligibility cap and seeking application of that published rate eligibility reduction to all PURPA QF projects.

II. BACKGROUND

Sections 201 and 210 of PURPA, and pertinent regulations of the Federal Energy Regulatory Commission ("FERC"), require that regulated electric utilities, such as Idaho Power, purchase power produced by cogenerators or small power producers that obtain QF status. 16 U.S.C. § 824a-3(a). The rate a QF receives for the sale of its power is generally referred to as the "avoided cost" rate and is to reflect the incremental cost to an electric utility of electric energy or capacity or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source. 16 U.S.C. §§ 824a-3(b), (d). The Commission has authority under PURPA Sections 201 and 210 and the implementing regulations of the FERC, 18 C.F.R. § 292, to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy from QFs, and to implement FERC rules. *See Connecticut Light and Power Co.*, 70 F.E.R.C. ¶ 61,012, 61,024 (1995).

Idaho Power has an obligation under federal law, FERC regulations, and this Commission's Orders, that it has not been relieved of, to enter into power purchase agreements with PURPA QFs. As stated in the Joint Petition filing, Idaho Power has received a large amount, in terms of both volume and megawatts ("MW"), of requests from PURPA QF developers demanding to enter into published avoided cost rate Firm Energy Sales Agreements ("FESA"). The Company continues to process these requests, in the ordinary course of business, and file the same for review with this Commission, as is its legal obligation. However, the continued and unfettered addition of PUPRA QF generation onto Idaho Power's system carries with it several negative and damaging effects to the both the utility and its customers on system reliability, utility operations, and the cost of providing energy to customers.

By lowering the published rate eligibility cap, the Commission would not be eliminating PURPA's requirement that utilities purchase power from QFs. It would simply be modifying the method in which the price, or avoided cost, is calculated and established for the QF. *See Southern California Edison Co.*, 70 F.E.R.C. ¶ 61,215, 61,677 (F.E.R.C. 1995) (FERC "has not, and does not intend in the future, to second-guess state regulatory authorities' actual determinations of avoided costs (i.e. whether the per unit charges are no higher than incremental costs)."). Despite what some may argue, PURPA is not meant to incent renewable energy projects with the price that is paid to a QF. In fact, an incentive price for QFs is illegal under PURPA, as PURPA requires prices to be set at the utility's avoided cost, which is to reflect the incremental cost to an electric utility of electric energy or capacity or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source. *See Independent Energy Producers Association v. California Public Utilities Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere."). The incentive to QF development from PURPA is therefore not in the price that a QF is entitled to but in the fact that the utility is required to contract with the QF. *See* 16 U.S.C. § 824a-3(a). Consequently, there is nothing in the request to reduce the published rate eligibility cap that is offensive to the "purpose" of PURPA. It is an action that is clearly within the authority and discretion of the Commission, as it is the body charged with implementing the requirements of PURPA and establishing each utility's avoided cost.

Lowering the published rate eligibility cap to 100 kW would essentially require all PURPA QF contracts to be individually negotiated with an individually determined price based upon that project's specific operating profile. This Integrated Resource Plan-("IRP") based methodology for individually negotiated rates and contracts is a better model with which to address the difficult issues raised by this case and a means to possibly arrive at creative solutions that will still allow the development of QF projects, but in a manner that is better for customers and better for the utilities in that the price would better reflect a value equivalent to that which the Company would receive if the utility were to generate itself or purchase from another source. The recently approved Rockland Wind Project FESA is a good example of this process and how it can result in a project that is both feasible for the developer and more favorable to Idaho Power customers than a project under the more prescriptive Surrogate Avoided Resource ("SAR") methodology.

PURPA requires that utility customers be economically indifferent to the effects of whether power is purchased from a QF or otherwise acquired (generated or purchased) by the utility. *Southern California Edison Co.*, 71 F.E.R.C. P 61,269, 1995 WL 327268 (F.E.R.C. 1995) ("The intention [of PURPA] was to make ratepayers indifferent as to whether the utility used more traditional sources of power of the newly-encouraged alternatives."). When the utility is forced to buy QF power in excess of its true avoided cost, or in excess of its minimum loads, customers are no longer indifferent. The issues raised in this docket should be addressed by the Commission at this time and not after the impacts on customers have become inevitable and acute.

As recently as November 2, 2010, in the Yellowstone Power case, the Commission reiterated to Idaho Power that, "we intend for the Company to assist the Commission in its gatekeeper role of assuring that utility customers are not being asked to pay more than the Company's avoided cost for the QF contracts. We expect Idaho Power to rigorously review such contracts." Order No. 32104. Even though Idaho Power is legally obligated to continue to negotiate, execute, and submit PURPA QF contracts for Commission review, it also feels obligated to call attention to several problems with the current methodology: (1) the continuing and unchecked requirement for the Company to acquire additional intermittent and other QF generation regardless of its need for additional energy or capacity on its system or the availability of other lower cost resources; (2) circumvention of the IRP process; (3) system reliability and operational issues; and, most importantly, (4) it dramatically increases the price that customers must pay for their energy needs beyond that which would otherwise be considered prudent.

III. THE ADVISABILITY OF REDUCING THE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP

In the Joint Petition, Idaho Power stated that today it has over 208 MW of wind generation currently operating on its system with an additional 264 MW of Commission-approved QF wind contracts, many of which are currently under construction and scheduled to be on-line by December 31, 2010. Additionally, the Company stated that it had 80 MW of QF wind pending approval at the Commission and over 570 MW of new

QF wind contract requests for a total of over 1,100 MW of wind powered generation potentially entering Idaho Power's system in the near term.

Since the November 5, 2010, Joint Petition filing, the Commission has approved the 80 MW of wind generation that was pending and Idaho Power has filed 23 signed PURPA contracts with the Commission for review which represent over 450 MW of wind generation (twenty contracts) and about 12 MW of non-wind generation (three contracts). To update the numbers from the Joint Petition, as of December 20, 2010, Idaho Power has over 326 MW of wind on-line, over 678 MW of signed QF contracts for wind, and another 162 MW in contract discussions – which totals over 1166 MW of wind. *See* Attachment No. 1 (Wind Project Summary) and Attachment No. 2 (showing all PURPA QFs). Attachments Nos. 1 and 2 itemize the wind and all-source QF generation that is currently on-line, pending Commission decision, or in contract negotiations.

The additional 678 MW of signed QF wind contracts that have been submitted to the Commission represent a total payment amount of over $3.9 billion over the 20-year term of the agreements. This estimate was calculated assuming a 2011 on-line date and an average annual capacity factor of 32 percent. The 162 MW of wind generation currently under contract discussions represents an additional total payment of over $932 million based on the same assumptions. For comparison, Idaho Power's total approved rate base is just over $2 billion.

Idaho Power is deeply concerned with the increase in power supply costs due to these contracts, and the resulting increase in rates to its customers, that the current published avoided cost, SAR methodology, causes. The Company projects that with the current amount of QF wind under contract and in contract discussions at published avoided cost rates assumed to be at 614 MW, that customers will face an additional cost averaging in excess of a $48 million PURPA premium above other, lower cost resources through at least 2020. This equates to an approximate 5 percent rate increase in the Company's Power Cost Adjustment ("PCA").

A. Approved Avoided Cost Methodologies – The Surrogate Avoided Resource and the IRP-Based Approach.

The Commission has authorized two methods for establishing the avoided cost rate that a QF is entitled to receive in its FESA with an Idaho utility. One method is applicable to those QFs that generate less than 10 aMW on a monthly basis. This method establishes the published avoided cost rate, and is set by the Commission using the cost of a SAR. The current SAR is a natural gas-fired combined-cycle combustion turbine. The other method is applicable to QFs that are larger than 10 aMW or, in other words, will generate in excess of 10 aMW on a monthly basis. This method is generally referred to as the IRP-based methodology. In the IRP-based methodology, the QF's generation profile is utilized with the utility's power supply modeling program to establish a base price for the QF's generation. Adjustments to that base price, if any, are based upon a project's individual characteristics and are separately considered by the Commission.

In Order No. 30873, the Commission described how the SAR methodology has evolved over time. In fact, it was just over thirty years ago, on August 8, 1980, when the Commission issued its first order, Order No. 15746, establishing the principles applicable to purchases of power from PURPA QFs. In Order No. 15746, the Commission determined that each of the three utilities would use a hypothetical baseload coal-fired generating plant as the generation facility that could be deferred or avoided. As such, the cost of this coal-fired facility would be used to set avoided cost rates. In 1993, Case No. IPC-E-93-28, the Commission concluded that the avoidable resource or SAR should no longer be a coal-fired generating plant but instead should be a natural gas-fired combined-cycle combustion turbine.

The more prescriptive SAR-based published avoided cost methodology was developed and intended for smaller projects and the more unsophisticated developers in part to ease the administrative burden on the developer and to "level the playing field" in negotiating the economic components of a QF contract. This concept, which has its inception in the Commission's 1980 Order, dates back to the infancy of the Public Utility Regulatory Policies Act of 1978. This concept was accepted and/or tolerated in order to accommodate small QF developers because historically (1) small QF developers generally had fewer resources to dedicate to complex contract negotiations and (2) the financial impact to the utility's customers for a relatively low volume of small QF projects was likewise small.

However, in the passage of the last thirty years, the size and scale of projects that are able to qualify for the published avoided cost rates has increased dramatically. Many of the current QF projects in actuality are not "small" projects but are large, utility-scale projects that are broken up into 10 aMW increments in order to qualify for the published avoided cost rates. Likewise, the historical "unsophisticated" QF project developers are no longer the norm, and QF projects have evolved to the point where they are sophisticated parties who are very knowledgeable within this field. In fact, in many instances, QF developers have large resources available to them and in some cases may be larger entities than the utilities themselves.

B. Problems with the SAR Methodology.

The SAR methodology currently used in the calculation of the avoided cost rates paid to QFs is a generic calculation which has at least three specific problems associated with it. First, the SAR methodology does not represent the actual costs avoided by adding a specific PURPA resource to Idaho Power's resource portfolio. A system specific analysis, such as the IRP-based methodology, that considers the characteristics of the specific resource under question is necessary to determine a more accurate assessment of the costs avoided as a result of adding a specific PURPA resource. A true avoided cost determination, which would be appropriate for renewable projects that generate renewable energy certificates ("RECs"), would consider the cost to the utility to develop and operate a similar project over a 20-year period. This would take into account the RECs, government tax incentives, accelerated depreciation allowances, and other similar cost incentives that the utility, and its customers, would have the advantage of if the utility were to build the resource, and that currently generate a double recovery windfall to the QF developer.

Second, the SAR methodology is essentially a static methodology. The published avoided cost rates calculated with the SAR methodology are updated infrequently at best; yet the power markets, natural gas costs, resource construction and development costs, government tax incentives, and other costs can vary on a day-to-day basis. The SAR methodology essentially gives PURPA developers a free option to force a QF's output onto the utility at the published avoided cost rate. When it becomes profitable for PURPA developers to develop their projects, regardless of whether Idaho Power needs the project's output and regardless of the cost impacts on existing customers, they proceed with development and exercise their option to "put" the project's output to Idaho Power.

Third, all PURPA resources are not equivalent. *See e.g.*, 18 C.F.R. § 292.304(c)(3)(ii) (avoided costs may "differentiate among [QFs] using various technologies on the basis of the supply characteristics of the different technologies."). In other words, two different resources under similar FESAs at the published avoided cost rate can provide significantly different levels of value to Idaho Power's customers – *cost* and *value* are two very different things. For example, a high capacity factor QF such as a biomass project which produces a significant amount of light load energy and a solar project which produces little, if any, light load energy, can bring significantly different levels of value to a utility's system and its customers. If the utility is surplus during light load hours, then a significant portion of energy produced by any QF during light load hours will need to be sold into the market – most likely at a significant loss.

Idaho Power is concerned about any new PURPA projects and their associated impact on customers. However, PURPA wind projects in particular present a number of challenges, not only because of the unique nature of their generation but also because of the magnitude and volume of proposed QF wind projects, that require a closer examination to determine the real costs associated with adding these resources.

C. **Circumvention of the IRP Planning Process.**

The IRP planning process conducted by Idaho Power is designed to determine the best mix of resources needed to meet future load growth considering cost, risk, and environmental concerns. This process was established in the early 1990s and has evolved over the years to include significant input from stakeholders, including major customer representatives, government agencies, environmental groups, and the general public. The current state of PURPA development in Idaho has created a situation where the IRP planning process is being circumvented in order to benefit independent developers wanting to build generation projects in Idaho Power's service area.

The recent flood of PURPA wind projects in Idaho Power's service area will put the total amount of wind generation on Idaho Power's system over 1,100 MW. In order to integrate this amount of wind generation, the IRP process will need to focus solely on dispatchable resources (such as natural gas-fired combustion turbines) that can provide operating reserves necessary to integrate wind.

For the past several years, Idaho Power's resource planning needs have been driven by summertime peak-hour loads. This has been demonstrated with the addition of approximately 430 MW of dispatchable simple-cycle combustion turbines, development of Langley Gulch to add approximately 300 MW of dispatchable combined-cycle combustion turbine capacity, and demand response programs (i.e., Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management programs), focused on reducing summertime peak-hour loads. Wind resources are not a dispatchable resource and the Company cannot depend on serving any significant portion of peak-hour summertime loads with wind resources. At present, for planning purposes, Idaho Power uses a 5 percent capacity expectation for wind resources. So, for each 100 MW of nameplate wind generation in its resource portfolio, Idaho Power plans on receiving 5 MW during the summertime peak-hour load. Actual performance of the wind projects under contract to Idaho Power during the summer of 2010 suggests that a 5 percent capacity expectation is accurate.

While a majority of the new developments being proposed are wind projects, many of the current issues surrounding PURPA are relevant to all generation technologies that can be certified as a QF under the rules of the FERC. When the Public Utility Regulatory Policies Act of 1978 was enacted, it was envisioned as a way to allow small, renewable projects to be developed, projects that would be considered too small by utility standards. *See e.g.*, *Southern California Edison Co.*, 71 F.E.R.C. P 61,269, 1995 WL 327268 at *6 (F.E.R.C. 1995) (Congress intended PURPA to diversify generation fuel mix and encourage renewable technologies). The concept of avoided cost rates was used to ensure the cost to customers was no more than a utility's cost to develop a larger project. *Id.* However, the quantity of PURPA development currently being seen in Idaho was never contemplated when the PURPA rules were establish by the Commission. The current avoided cost rates, combined with tax credits and other incentives, have created a situation where independent developers can easily justify the economics of (and finance) PURPA projects. The economics are in fact so favorable developers are taking utility scale projects and breaking them into smaller than 10 aMW projects in order to qualify for avoided cost rates. The result is that the Company's extensive IRP process, which is mandated and overseen by the Commission, is being circumvented by the current Idaho requirements of PURPA. The least cost planning aspects of the IRP process are also being circumvented in the process. The flood of PURPA projects onto the Company's system is now dictating the resource "choices" in the IRP planning process, and ultimately causing a dramatic increase in the price Idaho Power's customers must pay for their energy needs.

D. <u>PURPA QF Generation is Provided When it is Not Needed</u>.

While the Company does not dispute the value of having a diversified resource portfolio, there are costs that need to be considered, especially when contracting for resources that are not well matched to the system need. Idaho Power typically has much more energy than it has load to serve, it is surplus during light load ("LL") hours. Information contained in the November 2010 Operating Plan, shown in Figure 1 and 2 below, illustrates this point.

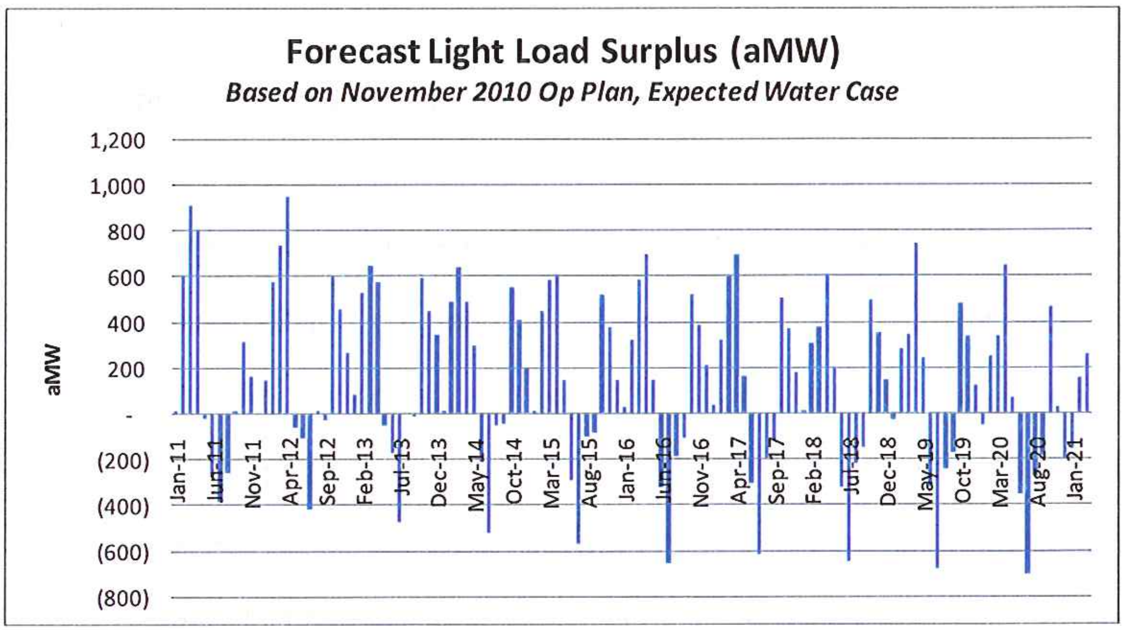

Figure 1

If the above light load surplus/deficit positions are averaged by year, under expected water conditions, Idaho Power has more light load energy than it currently needs to serve forecasted load. (*See* Figure 2 below.)

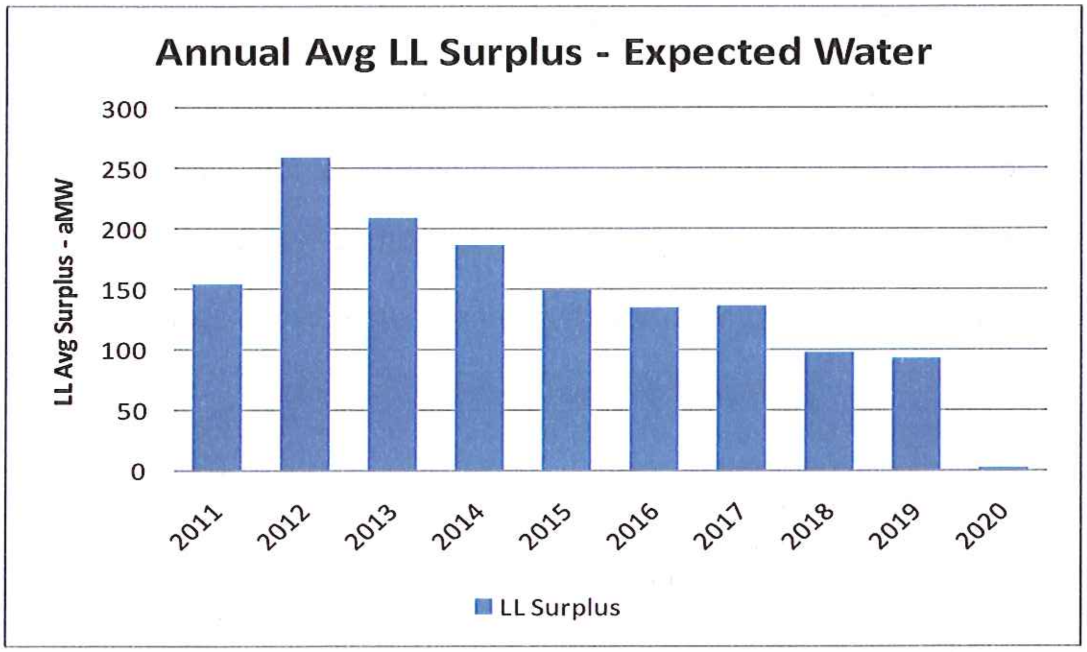

Figure 2

Additionally, and cumulatively, the generation profile of wind on Idaho Power's system typically delivers a significant amount of its generation during light load hours.

If the characteristics of a project are such that (1) the Company cannot plan on the project producing when it is needed, (2) the project produces variable amounts of energy when the Company typically does not need it, (3) the project does not provide any RECs, and, finally, (4) customers are paying more for these projects than the current market prices for firm energy products, it becomes clear that customers are not held indifferent to the effects of adding QF generation to the system. The Commission should therefore consider how large of a premium customers pay and to what extent customers are damaged because of the addition of QF generation.

E. <u>PURPA QF Generation Causes Significant Operational and Reliability Issues</u>.

Based on 2009 and 2010 data, Idaho Power's minimum hourly average load during the year is slightly over 1,000 MW. During 2009, the minimum hourly average load was 1,030 MW, recorded on April 13, 2009. During 2010, the minimum hourly average load to date is 1,033 MW, recorded on May 31, 2010. Using the minimum hourly loads recorded during 2009 and 2010 as proxies for future minimum loads, data from the November 2010 Operating Plan and the 2009 IRP can be used to estimate the system surpluses when various combinations of resources are in operation.

Sample Surplus Calculation for April		
Minimum Load	(1030)	MW
LL Hydro generation	1,037	MW
LL Thermal generation	657	MW
LL CCCT generation (Langley)	-	MW
LL Clatskanie exchange	12	MW
LL Cogeneration and small PP	209	MW
LL Elkhorn generation	35	MW
LL Geothermal generation	30	MW
Surplus	949	MW
Adder for a max wind event	952	MW
Potential surplus with a max wind event	1,901	MW
Reduce coal-fired generation to minimums	(312)	MW
Reduce Brownlee & Oxbow generation to zero	(510)	MW
Resulting Surplus after above actions	1,079	MW

At a typical annual minimum load level of 1,030 MW occurring during April, the Company could be 949 MW surplus during that hour. A 949 MW surplus is a large amount of energy to be moving off the Company's system and selling into the market; yet if a "max wind" event occurred, the surplus position could get much worse. A "max wind" event could add more than 952 MW to the surplus. This would increase the surplus to over 1,900 MW. If the Company were able to reduce its share of output from the coal-plants to their operational minimums, and reduce Brownlee and Oxbow generation to zero (which is an unrealistic expectation), it would still have a surplus of almost 1,100 MW. Coal cannot be taken down past minimum levels without shutting down or being unavailable to serve load the next day or for the next peak hour. Similarly, hydro cannot be taken to zero given minimum stream flow levels and resultant environmental effects.

This surplus electricity, if it cannot be used to serve Idaho Power load, must be moved across the system and sold into the market. The only available transmission capacity to move this electricity off the system and to market is across the Idaho to Northwest path. Idaho to Northwest transmission capacity has an operating rating of 2,304 MW and PacifiCorp has rights to up to 1,600 MW of that amount. That leaves Idaho Power with a maximum of 704 MW of transmission capacity to the Northwest, under normal operation conditions, which is insufficient to move the amount of surplus that could exist.

F. The Continued Addition of QF Generation at Published Avoided Cost Rates is Very Costly to Customers.

Assuming that all of the integration costs have been addressed, the fact of the matter is that if 614 MW of the QF contracts currently submitted for review to the Commission or in contract discussions at published avoided cost rates are approved, and if all of the PURPA wind under contract is built, Idaho Power will be purchasing the output of these projects at prices significantly greater than recent, and expected, market prices. Figure 3 below shows the average light load surplus from Figure 2, and superimposes curves representing the non-levelized PURPA rates during LL hours and recent Mid-C market prices. This illustrates the premium being paid for QF energy over market prices at a time when the Company does not need the energy.

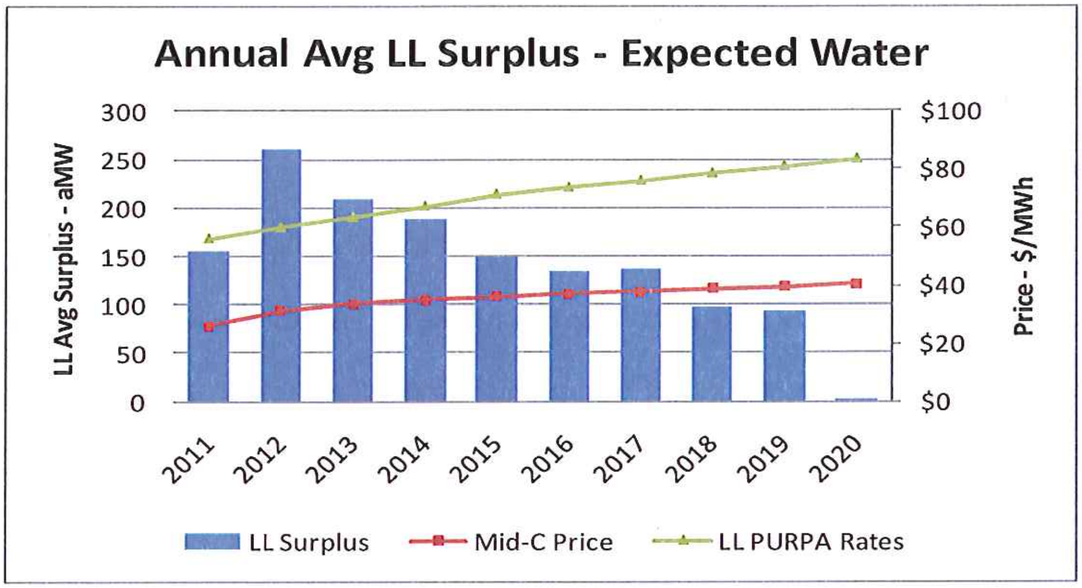

Figure 3

Between 2011 and 2020, current light load PURPA rates are approximately $35/MWh higher than November Mid-C light load forward market prices. In fact, with the amount of wind generation recently added in the region, light load prices have on occasion actually gone negative. This relationship of paying more than market prices is not just limited to light load hours. Customers also pay a premium over market for heavy load energy hours. Over the same period, current heavy load PURPA rates are approximately $25/MWh higher than November Mid-C heavy load forward market prices. If the 614 MW of PURPA wind contracts submitted for review or under discussions were to produce at a 30 percent capacity factor, they would generate about 1.5 million megawatt-hours ("MWh") per year. If Idaho Power is purchasing this energy, energy that it really does not need, at a $30/MWh premium to market, customers incur an additional cost of $48 million/year – and they end up with an energy product that is inferior, at least from a planning and scheduling perspective, to a standard firm market purchase. The net present value of the above-market cost, for the period of 2011 through 2020 (assuming all projects are on-line and operating in 2011), of entering into these QF contracts is over $325 million. These calculations do not include transmission costs, which may actually increase the cost to customers even more. The bottom line is that these QF contracts are far more costly to customers than would be suggested by recent Mid-C prices.

An additional $48 million in above-market costs equates to a rate increase of around 5 percent in the Company's PCA. It is difficult to see how the customers are held neutral, or indifferent, with a requirement to enter into FESAs, at above-market prices, for power that is not needed on the system and also withholds the value that could be derived from the RECs.

IV. THE APPROPRIATENESS OF EXEMPTING NON-WIND QF PROJECTS FROM THE REDUCED ELIGIBILITY CAP

The second issue that the Commission requested comments upon is "if the eligibility cap is reduced, the appropriateness of exempting non-wind QF projects from the reduced eligibility cap." Order No 32131 at 5. All PURPA QF projects should be included in the published avoided cost rate eligibility cap reduction for the simple reason that they all contribute to the same problems discussed above. All QFs generate during light load hours and contribute to the price and cost differentials already discussed. The lack of any consideration of the utility's need for the energy, or load, in relation to when the QF supplies generation that the utility must take from it does not change because the QF is a non-wind resource.

Additionally, as stated above, the more prescriptive SAR-based published avoided cost methodology was developed and intended for smaller QF projects and the more unsophisticated developers in part to ease the administrative burden on the developer and to "level the playing field" in negotiating the economic components of a QF contract. This concept was accepted and/or tolerated in order to accommodate small QF developers because historically (1) small QF developers generally had fewer resources to dedicate to complex contract negotiations and (2) the financial impact to the utility's customers for a relatively low volume of small QF projects was likewise small. However, this is no longer the case. The historical "unsophisticated" QF project developers are no longer the norm, and QF projects have evolved to the point where they are sophisticated parties who are very knowledgeable about the ups and downs of the PURPA process as well as negotiation of a QF contract. Likewise, with the cumulative nature of more than thirty years of QF projects entering onto the system, as well as the more recent phenomenon of larger and larger projects that are able to break themselves into 10 aMW increments, it can no longer be said that the financial impact to the utility's customers from any QF project, no matter how small, has a "small" impact to the rates that they pay for electricity.

While the scale of wind QFs is much larger, many of the same problems are, and the same financial harm is, caused by non-wind QFs just the same. A reduction in the published rate eligibility should apply equally to all QF projects.

V. THE CONSEQUENCES OF DIVIDING LARGER WIND PROJECTS INTO 10 aMW PROJECTS TO UTILIZE THE PUBLISHED RATE

The third issue that the Commission requested comments upon is "the consequences of dividing larger wind projects into 10 aMW projects to utilize the published rate." Order No. 32131 at 5. There are many negative consequences, some of which have already been referred to above, of the ease and ability of large QF projects, particularly large wind farms, to break themselves up into 10 aMW increments in order to qualify for the published avoided cost rate ("disaggregate" or "disaggregation") and avoid the individualized IRP-based methodology that is supposed to be applied to "larger" QF projects. Many of the "problems" discussed above are the "consequences" of these larger projects' ability to divide into 10 aMW increments. It is especially beneficial to an intermittent resource that provides a significant portion of energy primarily during light load times, or more particularly outside of the system peak hours to have a locked-in price that does not take into account the value of the energy that it provides, the need for the energy during the time in which it is provided, nor the availability of lower cost resources. This ultimately results in the most serious consequence of dramatically inflating the cost of power and the rates that customers must pay. Additionally, this ability to disaggregate compromises a utility's competitive acquisition processes in the form of requests for proposals ("RFP").

The Company has seen the issue of disaggregation as a potential problem for a number of years, and attempted to address the same in Case No. IPC-E-07-04. In that case, the Company proposed a five mile separation, rather than the currently accepted one mile separation required by FERC to be certified as a QF, between QF projects in order for the projects to be considered separate and distinct QFs. This was rejected by the Commission Staff and ultimately the Commission. Order No. 30415. The Commission stated:

> The Company asks the Commission to impose an ownership restriction on projects located within what we find to be an arbitrary "five-mile radius." This would be in addition to the geographic separation required by FERC for QF status. While it may be that it is "not Idaho Power's intent that its proposed five mile radius rule place undue burdens on the development of new QF generation projects," we cannot find that without change abuse will occur and the public interest

> will not be served. Petition, p. 5. It is a change that we find would encourage and might actually promote gamesmanship. On the basis of the established record we find no reason to change the eligibility criteria for published rates to require a standard different than FERC QF status requirements.

Order No. 30415 at 11.

Since the time of the Commission's Order No. 30415, issued on September 7, 2007, the norm for PURPA wind projects has been to take larger QF projects, create multiple legal entities, and reconfigure into multiple smaller projects in order to qualify for the published avoided cost rate and to avoid the more precise and individualized IRP-based methodology. In fact, the great majority of all QF wind projects follow just this type of development model. As can readily be seen by even a cursory look at Attachment No. 1, the list of all of the existing and proposed QF wind projects for Idaho Power's system, as well as a review of Attachment No. 3, which is a map showing the general location of these QF wind projects, nearly all of them are disaggregated large-scale projects that should be negotiating PURPA contracts under the IRP-based methodology.

Additionally, a slightly closer look at the last twenty QF wind contracts that have been filed for review with the Commission since November 2010 shows that these twenty, less than 10 aMW, published rate projects all belong to just four different developers and ultimate owners – and are physically located in only five different locations. They are large projects, and are disaggregating with the purposeful intent of gaining access to the published avoided cost rates and avoiding the IRP-based methodology. This practice is inflating the cost borne by Idaho Power's customers and providing an energy product that is not only not needed on the system but causes additional problems for reliability and operations.

Another significant fact about the large group of these most recently proposed QF wind projects is that the overwhelming majority (nearly all) of them were proposed projects in the unsuccessful 2012 wind RFP issued by Idaho Power in 2009, which Idaho Power recently concluded without awarding a contract. In the RFP, Idaho Power received bids from 25 projects, or project configurations, from 14 different bidders. The proposed projects ranged in size from 50 MW to 160 MW. The bids included projects in Idaho, Utah, Wyoming, Montana, Washington, and Oregon. The 20-year levelized prices ranged from approximately $85 per MWh to almost $150 per MWh. Many of these projects have reconfigured to disaggregate into 10 aMW projects, and have demanded and executed published rate QF contracts at the equivalent of a 20-year levelized price of $82.38 per MWh (if the project came in during 2011). This is gamesmanship to the detriment of Idaho Power and its customers.

While the Company believes that a change in the required separation between QF projects still has some merit, the request to lower the published rate eligibility cap accomplishes a similar result from a somewhat different and better approach. By lowering the cap, the IRP-based methodology that previously only applied to larger QF projects over 10 aMW would now apply to essentially all QF projects and remove the incentive to break up larger projects to technically meet one mile of separation because there would no longer be a disparate price advantage, either real or perceived, in doing so. The issue of disaggregation would no longer be an issue because all wind projects would have to negotiate an individually priced contract under the proper IRP-based methodology meant to apply to the acquisition of the resources they are selling. A "truer" avoided cost could be sought and the individual characteristics and uniqueness of these larger projects could better be taken into consideration, as was the intent of the IRP-based methodology for larger projects.

VI. CONCLUSION

There is a huge problem here. The great advantages that Idaho Power customers, its service territory, and its region enjoy from consistently having among the very lowest electricity prices in the nation are being eroded and eviscerated by a flood of QF generation that we are paying too much for. Idaho Power is forced to purchase this power with no regard to whether it is needed on its system, with no regard to whether it is called for in the Company's IRP process, and with no regard to whether there are other lower cost alternatives for its customers. Additionally, the Company is forced to deal with the difficult tasks and problems associated with integrating large amounts of intermittent and uncertain renewable generation into its system, once again with its customers paying the resulting price. Customers do not even get the "benefits" derived from the renewable aspects of that generation in the form of RECs, nor is the Company even able to "claim" or get credit for the existence of that renewable energy on its system.

The Company does not expect the parties, nor the Commission, to solve all of the issues or problems identified with avoided costs and QF generation at this moment. However, we are fortunate that an existing, approved avoided cost methodology, the IRP-based methodology, exists and, as demonstrated herein, is a very reasonable method for addressing some of the most pressing problems raised in this proceeding while these important issues are considered by the parties and the Commission.

Idaho Power respectfully urges the Commission to reduce the published avoided cost rate eligibility cap for PURPA QFs from 10 aMW to 100 kW.

DATED at Boise, Idaho, this 22nd day of December 2010.

DONOVAN E. WALKER
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 22nd day of December 2010 I served a true and correct copy of COMMENTS OF IDAHO POWER COMPANY upon the following named parties by the method indicated below, and addressed to the following:

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Donovan E. Walker

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-10-04

IDAHO POWER COMPANY

ATTACHMENT NO. 1

Wind Project Summary
As of December 20, 2010

Online	MW	State	Type	Initial Developer	Owner	Location	On-line Date	CSPP Forecast
Fossil Gulch	10.50	ID	PURPA	Exergy	Fossil Gulch Wind Park	Hagerman, Idaho	Sep-05	Yes
Horseshoe Bend	9.00	MT	PURPA	Exergy	United Materials of Great Falls, Inc.	Great Falls, Montana	Feb-06	Yes
Elkhorn	100.65	OR	PPA	Horizon	Telocaset Wind Power Partners	North Powder, Oregon	Dec-07	No
Bennett Creek	21.00	ID	PURPA	John Deere	Bennett Creek Wind Farm	Mountain Home, Idaho	Dec-08	Yes
Hot Springs	21.00	ID	PURPA	John Deere	Hot Springs Wind Farm	Mountain Home, Idaho	Dec-08	Yes
Cassia Wind	10.50	ID	PURPA	John Deere	Cassia Wind Farm	Hagerman, Idaho	Mar-09	Yes
Tuana Springs Expansion/Cassia Gulch	35.70	ID	PURPA	John Deere	Cassia Gulch Wind Park	Hagerman, Idaho	May-10	Yes
Milner Dam	19.92	ID	PURPA	Exergy	Milner Dam Wind Park	Burley, Idaho	Dec-10	Yes
Burley Butte	21.30	ID	PURPA	Exergy	Burley Butte Wind Park	Burley, Idaho	Dec-10	Yes
Golden Valley	12.00	ID	PURPA	Exergy	Golden Valley Wind Park	Burley, Idaho	Dec-10	Yes
Camp Reed	22.50	ID	PURPA	Exergy	Camp Reed Wind Park	Hagerman, Idaho	Dec-10	Yes
Payne's Ferry	21.00	ID	PURPA	Exergy	Payne's Ferry Wind Park	Hagerman, Idaho	Dec-10	Yes
Yahoo Creek	21.00	ID	PURPA	Exergy	Yahoo Creek Wind Park	Hagerman, Idaho	Dec-10	Yes
Total	**326.07**							

Signed Contracts (Not Yet Online)	MW	State	Type	Developer	Owner	Location	First Energy Date	Operation Date		CSPP Forecast
Lava Beds	18.00	ID	PURPA	Exergy	Lava Beds Wind Park	Taber, Idaho (Blackfoot)	Jul-11	Jul-11	*	Yes
Magic Wind	19.50	ID	PURPA	Exergy	Magic Wind	Hagerman, Idaho	Jul-11	Jul-11	*	Yes
Notch Butte	18.00	ID	PURPA	Exergy	Notch Butte Wind Park	Jerome, Idaho	Jul-11	Jul-11	*	Yes
Oregon Trail	13.50	ID	PURPA	Exergy	Oregon Trail Wind Park	Hagerman, Idaho	Dec-10	Dec-10	*	Yes
Pilgrim Stage Station	10.50	ID	PURPA	Exergy	Pilgrim Stage Station Wind Park	Hagerman, Idaho	Dec-10	Dec-10	*	Yes
Rockland Wind	80.00	ID	PURPA	Ridgeline Energy	Ridgeline Energy	American Falls, ID	Jul-11	Dec-11	*	Yes
Salmon Falls	21.00	ID	PURPA	Exergy	Salmon Falls Wind Park	Hagerman, Idaho	Dec-10	Dec-10	*	Yes
Sawtooth	21.00	ID	PURPA	Idaho Winds	Idaho Winds	Mountain Home, Idaho		Dec-12	*	Yes
Thousand Springs	12.00	ID	PURPA	Exergy	Thousand Springs Wind Park	Hagerman, Idaho	Dec-10	Dec-10	*	Yes
Tuana Gulch	10.50	ID	PURPA	Exergy	Tuana Gulch Wind Park	Hagerman, Idaho	Dec-10	Dec-10	*	Yes
Cold Springs	20	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Two Ponds	20	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Ryegrass	20	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Mainline	20	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Desert Meadow	20	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Hammett Hill	23	ID	PURPA	Glen Ikemoto	Idaho Windfarms	Mountain Home, ID	Dec-11	Dec-12	*	No
Murphy Flat Energy	20	ID	PURPA	Brian Jackson	Brian Jackson	Murphy, ID	Dec-11	Dec-12	*	No
Murphy Flat Mesa	20	ID	PURPA	Brian Jackson	Brian Jackson	Murphy, ID	Dec-11	Dec-12	*	No
Murphy Flat Wind	20	ID	PURPA	Brian Jackson	Brian Jackson	Murphy, ID	Dec-11	Dec-12	*	No
Rainbow Ranch Wind	20	ID	PURPA	Brian Jackson	Brian Jackson	Declo, ID	Dec-11	Dec-12	*	No
Rainbow West Wind	20	ID	PURPA	Brian Jackson	Brian Jackson	Declo, ID	Dec-11	Dec-12	*	No
Cottonwood Wind Park	20	ID	PURPA	Exergy	Exergy	Twin Falls, ID	May-11	Dec-11	*	No
Deep Creek Wind Park	20	ID	PURPA	Exergy	Exergy	Twin Falls, ID	May-11	Dec-11	*	No
Rogerson Flats Wind Park	20	ID	PURPA	Exergy	Exergy	Twin Falls, ID	May-11	Dec-11	*	No
Salmon Creek Wind Park	20	ID	PURPA	Exergy	Exergy	Twin Falls, ID	May-11	Dec-11	*	No
Alpha Wind	30	ID	PURPA		Cotterel WindEnergy	Burley, ID	Oct-14	Dec-14	*	No
Bravo Wind	30	ID	PURPA		Cotterel WindEnergy	Burley, ID	Oct-14	Dec-14	*	No
Charlie Wind	28	ID	PURPA		Cotterel WindEnergy	Burley, ID	Oct-14	Dec-14	*	No
Delta Wind	30	ID	PURPA		Cotterel WindEnergy	Burley, ID	Oct-14	Dec-14	*	No
Echo Wind	30	ID	PURPA		Cotterel WindEnergy	Burley, ID	Oct-14	Dec-14	*	No
Lime Wind	3	OR	PURPA	Randy Joseph	Randy Joseph	Oregon	Oct-11	Dec-11	*	No
Total	**678.00**									

Contract Discussions	MW	State	Type	Developer	Owner	Location	Estimated Operation Date		CSPP Forecast
Project 10	21	UT	PURPA			Lynn, Utah	Dec-12	*	No
Project 11	21	UT	PURPA			Lynn, Utah	Dec-12	*	No
Project 12	19	WY	PURPA			Rock Springs, WY	Dec-12	*	No
Project 13	19	WY	PURPA			Rock Springs, WY	Dec-12	*	No
Project 3	40	ID	PURPA			Twin Falls, ID	Sep-11	*	No
Project 9	27	MT	PURPA			Montana	Dec-11	*	No
Project 7	10	ID	PURPA			Mtn Home, ID	Dec-12	*	No
Project 8	5	ID	PURPA			Owyhee, ID	Oct-12	*	No
Total	**162.00**								

Summary	MW
On-line	326.07
Signed Contracts (Not Yet Online)	678.00
Contract Discussions	162.00
Total	**1,166.07**

Level of Confidence (Projects not yet online)	
Under construction	67.50
High degree of certainty	227.00
Unknown	545.50

*** Estimated Dates**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-10-04

IDAHO POWER COMPANY

ATTACHMENT NO. 2

Idaho Power Company
Cogeneration and Small Power Production
As of December 20, 2010

	Project Number	Resource Type	Project Name	State	County	Project Size (MW)
	Projects Online					
1	21615205	Hydro	Arena Drop	ID	Canyon	0.45
2	31616150	Digester	B6 Anaerobic Digester	ID	Gooding	2.28
3	21615078	Hydro	Barber Dam	ID	Ada	3.70
4	21615101	Wind	Bennett Creek Wind Farm	ID	Elmore	21.00
5	31615100	Digester	Bettencourt Dry Creek BioFactory, LLC	ID	Twin Falls	2.25
6	31616100	Digester	Big Sky West Dairy Digester (DF-AP #1, LLC)	ID	Gooding	1.50
7	31214058	Hydro	Birch Creek	ID	Gooding	0.05
8	31415065	Hydro	Black Canyon #3	ID	Gooding	0.14
9	31615139	Hydro	Blind Canyon	ID	Gooding	1.50
10	31416013	Hydro	Box Canyon	ID	Twin Falls	0.36
11	31515100	Hydro	Briggs Creek	ID	Twin Falls	0.60
12	31765170	Wind	Burley Butte Wind	ID	Cassia	21.30
13	31715126	Hydro	Bypass	ID	Jerome	9.96
14	31315050	Wind	Camp Reed Wind Park, LLC	ID	Elmore	22.50
15	31416020	Hydro	Canyon Springs	ID	Twin Falls	0.13
16	31318100	Wind	Cassia Wind Farm LLC	ID	Twin Falls	10.50
17	31616081	Hydro	Cedar Draw	ID	Twin Falls	1.55
18	31516014	Hydro	Clear Springs Trout	ID	Twin Falls	0.52
19	31615057	Hydro	Crystal Springs	ID	Twin Falls	2.44
20	31415023	Hydro	Curry Cattle Company	ID	Twin Falls	0.22
21	31615106	Hydro	Dietrich Drop	ID	Jerome	4.50
22	11615077	Hydro	Elk Creek	ID	Idaho	2.00
23	41717137	Hydro	Falls River	ID	Fremont	9.10
24	31615121	Hydro	Faulkner Ranch	ID	Gooding	0.87
25	31415134	Hydro	Fisheries Dev.	ID	Gooding	0.26
26	31315035	Wind	Fossil Gulch Wind	ID	Twin Falls	10.50
27	31615098	Hydro	Geo-Bon #2	ID	Lincoln	0.93
28	31765160	Wind	Golden Valley Wind	ID	Cassia	12.00
29	31315093	Hydro	Hailey Cspp	ID	Blaine	0.06
30	31715128	Hydro	Hazelton A	ID	Jerome	7.70
31	31715140	Hydro	Hazelton B	ID	Jerome	7.60
32	21615100	Landfill gas	Hidden Hollow Landfill Gas	ID	Ada	3.20
33	11715144	Hydro	Horseshoe Bend Hydro	ID	Boise	9.50
34	41718140	Wind	Horseshoe Bend Wind	MT	Cascade	9.00
35	21615105	Wind	Hot Springs Wind Farm	ID	Elmore	21.00
36	31415094	Hydro	Jim Knight	ID	Gooding	0.34
37	31615031	Hydro	Kasel & Witherspoon	ID	Twin Falls	0.90
38	31615030	Hydro	Koyle Small Hydro	ID	Gooding	1.25
39	31615056	Hydro	Lateral # 10	ID	Twin Falls	2.06
40	31316015	Hydro	Lemoyne	ID	Gooding	0.08
41	31615105	Hydro	Little Wood Rvr Res	ID	Blaine	2.85
42	31515107	Hydro	Littlewood / Arkoosh	ID	Lincoln	0.87
43	31715099	Hydro	Low Line Canal	ID	Twin Falls	7.97
44	31615130	Hydro	Low Line Midway Hydro	ID	Twin Falls	2.50
45	31615125	Hydro	Lowline #2	ID	Twin Falls	2.79
46	31715123	Hydro	Magic Reservoir	ID	Blaine	9.07
47	31765150	Cogen	Magic Valley	ID	Minidoka	10.00
48	21765151	Cogen	Magic West	ID	Elmore	10.00
49	31515009	Hydro	Malad River	ID	Gooding	0.62
50	31615117	Hydro	Marco Ranches	ID	Jerome	1.20
51	31615154	Hydro	Mile 28	ID	Jerome	1.50
52	31720190	Wind	Milner Dam Wind	ID	Cassia	19.92
53	12614070	Hydro	Mitchell Butte	OR	Malheur	2.09
54	21615200	Hydro	Mora Drop Small Hydroelectric Facility	ID	Ada	1.85
55	31515004	Hydro	Mud Creek/S & S	ID	Twin Falls	0.52
56	31414111	Hydro	Mud Creek/White	ID	Twin Falls	0.21
57	12616071	Hydro	Owyhee Dam Cspp	OR	Malheur	5.00
58	31315060	Wind	Payne's Ferry Wind Park, LLC	ID	Twin Falls	21.00
59	31615067	Hydro	Pigeon Cove	ID	Twin Falls	1.89
60	41455091	Digester	Pocatello Waste	ID	Bannock	0.46
61	31415164	Hydro	Pristine Springs #1	ID	Jerome	0.13
62	31415165	Hydro	Pristine Springs Hydro #3	ID	Jerome	0.20

Idaho Power Company
Cogeneration and Small Power Production
As of December 20, 2010

	Project Number	Resource Type	Project Name	State	County	Project Size (MW)
63	21415119	Hydro	Reynolds Irrigation	ID	Canyon	0.26
64	31216020	Hydro	Rim View	ID	Gooding	0.20
65	31615003	Hydro	Rock Creek #1	ID	Twin Falls	2.05
66	31615104	Hydro	Rock Creek #2	ID	Twin Falls	1.90
67	31515103	Hydro	Sagebrush	ID	Lincoln	0.43
68	31617100	Hydro	Sahko Hydro	ID	Twin Falls	0.50
69	41515122	Hydro	Schaffner	ID	Lemhi	0.53
70	11415009	Hydro	Shingle Creek	ID	Adams	0.22
71	31615158	Hydro	Shoshone #2	ID	Lincoln	0.58
72	31416001	Hydro	Shoshone Cspp	ID	Lincoln	0.37
73	41866112	Industrial	Simplot Pocatello	ID	Power	12.00
74	31315021	Hydro	Snake River Pottery	ID	Gooding	0.07
75	31414075	Hydro	Snedigar	ID	Twin Falls	0.54
76	11766002	Biomass	Tamarack Cspp	ID	Adams	5.00
77	21662100	Cogen	Tasco - Nampa	ID	Canyon	2.00
78	31616082	Cogen	Tasco - Twin Falls	ID	Twin Falls	3.00
79	41717139	Hydro	Tiber Dam	MT	County	7.50
80	31415027	Hydro	Trout-Co	ID	Gooding	0.24
81	31315150	Wind	Tuana Springs Expansion	ID	Twin Falls	35.70
82	12616072	Hydro	Tunnel #1	OR	Malheur	7.00
83	55653167	Biomass	Vaagen Brothers	WA	Stevens	4.50
84	31315029	Hydro	White Water Ranch	ID	Gooding	0.16
85	31715141	Hydro	Wilson Lake Hydro	ID	Jerome	8.40
86	31315070	Wind	Yahoo Creek Wind Park, LLC	ID	Twin Falls	21.00
				Subtotal		**422.56**

Projects Under contract not yet online

							Estimated First Energy Date	Estimated Operation Date
1	41455301	Wind	Alpha Wind Project	ID	Cassia	29.90	Oct-14	Dec-14
2	41455350	Wind	Bravo Wind Project	ID	Cassia	29.90	Oct-14	Dec-14
3	41455400	Wind	Charlie Wind Project	ID	Cassia	27.60	Oct-14	Dec-14
4	21615115	Wind	Cold Springs Windfarm	ID	Elmore	20.00	Dec-11	Dec-12
5	31721100	Wind	Cottonwood Wind Park	ID	Twin Falls	20.00	May-12	Jun-12
6	31721200	Wind	Deep Creek Wind Park	ID	Twin Falls	20.00	May-12	Jun-12
7	41455450	Wind	Delta Wind Project	ID	Cassia	29.90	Oct-14	Dec-14
8	21615120	Wind	Desert Meadow Windfarm	ID	Elmore	20.00	Dec-11	Dec-12
9	31616115	Digester	Double A Digester	ID	Lincoln	4.50	Jun-11	Jan-12
10	31616120	Digester	Double B Dairy	ID	Cassia	2.00	Oct-11	Dec-12
11	41455500	Wind	Echo Wind Project	ID	Cassia	29.90	Oct-14	Dec-14
12	21615150	Solar	Grand View Solar	ID	Elmore	20.00	Dec-10	Dec-11
13	21615125	Wind	Hammett Hill Windfarm	ID	Elmore	23.00	Dec-11	Dec-12
14	21615102	Landfill Gas	Hidden Hollow Energy II Landfill Gas Project	ID	Ada	3.20	Feb-12	Feb-12
15	41455200	Wind	Lava Beds Wind	ID	Bingham	18.00	Jul-11	Jul-11
16	12618200	Wind	Lime Wind Energy	OR	Baker	3.00	Oct-11	Dec-11
17	31315500	Wind	Magic Wind Park	ID	Twin Falls	19.50	Jul-11	Jul-11
18	21615130	Wind	Mainline Windfarm	ID	Home	20.00	Dec-11	Dec-12
19	12616500	Wind	Murphy Flat Energy	ID	Owyhee	20.00	Dec-11	Dec-12
20	12616550	Wind	Murphy Flat Mesa	ID	Owyhee	20.00	Dec-11	Dec-12
21	12616600	Wind	Murphy Flat Wind	ID	Owyhee	20.00	Dec-11	Dec-12
22	31615300	Wind	Notch Butte Wind	ID	Jerome	18.00	Jul-11	Jul-11
23	31315075	Wind	Oregon Trail Wind	ID	Twin Falls	13.50	Dec-10	Dec-10
24	31315045	Wind	Pilgrim Stage Station Wind	ID	Twin Falls	10.50	Dec-10	Dec-10
25	31615500	Wind	Rainbow Ranch Wind	ID	Cassia	20.00	Dec-11	Dec-12
26	31615550	Wind	Rainbow West Wind	ID	Cassia	20.00	Dec-11	Dec-12
27	31616110	Digester	Rock Creek Dairy	ID	Twin Falls	4.00	May-11	May-12
28	41455300	Wind	Rockland Wind Project	ID	Power	80.00	Jul-11	Dec-11
29	31721300	Wind	Rogerson Flats Wind Park	ID	Twin Falls	20.00	May-12	Jun-12
30	21615135	Wind	Ryegrass Windfarm	ID	Elmore	20.00	Dec-11	Dec-12
31	31721400	Wind	Salmon Creek Wind Farm	ID	Twin Falls	20.00	May-12	Jun-12
32	31618100	Wind	Salmon Falls Wind	ID	Twin Falls	22.00	Dec-10	Dec-10
33	21615110	Wind	Sawtooth Wind Project	ID	Elmore	21.00	Oct-12	Dec-12
34	31616130	Digester	Swager Farms	ID	Twin Falls	2.00	Sep-11	Oct-12
35	31315055	Wind	Thousand Springs Wind	ID	Twin Falls	12.00	Dec-10	Dec-10

Idaho Power Company
Cogeneration and Small Power Production
As of December 20, 2010

	Project Number	Resource Type	Project Name	State	County	Project Size (MW)		
36	31315065	Wind	Tuana Gulch Wind	ID	Twin Falls	10.50	Dec-10	Dec-10
37	21615140	Wind	Two Ponds Windfarm	ID	Elmore	20.00	Dec-11	Dec-12
38	11866075	Biomass	Yellowstone Power	ID	Gem	10.00	Sep-11	Dec-11
				Subtotal		**723.90**		

Proposed Projects

As these are not yet completed contracts, the project names etc is confidential

Interconnection Que number	Resource Type	Project Name	State	County	Project Size (MW)
304	Biomass	Project 1	ID	Adams	10.00
360	Hydro	Project 2	ID	Canyon	0.90
334	Wind	Project 3	ID	Twin Falls	40.00
345	Solar	Project 4	ID	Owyhee	20.00
356	Solar	Project 5	ID	Owyhee	20.00
331	Solar	Project 6	ID	Elmore	10.00
332	Wind	Project 7	ID	Elmore	10.00
318	Wind	Project 8	ID	Owyhee	5.00
Off system	Wind	Project 9	Reed Point, MT		27.00
Off system	Wind	Project 10	Lynn, UT		21.00
Off system	Wind	Project 11	Lynn, UT		21.00
Off system	Wind	Project 12	Rock Springs,		19.00
Off system	Wind	Project 13	Rock Springs,		19.00
Off system	Hydro	Project 14	ID	Fremont	3.60
			Subtotal		**226.50**
			Total		**1372.96**

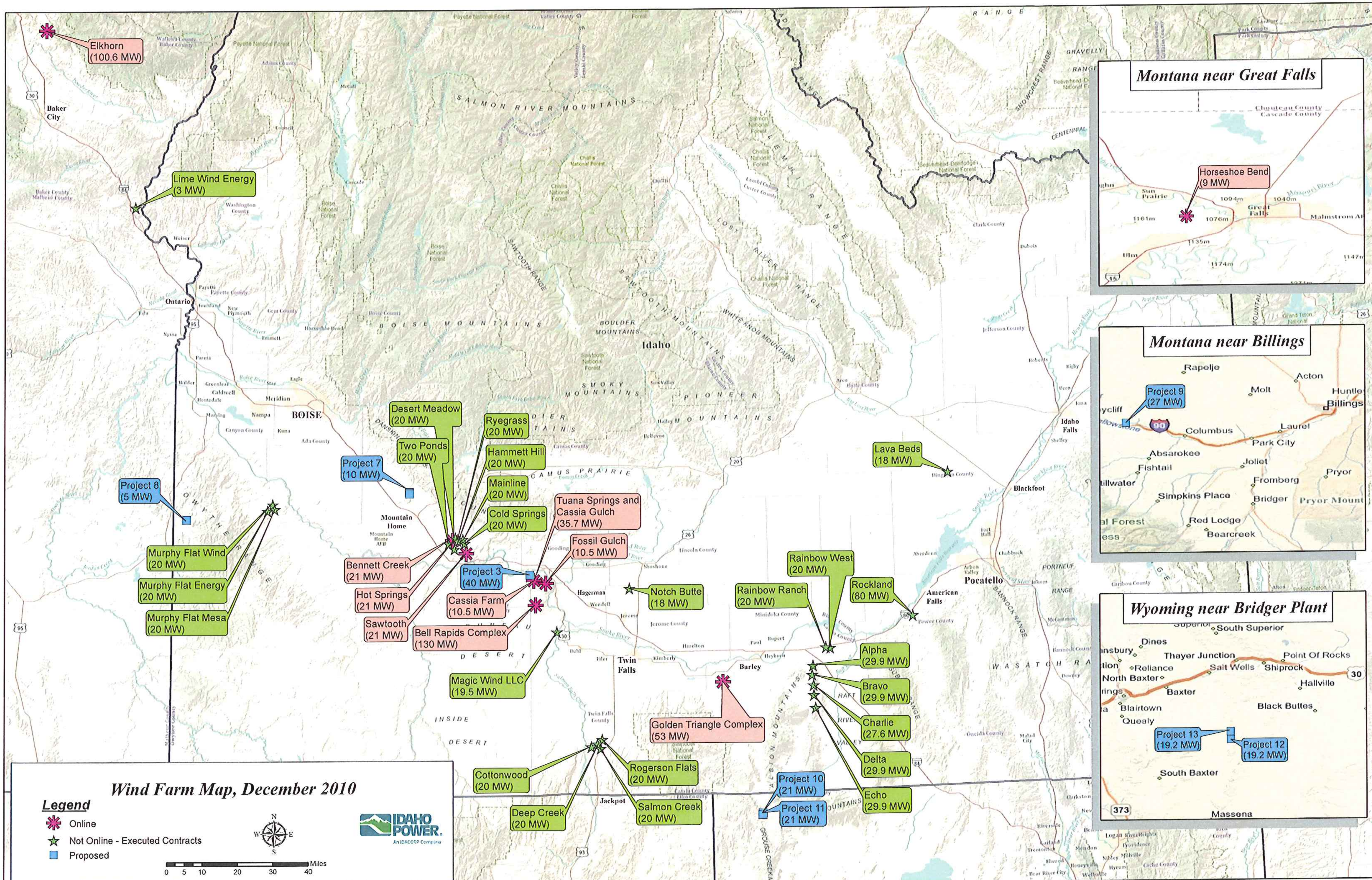
BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-10-04

IDAHO POWER COMPANY

ATTACHMENT NO. 3



Wind Farm Map, December 2010
Legend
Online
Not Online - Executed Contracts
Proposed
IDAHO POWER
An IDACORP Company
Miles
0 5 10 20 30 40
Elkhorn (100.6 MW)
Lime Wind Energy (3 MW)
Project 8 (5 MW)
Murphy Flat Wind (20 MW)
Murphy Flat Energy (20 MW)
Murphy Flat Mesa (20 MW)
Project 7 (10 MW)
Desert Meadow (20 MW)
Two Ponds (20 MW)
Ryegrass (20 MW)
Hammett Hill (20 MW)
Mainline (20 MW)
Cold Springs (20 MW)
Tuana Springs and Cassia Gulch (35.7 MW)
Fossil Gulch (10.5 MW)
Bennett Creek (21 MW)
Hot Springs (21 MW)
Sawtooth (21 MW)
Project 3 (40 MW)
Cassia Farm (10.5 MW)
Bell Rapids Complex (130 MW)
Magic Wind LLC (19.5 MW)
Notch Butte (18 MW)
Lava Beds (18 MW)
Rainbow West (20 MW)
Rainbow Ranch (20 MW)
Rockland (80 MW)
Alpha (29.9 MW)
Bravo (29.9 MW)
Charlie (27.6 MW)
Delta (29.9 MW)
Echo (29.9 MW)
Golden Triangle Complex (53 MW)
Cottonwood (20 MW)
Deep Creek (20 MW)
Rogerson Flats (20 MW)
Salmon Creek (20 MW)
Project 10 (21 MW)
Project 11 (21 MW)
Baker City
Ontario
BOISE
Mountain Home
Idaho
Twin Falls
Burley
Pocatello
American Falls
Blackfoot
Idaho Falls
Jackpot
SALMON RIVER MOUNTAINS
BOISE MOUNTAINS
SMOKY MOUNTAINS
PIONEER MOUNTAINS
CAMAS PRAIRIE
INSIDE DESERT
Montana near Great Falls
Horseshoe Bend (9 MW)
Great Falls
Montana near Billings
Project 9 (27 MW)
Columbus
Billings
Wyoming near Bridger Plant
Project 13 (19.2 MW)
Project 12 (19.2 MW)