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IDAHO PUBLIC
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December 10, 2007

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
P O Box 83720
Boise ID 83720-0074

RE: **Case No.IPC-E-07-08**

Dear Ms. Jewell:

Enclosed please find nine (9) copies of the **DIRECT TESTIMONY OF DR. DON READING ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER** in the above case. An additional copy is enclosed as a reporter's copy, and a CD as required by Rule 231.05.

I have also enclosed an extra copy to be service-dated and returned to us for our files. Thank you.

Sincerely,

Nina Curtis
Administrative Assistant

encl.

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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-07-08

Direct Testimony of

Don C. Reading, Ph.D.

Ben Johnson Associates, Inc.

On behalf of the

Industrial Customers of Idaho Power (ICIP)

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)	CASE NO. IPC-E-07-08

Exhibit List
Don C. Reading, Ph.D.
Ben Johnson Associates, Inc.
On behalf of the
Industrial Customers of Idaho Power (ICIP)

Exhibit No. 201	Qualifications
Exhibit No. 202	Natural Gas Price Forecast Comparison
Exhibit No. 203	Marginal Generation Capacity Costs
Exhibit No. 204	Marginal Power Supply Costs
Exhibit No. 205	Idaho Power Rate Case Power Supply Cost
Exhibit No. 206	Base Case Comparison to Full Weighted Marginal COS
Exhibit No. 207	Cumulative CSPP
Exhibit No. 208	Total PURPA Resources 2002 – 2006
Exhibit No. 209	Base Case Comparison to PURPA Resources
Exhibit No. 210	Base Case Comparison to Hydro Reallocation 75%/25%
Exhibit No. 211	Base Case Comparison to Cumulative Changes
Exhibit No. 212	Distributed Generation Report
Exhibit No. 213	PGE Distributed Generation Promotional Materials

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Don Reading and my business address is 6070 Hill Road, Boise, Idaho. I am a principal with Ben Johnson Associates.

Q. HAVE YOU PREPARED AN EXHIBIT OUTLINING YOUR QUALIFICATIONS AND BACKGROUND?

A. Yes. Exhibit No. 201 serves that purpose.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. I have been retained by the Industrial Customers of Idaho Power ("ICIP") to review Idaho Power Company's (IPC, company) application for authority to increase its rates and charges for electric service. Specifically I examine the Company's rate allocations that are derived from its cost of service (COS) study. I propose changes to Idaho Power's COS that will bring cost assignments closer to the Company's load profile for this capacity constrained utility. I conclude that the cost of service study produces results that are counter intuitive and therefore ultimately recommend the use of a uniform percentage allocation of any increase in rates.

I discuss the Company's filing of a projected test year and show it to be a flawed approach. I therefore recommend the Commission reject the use of a forecast test year. I also address the company's proposal to revisit the load growth adjustment as it relates to fine tuning the power cost adjustment mechanism.

In addition to addressing issues related to test year, the Company's cost of service study

1 and the load growth adjustment, I discuss the company's poor performance with respect to
2 distributed generation initiatives as well as the failure of time of use rates to provide any
3 meaningful benefits to either the company or its industrial customers.

4 **Forecast Test Year**

5 **Q. DR. READING, LET'S TURN TO YOUR DISCUSSION OF THE COMPANY'S**
6 **PROPOSAL OF A FORECAST TEST YEAR. THE COMPANY STATES THIS IS THE**
7 **MOST FUNDAMENTAL POLICY DECISION IN ITS RATE FILING. DO YOU**
8 **AGREE?**

9 A. Yes, I would rank it right up with the dramatic changes we are seeing in the Company's
10 cost of service study. In terms of this Commission's general approach to rate cases, it is one of
11 the biggest changes I have seen proposed.

12 **Q. IN 2005, THE COMPANY USED A 'SPLIT TEST YEAR' WITH SIX MONTHS**
13 **ACTUAL DATA AND SIX MONTHS FORECASTED DATA. WHY THEN IS A FULLY**
14 **FORECAST TEST YEAR SUCH A MAJOR DEPARTURE?**

15 **A.** There are two major departures from the general rate filings the Company made in 2003
16 and 2005. First, the Company's 2007 test year filed in this docket forecasts the full twelve
17 months of 2007 rather than using 6 months actual data and 6 months forecast data. The second
18 major departure is the forecast was 'trued up' at the end of the previous two cases. In this case
19 the Company recommends the revenue requirement be set purely on forecast data that will be
20 reflected in rates once the Commission's decision is made – with no true up. Any meaningful
21 differences in the Company's actual costs versus projected costs and revenue for 2008 will be
22 reflected in rates until the next general rate case. Furthermore if, as the Company intends, the

next general rate case is also based on a forecasted test year, then the link between rates and historical costs and revenues will be completely broken. It is true that forecasts will be updated based on historical data in each successive general rate case. Nevertheless, the fact remains that rates will be based on projections, not reality. With no 'true up' mechanism proposed by the Company, neither ratepayers nor the Company will be able to recoup or correct any error between actual and projected data.

Q. SO YOU AGREE WITH THE COMPANY THAT THE FORECASTED TEST YEAR IS A MAJOR DEPARTURE FROM HISTORICAL PRECEDENTS OF RATE MAKING POLICIES OF THE IDAHO COMMISSION?

A. Yes, according to Mr. Gale, this step to a full forecasted test year is so 'bold' that the Company has approached its proposal to implement a fully forecasted test year incrementally:

> The Company believed that moving to a full forecast test year at that time was too bold a step and instead chose the split year approach, which reduced regulatory lag by six months yet still provided access to the actual information prior to a final order by the Commission. Additionally, Idaho Power believed that the use of a split year could provide a bridge to a full forecast year in the future. [Direct Testimony, Gale, page 9.]

Even though the Company has used a partial forecasted 'split year' with a 'true up' in the past, in this case the Commission is being asked to make a major policy change and break with long standing precedent.

Q. WHAT IS THE ICIP'S POSITION ON THE USE OF A FORECASTED TEST YEAR AS PROPOSED BY IDAHO POWER?

1 A. The ICIP is opposed to the forecasted test year for both theoretical and practical
2 reasons.

3 **Q. COULD YOU PLEASE EXPLAIN THE THEORETICAL REASONS YOU**
4 **ARE OPPOSED TO A FORECASTED TEST YEAR?**

5 **A.** One of the pillars of ratemaking is that ratepayers should only pay for 'known and
6 measurable' costs. Projections, by definition, are nothing more than educated guesses about
7 future events. The standard approach for a forecasted test year, and the one used by the
8 Company, is to make projections based on historical data and then make adjustments for
9 expected changes. For example, in this case the Horizon Wind purchase power agreement and
10 expected PURPA projects are used in the development of the Company's net power supply costs.
11 The Company states the reason for the inclusion of these costs is that they are expected to be part
12 of Idaho Power's resource portfolio by the start of 2008. [Direct Testimony, Gale, page 13.]

13 In reality, these resources may or may not actually materialize during the year rates are in
14 effect. Therefore, they would be inaccurately reflected in the Company's resource portfolio.
15 Using a forecasted test year allows Idaho Power to enjoy rates as if these resources actually are in
16 the Company's resource stack – regardless of their actual status. I chose this example, even
17 though, along with the projected price and amount of off system purchases, the inclusion of the
18 Horizon and PURPA resources actually reduce forecasted power supply costs by nearly $51
19 million. Although their inclusion appears to be a good deal for ratepayers, the power supply
20 costs on which the Company is asking be included in rates is also based on projected, not actual,
21 power supply costs from other Company resources as well as these two resources.

22 The price of off system purchases and the cost of producing power from the company's

1 gas fired units are also based on projected gas prices. For PURPA resources the company's
2 power supply costs include an estimate of the costs associated with the addition of 100 MW of
3 wind resources. As the Commission is aware, the costs of all new PURPA resources are
4 currently being disputed along with the costs associated with wind integration. This means Idaho
5 Power's proposed rates will be set on what, at this time, is merely a guess by the Company about
6 what these costs may be. It also means that these cost estimates are sure to be wrong.

7 **Q. DOES THIS MEAN, ON BEHALF OF A RATEPAYER GROUP, YOU**
8 **ARE ADVOCATING DISREGARDING $50 MILLION IN RATEPAYER BENEFITS?**

9 A. No. As I stated above, the inclusion of the Horizon and PURPA contracts are part of an
10 overall projection of power supply costs that include a variety of assumptions. The only thing
11 that we will know for certain is the actual power supply costs based on the resources that are
12 actually on the Company's system for 2007 after the books have been closed for that year.

13 Fundamentally, if the Commission accepts a forecasted test year as its standard for rate
14 making, it is accepting the certainty that some resources will be included in rates before they
15 become 'used and useful'. In such a circumstance ratepayers would be paying for resources that
16 are not providing power to the system. My attorney advises me that there may be a legal problem
17 with the use of a forecast year as well. I will let the lawyers worry about that aspect of this issue,
18 however.

19 **Q. WON'T INTERVENERS AND THE COMMISSION STAFF HAVE THE**
20 **ABILITY TO REVIEW ALL OF THE COMPANY'S FORECASTS AND MAKE**
21 **JUDGMENTS ABOUT THEIR REASONABLENESS?**

22 **A.** Yes, and this leads me to my second objection about the acceptance of a forecasted test

1 year.

2 **Q. WHAT IS YOUR SECOND OBJECTION TO THE USE OF A FORECAST TEST**

3 **YEAR?**

4 Major problems with forecast data are the controversies that swirl over the models as well

5 as the many assumptions that are used to forecast costs and revenues. The statutory time

6 constraints for prosecuting a general rate case impact the ability to thoroughly analyze models

7 and evaluate assumptions. It very difficult for staff and interveners to critically review each of

8 the numerous forecasts that make up an overall rate filing. Attempting to review all the forecasts

9 and assumptions imposes a real burden on limited Staff and intervenor resources and can be very

10 expensive. In fact, many of the forecasts and their underlying assumptions may well be

11 incorporated into rates without any critical analysis. Historical data on the other hand can be

12 audited and verified at a lower cost and with more accuracy.

13 **Q. ARE YOUR CONCERNS SHARED BY OTHER EXPERTS ON UTILITY**

14 **RATEMAKING?**

15 A. Yes. In the respected treatise, *Principles of Public Utility Rates*, Dr. Bonbright points

16 out:

17 In the first place, the commission's staff must audit the utility's books. For
18 ratemaking purposes, only just and reasonable expenses are allowed; only used
19 and useful property is permitted in the rate base. In the second place, the
20 Commission must have a basis for estimating future revenue requirements. This
21 estimate is one of the most difficult problems in a rate case. A commission is
22 setting rates for the future but it has only past experience (expenses, revenues,
23 demand conditions) to use as a guide. [James Bonbright, with Albert Danielsen
24 and David Kamerschen, Principles of Public Utility Rates, 2nd Ed., March, 1988.]

Q. YOU DISCUSS ABOVE THE COMPANY'S NATURAL GAS FORECAST AS AN IMPORTANT INPUT TO THE POWER SUPPLY COST PROJECTION. AREN'T NATURAL GAS FORECASTS VERY SPECULATIVE AND SUBJECT TO ERROR?

A. Yes. Natural gas forecasts have been notorious in recent years for being wrong. This is a good example of erroneous costs being rolled into rates. The assumed gas prices have a significant impact on the power supply cost estimate that rolls directly into rates.

Q. ON WHAT DO YOU BASE YOUR FINDING THAT NATURAL GAS PRICE FORECASTS HAVE BEEN NOTORIOUSLY WRONG?

A. An illustration of how dramatically wrong natural gas forecasts have been recently is illustrated by the region's experience with the Northwest Power and Conservation Council's periodic natural gas forecasts for the region. The Power Council's forecast for gas prices for 2006 that was made five years ago in 2002 was $3.15 MMbtu in real 2000 dollars. When adjusted for inflation (at 1.7% annually) this would mean a price of $3.71 in 2006. The Council's just issued forecast shows the price for 2006 in 2006 dollars of $6.15 or a 66% higher than projected five years earlier. This example is not to single out the Power Council; it does a fine job of forecasting. Nearly all projections of natural gas prices made in the early 2000's missed the significant run up in natural gas prices. I used this example to show how dramatically incorrect forecasts can be. We should avoid rolling data we know to be wrong into rates and instead use historical data for setting retail rates.

Q. IS THE POWER COUNCIL'S CURRENT FORECAST BEING USED BY IDAHO POWER IN THIS CASE TO PROJECT NATURAL GAS PRICES?

A. No. The Company uses its own natural gas price forecast in its AURORA model runs for projecting power supply costs in this case. On the other hand, the Company is using the Council's forecast to set PURPA rates in Docket No. IPC-E-07-15. Without discussing the merits of either gas forecast, the fact is the Company has two dramatically different natural gas forecasts before the Commission in concurrently open dockets. As shown on Exhibit 202, the higher of the two forecasts is being used to set rates in this docket (which determines how much

1 Idaho Power's ratepayers pay), while the other (lower) forecast is being used to set PURPA
2 rates, (which determines how much Idaho Power pays small power producers). This is sort of a
3 'heads I win and tails you lose' proposition in that in each case the natural gas price forecast that
4 most benefits the Company is being proposed.

5 **Q. DO YOU HAVE AN EXAMPLE OF HOW FORECASTED DATA MAY**
6 **LEAD TO RATES BEING SET THAT DO NOT MATCH THE COMPANY'S REVENUE**
7 **REQUIREMENT?**

8 A. Company witness Said, on page 34 of his direct testimony, states that Idaho Power's
9 projected revenue requirement for the 2007 test year is $681.8 million and 'envisions' a 2008
10 revenue requirement that is $37.0 million higher at $718.8 million. This means the Company is
11 projecting that 2008 will exceed the 2007 projection by an increase in costs of $37.0 million.
12 Mr. Said testifies that the Company expects 2008 revenues to be $695.4 million or $13.7 million
13 higher than the 2007 projected revenue requirement. Should Idaho Power receive its full
14 requested rate increase beginning in 2008, it would start collecting nearly $14 million more than
15 the 2007 estimated revenues.

16 Mr. Said additionally states that, given the projected revenues and projected costs, the
17 Company expects to be short of its revenue requirement for 2008 by $23.3 million. This
18 projection is based on the Company's projected 2008 costs layered on top their 2007 projected
19 costs. Should costs not materialize as rapidly as the Company expects, it would be over
20 collecting. In response, the Company could argue that it also could be under collecting more
21 than expected. While possibly true, the point of this example is that when costs and revenues are
22 not based on reality, but rather are forecasts based on other forecasts, there can be significant
23 mismatches between revenues and costs which is contrary to fair and equitable ratemaking.

24 **Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ABOUT A**
25 **FORECASTED TEST YEAR?**

26 A. Yes. A forecasted test year tends to reduce risk for the utility because it allows it to
27 obtain rate relief for expected actions rather than basing rates on actual costs and revenues. In

1 the case of Idaho Power, the Company also has an annual PCA, and currently has decoupled rates
2 for residential customers. Should it be allowed to set rates based on a forecasted test year the
3 Commission should recognize this lowered risk in establishing the Company's rate of return on
4 equity.

5 **Cost of Service**

6 **Q. DR. READING, LETS TURN TO YOUR EXAMINATION OF IDAHO POWER'S**
7 **COST OF SERVICE STUDY. COULD YOU PLEASE BRIEFLY REVIEW THE**
8 **COMPANY'S APPROACH?**

9 A. Yes. Staff witness Tatum presents four separate COS studies; (i) Base Case, (ii) Non-
10 Weighted, (iii) 3 CP/12 CP, and (iv) 3 CP/Average. The Company's preferred approach is the 3
11 CP/12 CP study because it argues it is the most effective method of allocating production plant
12 costs consistent with the costs imposed by each given customer class. [Idaho Power witness
13 Tatum Direct Testimony, pages 38, 39.] Before I discuss some specific modifications to the
14 Company's COS, I have two general observations. First Mr. Tatum states that the Base Case is
15 consistent with the "Normalized" method filed in the last general rate proceeding. That case
16 (Docket No. IPC-E-05-28) was settled and thus the cost of service study was not litigated or
17 approved in that docket. Therefore, when comparing the current cost of service study with those
18 in past filings, the base of comparison should be the last general rate case that preceded the '-28'
19 docket which is the general rate case in Docket No. IPC-E-03-13.

20 Second, as indicated by Company Exhibit 57, a disproportionate share of the overall
21 10.35% increase requested by Idaho Power falls on high load factor customers under all four
22 COS scenarios presented by the Company. The range of indicated increases for all four studies

1 presented for residential customers is from -1.7% (3 CP/Energy) to 3.6% (Non-Weighted). On
2 the other hand, the range of indicated increases for the Schedule 19 and Special Contract
3 customers is from 17.2% (Schedule 19, Base Case) to 37.2% (JR Simplot, 3 CP/Energy).

4 **Q. WHY DO YOU ASSERT THAT THE CURRENT COST OF SERVICE STUDY**
5 **FILED BY THE COMPANY SHOULD BE COMPARED TO THE ONE FILED IN CASE**
6 **NO. IPC-E-03-13 AND NOT THE MOST RECENT GENERAL RATE CASE?**

7 A. As I note above, Idaho Power's last general rate case was settled. In the Settlement
8 Agreement the parties specifically agreed that the cost of service study filed in that case would
9 not be precedent setting. As observed by the Commission in its order approving the settlement:

10 The parties also agreed that the underlying cost-of-service model filed by the
11 Company in this proceeding will not constitute precedent in any subsequent
12 general rate case. The parties specifically recognize that any party's failure to
13 specifically object to the Company s cost-of-service analysis in this case will not
14 constitute a waiver in any future general rate case proceeding. [Idaho Public
15 Commission Order 30035, IPC-E-05-28, page 5.]

16 The COS filed in the last case also allocated the major share of the proposed rate increase to the
17 high load factor customers. A foreshadowing of the disproportionate increase for high load
18 factor customers is found in Company witness Brilz' IPC-E-05-28 Direct Testimony filed in that
19 case.

20 **Q. WHAT REASONS DID MS. BRILZ GIVE FOR THE DISPROPORTIONATELY**
21 **HIGHER ALLOCATIONS TO HIGH LOAD FACTOR FOUND IN THE COMPANY'S**
22 **COST OF SERVICE STUDIES?**

A. In her pre-filed testimony she stated:

> Since the conclusion of the Company's last general rate case it has been determined that the deficit months of June, July, August, November, and December used in the 2003 marginal cost analysis were primarily determined by firm generation supply acquisition need rather than determination of months in which a peak-hour deficiency occurred. The deficit months of January, May, June, July, August, September, November, and December used in the current marginal cost analysis are directly tied to peak-hour deficiency months identified in the 2004 IRP.

And,

> The use of eight deficit months (January, May, June, July, August, September, November, and December) in the current marginal cost analysis results in weighting factors that attribute more generation capacity cost responsibility to customer classes with usage throughout most of the year. [Direct Testimony, Maggie Brilz, IPC-E-05-28, page 21, 22.]

Extending the number of months used in the marginal cost study from 5 to 8 months spreads the costs of generation to customer classes with high use over a greater numbers of months.

Q. THE COMPANY HAS EXTENDED THE NUMBER OF MONTHS THAT IT IS APPLYING CAPACITY COSTS. WHAT HAVE BEEN THE TRENDS IN THE MARGINAL COST OF CAPACITY AND ENERGY FOR IDAHO POWER SINCE THE IPC-E-03-13 GENERAL RATE CASE?

1 A. There have been dramatic shifts in the costs of capacity and energy for the Company in
2 the last 4 years since our benchmark case, IPC-E-03-13, was filed. Marginal generation capacity
3 costs have dropped by 24% from $90.71 per KW to $69.00 per KW. The monthly amounts are
4 shown in the graph on Exhibit 203

5 While capacity costs have dropped, the marginal power (energy) supply costs over the
6 same 4 year period increased dramatically by 127%, from $33.38 to $75.84 per MWh. The
7 increase has been especially large in July and August with currently estimated marginal power
8 (energy) costs of $127.75 and $111.10 per MWh respectively. The monthly marginal power
9 supply costs over the last 3 filed general rate cases are shown on Exhibit 204.

10 **Q. HOW DO YOU EXPLAIN THE SIGNIFICANT DROP IN MARGINAL**
11 **CAPACITY COSTS COUPLED WITH THE DRAMATIC INCREASE IN MARGINAL**
12 **ENERGY COSTS?**

13 A. It appears to be the function of two interrelated factors. Natural gas prices have increased
14 since the filing of our benchmark general rate case in 2003 and the Company has added gas
15 peaking resources. The capacity costs of a gas peaking unit on a per KW basis are relatively
16 lower than other generating resources. The trade off for these lower capacity costs is higher fuel
17 costs and hence higher energy costs. The higher gas prices have also driven the cost of
18 purchasing off-system power to higher levels.

19 **Q. IDAHO POWER HAS A RESOURCE STACK WITH A MIX OF DIFFERENT**
20 **TYPES OF RESOURCES. WHAT HAVE BEEN THE CHANGES IN THE COST OF**
21 **ENERGY ON A NORMALIZED BASIS OVER THE PAST 4 YEARS?**

22 A. As shown in Exhibit 205 energy costs have increased from a variety of resources. For

example, Idaho Power's two coal plants (Bridger and Valmy) had essentially the same output in 2007 and as they did in 2005, yet their energy production costs have increased by $10 million each. The two gas fired units in the Company's resource stack have power supply costs of $86.42 per MWh for Bennett Mountain and $1,049.72 per MWh for Danskin. Off-system purchases have increased from $39.9 per MWh in case IPC-E-03-13 to $70.9 per MWh in the current case. Off-system sales have also increased -- but by a lesser amount from $20.9 per MWh in 2003 to $48.4 per MWh. It should be emphasized again that these current case values are based on projections by the Company.

Q. YOU HAVE DEMONSTRATED THE INCREASES IN ENERGY COSTS OVER THE PAST 4 YEARS FOR IDAHO POWER. IS THIS THE REASON HIGH LOAD FACTOR CUSTOMERS ARE BEING ASSIGNED THE MAJOR SHARE OF THE PROPOSED RATE INCREASE IN THIS CASE?

A. Yes. The paradoxical aspect of this increase in energy costs relative to capacity costs is caused by the fact that Idaho Power has changed from an energy constrained utility to a capacity constrained utility over the past 15 years. This shift has been driven primarily by the growth in residential and small commercial customers over the past dozen years. This is the reason the Utility has constructed 260 MWs of gas peaking units as its most recent resource additions. These higher energy costs are reflected in the Company's cost of service studies which indicate that high load factor customers should suffer higher energy costs.

Q. DOES IT MAKE SENSE FOR HIGH LOAD FACTOR CUSTOMERS TO BE ASSIGNED DISPROPORTIONATE INCREASES IN THEIR ENERGY RATES BY A UTILITY, LIKE IDAHO POWER, THAT IS NOW CAPACITY CONSTRAINED?

1 A. No. For a capacity constrained utility, higher price signals should be sent to those
2 customer classes that have the poorest (low) load factors. Idaho Power's cost of service studies
3 do just the opposite by charging a disproportionate share to customers with high load factors.
4 **Q. AS YOU POINTED OUT ABOVE, THE RESIDENTIAL, AND TO A LESSER**
5 **EXTENT THE SMALL COMMERCIAL CUSTOMER, CLASSES ARE RECEIVING**
6 **THE LOWEST PERCENTAGE INCREASES WHILE THE HIGH LOAD FACTOR**
7 **CUSTOMERS ARE RECEIVING THE HIGHEST. WHAT DOES THIS SAY ABOUT**
8 **PRICE SIGNALS TO CUSTOMERS?**
9 A. The results of the Company's COS allocate more costs to energy rather than capacity
10 which are reflected in the Company's proposed rates. The indicated rate increase for Schedule
11 19 customers is 3.3 times higher than for the residential class. The indicated rate increase for
12 special contract customers is 4.4 times higher than for residential customers. Yet the Company
13 has been adding peaking resources to meet the increasing demand during peak periods that is
14 being driven largely by residential customer growth. From an economist's standpoint this result
15 is counterintuitive.
16 **Q. DO YOU HAVE ANY RECOMMENDATIONS THAT WOULD HELP REMEDY**
17 **THE PARADOXICAL RESULTS OF THE COMPANY'S COST OF SERVICE**
18 **STUDIES?**
19 A. Yes. Should the Commission elect to spread rates among customer classes using any
20 method other than a uniform percentage increase across the board, then I have three
21 recommended changes to the company's methodology. The cost of service results described
22 below are based on changes to the Company's Base Case. I am using the Base Case because it is

1 the one that is most similar to the methodology accepted by the Commission in the last litigated
2 case IPC-E-03-13 and the one that I believe best represents an equitable spread for rates.

3 **Q. WHAT ARE THE THREE CHANGES YOU RECOMMEND BE MADE TO THE**
4 **COMPANY'S COST OF SERVICE STUDY?**

5 A. The three changes are:

6 First, I adjust the weightings for customer classes to reflect full marginal cost rather than
7 the average of marginal and embedded weightings used by the Company. This change more
8 accurately reflects the costs that are being incurred by the Company. Marginal costs best
9 represent the costs of additional capacity and energy of needed additional resources.

10 My second modification changes the allocation of PURPA power delivered to the
11 Company to reflect the same demand/energy split as are assigned to Idaho Power's own
12 generating resources. There are now sufficient PURPA resources on Idaho Power's system that,
13 as a group, can now be counted on to supply capacity to the Company. In addition, because the
14 predominance of canal drop on PURPA resources on Idaho Power's system, QF output is highest
15 and most reliable in the summer when the Company needs the capacity the most.

16 My final change reallocates the Company's hydro resources between demand/energy to
17 75% capacity and 25% energy rather than the system average split that is used by Idaho Power.
18 This reallocation is more in line with standard cost allocations and are, in fact, identical
19 allocations used by PacifiCorp in its current rate case before the Commission.

20 I individually outline the results of these three modifications to the Company's approach
21 below and then present all three in combination with one another.

1 **Q. DR. READING, LET'S TURN TO YOUR FIRST MODIFICATION TO THE**
2 **COST OF SERVICE STUDY PRESENTED BY THE COMPANY. FROM AN**
3 **ECONOMIC STANDPOINT, WHY DOES THE FULL MARGINAL COST**
4 **WEIGHTING BETTER REFLECT THE COMPANY'S COSTS THAN ACTUAL**
5 **VALUES?**
6 A. As explained above, one of the problems with the class cost allocations that result
7 from the Company's cost of service studies is that cost allocations are not reflected in the
8 customer classes that drive costs on Idaho Power's system. My Exhibits 203 and 204 depicting
9 the marginal costs of capacity and energy indicate the dramatic differences in costs over the
10 different months of the year. Full marginal cost weightings reflect more fully these differences
11 among customer classes and thus better reflect the costs each customer class is placing on the
12 system.
13 **Q. WHAT ARE THE RESULTS OF THIS MODIFICATION TO THE COMPANY'S**
14 **BASE CASE?**
15 A. It should be noted before I discuss the results of these cost of service modifications that
16 all values assume the Company receives its full proposed overall increase of 10.35%. A different
17 overall rate increase will change the percentage change for each customer class in ratio with that
18 difference.
19 As shown in Exhibit 206, weighting customer classes at full marginal cost, in general,
20 lowers the percent increase to high load factor customers (Schedule 19, Special Contract). Cost
21 allocations to the irrigation class are increased while residential customers would receive a rate
22 decrease. The other classes remain about the same. This result tends to move the cost of service

1 away from high load factor customers but it does not send the correct price signal to residential
2 customers who are a major cause of increasing the Company's need for capacity.

3 **Q. YOUR SECOND RECOMMENDATION ADDRESSES THE ALLOCATION OF**
4 **PURPA GENERATION BETWEEN CAPACITY AND ENERGY. WHAT IS YOUR**
5 **RECOMMENDED CHANGE FROM THE COMPANY'S BASE METHOD?**

6 A. Currently the Company allocates nearly 100% of PURPA purchases to energy, even
7 though these resources contribute to meeting system peak. These resources should be allocated
8 to reflect the fact that they do contribute to meeting the system peak. Therefore I recommend
9 they be allocated on the same basis as the Company's other resources which is 41.47% to
10 demand and 58.53% to energy. That helps to move some of the cost responsibility for PURPA
11 resources to those customers that are causing the Company to add resources and who are
12 enjoying the benefits of the capacity contribution PURPA resources make to the system.

13 **Q. IS YOUR RECOMMENDATION A DEPARTURE FROM THE**
14 **METHODOLOGY THIS COMMISSION HAS USED TO ALLOCATE PURPA**
15 **RESOURCES BETWEEN CAPACITY AND ENERGY IN THE PAST?**

16 A. Yes, almost thirteen years ago, in case IPC-E-94-5 the Commission said,

17 IPCo's class cost-of-service study classified the costs associated with
18 cogeneration and small power production (CSPP) based on the type of payment
19 made to developers. Thus, capacity payments are classified as capacity related
20 costs and energy payments are classified as energy related costs. Tr. p. 2877-78.
21 Because IPCo cannot call upon the capacity provided by CSPP when needed nor
22 rely upon any given amount of capacity to be available at any point in time, the

1 capacity value for CSPP is small. Accordingly, the methodology used by IPCo to
2 classify CSPP related costs to demand and energy results in the classification of
3 approximately 92% of the costs as energy related. Tr. p. 2878-79.
4 And,
5 We find: The CSPP purchases primarily have value to IPCo as energy
6 resources and not capacity resources. Accordingly, IPCo's classification of its
7 CSPP related costs is appropriate. We also find that conservation resources
8 provide both demand and energy benefits and should be classified accordingly.
9 The easiest method to classify conservation program expenses is in the same
10 manner in which generation resources are classified, i.e., on the basis of the
11 system load factor. [Idaho Public Utilities Commission Order 25880, IPC-E-94-5,
12 page 29.]
13 **Q. WHY IS IT NOW APPROPRIATE FOR THE COMMISSION TO CHANGE THE**
14 **CAPACITY/ENERGY ALLOCATION FOR PURPA RESOURCES IN LIGHT OF THE**
15 **COMMISSION'S FINDINGS YOU JUST CITED?**
16 A. There are two reasons why it now makes sense to change the classification of PURPA
17 resources in the Company's COS. First, the COS should assign costs that match the resources
18 needed by the Company. Idaho Power's load profile has changed significantly since the last time
19 this issue was addressed. When the Commission last visited this issue, Idaho Power was an
20 energy constrained utility. It is now a capacity constrained utility. As pointed out above, the
21 Company is now building peaking resources. Since the load profile of the Company has
22 changed, it is appropriate that allocations within the COS also change to better match Idaho

1 Power's new load profile. The cost of service studies set the base for rates among customer
2 classes and drive the price signals that are sent to ratepayers. They should therefore match the
3 resource demands of the Company.
4 Second, the PURPA resource mix has grown in both KW and the number of QF units that
5 are on line. In addition, they are significantly diverse and large enough that their capacity can be
6 relied on. One of the advantages of CSPP resources is, as a collective group, it is a reliable
7 resource. It is true CSPP is not dispatched by the Company as one of their own resources.
8 However, in a collective sense they are reliable. If one of the Company's resources goes down,
9 Idaho Power loses all of the output of that given resource. There are nearly 100 PURPA units on
10 Idaho Power;s system; if any one, or even several, of these PURPA resources becomes
11 unavailable, the others will still be providing power to the system. I prepared Exhibit 207 to
12 show the PURPA cumulative KW and the number of units on Idaho Power's system.
13 As can be seen from Exhibit 207, PURPA resources together provide Idaho Power with a
14 resource that contributes capacity to the system. Because it contributes capacity, it is rational to
15 assign a percentage of its output to capacity.
16 **Q. HOW DO PURPA RESOURCES SUPPLY CAPACITY VALUE TO IDAHO**
17 **POWER OVER THE COURSE OF THE YEAR?**
18 A. As shown in my Exhibit 208, PURPA resource output is consistently much higher during
19 the summer months when the Company is most in need of additional power and when system
20 peaks are occurring. With large number of diverse PURPA projects on line, Idaho Power can
21 rely on PURPA resources to help meet its summer peaks. [Response to ICIP Fourth Production
22 Request, No. 9, 10.]

1 **Q. WHAT ARE THE IMPACTS ON COST OF SERVICE IF PURPA RESOURCES**
2 **ARE ALLOCATED IN THE SAME MANNER AS OTHER COMPANY RESOURCES?**
3 A. I prepared Exhibit No. 209 to show the changes to the Company's Base Case caused by
4 the reassignment of PURPA to match the method the Company uses to assign its other resources
5 for capacity and energy. This change has about the same impact as weighting at full marginal
6 cost described above with the high load factor customers receiving lower increases. The major
7 difference is that the residential class would now receive a slightly larger increase as opposed to a
8 decrease.
9 **Q. PLEASE EXPLAIN THE THIRD MODIFICATION YOU ARE**
10 **RECOMMENDING BE MADE TO THE COST OF SERVICE STUDY PRESENTED BY**
11 **THE COMPANY?**
12 A. On pages 4 and 5 of his testimony, Company witness Tatum states,

13 Demand related costs are investments in generation, transmission, and a portion of
14 the distribution plant and the associated operation and maintenance expenses
15 necessary to accommodate the maximum demand imposed on the Company's
16 system. Energy related costs are generally the variable costs associated with the
17 operation of the generating plants, such as fuel. However, due to the hydro
18 production capability of the Company, a portion of the hydro and thermal
19 generating plant investment has historically been classified as energy-related.
20 [Pages 4 – 5.]

21 He goes on to say,

22 Q. What did you use as your primary guide in classifying costs as customer-,
23 demand-, or energy related?
24 A. I used the Electric Utility Cost Allocation Manual published by the National
25 Association of Regulatory Utility Commissioners [NARUC] as my primary guide

to the classification of customer-, demand-, and energy-related costs. [Page 5.] According to the NARUC Cost Allocation Manual relied upon by Mr. Tatum, hydro facilities are usually treated as capacity. Mr. Tatum is correct that 'traditionally' the Company has treated, and the Commission has accepted, the allocation of Company's hydro resources to energy. As explained above, when the Company was energy (as opposed to capacity) constrained, this made sense. As noted above, Idaho Power is now capacity constrained and not energy constrained. Furthermore, it is adding additional resources which reduce its reliance on hydro resources. It therefore now makes sense to allocate its hydro resources more to capacity rather than to energy.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ASSIGNMENT OF HYDRO RESOURCES BETWEEN ENERGY AND CAPACITY?

A. A reasonable method for allocating Idaho Power's hydro resources between capacity and energy is to assign 75% to capacity and 25% to energy. This is the same allocation used by PacifiCorp in that company's cost of service in its current rate case that is pending before this Commission. PacifiCorp's witness testified that, "Production and transmission plant and non-fuel related expenses are classified as 75 percent demand related and 25 percent energy related" [PAC-E-07-05, Rocky Mountain Power, Mark E. Tucker, Di-4]. It is my understanding this capacity/energy split was established in the Multi-State Process used by the various state commissions that regulate PacifiCorp.

Q. ARE THERE OTHER WAYS TO ALLOCATE HYDROELECTRIC RESOURCES?

A. Yes. There are a variety of ways hydro facilities can be allocated. They range from 100% to demand related to some mixture between demand and energy. This allocation of 75%

1 to capacity and 25% to energy is reasonable for hydro plants. The NARUC Cost Allocation
2 Manual states, "Most hydro capacity today is being used for peaking purposes, and its costs
3 therefore are properly classified as demand-related." [Electric Utility Cost Allocation Manual,
4 NARUC, 1967, footnote page 33.] While the Company has numerous run-of-river facilities, its
5 major hydro complex is Hells Canyon which is used for peaking.

6 **Q. WHAT IS THE RESULT OF YOUR RECOMMENDATION THAT**
7 **HYDRO RESOURCES BE ASSIGNED 75% TO CAPACITY AND 25% TO ENERGY?**

8 A. Exhibit 210 displays the results of allocating the Company's hydro resources 75% to
9 capacity and 25% to energy. This modification produces approximately the same result as
10 reclassifying PURPA projects at the system average between capacity and energy. With this
11 change, the revenue requirement for high load factor customers is lowered and the residential
12 class would experience a slightly higher increase. In addition, as was true with the other two
13 recommended changes, the irrigation class receives a higher percent increase.

14 **Q. YOU HAVE INDICATED WHAT THE RESULTS ARE FOR EACH OF**
15 **YOUR THREE RECOMMENDED CHANGES INDEPENDENTLY. WHAT IS THE**
16 **CUMULATIVE IMPACT IF ALL THREE ARE IMPLEMENTED?**

17 A. These results are shown in Exhibit 211. When the three modifications are made
18 simultaneously, the high load factor customers' revenue requirement increases are lowered into
19 single digit percentage. The percentage increase for irrigation class is increased to 72%. The
20 residential class shows a decrease of 2.2%.

21 **Q. YOU HAVE DESCRIBED THREE CHANGES TO THE COMPANY'S**
22 **COST OF SERVICE METHODS. ARE YOU ADVOCATING THAT THESE CHANGES**

1 **BE IMPLEMENTED BY THE COMMISSION?**

2 A. If the Commission chooses to use a cost of service study to allocate rates among customer
3 classes, I would recommend using the Company's Base Case as modified by my three
4 recommended changes described above. I am concerned, however, by the fact that even with my
5 changes, the cost of service studies are still not sending the correct price signals to customer
6 classes. With my changes, the revenue requirement for the high load factor customers is lowered
7 appropriately. However, even with my changes, the residential class is not seeing the appropriate
8 cost causation price signal. This is so, even though we know new residential load is a major
9 cause of the Company's need for new generation plant. The results of my three changes also
10 increase the revenue requirement for the irrigation class by over $20 million. The irrigation class
11 has the misfortune of having their need for power during summer peak which is when the
12 Company's system needs are growing the fastest. Unlike the residential class, the Irrigation class
13 is not growing. Yet due to increasing residential and commercial demand in the summer, the
14 irrigation class' allocations increase their share of Company costs.

15 **Q. YOU SAID "IF" THE COMMISSION CHOOSES TO USE A COST OF SERVICE**
16 **TO ALLOCATE RATES AMONG CUSTOMER CLASSES. DOES THAT MEAN, EVEN**
17 **GIVEN YOUR RECOMMENDED CHANGES, THAT YOU ARE NOT**
18 **RECOMMENDING THE USE OF A COST OF SERVICE STUDY FOR RATE**
19 **ALLOCATION IN THIS CASE?**

20 A. Even with my modifications, the fundamental problems in the allocation of costs among
21 Idaho Power's customer classes are not solved. These fundamental problems that are occurring
22 within the cost of service studies presented by the company create perverse results.

1 **Q. WHAT PERVERSE RESULTS ARE YOU REFERRING TO?**

2 A. It does not make sense that a stagnant (or even shrinking) class like the irrigators are
3 being saddled with the responsibility to cover the costs of new plant used to serve the burgeoning
4 residential and commercial classes. It makes even less sense for another class, like the industrial
5 class, whose load has also been static over the last decade and whose load is pretty much flat
6 year-round to now suddenly be targeted for disproportionate increases in order to pay for new
7 plant used to serve the residential and commercial classes. Finally, it certainly defies logic for
8 these cost of service studies to indicate that, even in the face of an overall ten percent increase,
9 that the residential rates should actually decrease. From an economic standpoint, the cost of
10 service studies, even when corrected as best I can, result in perverse outcomes.

11 **Q. IN LIGHT OF THE PERVERSE RESULTS YOU IDENTIFY, WHAT DO YOU**
12 **RECOMMEND THIS COMMISSION DO?**

13 A. For this case, the most equitable solution is an equal percentage increase for all customer
14 classes. While not solving the problem, it would buy us time, without causing undue damage, to
15 find a solution. I recommend the parties investigate new cost of service approaches that produce
16 results more in line with what we all know is driving the Company's resource acquisition
17 strategy and hence higher costs. Unless an alternative approach is found, it appears the
18 methodology that has been used in the past will continue to produce counter-intuitive results and
19 yield perverse price signals. That is simply an unacceptable result.

20 **<u>Load Growth Adjustment</u>**

21 **Q. COMPANY WITNESS SAID ADVOCATES SETTING THE LOAD**
22 **GROWTH ADJUSTMENT AT $29.16 PER MWH. DO YOU CONCUR WITH THIS**

1 **VALUE?**

2 A. No. The load growth adjustment was litigated just one year ago in signal issue Docket
3 No. IPC-E-06-08. In that case, the Commission clearly states the load growth adjustment should
4 be based on the Company's estimate of marginal cost found in its marginal cost studies,

5 We continue to find it reasonable to use a marginal cost based number to establish
6 the expense adjustment rate for the load growth component of the PCA formula
7 for annual true-ups. We adopt the $29.41 MWh adjustment factor proposed by
8 Staff in the Company's IPC- 03-13 rate case. We find this number to be derived
9 from the $27.01 MWh marginal generation cost in the Company's 2003 Marginal
10 Cost Analysis study, adjusted for 8.9% line losses. [Idaho Public Utilities
11 Commission, Order No. 30215, IPC-E-06-08, p. 11.]

12 The Company is again attempting, as it did in IPC-E-06-08, to redefine what the Commission
13 originally understood and meant when it established the PCA. In the IPC-E-06-08 case I
14 testified:

15 I agree with the Idaho Commission's decision in the original PCA case to set the
16 load growth adjustment based on the marginal costs of serving new load. The
17 Company's arguments presented in this docket simply rehash an issue settled by
18 the Commission some time ago, when it established the PCA. The underlying
19 reasons for setting the load growth adjustment based on the marginal costs of
20 serving new load remain sound and compelling.

21 The past 12 months have not changed my mind. I consider the Company's attempts to use its
22 definition of 'incremental' costs and a substitute for marginal cost as a rehash of a rehash. A

1 review of the filings and Order in case IPC-E-06-08 fully explains the load growth adjustment
2 and the Commission's rationale for its decision. Since that case was litigated just one year ago
3 these issues need not be revisited here.

4 **Q. WHAT LOAD GROWTH VALUE ARE YOU PROPOSING FOR USE IN**
5 **THE COMING PCA?**

6 A. As shown in Exhibit Nos. 203 and 204, the Company's marginal cost studies show that
7 the marginal cost of energy has increased from $39.9 per MWh in Case No. IPC-E-03-13 to
8 $70.9 per MWh in the current case. Mr. Said indicates a five year average value of $71.58 per
9 MWh (including line losses) for the Company's marginal cost, with a single test year value of
10 $67.74 per MWh. Either one of these values would fit the Commission's definition of marginal
11 cost and could be used for the load growth adjustment in the PCA. These values fit what the
12 Company itself defines as marginal cost and is driven, as discussed above, by the Company's
13 choice of new generation units to meet its growing loads.

14 **<u>Distributed Generation</u>**

15 **Q. DO YOU HAVE ANY COMMENTS ON IDAHO POWER'S PROGRESS IN THE**
16 **AREA OF DISTRIBUTED GENERATION?**

17 **A.** I think this is an important area that Idaho Power has been neglecting in its resource
18 planning – especially in meeting peak demand. As the Commission knows, Idaho Power now
19 relies on expensive natural gas fired peak plants to meet summer and, at times, winter peaks.
20 The industrial customers opposed the construction of those plants because of the availability of
21 less expensive alternatives such as the "Virtual Peaking Program" that had been successfully
22 offered by PGE in Portland, Oregon.

1 **Q. WHAT WAS YOUR RECOMMENDATION IN IDAHO POWER'S**
2 **PROCEEDING TO OBTAIN A CERTIFICATE OF CONVENIENCE AND NECESSITY**
3 **TO CONSTRUCT THE EVANDER ANDREWS NATURAL GAS PEAKING PLANT?**
4 **A.** I testified in Case No. IPC-E-06-09 that Portland General Electric (PGE) had established
5 a Dispatachable Standby Generation (DSG) program through which it acquired a significant
6 virtual peaking plant at a low cost. In exchange for the right to dispatch its customers'
7 emergency back up generators during time of system peak, PGE provides the fuel and
8 maintenance for those generators. I reported that in 2006, PGE successfully dispatched 26.5
9 megawatts of customer owned generation to help meet system peak.
10 **Q. WHAT IS THE COST OF SUCH A SYSTEM?**
11 **A.** I testified that the cost of using customer owned back up generation to meet system peak
12 was approximately one-half of what then current estimates of cost of the construction of a simple
13 cycle combustion turbine.
14 **Q. WHAT WAS YOUR RECOMMENDATION TO THE COMMISSION IN LIGHT**
15 **OF YOUR FINDINGS ABOUT PGE'S DISPATCHABLE STANDBY GENERATION?**
16 **A.** I recommended that no certificate of convenience and necessity for Evander Andrews be
17 issued pending an investigation into the size of this potential resource that is available for Idaho
18 Power's use.
19 **Q. WHAT WAS THIS COMMISSION'S ORDER IN RESPONSE TO YOUR**
20 **TESTIMONY?**
21 A. Although the Commission granted Idaho Power a certificate of convenience and necessity
22 to construct the Evander Andrews plant, it did order Idaho Power to:

1 [I]nvestigate and submit a report for the implementation of a "virtual peaking
2 plant" program based upon the use of existing emergency generator resources in
3 the Company's service territory. This report shall be filed no later than June 1,
4 2007. [Order No. 30201 at p. 12.]
5 The Commission also indicated it was "particularly interested" in the virtual peaking
6 program.
7 **Q. HOW DO YOU INTERPRET THE COMMISSION'S DIRECTIVE TO IDAHO**
8 **POWER?**
9 **A.** I think the Order speaks for itself. Idaho Power was directed to file a report on how it
10 plans to implement a virtual peaking plant program.
11 **Q. DID IDAHO POWER COMPLY WITH THE COMMISSION'S DIRECTIVE?**
12 **A.** I do not believe they fully complied with the Commission's Order.
13 **Q. WHY NOT?**
14 **A.** To be fair, the Company did file a report on June 1, 2007, the day of the filing deadline. I
15 would hope a Company trying to get such a program off the ground would be more enthusiastic
16 about meeting the Commission's Order rather than just complying with the minimum
17 requirement of filing a report on the due date.
18 **Q. WHAT WAS IN THE REPORT?**
19 **A.** I have attached the entire three page report as Exhibit No. 212. The report concludes:
20 The Company plans to conduct the interconnection cost estimate analyses over the
21 next three months. Once detailed interconnection cost information is available,
22 the Company will update its financial analysis to determine if a "virtual peaker"

1 program is economically viable and submit a detailed report of its findings to the
2 Commission.

3 **Q. HAVE ANY ADDITIONAL VIABILITY REPORTS BEEN FILED WITH THE**
4 **COMMISSION SINCE JUNE 1?**

5 **A.** Not that I am aware.

6 **Q. WHY DO YOU CONCLUDE THAT THE COMPANY DID NOT FULLY**
7 **COMPLY WITH THE COMMISSION'S ORDER WITH RESPECT TO A VIRTUAL**
8 **PEAKER PROGRAM?**

9 **A.** Because the Order required Idaho Power to investigate and submit a report for the
10 implementation of a virtual peaker program. The June 1, 2007, report states that Idaho Power
11 has yet to determine if a peaker program is economically viable. In other words, the report
12 simply stated that the investigation the Commission wanted completed by June first was just
13 getting started. For example, the report observes that "Idaho Power hopes to identify four to six
14 customers who are willing to work with company personnel…" -- hardly a bold statement of a
15 utility looking for lower cost solutions to its power supply problems.

16 **Q. DO YOU KNOW THE CURRENT STATUS OF PGE'S DISPATACHABLE**
17 **STANDBY GENERATION PROGRAM?**

18 **A.** Since I last testified in 2006 that PGE had 25.5 MW of DSG on line, that utility has added
19 an added an additional 18 MW for a current total of 43 MW on line. It also currently has 17
20 more under active development and plans to add an additional 80 MW. In other words, in the
21 time it took Idaho Power to file a report in which it states it "hopes to identify 4 to 6 customers to
22 work with", PGE added 18 megawatts to its system and is actively developing 17 more.

1 Attached as Exhibit 213 are materials PGE is using to promote and explain its virtual peaking
2 program for its customers. It has signed up universities, water treatment plants, military
3 facilities, correctional facilities, data centers, lumber mills, bank operations, and semi conductor
4 plants – to just name a few. It has connected facilities as small as 0.4 MW and as large as 2.8
5 MW.

6 **Q. WHAT DO YOU CONCLUDE FROM YOUR UNDERSTANDING OF THE PGE**
7 **PROGRAM AND IDAHO POWER'S RESPONSE TO THE COMMISSION'S**
8 **DIRECTIVE IN THE EVANDER ANDREWS PROCEEDING?**

9 **A.** Given the obvious success of the PGE program, it would be reasonable for Idaho Power
10 to use what that company has learned rather than building a virtual peaking program from the
11 ground up – as it appears to be doing. It is difficult to know from the Report filed on June 1,
12 2007, exactly what the Company has been doing. I have to conclude that Idaho Power must be
13 more interested in building expensive new plant to meet its future peak loads rather than
14 aggressively looking at alternative resources such as virtual peaking resources.

15 **Q. DOES THE ICIP OFFER ANY OTHER RESOURCE SOLUTIONS THAT IDAHO**
16 **POWER COULD TAKE ADVANTAGE OF?**

17 **A.** Yes. Strung across southern Idaho is a series of large natural gas consuming food
18 processing plants that are ideal for siting what are called combined heat and power plants. These
19 systems, also known as cogeneration plants are an efficient and cost effective method of
20 generating electricity. The ICIP's members are more than happy to work with Idaho Power to
21 develop the full potential of these resources to help meet Idaho Power's growing system load.
22 However, it is my experience that Idaho Power is unwilling to assume fuel cost risk escalations

1 when exploring such options. That is short sighted because the ratepayers are already assuming
2 all of the fuel price risk when Idaho Power builds new gas fired peakers.
3 **Time of Use Rates:**
4 **Q. CAN YOU OFFER A REPORT ON THE SUCCESS, OR LACK THEREOF, OF**
5 **THE MANDATORY TIME OF USE RATE SCHEDULE IMPOSED ON THE**
6 **INDUSTRIAL CUSTOMERS?**
7 A. Yes. Idaho Power was allowed to impose mandatory time of use rates on the Schedule 19
8 customers by this Commission in IPC-E-03-13 in Order No. 29505. The Industrial Customers
9 opposed mandatory time of use rates at that time and they still oppose mandatory time of use
10 rates.
11 **Q. WHAT IS THE BASIS OF THE OBJECTION OF THE INDUSTRIAL**
12 **CUSTOMERS TO MANDATORY TIME OF USE RATE?**
13 A. We did not support time of use rates because of the belief that the Schedule 19 class
14 would not be able to adjust its load usage pattern to maximize the potential savings of moving
15 load to off peak times. Experience has borne that out. Whenever I discuss this issue with the
16 members of the ICIP, I am reminded of the uselessness of this rate product. It is exceedingly
17 complex and industrial users are simply not responding to the "price signals" being sent by the
18 time of use rates. Potato processors are not able to shift refrigeration load to cooler times of the
19 day. Large office buildings are not able to run graveyard shifts and maintain employee morale.
20 Meat packers and other food processors are at the mercy of when their product is available for
21 processing.

1 **Q. IS THE OPPOSITION TO TIME OF USE RATES UNIVERSAL AMONG THE**

2 **INDUSTRIAL CUSTOMERS?**

3 A. Within the Industrial Customers of Idaho Power, opposition is pretty much universal.

4 That is not to say, however, that there may be an industrial customer who may be able to take

5 advantage of time of use rates. That said, the classes that are best suited to being able to respond

6 to time of use rates are the residential class, the irrigation class and, I think to a lesser extent, the

7 commercial class.

8 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO MANDATORY TIME OF**

9 **USE RATES FOR THE INDUSTRIAL CLASS?**

10 A. I recommend they be offered only as a voluntary optional rate. Certainly if there are

11 industrial customers who can take advantage of time of use rates they should be encouraged to do

12 so. However, experience has shown that time of use rates are not very effective with the vast

13 majority of industrial customers.

14 **Q. DOES THIS END YOU TESTIMONY AS OF DECEMBER 7, 2007?** A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 10th day of December, 2007 a true and correct copy of the within and foregoing DIRECT TESTIMONY OF DON C. READING, Ph.D. was filed with the Idaho Public Utilities Commission and parties as indicated below:

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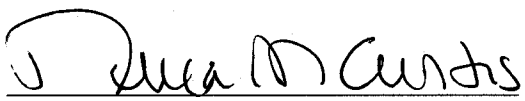


Nina M. Curtis

EXHIBIT NO. 201

Reading, DI
Industrial Customers
of Idaho Power

Don C. Reading

Present position	Vice President and Consulting Economist
Education	B.S., Economics C Utah State University M.S., Economics C University of Oregon Ph.D., Economics C Utah State University
Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 ---- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University
Firm experience	Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, Texas, Utah, Wyoming, and Washington. Dr. Reading has more than 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates. In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature=s Committee on Electric Restructuring.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination. He is currently a adjunct professor of economics at Boise State University (Idaho economic history, urban/regional economics and labor economic.)

Dr. Reading has recently completed a public interest water rights transfer case. He has also just completed an economic impact analysis of the 2001 salmon season in Idaho.

Publications

"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/history/issuesonline/fall2006_issues/index.html

The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003.

The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999.

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997.

ACost Savings from Nuclear Resources Reform: An Econometric Model@ (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983.

An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980.

Phosphate and Southeast: A Socio Economic Analysis (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975.

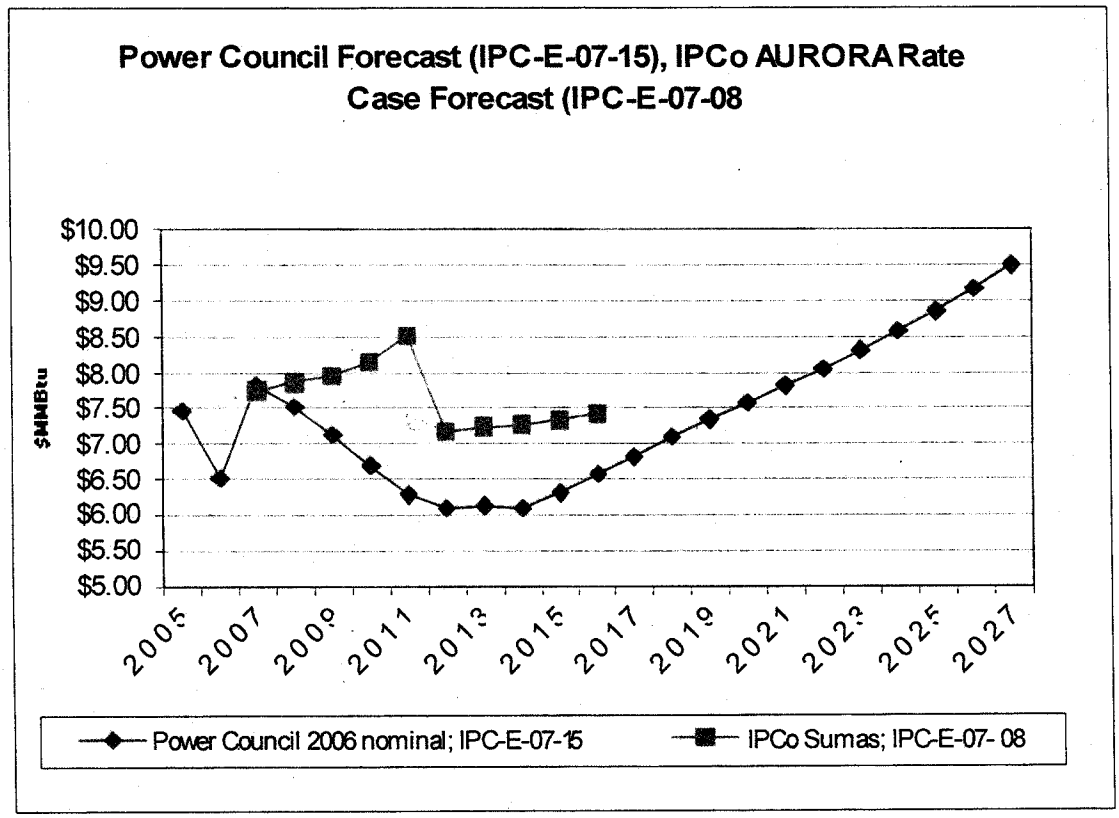
Estimating General Fund Revenues of the State of Idaho (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975.

"A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128.

"New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.

EXHIBIT NO. 202

Reading, DI
Industrial Customers
of Idaho Power



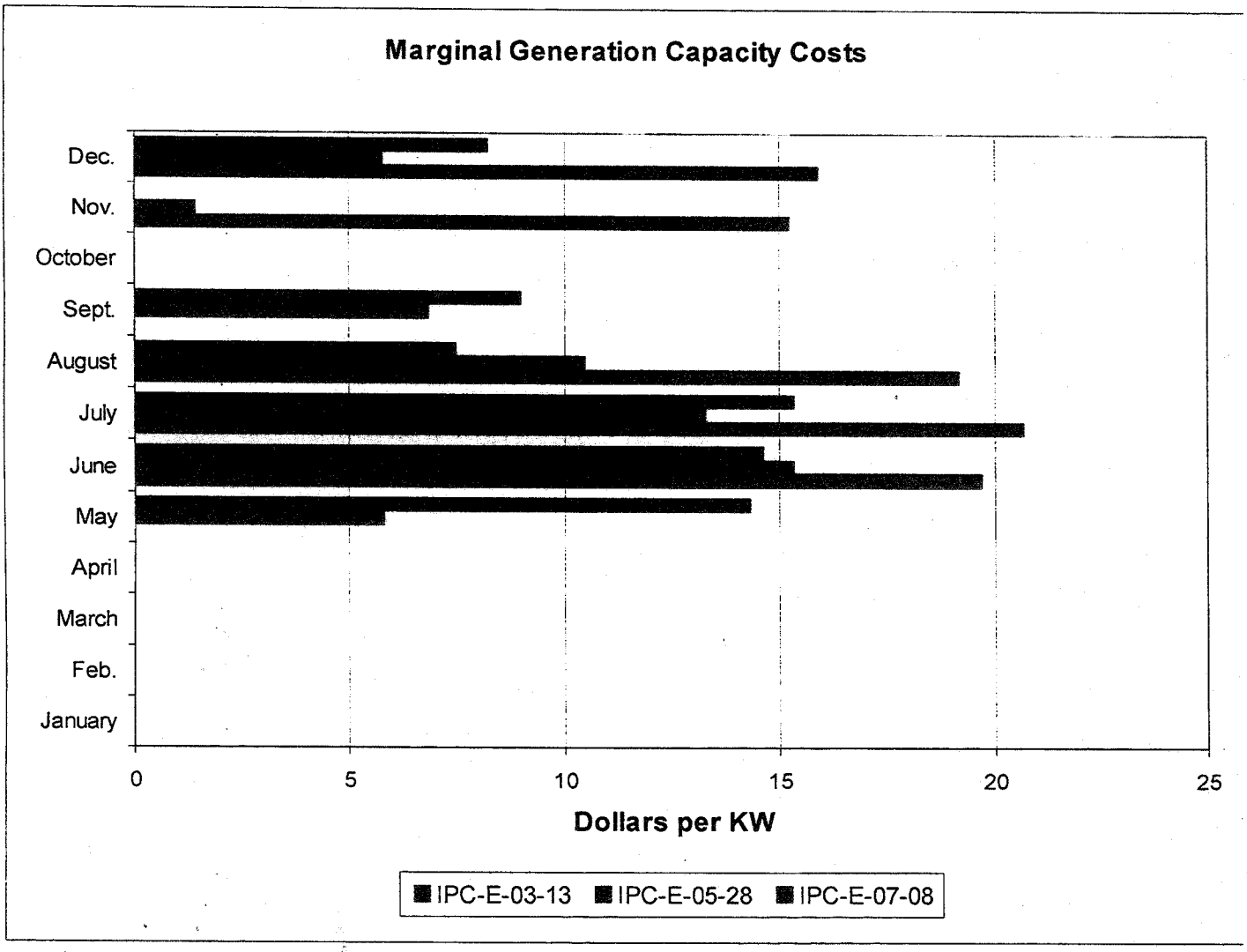
The IPCo Sumas; IPC-E-07-08 forecast (top line) is being used to set rates in the general rate case. The Power Council 2006 nominal; forecast (bottom line) is being used to set rates in Idaho Power avoided cost rate setting proceeding.

Reading, DI
Industrial Customers
of Idaho Power

EXHIBIT NO. 202

EXHIBIT NO. 203

Reading, DI
Industrial Customers
of Idaho Power

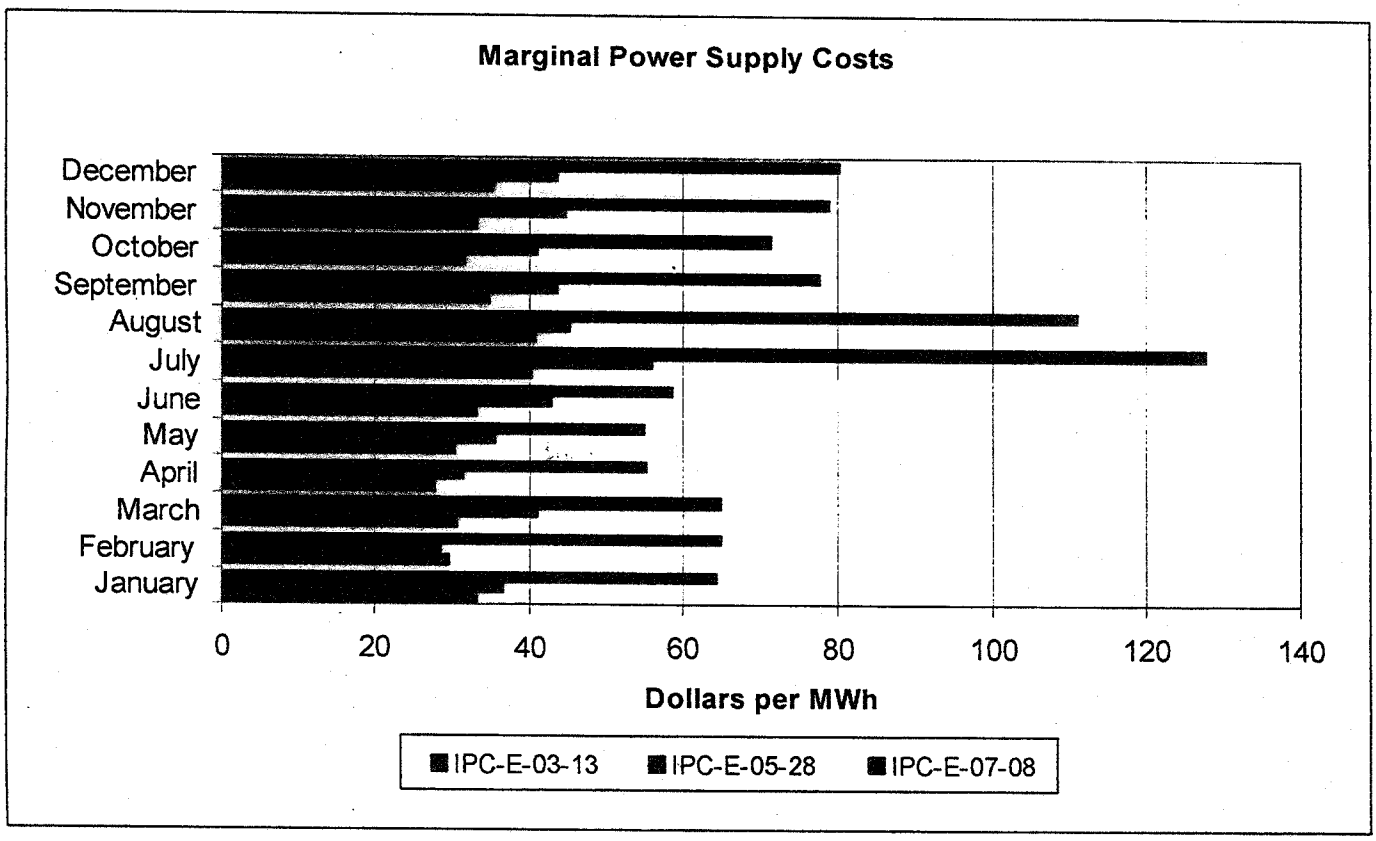


Reading, DI
Industrial Customers
of Idaho Power

EXHIBIT NO. 203

EXHIBIT NO. 204

Reading, DI
Industrial Customers
of Idaho Power



Reading, DI
Industrial Customers
of Idaho Power

EXHIBIT NO. 204

EXHIBIT NO. 205

Reading, DI
Industrial Customers
of Idaho Power

IDAHO POWER RATE CASE POWER SUPPLY COST
IPC-E-07-08

	2007 After PURPA & Horizon Annual	2007 Prices mills/kwh
Hydroelectric Generation (mwh)	8,748,179.7	
Bridger		
Energy (mwh)	5,052,875.3	
Cost ($ x 1000)	$73,318.8	14.51
Boardman		
Energy (mwh)	422,213.2	
Cost ($ x 1000)	$5,874.6	13.91
Valmy		
Energy (mwh)	1,826,704.5	
Cost ($ x 1000)	$40,291.4	22.06
Danskin		
Energy (mwh)	2,970.9	
Cost ($ x 1000)	$292.1	
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$2,826.5	
Total Cost	$3,118.6	1,049.72
Bennett Mountain		
Energy (mwh)	45,890.0	
Cost ($ x 1000)	$3,967.3	
Fixed Capacity Charge - Gas Transportation ($ x 1000)		
Total Cost	$3,967.3	86.45
Purchase Power (Excluding CSPP)		
Market Energy (mwh)	401,368.2	
Contract Energy (mwh)	406,843.9	
Total Energy Excl. CSPP (mwh)	808,212.1	
Market Cost ($ x 1000)	$37,984.5	94.64
Contract Cost ($ x 1000)	$19,299.4	47.44
Total Cost Excl. CSPP ($ x 1000)	$57,283.9	70.88
Purchase mills per kWh Total	*70.9*	
Surplus Sales		
Energy (mwh)	2,950,604.2	
Revenue Including Transmission Costs ($ x 1000)	$145,834.2	49.43
Transmission Costs ($ x 1000)	$2,950.6	1.00
Revenue Excluding Transmission Costs ($ x 1000)	$142,883.6	48.43
Sales mills per kWh include Trans	*48.4*	
Net Purchase-Sales	*$85,599.7*	
Power Supply Costs ($ x 1000)	$40,971.0	

Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 205

EXHIBIT NO. 206

Reading, DI
Industrial Customers
of Idaho Power

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
BASE CASE AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	$63,945,258	$333,283	$2,364,385	$1,656,375	$11,538,519	($179,041)	$11,310,928	$30,168,247	$12,688	$101,348	$29,541	$1,160,379	$1,167,597	$4,281,010
'ERCENT CHANGE REQUIRED	10.35%	0.11%	15.37%	12.97%	9.14%	19.23%	17.17%	42.64%	1.44%	4.93%	15.67%	21.55%	25.07%	22.97%
RETURN AT CLAIMED ROR	$161,175,457	$70,851,373	$3,767,205	$3,611,745	$33,161,091	$78,210	$18,104,719	$23,662,175	$208,689	$249,453	$48,681	$1,369,270	$1,424,294	$4,638,553
EARNINGS DEFICIENCY	$38,943,519	$202,974	$1,439,942	$1,008,754	$7,027,113	($109,035)	$6,888,507	$18,372,866	$7,727	$61,722	$17,991	$706,686	$711,082	$2,607,192
BASE CASE; FULL WEIGHTED MARGINAL COST														
REVENUE DEFICIENCY	$63,945,252	($6,817,685)	$2,353,548	$1,548,434	$10,961,351	($190,438)	$9,766,531	$41,678,141	$6,887	$71,613	$21,944	$740,228	$974,532	$3,726,987
'ERCENT CHANGE REQUIRED	10.35%	2.32%	15.30%	12.12%	8.68%	20.45%	14.83%	58.91%	0.78%	3.48%	11.64%	13.75%	20.92%	20.00%
RETURN AT CLAIMED ROR	$161,175,457	$69,709,486	$3,769,444	$3,592,711	$33,059,316	$76,442	$17,893,501	$25,395,571	$208,337	$245,021	$47,566	$1,305,446	$1,395,459	$4,562,903
EARNINGS DEFICIENCY	$38,943,515	($4,152,061)	$1,433,342	$943,017	$6,675,610	($115,979)	$5,947,948	$25,382,546	$4,195	$43,613	$13,364	$450,809	$593,503	$2,269,785

Exhibit 206
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 207

Reading, DI
Industrial Customers
of Idaho Power

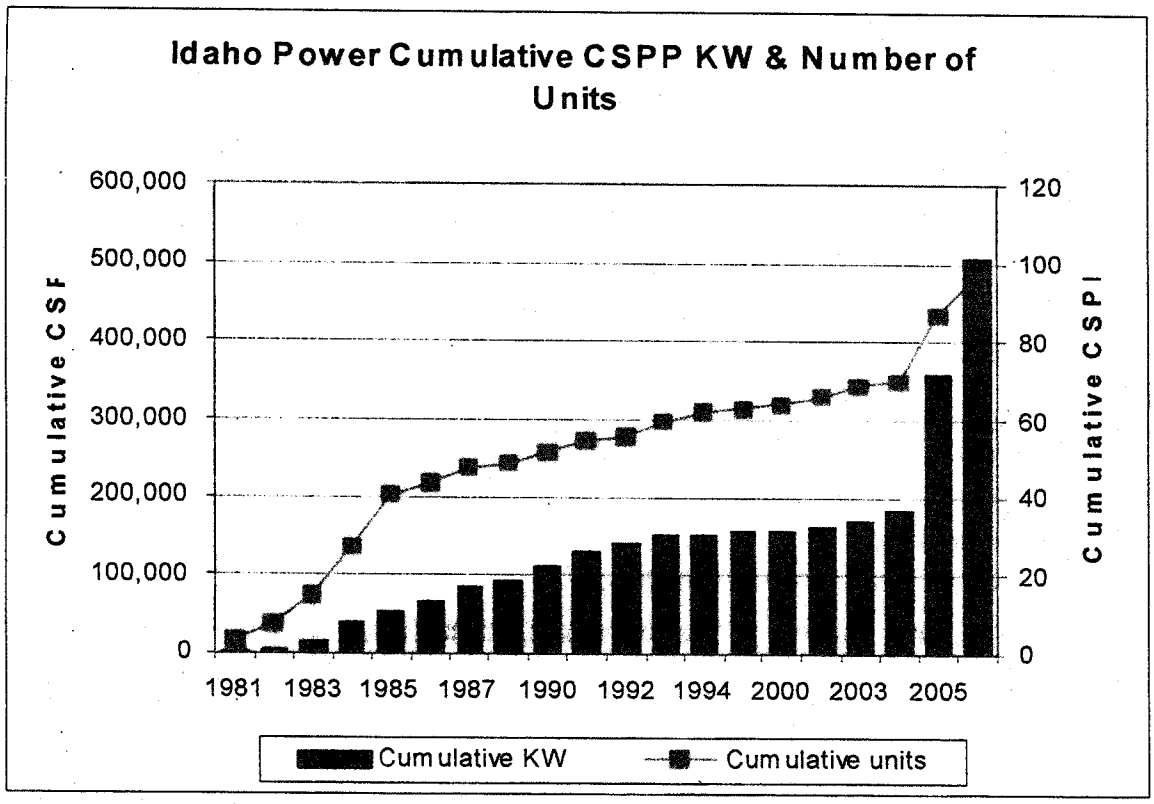


Exhibit 207
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 208

Reading, DI
Industrial Customers
of Idaho Power

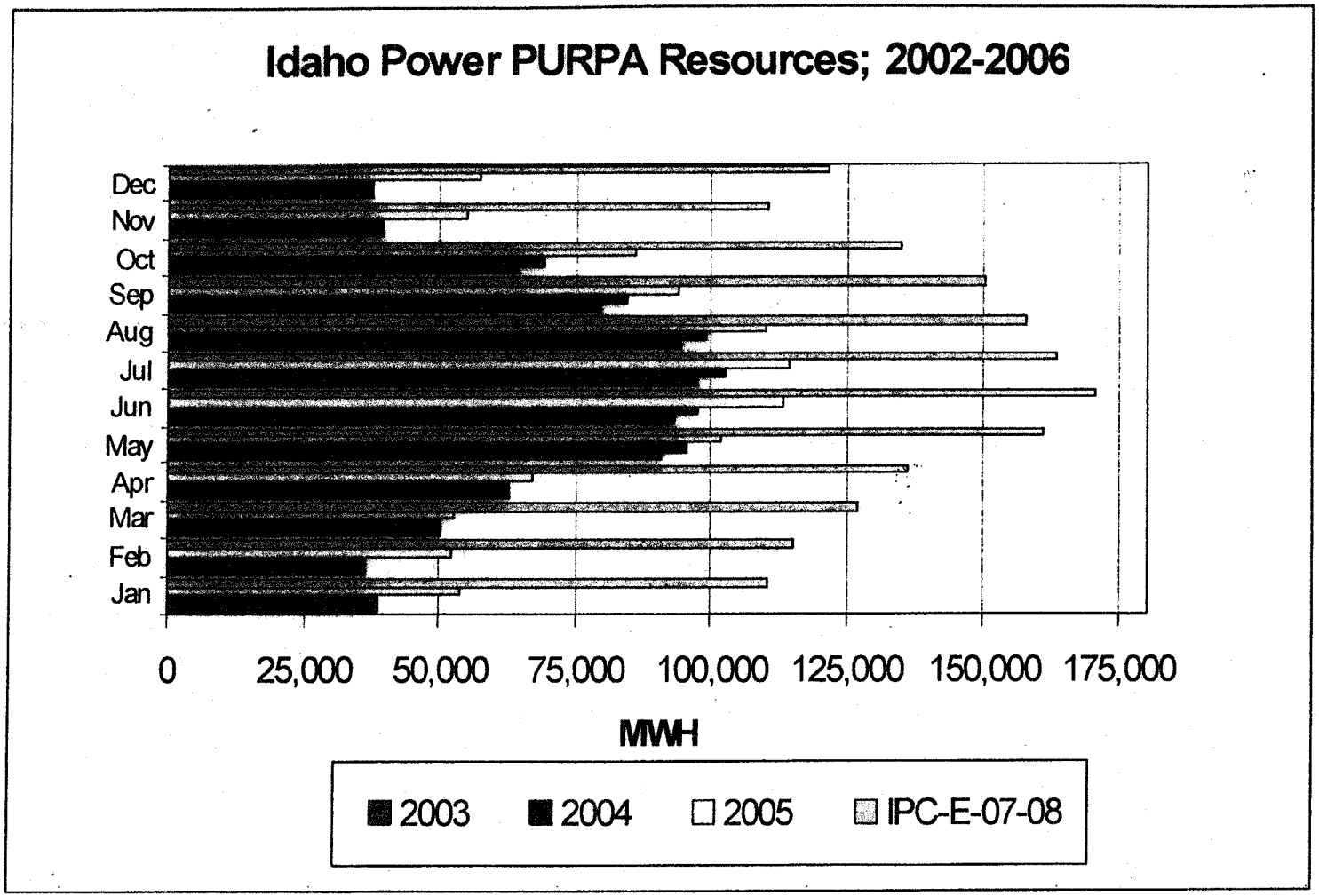


Exhibit 208
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 209

Reading, DI
Industrial Customers
of Idaho Power

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	TOTAL	RESIDENTIAL	GEN SRV	GEN SRV PRIMARY	GEN SRV SECONDARY	AREA LIGHTING	LG POWER PRIMARY	IRRIGATION SECONDARY	UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
		(1)	(7)	(9-T)	(9-P)	(9-S)	(19-P)	(24-S)	(40)	(41)	(42)			
BASE CASE AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	$63,945,258	$333,283	$2,364,385	$1,656,375	$11,538,519	($179,041)	$11,310,928	$30,168,247	$12,688	$101,348	$29,541	$1,160,379	$1,167,597	$4,281,010
PERCENT CHANGE REQUIRED	10.35%	0.11%	15.37%	12.97%	9.14%	-19.23%	17.17%	42.64%	1.44%	4.93%	15.67%	21.55%	25.07%	22.97%
RETURN AT CLAIMED ROR	$161,175,457	$70,851,373	$3,767,205	$3,611,745	$33,161,091	$78,210	$18,104,719	$23,662,175	$208,689	$249,453	$48,681	$1,369,270	$1,424,294	$4,638,553
EARNINGS DEFICIENCY	$38,943,519	$202,974	$1,439,942	$1,008,754	$7,027,113	($109,038)	$6,888,507	$18,372,866	$7,727	$61,722	$17,991	$706,686	$711,082	$2,607,192
BASE CASE; PURPA RESOURCES SET AS OTHER RESOURCES (.5863 ENERGY/.4147 DEMAND)														
REVENUE DEFICIENCY	63,945,258	3,220,048	2,469,142	1,481,924	10,754,503	(211,154)	9,007,192	32,505,965	(26,146)	(16,053)	19,580	845,879	792,307	3,102,071
PERCENT CHANGE REQUIRED	10.35%	1.09%	16.05%	11.60%	8.52%	-22.68%	13.67%	45.94%	-2.97%	-0.78%	10.39%	15.71%	17.01%	16.64%
RETURN AT CLAIMED ROR	161,175,457	70,851,373	3,767,205	3,611,745	33,161,091	78,210	18,104,719	23,662,175	208,689	249,453	48,681	1,369,270	1,424,294	4,638,553
EARNINGS DEFICIENCY	38,943,519	1,961,053	1,503,740	902,512	6,549,636	(128,596)	5,485,501	19,796,568	(15,923)	(9,777)	11,925	515,152	482,526	1,889,203

Exhibit 209
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 210

Reading, DI
Industrial Customers
of Idaho Power

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-T)	(9-P)	(9-S)	(19-P)	(24-S)	(40)	(41)	(42)			
BASE CASE AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	$63,945,258	$333,283	$2,364,385	$1,656,375	$11,538,519	($179,041)	$11,310,928	$30,168,247	$12,688	$101,348	$29,541	$1,160,379	$1,167,597	$4,281,010
PERCENT CHANGE REQUIRED	10.35%	0.11%	15.37%	12.97%	9.14%	-19.23%	17.17%	42.64%	1.44%	4.93%	15.67%	21.55%	25.07%	22.97%
RETURN AT CLAIMED ROR	$161,175,457	$70,851,373	$3,767,205	$3,611,745	$33,161,091	$78,210	$18,104,719	$23,662,175	$208,689	$249,453	$48,681	$1,369,270	$1,424,294	$4,638,553
EARNINGS DEFICIENCY	$38,943,519	$202,974	$1,439,942	$1,008,754	$7,027,113	($109,036)	$6,888,507	$18,372,866	$7,727	$61,722	$17,991	$706,686	$711,082	$2,607,192

BASE CASE; HYDRO SET AT .25 ENERGY/.75 DEMAND														
REVENUE DEFICIENCY	63,945,258	2,255,006	2,434,122	1,540,243	11,016,598	(200,419)	9,777,328	31,724,469	(13,164)	23,194	22,910	951,016	917,766	3,496,189
PERCENT CHANGE REQUIRED	10.35%	0.77%	15.83%	12.06%	8.73%	-21.52%	14.84%	44.84%	-1.49%	1.13%	12.15%	17.66%	19.70%	18.76%
RETURN AT CLAIMED ROR	161,175,457	71,167,131	3,778,663	3,592,663	33,075,334	74,697	17,852,734	23,917,878	204,441	236,612	47,592	1,334,870	1,383,244	4,509,599
EARNINGS DEFICIENCY	38,943,519	1,373,329	1,482,413	938,028	6,709,256	(122,058)	5,954,524	19,320,627	(8,017)	14,125	13,953	579,181	558,932	2,129,226

Exhibit 210
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 211

Reading, DI
Industrial Customers
of Idaho Power

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
BASE CASE AS FILED BY IDAHO POWER														
REVENUE DEFICIENCY	$63,945,258	$333,283	$2,364,385	$1,656,375	$11,538,519	($179,041)	$11,310,928	$30,168,247	$12,688	$101,348	$29,541	$1,160,379	$1,167,597	$4,281,010
PERCENT CHANGE REQUIRED	10.35%	0.11%	15.37%	12.97%	9.14%	-19.23%	17.17%	42.64%	1.44%	4.93%	15.67%	21.55%	25.07%	22.97%
RETURN AT CLAIMED ROR	$161,175,457	$70,851,373	$3,767,205	$3,611,745	$33,161,091	$78,210	$18,104,719	$23,662,175	$208,689	$249,453	$48,681	$1,369,270	$1,424,294	$4,638,553
EARNINGS DEFICIENCY	$38,943,519	$202,974	$1,439,942	$1,008,754	$7,027,113	($109,038)	$6,888,507	$18,372,866	$7,727	$61,722	$17,991	$706,686	$711,082	$2,607,192
BASE CASE; FULL WEIGHTED MARGINAL COST														
REVENUE DEFICIENCY	$63,945,252	($6,817,685)	$2,353,548	$1,548,434	$10,961,351	($190,438)	$9,766,531	$41,678,141	$6,887	$71,613	$21,944	$740,228	$974,532	$3,726,987
PERCENT CHANGE REQUIRED	10.35%	-2.32%	15.30%	12.12%	8.68%	-20.45%	14.83%	58.91%	0.78%	3.48%	11.64%	13.75%	20.92%	20.00%
RETURN AT CLAIMED ROR	$161,175,457	$69,709,486	$3,769,444	$3,592,711	$33,059,316	$76,442	$17,893,501	$25,395,571	$208,337	$245,021	$47,566	$1,305,446	$1,395,459	$4,562,903
EARNINGS DEFICIENCY	$38,943,515	($4,152,061)	$1,433,342	$943,017	$6,675,610	($115,979)	$5,947,948	$25,382,546	$4,195	$43,613	$13,364	$450,809	$593,503	$2,269,785
BASE CASE; FULL WEIGHTED MARGINAL COST PLUS PURPA RESOURCES SET AS OTHER RESOURCES (.5853 ENERGY/.4147 DEMAND)														
REVENUE DEFICIENCY	$63,945,252	($6,545,078)	$2,490,889	$1,244,025	$9,256,045	($226,234)	$7,224,090	$47,261,139	($28,780)	($53,748)	$10,111	$302,213	$547,025	$2,463,534
PERCENT CHANGE REQUIRED	10.35%	-2.23%	16.19%	9.74%	7.33%	24.30%	10.97%	66.80%	-3.27%	-2.61%	5.36%	5.61%	11.74%	13.22%
RETURN AT CLAIMED ROR	$161,175,457	$69,709,486	$3,769,444	$3,583,596	$32,982,671	$76,442	$17,893,501	$25,395,571	$208,337	$245,021	$47,566	$1,305,446	$1,395,459	$4,562,903
EARNINGS DEFICIENCY	$38,943,515	($3,986,040)	$1,516,985	$757,628	$5,637,056	($137,779)	$4,399,567	$28,782,667	($17,528)	($32,733)	$6,157	$184,052	$333,146	$1,500,325
BASE CASE; FULL WEIGHTED MARGINAL COST PLUS PURPA RESOURCES SET AS OTHER RESOURCES (.5853 ENERGY/.4147 DEMAND) PLUS HYDRO SET AT .25 ENERGY/.75 DEMAND														
REVENUE DEFICIENCY	$63,945,250	($6,363,606)	$2,582,317	$1,104,836	$8,654,391	($250,063)	$5,531,582	$50,977,747	($52,524)	($137,201)	$2,233	$10,625	$262,433	$1,622,451
PERCENT CHANGE REQUIRED	10.35%	-2.16%	16.79%	8.65%	6.86%	-26.86%	8.40%	72.05%	-5.96%	-6.67%	1.18%	0.20%	5.63%	8.71%
RETURN AT CLAIMED ROR	$161,175,457	$69,739,303	$3,784,466	$3,560,726	$32,883,813	$72,527	$17,615,405	$26,006,246	$204,435	$231,309	$46,272	$1,257,536	$1,348,698	$4,424,705
EARNINGS DEFICIENCY	$38,943,514	($3,875,521)	$1,572,666	$672,860	$5,270,640	($152,292)	$3,368,808	$31,046,131	($31,988)	($83,557)	$1,360	$6,471	$159,825	$988,095

Exhibit 211
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

EXHIBIT NO. 212

Reading, DI
Industrial Customers
of Idaho Power

IDAHO POWER.
An IDACORP Company

2007 JUN -1 PM 2:45
IDAHO PUBLIC
UTILITIES COMMISSION

June 1, 2007

IPC-E-06-09

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

RE: Virtual Peaker Program
Case No. IPC-E-06-09

Dear Ms. Jewell:

Enclosed please find eight copies of Idaho Power's Virtual Peaking Program status report. This report is filed in compliance with the Idaho Public Utilities Commission Order No. 30201.

The Company previewed the information included in this report with Commission Staff and the Industrial Customers of Idaho Power on May 15th, 2007. As stated in this report, the Company will submit a detailed report of its findings to the Commission after the completion of its "Engineering Analysis Pilot Program" and updated financial analysis.

If you have any questions regarding this filing, please do not hesitate to contact me.

Sincerely,

Courtney Waites
Pricing Analyst

CW:cw

cc: Ric Gale
Maggie Brilz

Exhibit 212
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08

Pricing & Regulatory Services
Voice: 208-388-5612
Fax: 208-388-6449
cwaites@idahopower.com

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

IDAHO POWER®
An IDACORP Company

2007 MAY -1 PM 2:49
IDAHO PUBLIC UTILITIES COMMISSION

IPC-E-06-09

VIRTUAL PEAKER PROGRAM

Background

Over the past ten years, Idaho Power has periodically investigated the possibility of implementing a distributed generation program as an alternative resource to help meet peak demands. In the fall of 2006, the Company once again began investigating the potential for a program. Shortly after, the Industrial Customers of Idaho Power and the Idaho Public Utilities Commission (IPUC) expressed an increased interest in this type of program and on December 15, 2006, the IPUC issued Order No. 30201, which directed Idaho Power to "investigate and submit a report for the implementation of a 'virtual peaking plant' program based upon the use of existing emergency generator resources in the Company's service territory." This report is filed in compliance with Order No. 30201.

As part of our research, the Company reviewed virtual peaking programs other utilities have successfully operated and focused on two designs: The Dispatchable Standby Generation program conducted by Portland General Electric Company (PGE) and Madison Gas and Electric's (MGE) Backup Generation Service. The primary difference between the two programs is in regards to the ownership of the generator: MGE owns the generator located on the customer's premises whereas PGE's customers own their generator. Also, MGE customers pay a monthly service charge based on their maximum annual kilowatt demand for electricity. Idaho Power chose PGE's program model to use as a basis for our program development.

Program Description

A dispatchable standby generation program would allow the Company to use nonresidential customers' standby generators for up to 400 hours a year to meet system peak power demands. Customers' generators would operate in parallel with Idaho Power's system while also being available to back up their facility when needed. The Company's design will be such that during an outage situation, the customer's generator(s) will automatically start and provide backup power to the customer for as long as needed as originally intended by the customer. During times when customers' generators can be beneficial to the Company's system, the generators will be started remotely by the Company's dispatch center.

The following are the responsibilities of the customer and the Company under the proposed program design:

> *Customer Responsibilities:* Customers will be responsible for purchasing the generator(s) and providing the site for generator installation. In addition, customers will grant the Company access to their generation such that the Company can control operation of the generator(s) remotely in parallel with the Company's distribution system from the Company's dispatch center for up to 400 hours per year. Customers may operate the generator(s) at their sites as needed for emergency back-up power.
>
> *Company Responsibilities:* The Company will conduct an analysis of the customer's generator project and develop a comprehensive cost estimate. The Company will be responsible for providing interconnection engineering, facilities, and installation and any other equipment necessary for participation in the program. The Company will pay for and own all communications and metering equipment.

In addition, the Company will be responsible for routine maintenance of the generator(s) including overhauls over the term of the service agreement. The Company will also pay for all fuel used to operate the customer's generator(s) throughout the term of the service agreement. The Company will perform monthly full-load testing of the customer's generator(s) and control system and testing of the Company's dispatch control and interconnection facilities. All energy consumed by the customer while participating in the program will be billed at standard tariff rates.

The following is a partial listing of the infrastructure that would need to be in place for such a program to run:

- *Utility Paralleling Power System (UPPS)* – The UPPS will ensure that the customer is provided with a continuous supply of electric power by, almost instantaneously, switching from the Company's power supply to the back-up generator's power supply in the event of a power failure.
- *Metering* – For an existing generator to be retrofitted, an additional time-based meter would be required. New generators would require two time-based meters be installed. The time-based meters would ensure that whether customers are drawing energy from the Company's system or from the back-up generator, their usage is tracked and billed under the standard service schedule.
- *Communication Node Network* – For communication between the customer's system and the Company's system, a frame relay based network would be installed in order to provide a secure network.
- *Energy Management System (EMS)* – The EMS would need to be programmed to accept the data from the UPPS.

Feasibility Analysis

In our feasibility analysis, the Company looked at the various costs involved in the interconnection of a back-up generator as well as the resulting operations and maintenance costs which will be covered by the Company. Both initial generator installations and existing retrofits were considered. The initial analysis indicated there is enough potential benefit associated with the program to continue pursuing its investigation.

Pilot Program

The feasibility analysis concluded that Idaho Power would need to make an investment in infrastructure of approximately $1 million in order to integrate customer-owned generators into our system. Because of the investment size and the potential complexity of the interconnection of some generators, the Company determined it was necessary to do an in-depth analysis of the interconnection costs, targeting generators of different sizes, ages, and locations. This thorough analysis would provide more detailed costs of interconnection and a more accurate determination of the program's potential viability.

In order to complete the in-depth cost analysis, Idaho Power met with numerous customers, as well as representatives of the Industrial Customers of Idaho Power, to describe the potential program and solicit participation in an "Engineering Analysis Pilot Program". Through this process, Idaho Power hopes to identify four to six customers who are willing to work with Company personnel in the development of this initial cost estimate for their specific facilities. The Company is targeting customers whose existing generators vary in size and customers who do not currently have back-up generators but would consider installing one if a "virtual peaker" program were offered.

The Company plans to conduct the interconnection cost estimate analyses over the next three months. Once detailed interconnection cost information is available, the Company will update its financial analysis to determine if a "virtual peaker" program is economically viable and submit a detailed report of its finding to the Commission.

EXHIBIT NO. 213

Reading, DI
Industrial Customers
of Idaho Power

CustomerNews

2008 PGE pricing adjustments

The new year will bring slight price adjustments to your bill. Here is how they are shaping up:

- We estimate that prices for large business customers (Schedules 83 and 89) will increase an average of 1 to 2 percent in January, then decrease in June.
- The net change for 2008 is expected to be less than 1 percent for Schedules 83 and 89; for Schedule 32 accounts, the expected net change is just over 2 percent.

See chart for details about these pricing adjustments.

The Oregon Public Utility Commission is in the process of reviewing these proposed changes. We anticipate their final decision by the end of December.

Other customer news

See the topics below for the latest energy news from PGE.

- Make your generators earn their keep
- Employee teams help cut energy waste
- Focus on power quality and reliability
- Burgerville serves up sustainability
- New local solar plant
- Last energy class of 2007

Growing Dispatchable Standby Generation program offers reliability and savings

When Salem Hospital decided to install standby generators in their new central energy plant this year, they signed up with the PGE Dispatchable Standby Generation program. Rather than standing idle during non-emergency times, their two 2,000 kilowatt (kW) generators will work up to 400 hours annually, helping meet peak power demands for PGE customers. In return, PGE covers all generator maintenance and fuel expenses, as well as monthly testing.

According to Tom Bickett, director of facilities management for Salem Hospital – which is in the midst of a major renovation – the DSG program benefits the hospital and the Salem community in several ways. "First, we're helping PGE meet the area's need for power during peak periods. This supports the hospital's commitment to being a valued and integral part of the communities we serve," says Bickett.

"Second, we were able to increase our generating capacities from two 1,500 kW generators to two 2,000 kW generators and connect to primary metering, which saves on kilowatt hour (kWh) costs. And during the 10-year DSG agreement, PGE provides for all of the maintenance and fuel expenses. This is a significant operating savings to the hospital, which in turn helps us hold the line on the cost of health care. With all the savings, payback is less than three years, which is an outstanding return."

Salem Hospital never has to worry about being without power because the generators are always available for back up in the event of a power outage. They are continuously monitored and may be dispatched from the PGE control center if needed. The generators are synchronized and operate in parallel with PGE power so there is no service interruption to the hospital when the generators are operated by PGE.

For DSG program participants, PGE will:

- Cover all maintenance, repair, fuel and other operation costs

Exhibit 213
Reading, DI
Industrial Customers
of Idaho Power
IPC-E-07-08
Page 1 of 34

0 1

costs.

- Provide alerts to facility staff regarding critical alarms or other potential generator problems.
- Improve exhaust emissions by installing oxidation catalysts.
- Conduct monthly testing — fully loading the generators and eliminating expensive load bank tests.

Salem Hospital is just one of more than 20 PGE customers already signed up for the growing DSG program. Collectively, these standby generators represent 40 megawatts of power. Over the next five years PGE aims to recruit eight to 10 customers annually, growing the program by an additional 80 megawatts.

"DSG represents a least-cost option for meeting peak capacity and providing necessary reserves," says Mark Osborn, distributed resources manager. "We don't call on the generators every day, just on critical winter and summer days when energy use is really high and when other resources are challenged. This program is sort of like an emergency backup generator for all PGE customers."

Visit the DSG section on our Web site to **learn more**. If you have standby generators and want to know if you are eligible to participate in the DSG program, contact your PGE representative today.

[redacted]

0 2

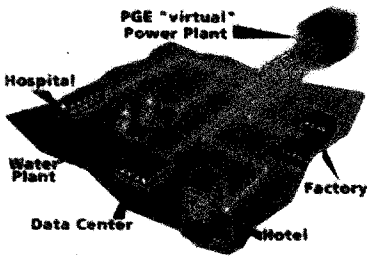
[redacted]

Dispatchable Standby Generation

Capture enhanced reliability and operational savings from your backup electric generation system.

If your business requires standby electric generation to ensure vital production or service performance, you know the daily reality: constant maintenance of your backup system in the hope that it will perform when you need it.

For most of the year, however, the only thing your backup system generates is a stream of operational and maintenance expenses.



From PGE's control center, a dispatcher can start any or all of the standby generators within the system. Up to 100 megawatts of power can be generated during peak hours.

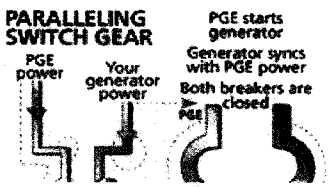
PGE's Dispatchable Standby Generation program puts your standby generators to work for up to 400 hours annually to meet peak power demands — and PGE picks up all your maintenance and fuel expenses. Your generator is always available to backup your facility and will operate synchronized and in parallel with PGE power so there is no service interruption.

For the option of running your generators when needed, PGE will:

- Upgrade switchgear and install control and communications hardware at no charge, increasing reliability and improving control of your system.
- Assume all maintenance and operation costs for your system, eliminating your costs for fuel, repairs, tune-ups, oil changes, filter replacements and overhauls.
- Provide additional sound attenuation, if needed, quieting the generator system.
- Provide additional fuel storage, if needed, expanding your operating time during those weather-related, long-term power outages.
- Test your system at least once a month under full load; frequent full-load testing ensures the generator will operate successfully during an outage and is better for the engine.

A powerful network

PGE equips your standby generator with paralleling switchgear, allowing the unit to be operated in synchronization with the electric distribution system. Qualifying commercial and industrial customers



(those with standby generators of 250 kilowatts and up) are networked with PGE's communications and power control system. The standby units can be

E-Manager

E-Manager provides easy-to-read charts and graphs that help analyze your facility's energy use.

News to Power Your Business

Subscribe to our quarterly e-mail newsletter for the latest on energy savings, electricity prices and more.

0 3

monitored and dispatched from PGE's control center.

In case of an outage, the standby generator functions as it normally would, providing backup power to your facility for the duration of the outage. However, when power returns to the grid, your facility moves back to utility power without additional interruption.

Program participants pay standard electric rates for power used, regardless of where it's being generated. PGE pays all the fuel costs for the standby generators, even during an outage, adding to the operational savings.

So how does this work?

Read our **FAQ**, which answers common questions about how the program works, why PGE is offering the DSG program and how your business can take advantage of this savings opportunity.

Unleash the full potential of your standby generator

Interested? At your request, we will provide a detailed analysis and proposal tailored to your business requirements. Please contact your PGE representative or **e-mail us**. You may also call Mark Osborn, DSG program manager, at 503-464-8347.

If you are considering purchasing a new generator or upgrading to a larger system of backup generation, PGE provides convenient financing on request. Financing can be added to your monthly electric bill.

FAQ

Q: Why is PGE offering the Dispatchable Standby Generation (DSG) program?

- The tight supply of electricity and resulting high prices have created new business opportunities for PGE customers who can simultaneously use power, while making more power available in PGE's territory. The DSG program improves a participant's bottom line by having PGE:
  - Cover the operating and maintenance costs of the DSG power system
  - Contribute to the customer's standby generator system installation

  PGE benefits by accessing new power resources for all its customers. By linking many generators to the electric distribution system and turning them on at peak demand hours, PGE and program participants are helping keep the price of power down and the supply up with an innovative business relationship.

Q: What happens if we need power at the same time PGE is using the DSG system?

- Your backup generator is always available to serve you without interruption. Your generator and PGE are synchronized and operate in parallel, automatically backing each other up. If one system fails, the other takes over — significantly increasing your reliability.

  The DSG system is set up so your facility's loads are automatically served first and then any excess power you generate flows into the PGE system. For example, if your building load is 1,000 kilowatts, and the generator is putting out 1,500 kilowatts, only 500 kilowatts are serving other PGE customers.

Q: Will the DSG program put more wear and tear on my company's generator?

- The DSG program will probably extend the life of your backup/emergency power system. The program operators regularly start up the generators and test them at full load. More frequent full load runs are better for the diesel engines. The tests also save the costs of load bank testing and assure your organization that the equipment will start up and function properly in a power outage.

Q: Will PGE help pay for new generators? Does PGE help if I'm installing new generators?

E-Manager

E-Manager provides easy-to-read charts and graphs that help analyze your facility's energy use.

Own high voltage equipment?

Get the most value with regular maintenance. PGE's Distribution and High Voltage Services makes it easy.

0 5

- The generators themselves are not funded by PGE. However, whether you are building a new facility with backup power, adding generators or upgrading your switch gear, PGE helps fund the installation. PGE provides most of the cost for the latest generator control and paralleling circuit breaker technology. Many high-tech companies are already using this equipment for seamless transition from generators to the power grid.

Q: Can you assure us that our emergency power system is maintained to our standards of reliability and quality?

- Yes, your facility's staff and PGE will jointly decide on the most qualified maintenance provider. This may be your existing provider, your own staff or a new provider that best meets your needs. Our agreement with maintenance providers will include annual performance reviews and if they are not performing at the levels we expect, we can agree to change providers.

Q: Who is responsible for maintenance and repair?

- This is another win-win aspect of the program for participating businesses, institutions and PGE. All regular maintenance and any repair bills are paid by PGE. The utility sees this as a reasonable cost to assure that your generator is available at all times to participate in the program, and it lowers your cost of doing business. We estimate that this may easily save $50,000 to $100,000 over a five-year period.

  PGE has created the DSG program with the highest standards. Should your equipment fail to function as required for your emergency/backup use, the maintenance provider selected by you and PGE will begin diagnosing the problem within four hours of notification. If appropriate, the provider will then repair or replace the equipment (at PGE's discretion) with comparable items as required to meet your system's needs.

Q: Who pays for fuel?

- PGE pays for fuel regardless of whether the fuel was used only for your needs or to serve the utility distribution system. We do require the use of transportation grade, low-sulfur, diesel fuel.

Q: Can I still participate if I choose to buy power from an independent supplier?

- Under Oregon's restructuring law, you can choose to purchase your power from an independent provide. If you make this choice, you can still take advantage of the DSG program. You, PGE and your independent supplier would negotiate an agreement, which would provide accurate billing and properly account for the power used by your facility, even when the generators are operating.

Q: Are there any regulatory or tax issues I should be aware of?

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- Participating in the DSG program will not affect your taxes. Because PGE will own a portion of the system of which the generators are a part, the output of the generators will be considered PGE power. PGE will also handle all power regulation issues related to the operation of your DSG power system.

Q: Under what circumstances would my organization have to reimburse PGE for its investment?

- PGE is providing a significant investment to upgrade your property. PGE is counting on your generation to maintain an efficient power system and reduce costs. If you cancel the agreement without cause or without proper notice, most of the equipment would typically remain with you and you would be responsible for reimbursing PGE for the value of that equipment.

  If PGE cancels the agreement, PGE will remove any PGE equipment and leave your facility in such condition as will enable you to operate the generators for your own backup use. Under these circumstances, no equipment reimbursement would be required.

Q: Can a business cancel the DSG agreement?

- In the unlikely event that PGE fails to maintain or repair the equipment as required in the agreement, you may cancel the contract before its normal expiration date. As mentioned above, the maintenance service provider is required to begin diagnosing a problem within four hours. If a problem cannot be fixed within 30 days, you would have the option to terminate the agreement.

Q: What happens if the actual project cost is greater than PGE's projections because of unforeseen conditions?

- In a retrofit installation or for PGE owned equipment, PGE will be responsible for all cost over-runs related to items installed under the Dispatchable Generation Agreement. With a new facility or new generator plant, where you would have primary responsibility, we would negotiate an appropriate cost sharing solution.

Q: How is PGE handling the environmental impact of the DSG program?

- PGE cares a great deal about the environment. We will be installing oxidation catalysts on all DSG program engine-generators. These catalysts significantly reduce carbon monoxide (CO), hydrocarbons (HC) and odor from the diesel engines. Research is also underway to explore new ways to reduce nitrogen oxides (NO_x) in the engines we use for the program. PGE is also doing extensive research on the use of dual fuels. This could create opportunities to burn natural gas instead of diesel oil in many generators, significantly reducing emissions into the air. Every generating system in the program is issued a permit by the Oregon Department of Environmental quality, assuring that the engines are operating within standards.

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Q: How can I learn more about PGE's Dispatchable Standby Generation program?

- Please contact your PGE representative or **e-mail us**. You may also call Mark Osborn, DSG program manager, at 503-464-8347.

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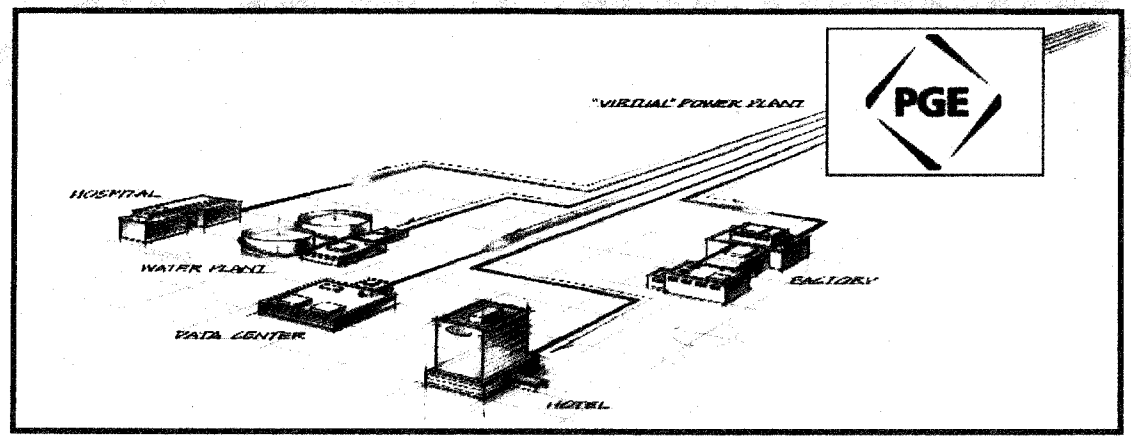


Virtual Peaking Network

Customer Owned – PGE Managed

Grid-Interop Conference - 2007

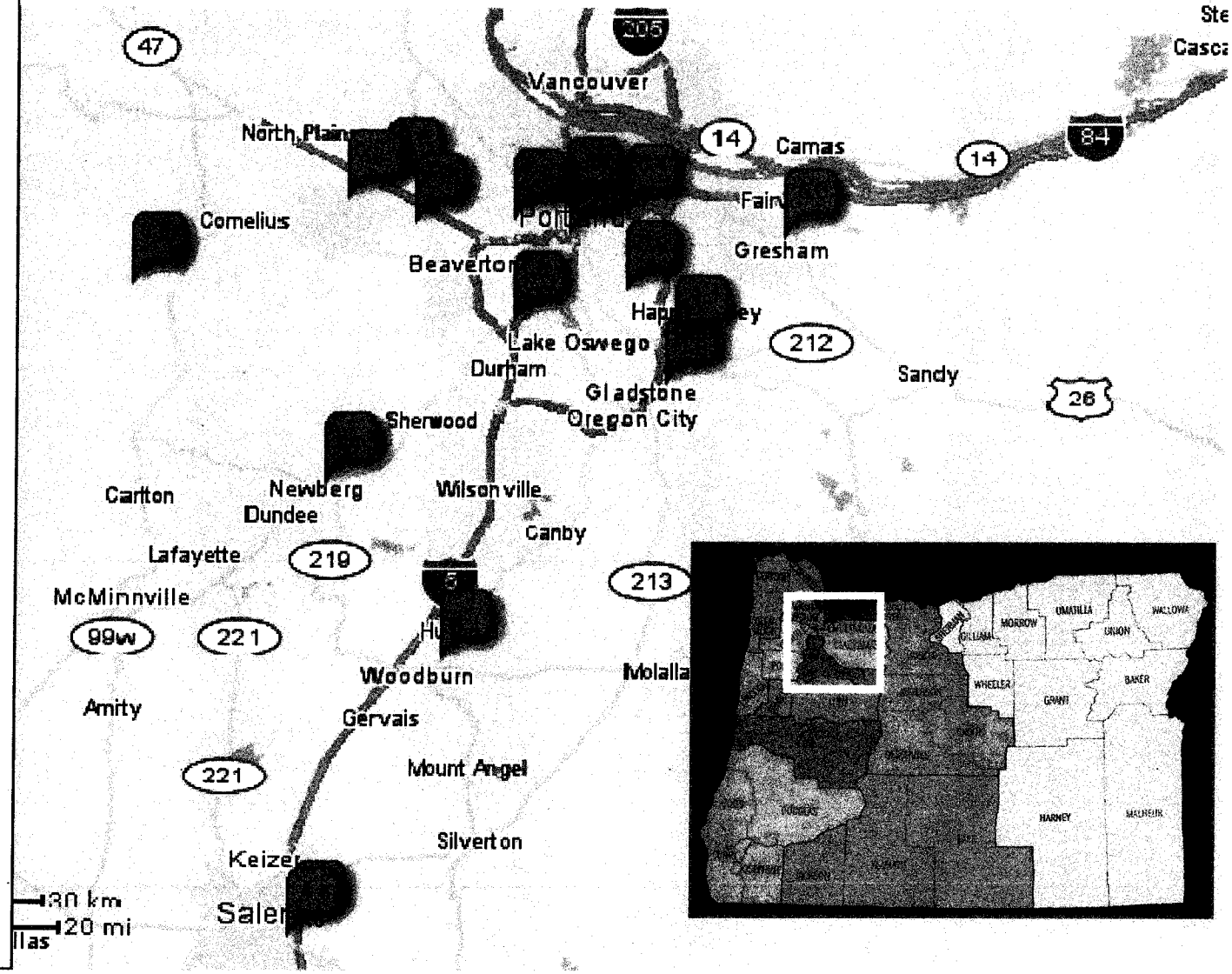
Mark Osborn

GenOnSys Site Aggregation

Provides a Virtual Peaking Plant for Dispatchers

Dispatchable Standby Generation Online:

Site	MWs
Lumber	0.5
Semi Cond	0.5
Data Center	0.9
HighTech	0.7
Comm Site	1.8
Data Center	1.8
University	2.8
Hospital	5.4
Bank Ops	5.8
Health Data	1.8
Manuf.	0.9
Water Plant	1.1
Water Plant	1.8
Hospital	1.4
Youth Corr	0.4
Military	1.6
Additional	13.8
Virtual Peaking	43.0



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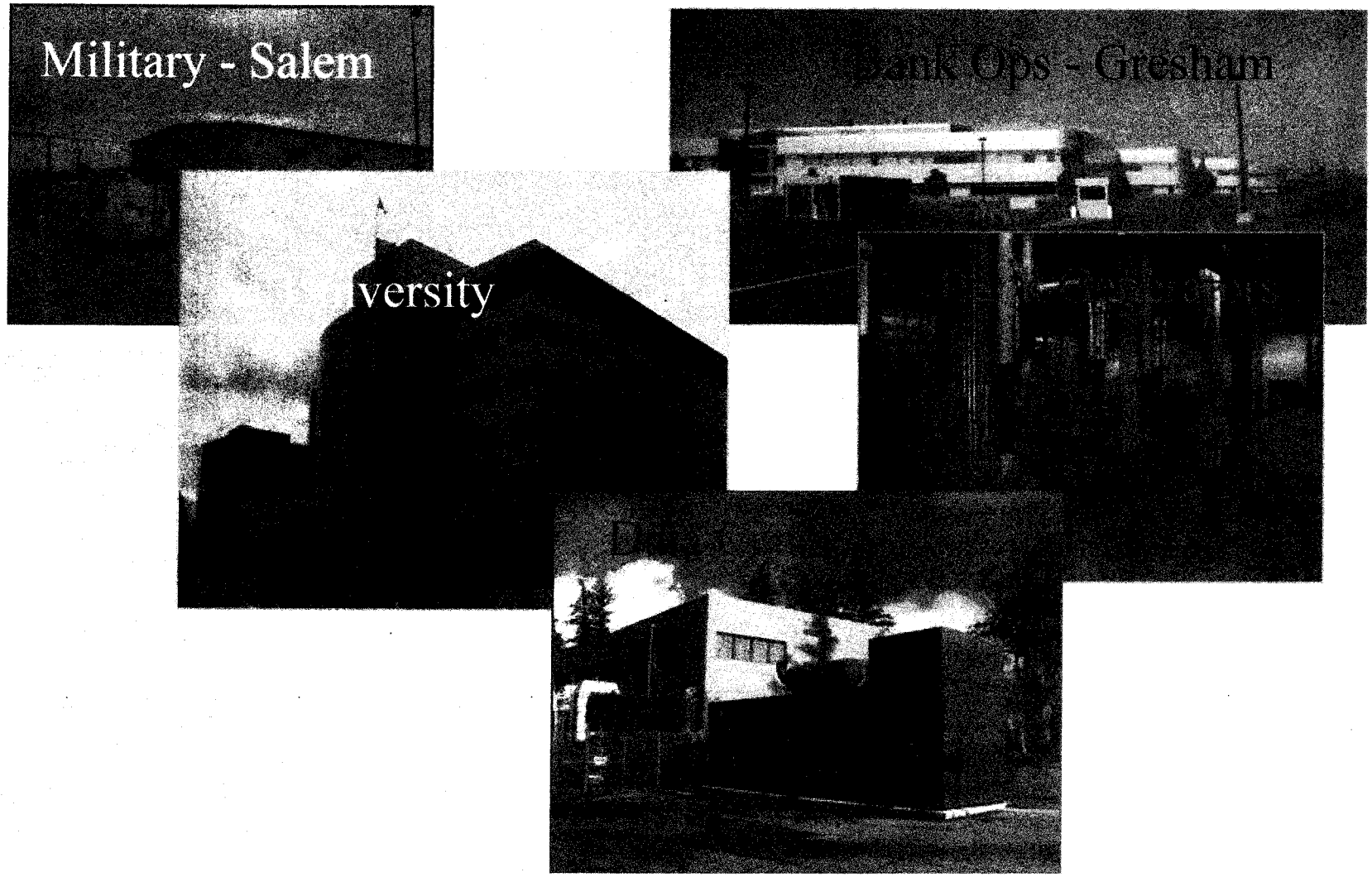
Dispatchable Standby Generation

Winner - 2006 PLMA Innovative Program Design Award



EIGHT FIRMS RECEIVE GRAND AWARDS

SPARLING Central Utility Plant

Research and innovation creates a new model for health care emergency power systems by generating peak power during an energy shortage.

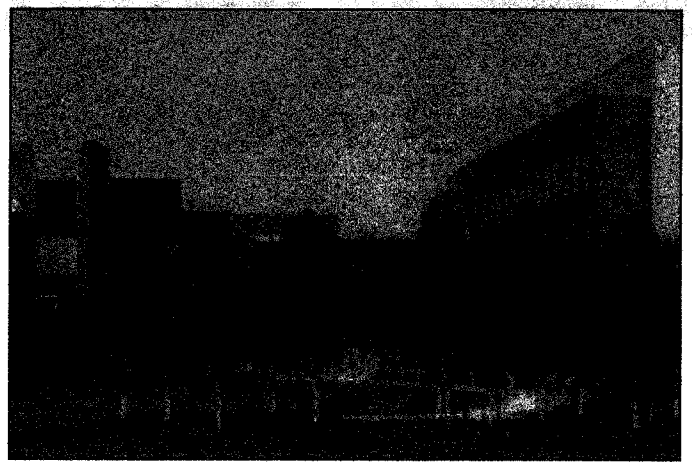
Sparling teamed with CDi Engineers to complete electrical design of a central utility plant that serves an 11-story medical tower at Providence Portland Medical Center. Through a pioneering partnership with Portland General Electric, a unique **Dispatchable Standby Generation** (DSG) power system was engineered that "shares power" by using the emergency generators to meet peak power requirements. As the first hospital in Oregon to synchronize the electrical generators to the utility power grid, new design criteria and testing protocols governing DSG systems in hospitals were needed. To facilitate this, Sparling engaged many experts including Portland General Electric, State Fire Marshal, the electrical code authority, Underwriters Laboratories and the owner to develop criteria for a complex control system that would automatically prioritize and immediately switch generator power to patients during any loss of hospital power.
This project is just one example of the incredible value that the engineering profession delivers to communities through research and innovation. A new model for health care emergency power systems has been created that benefits both patients and the community by generating peak power during an energy shortage.

GRAND AWARD: Central Utility Plant for Providence Medical Center Pictured, from left, are Mark Engdall, Sparling; Karen Weylandt, Providence Medical Center; Kimberly Krull, Sparling; and ACEC Oregon President Ken Wightman.

Providence gets gold for going green

The Sherwood Gazette Aug 28, 2006

COURTESY OF / PROVIDENCE HEALTH SYSTEM
The Providence-Newberg Medical Center healing garden.



Oregon's newest hospital is also the nation's greenest.

The U.S. Green Building Council has announced that Providence Newberg Medical Center (PNMC) received Gold LEED (Leadership in Energy and Environmental Design) certification, making it the "greenest" hospital in the United States. Providence Newberg is the first hospital in the nation to earn this designation.

Highlights of this state-of-the-art green medical facility include:

•100 percent outdoor air fills the building through a unique ventilation system, creating a dramatically healthier indoor air quality for patients, visitors and employees.

•100 percent of all electrical needs met by purchasing green power (50 percent wind, 25 percent geothermal, 25 percent low impact hydro). PNMC is the only hospital in the nation to purchase 100 percent green power.

•Participation in the Dispatchable Standby Generation program through Portland General Electric (PGE)

•Occupancy sensors, daylight controls and centralized lighting control systems turn off lights when spaces are unoccupied.

*All public spaces and waiting areas include use of natural light through design and feature views of nearby hillsides and natural scenery.

PGE Program Goals
Dispatchable Standby Generation

Build 150 MW DSG Virtual Peaking Plant

- Utilize Our Customer's Backup Diesel Generators
- Provide Operating Reserves to Support Thermal & Hydro Plants
- Currently: 43 MW On-line – 17+ MW Under Development

Provide the Least-cost Peaking Resource in IRP

Promote Environmental Stewardship

Enhance Services for Customers

- With Operations, Maintenance & Fuel for Backup Power
- *plus* PQ Monitoring for Facility Operations

Customer Benefits

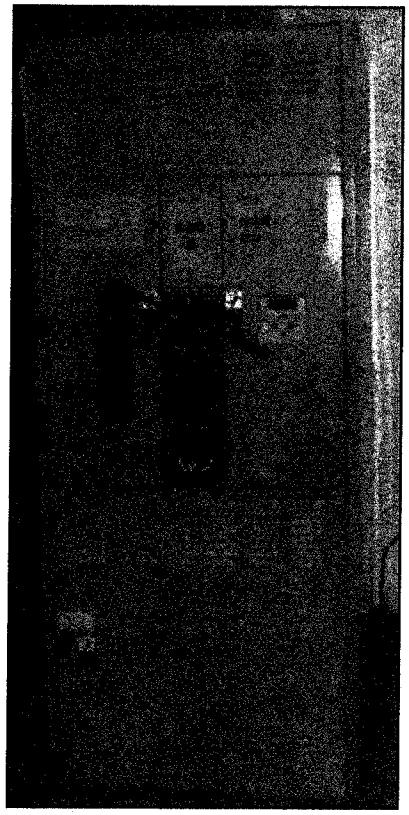
Greater Reliability

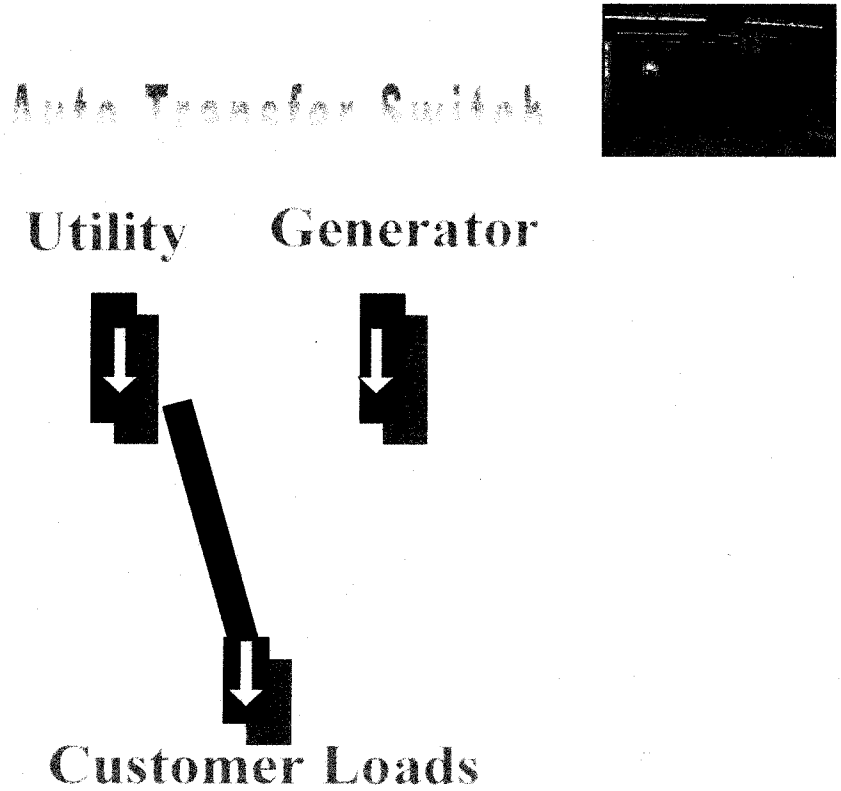
- High Quality "Seamless Paralleling" Equipment
- State of the art Relay Protection System
- Power Quality Monitoring

Reduced Operations & Maintenance

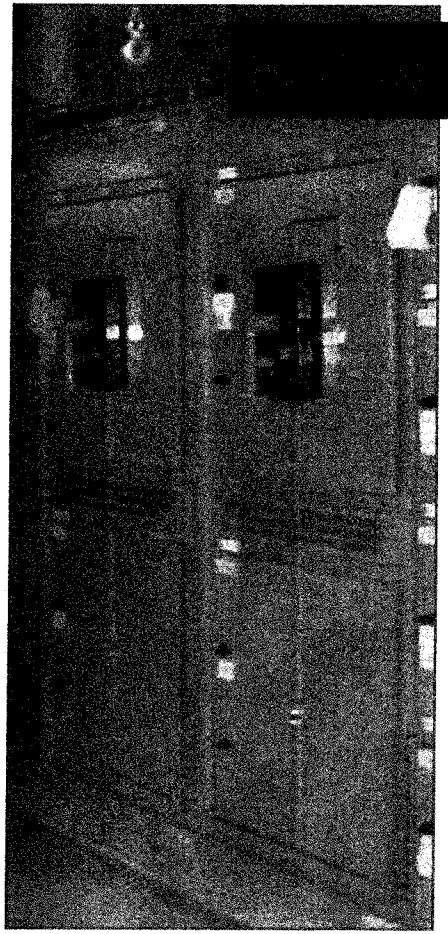
- Preventive Maintenance on Switchgear & Gens
- Repairs & Replacement
- DEQ Permit Modifications & Renewals
- Fuel

Conventional Generator Connection





More Reliable DSG System



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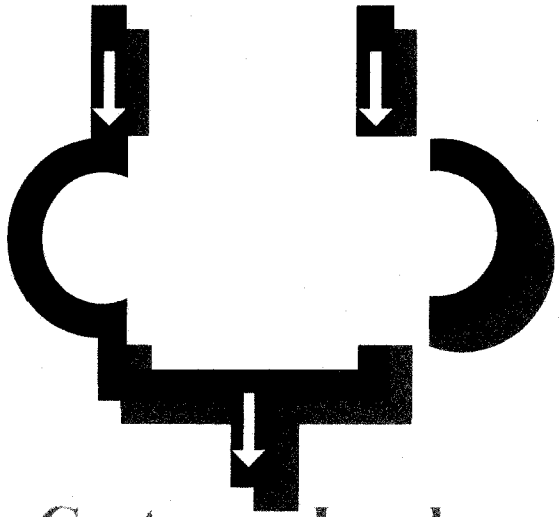
Dual Electrically Operated Breakers



Power Quality Monitoring - adds Value

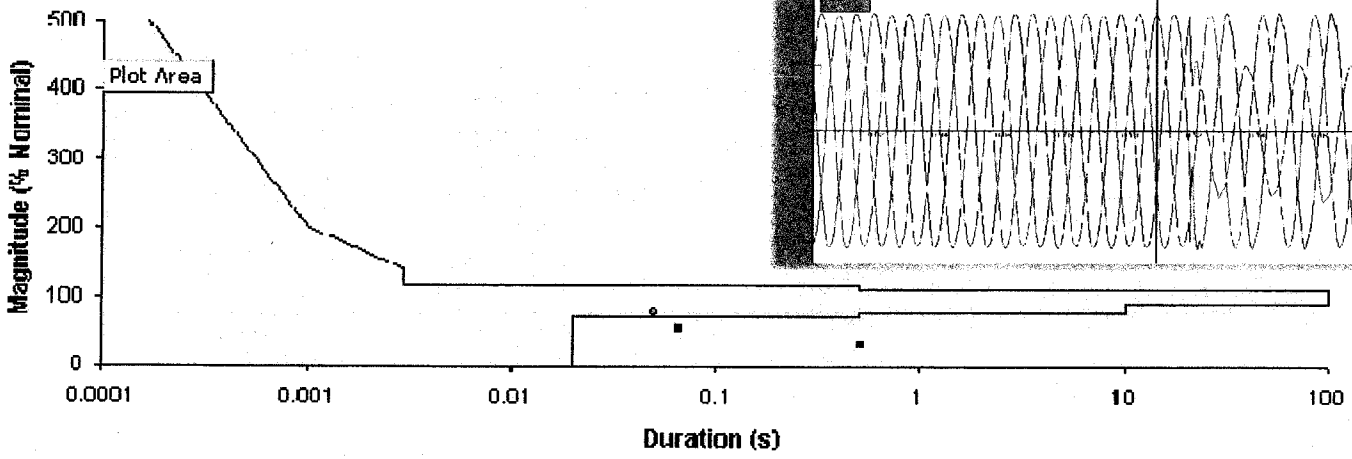
Power Quality

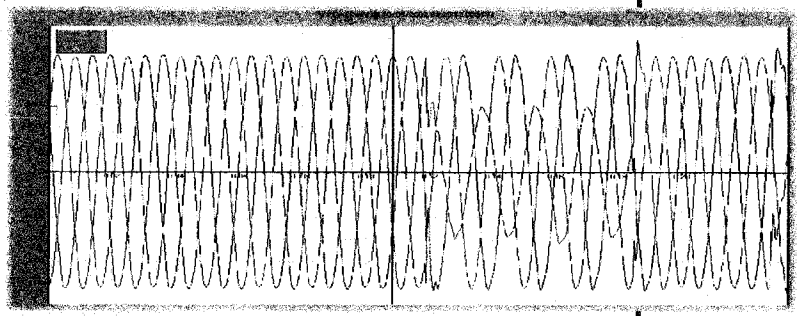
PGE Dispatchable Standby Generation

From: 2002-Oct-05 14:23:53.944
To: 2002-Oct-05 14:24:26.196

Reporting technology provided by: Power Measurement

Disturbances [1996 CBEMA - ITIC]

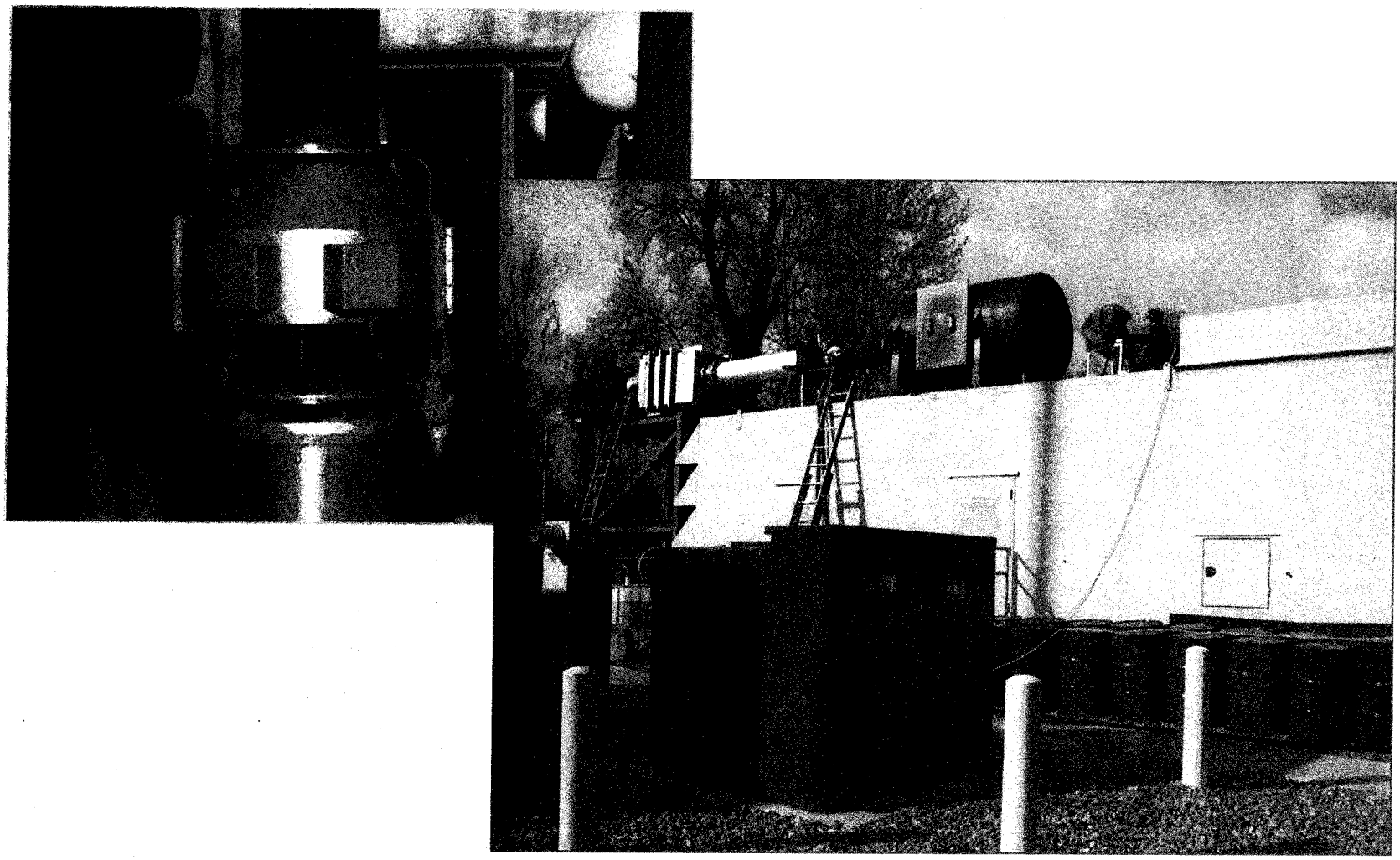




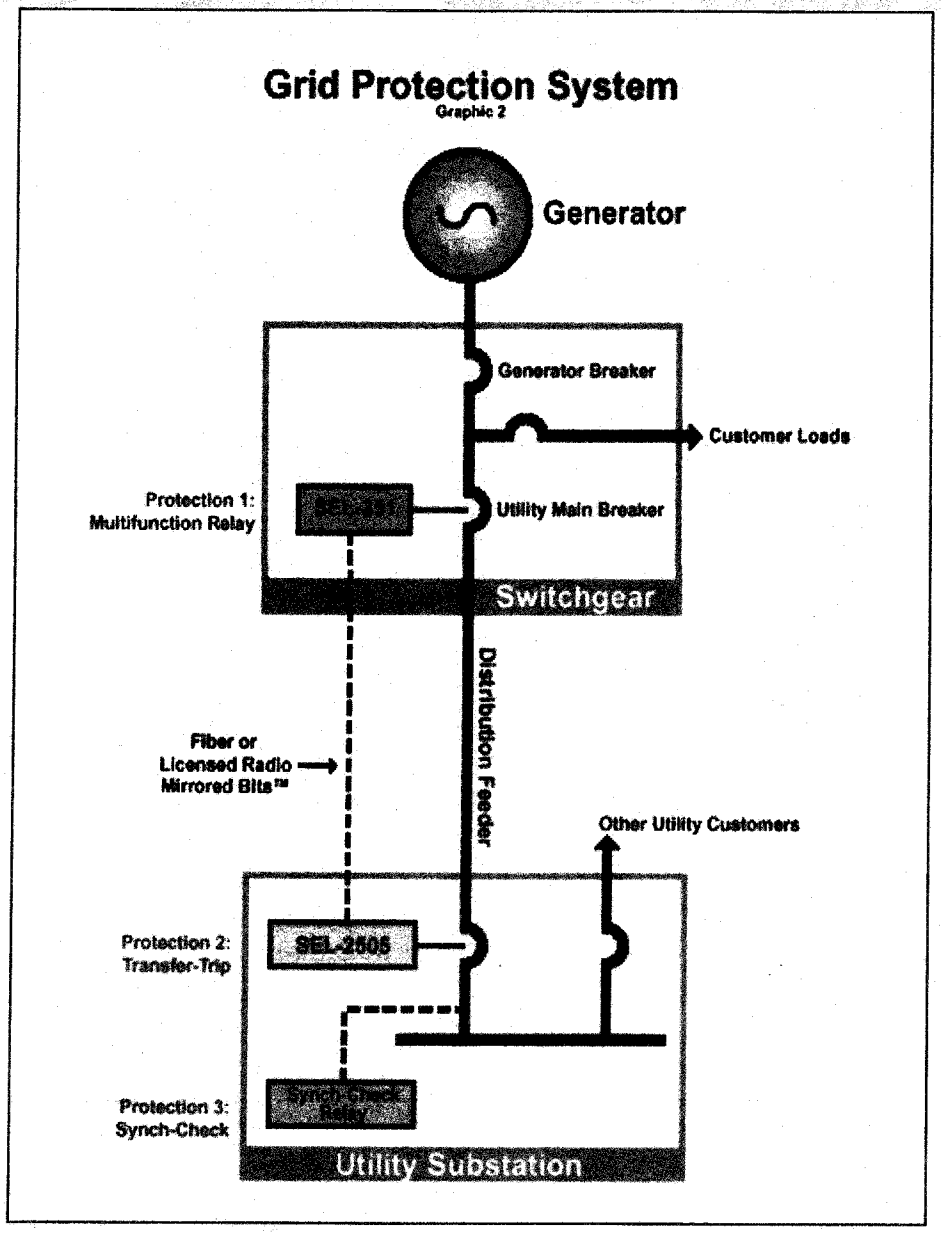
PCG0706.Customer - Sags, Swells & Transients

TimeStamp	Type	Phase	Duration (s)	Magnitude (% Nominal)
2002-Oct-05 14:23:53.944	Sag *Exceeds Tolerance	V3	0.066	55
2002-Oct-05 14:23:54.052	***Sag *Exceeds Tolerance***	***V3***	***0.515999973***	***31***
2002-Oct-05 14:23:54.901	Sag	V3	0.050000001	79
2002-Oct-05 14:24:25.195	Sag	V1	0.050000001	80

Environmental Improvements
Catalyst & SCR Exhaust Treatments



Establishes Feeder Protection for Future DR



"GenOnSys"

Dispatching Distributed Resources for Grid Support

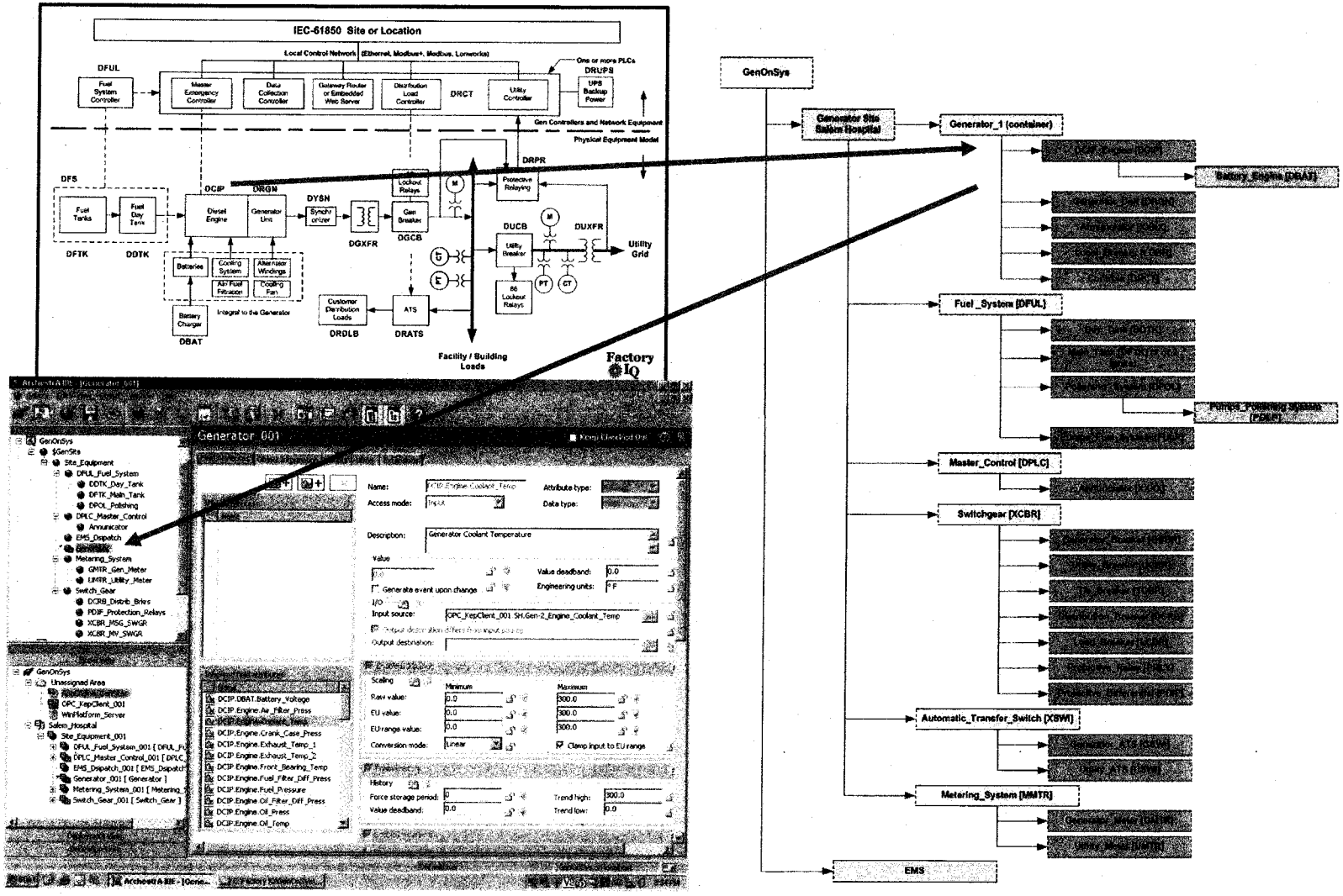
PGE Developed Software:

- Aggregates Distributed Resources for System Dispatchers – provides generator control, monitoring & alarming
- Uses open & established communication protocols (OPC)
- Interops with substations for Feeder Load Monitoring
- Server time synchs for sequence of operation analysis
- Is secure - meeting FERC / NERC Cyber Security Standards
- Has flexible communications via Ethernet: leased lines, radio systems, or fiber-optic links to the sites
- Provides direct connection to generator, switchgear, fuel system, relay protection, metering, UPS systems, and emissions controls at Customer site – Real-Time
- Upgrade to GenOnSys 2.0 April 2008 – Moves to Object/Container Programming

GridApp Grant - Funds Upgrades

Phase 1: IEC 61850-7-420 - Communications systems for distributed energy resources

Phase 2: IEC 60870-6 - Telecontrol Application Service Element 2 (TASE.2) - **ICCP**



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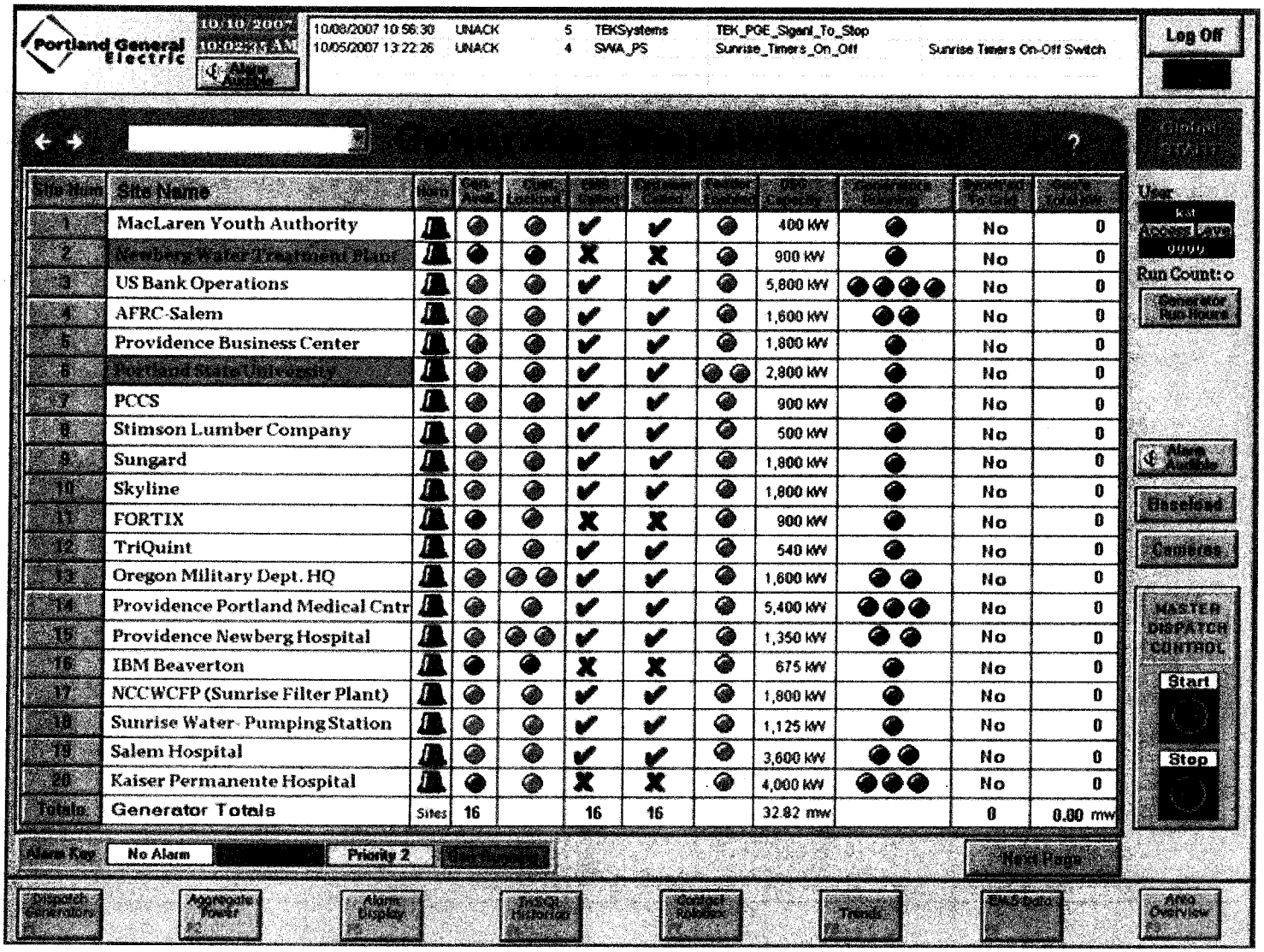
Aggregated DG Power

Ready to Start / "On Reserve"



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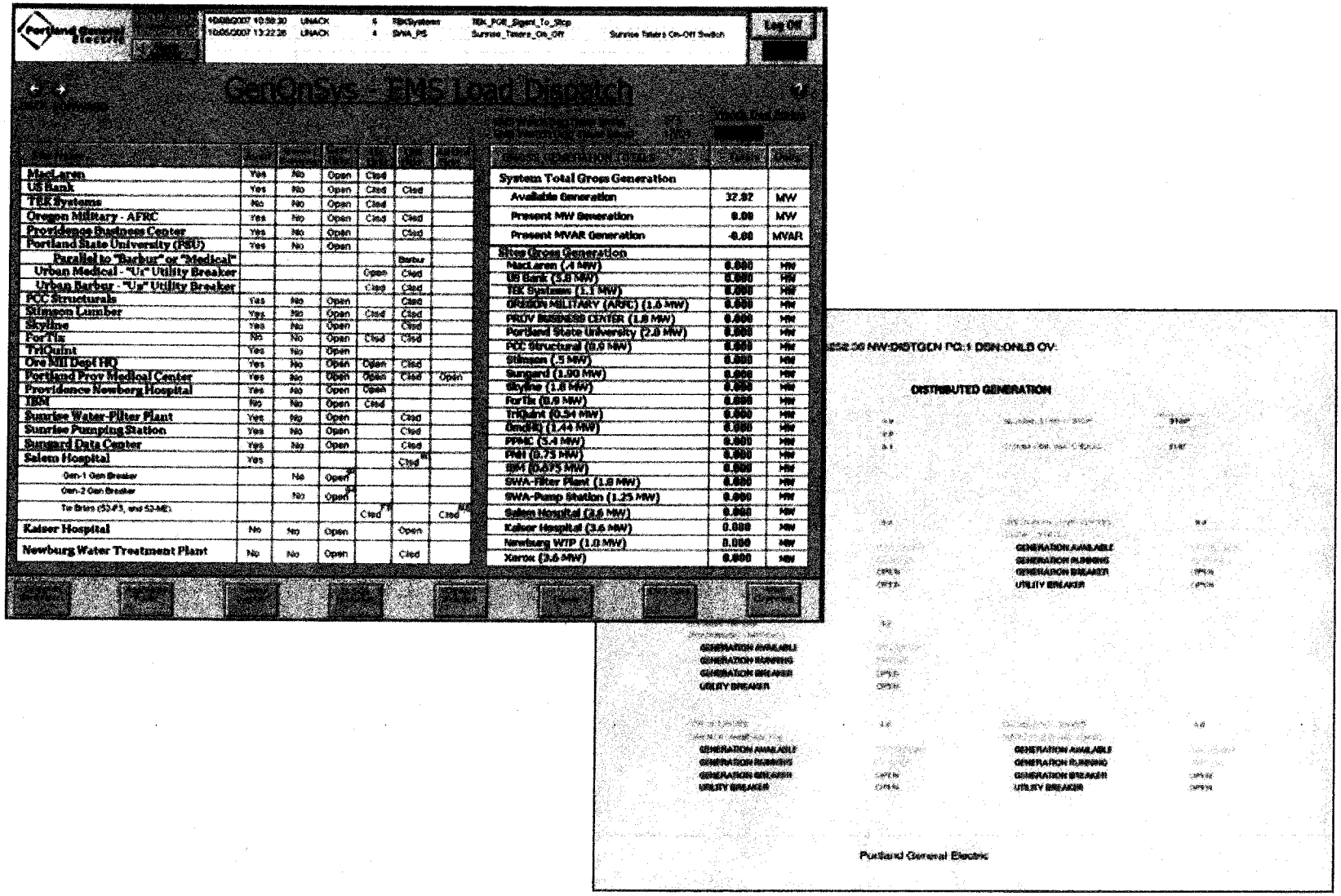
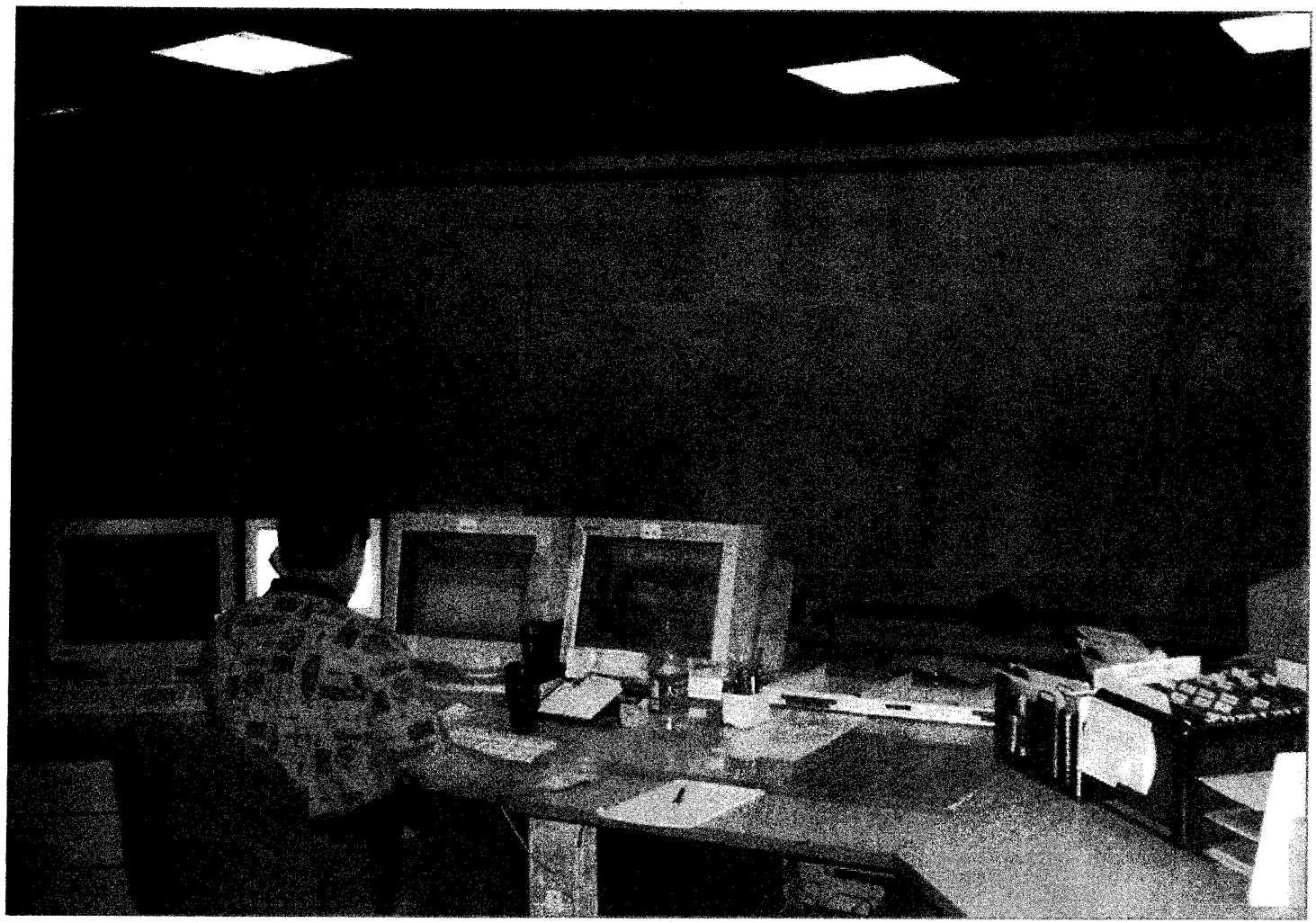
GenOnSys

Interops with Existing System Control Center Software



System Control Center

Starts Virtual Peaking Network



Portland General Electric

10/10/2007
10:27:53 AM
Alarm silenced20

10/10/2007 10:26:13	UNACK_RTN	1	Skyline_Pri1	Skyline_Gen_CoolTempHi	Skyline Genset Coolant Tempera
10/10/2007 10:26:13	UNACK_RTN	1	Skyline_Pri1	Skyline_Gen_Mode_NotAuto	Skyline Genset ECS Switch in A
10/10/2007 10:26:13	UNACK_RTN	2	Skyline_Pri1	Skyline_SystemNotAuto	Skyline Control System Overall N
10/10/2007 10:26:13	UNACK_RTN	2	Skyline_Pri2	Skyline_System_CommonAlarm	Skyline System Common Alarm

Log Off

Global START

User: kat
Access Level: 9999
Run Count: 13
Generator Run Hours

Alarm 128 Silenced
Baseload
Cameras

MASTER DISPATCH CONTROL
Start
Stop

Site Num	Site Name	Horn	Gen. Avail.	Curr. Lockout	Elec. Closed	Customer Closed	Protection Enabled	DSG Capacity	Generators Running	Synchronized To Grid	Genset Total kW
1	MacLaren Youth Authority				✔	✔		400 kW		No	0
2	Newberg Water Treatment Plant				✘	✘		900 kW		No	0
3	US Bank Operations				✔	✔		5,800 kW		Online	5,788
4	AFRC-Salem				✔	✔		1,600 kW		Online	1,605
5	Providence Business Center				✔	✔		1,800 kW		Online	1,800
6	Portland State University				✔	✔		2,800 kW		Online	2,802
7	PCCS				✔	✔		900 kW		Online	893
8	Stimson Lumber Company				✔	✔		500 kW		Online	505
9	Sungard				✔	✔		1,800 kW		Online	1,812
10	Skyline				✔	✔		1,800 kW		No	0
11	FORTIX				✘	✘		900 kW		No	0
12	TriQuint				✔	✔		540 kW		Online	532
13	Oregon Military Dept. HQ				✔	✔		1,600 kW		Online	1,617
14	Providence Portland Medical Cntr				✔	✔		5,400 kW		Online	5,377
15	Providence Newberg Hospital				✔	✔		1,350 kW		Online	1,355
16	IBM Beaverton				✘	✘		675 kW		No	0
17	NCCWCFP (Sunrise Filter Plant)				✔	✔		1,800 kW		Online	1,804
18	Sunrise Water- Pumping Station				✔	✔		1,125 kW		Online	1,130
19	Salem Hospital				✔	✔		3,600 kW		Online	3,675
20	Kaiser Permanente Hospital				✘	✘		4,000 kW		No	0
Totals	Generator Totals	Sites	16		16	16		32.82 mw		13	30.67 mw

Alarm Key: No Alarm | Priority 2

Next Page

Dispatch Generators F1 | Aggregate Power F2 | Alarm Display F5 | InSQL Historian F6 | Contact Rolodex F7 | Trends F8 | EMS Data F9 | Area Overview F3

Portland General Electric

3/8/2006
10:23:06 AM
Run Count: 12

Date	Time	State	P...	Group	Name	Comment
08 Mar	10:06:24 AM	ACK	3	PSU_Pri3	PSU_React_Power_Contro...	Reactive Power Control (PFA...

Log Off

Portland State University

4th Ave. Building
Portland, Oregon 97223
(503) 216-0012

2,800 kW Generator

PLC Watch Dog Timers
Turbine PLC
Read Timer 812
Write Timer 1384
Switch Gear PLC
Read Timer 60746
Write Timer 1384

Switch Gear #3
Generator Sychronized
Fire Pump
12.47 KV
52-T1
Relay Good
Volts/Hz - Ok
52-T2
Relay Good
Volts/Hz - Ok
52-G1
12.47 KV
4,160 V
Kilowatts 2,801.5
Volts 4320.3
Amps
Kilowatt Hours 21.84
Site Ready
5 kV Breaker

Switch Gear #1
Relay Good
Volts/Hz "Ok"
DSG Not Blocked
Urban Medical
52-U1
Kilowatts 2,040.1
Volts 13022.2
Amps
52F-1F
52F-1D
52F-1B
USB-1
USB-3
USB-6
12.47 KV
PGE
2,682.82
KWH EXPORT
Medical Request
Barbur Request
Parallel Feeder Selector
Urban Medical
Urban Barbur
U1
U2

Switch Gear #2
Relay Good
Volts/Hz "Ok"
DSG Not Blocked
Urban Barbur
52-U2
Kilowatts 1,160.5
Volts 12850.7
Amps
52F-2B
52F-2D
52F-2F
USB-7
USB-5
USB-2
12.47 KV
PGE
5,116.00
KWH EXPORT

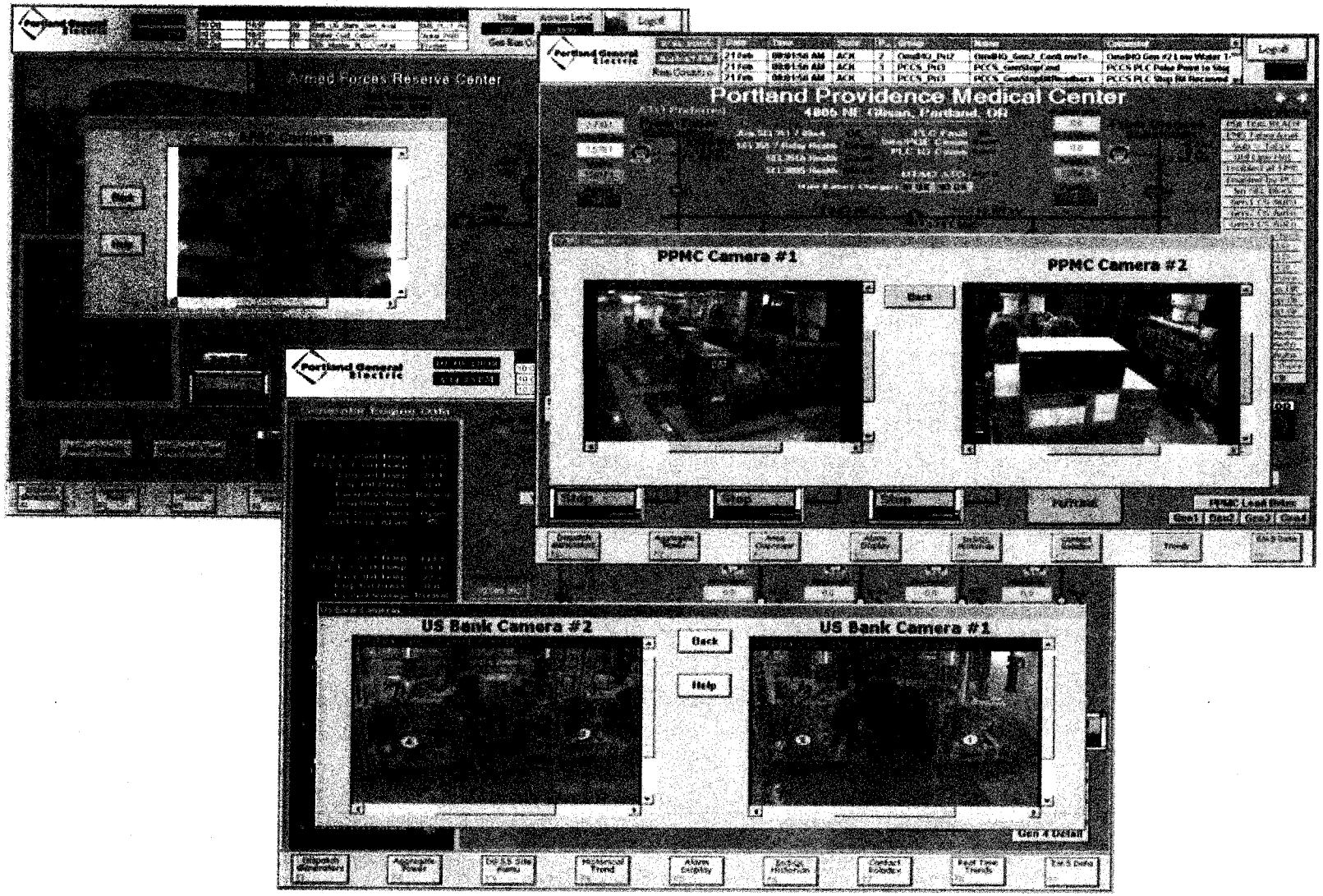
Turbine Status
Running
On Load
99 % RPM 1,074 °F
Start
Stop
Start/Stop Diagnostics

Availability Status
PGE DSG READY
EMS BarburAvail
EMS MedicalAvail
Util Line Hot
Util BrkrClosed
Turb-Remote

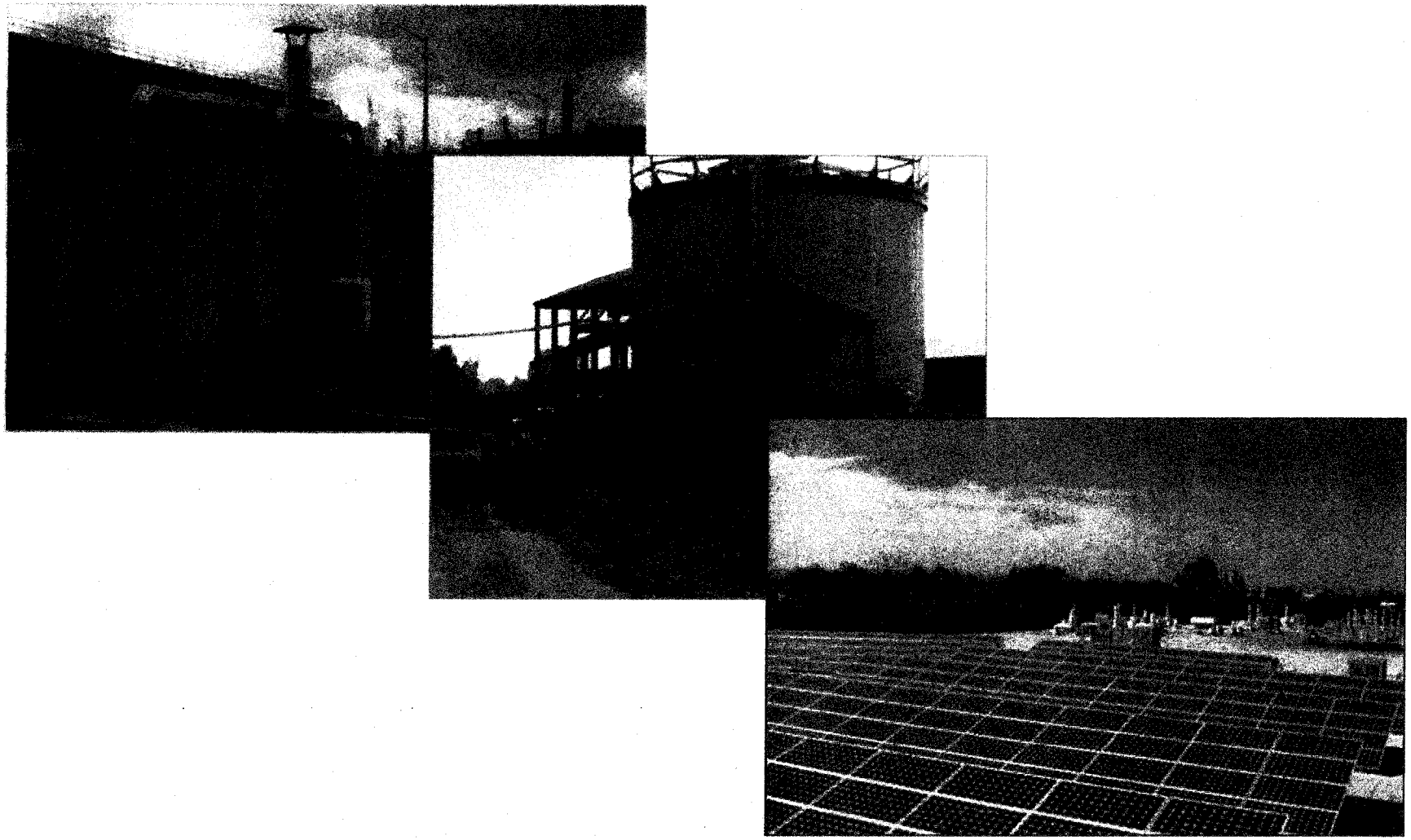
Dispatch Generators
Aggregate Power
Area Overview
Alarm Display
InSQL Historian
Contact Rolodex
Trends
EMS Data

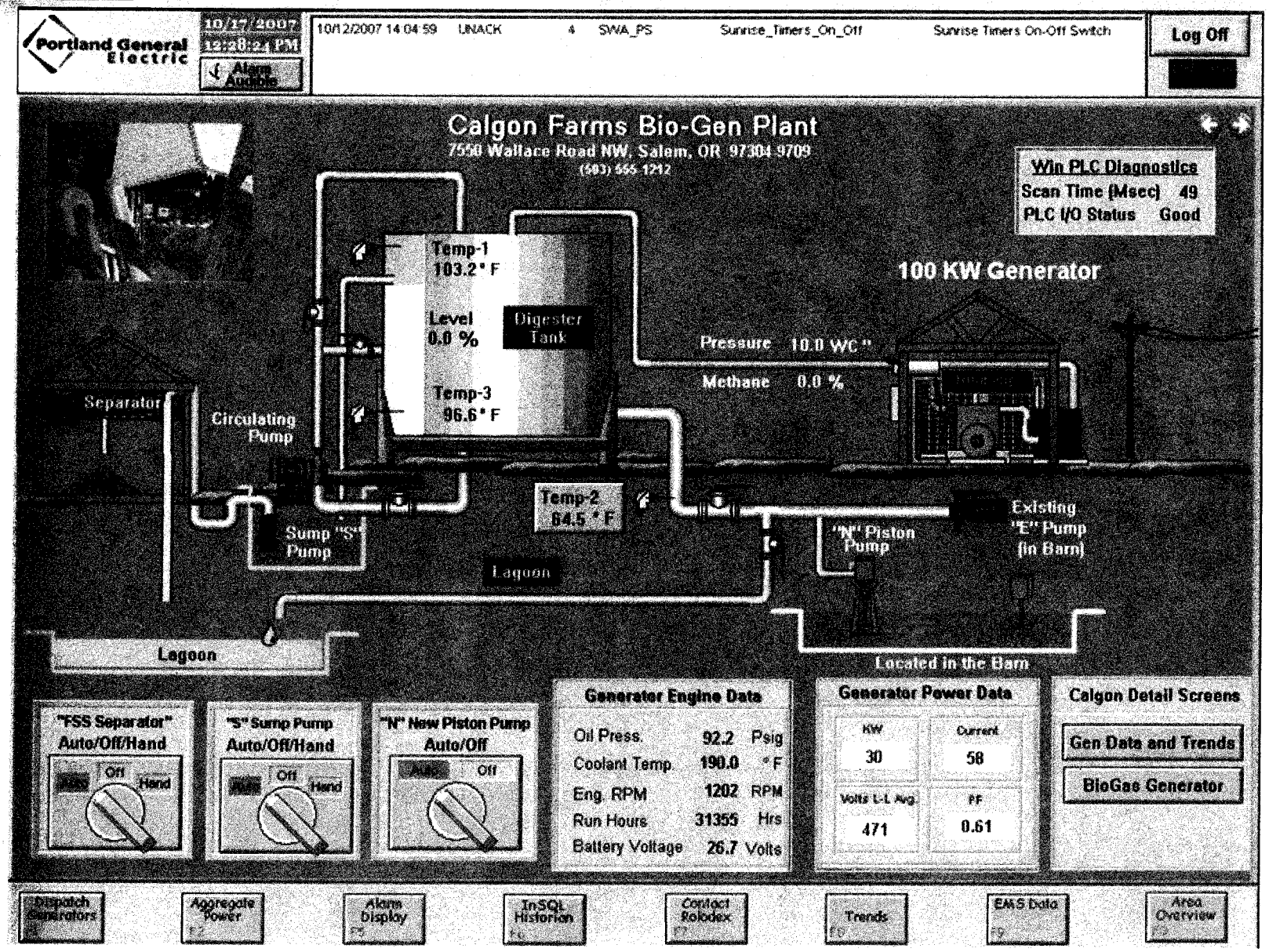
Live Video Pictures

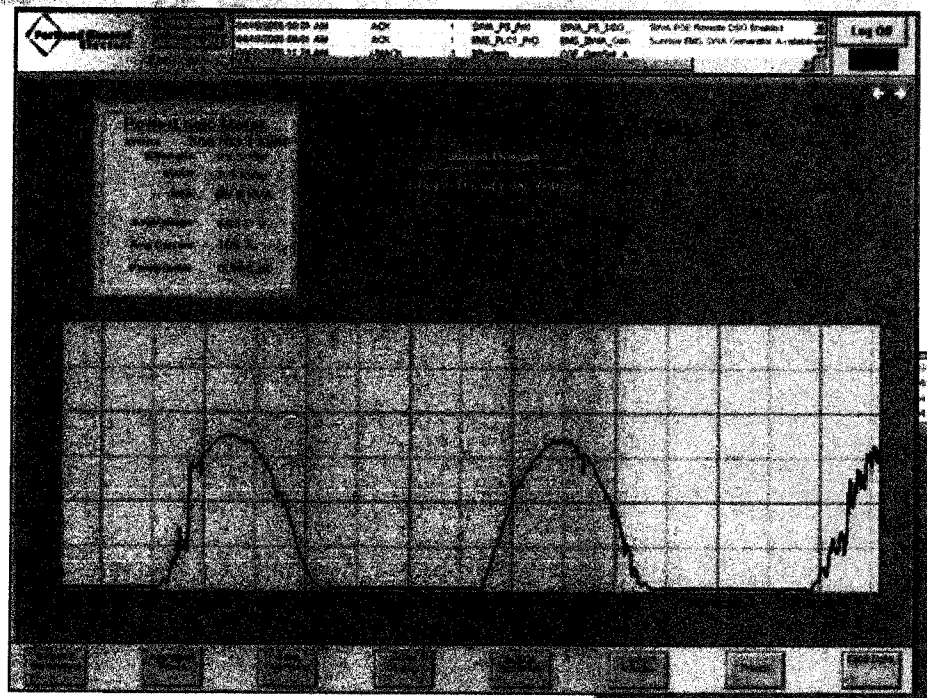
For Safety

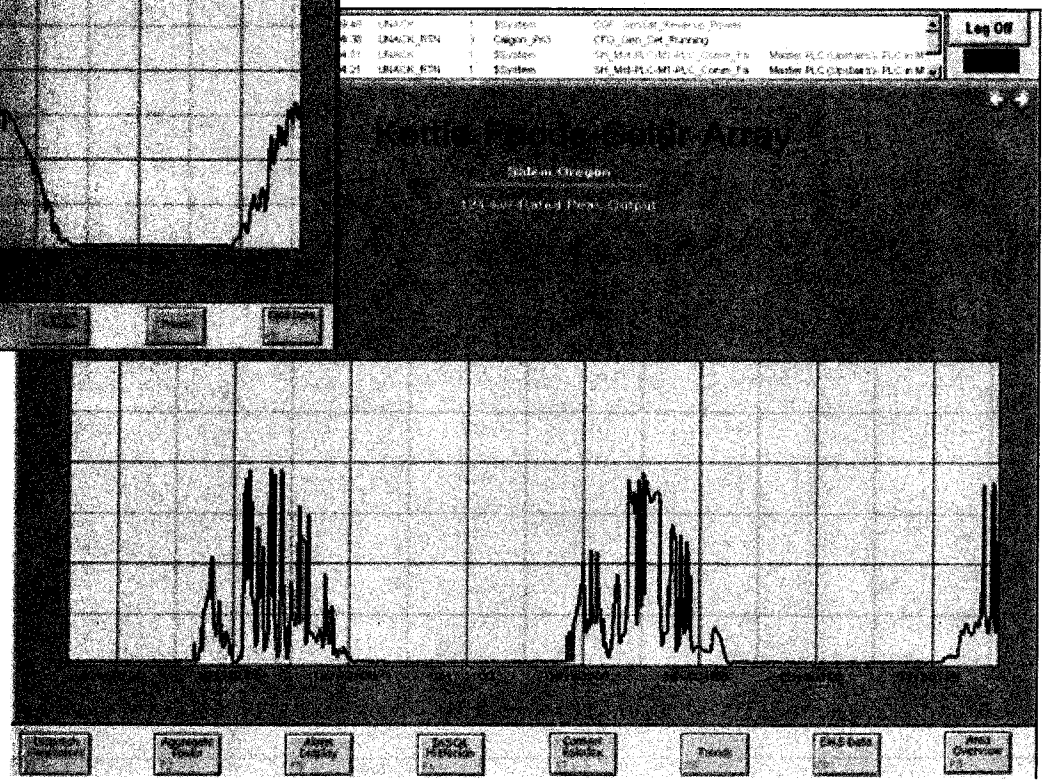


Interops with other Distributed Resources



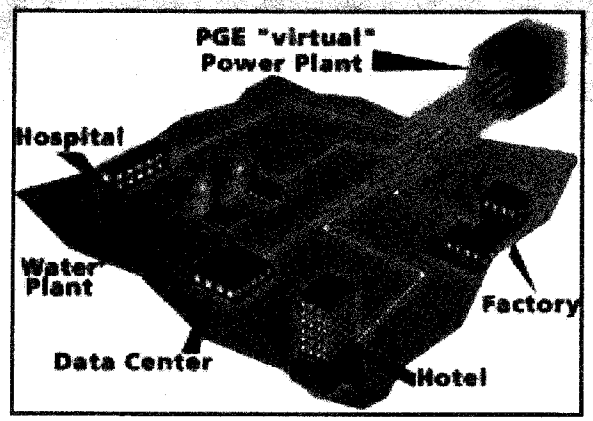

Portland General Electric
10/17/2007
13:28:27 PM
Alarm Audible
10/12/2007 14:04:59 UNACK 4 SWA_PS Sunrise_Timers_On_Off Sunrise Timers On-Off Switch
Log Off
Calgon Farms Bio-Gen Plant
7550 Wallace Road NW, Salem, OR 97304-9709
(503) 556-1212
Win PLC Diagnostics
Scan Time (Msec) 49
PLC I/O Status Good
100 KW Generator
Temp-1
103.2 ° F
Level
0.0 %
Digester Tank
Temp-3
96.6 ° F
Pressure 10.0 WC "
Methane 0.0 %
Separator
Circulating Pump
Sump "S" Pump
Temp-2
64.5 ° F
Lagoon
"N" Piston Pump
Existing "E" Pump (in Barn)
Lagoon
Located in the Barn
"FSS Separator" Auto/Off/Hand
Auto Off Hand
"S" Sump Pump Auto/Off/Hand
Auto Off Hand
"N" New Piston Pump Auto/Off
Auto Off
Generator Engine Data
Oil Press. 92.2 Psig
Coolant Temp. 190.0 ° F
Eng. RPM 1202 RPM
Run Hours 31355 Hrs
Battery Voltage 26.7 Volts
Generator Power Data
KW 30
Current 58
Volts L-L Avg. 471
PF 0.61
Calgon Detail Screens
Gen Data and Trends
BioGas Generator
Dispatch Generators
Aggregate Power
Alarm Display
InSQL Historian
Contact Rolodex
Trends
EMS Data
Area Overview


Log Off


Log Off

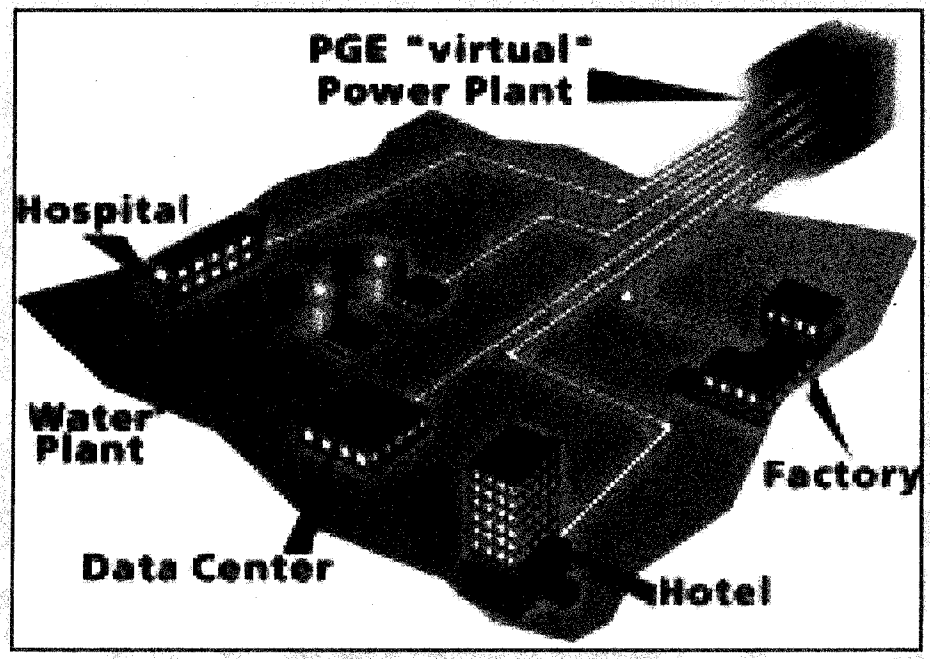
DSG -Top Grid-Interop Needs

- IEC - IEEE - DER Communication & Naming Standards
  - Every manufacturer has a different name for the same thing
  - Needs IEC 61850-7-420 spec adopted by all vendors for aggregation
  - Better tools for PLC programming & training for PLC programmers
  - Ethernet ports on <u>all</u> equipment (NO MORE SERIAL COMMUNICATIONS!)
- Paralleling Switchgear
  - EUSERC – standard metering built into paralleling switchgear
  - For 500 kW generators and less - Competitive with ATS in size and price
- Diesel Generation Environmental Improvements
  - Biodiesel additive for shelf life, so DSG gens move to Renewable Power
  - Dual fuel capability – provided by Manufacturers
  - Less Expensive SCR Technology
- Established Distributed Resources Market
  - GenOnSys allows PGE to market distributed resources, what's needed is an open market and established aggregation & communication methods for DR in the wholesale marketplace
  - DSG and other demand response resources should be allowed spinning reserve like status



- Dispatchable Standby Generation Summary:
  - Award Winning Program
  - 43 MWs Virtual Peaking for PGE
  - 17 MWs Additional Under development
  - 80 MWs More Proposed in new IRP
  - Opens new opportunities for distributed resources

- DSG - The *next* generation of Utility Services for High Customer and Grid Reliability


PGE "virtual"
Power Plant
Hospital
Water
Plant
Data Center
Hotel
Factory