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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	)))))))))	**CASE NO. AVU-E-04-1/ AVU-G-04-1**

DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

JUNE 21, 2004

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of utility applications and customer petitions.

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

A. The first purpose of my testimony is to discuss the Company's weather normalization. Another purpose is to detail the test year power supply adjustments proposed by Avista and describe my investigation of those adjustments. I will also discuss Avista's investments in the Coyote Springs 2, Kettle Falls CT and Boulder Park projects.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Staff Exhibit Nos. 128 through 131.

Q. Please summarize your testimony.

A. My review of the Company's weather normalization consisted of replicating the results obtained by the Company, in addition to evaluating the effects of varying the weather data and period of record used in the Company's analysis. I conclude that the weather normalization performed by Avista is accurate and reasonable, and recommend that it be accepted.

The test year power supply adjustments proposed by the Company in this case consist of contractual changes due to new or expiring contracts, and changes due to specific contract rates or terms; and power supply cost adjustments for normalized loads and water conditions. As a result of these adjustments, the Company has proposed a net, system-wide decrease in test year expenses of $30.5 million.

My investigation of test year power supply adjustments included evaluation of known and measurable changes through August 2005 and replication of the Company's dispatch simulation model and evaluation of its inputs and assumptions. I specifically focused on short-term sales and purchases and long-term wholesale sales and purchase contracts.

I found that the power supply pro forma adjustments proposed by the Company adequately reflect known and measurable changes that will occur through August 2005. I also found that the dispatch simulation model adequately reflects anticipated dispatch of Company resources, the availability and price of regional surplus energy, the normalization of hydro resources, and the normal cost of fuel for Company-owned thermal resources. Therefore, as a result of my investigation, I recommend that the Commission accept the power supply adjustments as proposed by the Company.

Based on my review of the Company's decision to pursue the Coyote Springs 2 project (CS2), I concluded that the Company's need for power justified the decision. My review of the Request for Proposal (RFP) process also led me to conclude that the process was fair and that the CS2 project was the best alternative. Because the project was transferred from Avista Power to Avista Utilities at cost, I believe that it was appropriate to consider the project as an alternative in the Company's RFP evaluation.

Despite the problems caused by the bankruptcy of the construction contractor, and the numerous problems experienced with the generator step-up transformer, I believe Avista did all it reasonably could to minimize the construction delays and the cost overruns.

The Kettle Falls CT and Boulder Park projects were pursued to obtain some relief from the extremely poor water conditions and high market prices in 2000 and 2001. I reviewed the Company's analysis justifying the Kettle Falls project and conclude that it was reasonable given the circumstances at the time. In reviewing the Boulder Park project, however, I found that there were exceptional cost overruns and delays. While some of the cost overruns and delays were unavoidable, others could have been avoided if Avista had better planned and managed the project. Because the cost overruns and delays were so excessive, I contend that ratepayers should not be stuck with all of the excess costs and recommend that ten percent of the project investment not be allowed in rate base.

WEATHER NORMALIZATION

Q. What is the purpose of weather normalization?

A. Customer energy usage in the test year is typically higher or lower than normal due to unusually warm, cold, wet or dry weather. The purpose of weather normalization is to adjust test year customer energy usage to reflect a level of usage that would reasonably be expected in a year with normal weather conditions. Normalized customer energy usage is then used to establish retail sales revenue that can be expected in a normal year. It is also used to determine the demand that must be met by the Company's generation or purchased resources, thus it affects the normalized net power supply expenses.

Q. Have you reviewed the weather normalization performed by the Company in this case?

A. Yes, I reviewed it in detail. I replicated the method used by the Company in order to verify the accuracy of the Company's results. I also varied the analysis by using weather and customer usage data for different periods of record than used by the Company. I also examined different weather variables. In addition, I performed weather normalization analysis for each of the Company's customer classes to determine which classes are sensitive to weather conditions.

Q. Avista made separate weather normalization adjustments for usage by its electric and its gas customers. Did you review the Company's weather normalization for its gas customers?

A. Yes, I conducted a similar review of the Company's gas weather normalization as I did for the electric weather normalization. The techniques and weather variables used by the Company were nearly identical for both the electric and gas weather normalization.

Q. What is your opinion of the Company's weather normalization?

A. I believe the Company's weather normalization fairly and accurately adjusts test year energy consumption and that no further adjustment to the weather normalization proposed by the Company is necessary.

POWER SUPPLY EXPENSE AND REVENUE ADJUSTMENTS

Q. Why is it necessary to make adjustments to the test year power supply costs?

A. The Company’s adjustments to the 2002 test period power supply revenues and expenses are designed to reflect the normalized level of revenues and expenses, and to include known and measurable changes to the revenue and expense items. The purpose of the adjustments is to come up with revenues and expenses that can be reasonably expected going forward with the rates that are established by the Commission.

Q. What are the primary differences in net power supply costs since Avista’s last general rate case in 1997?

A. Net power supply costs in this case are approximately $11 million (Idaho share) higher than in the last general rate case in 1997. The two primary changes include a reduction in wholesale sales revenue (PGE capacity sale) of $6 million, and an increase in net fuel expense for thermal generation (primarily Coyote Springs 2) of $4.5 million.

Q. Have you reviewed the testimony of Company witness Johnson and the power supply adjustments shown in Exhibit No. 10, Schedule 1?

A. Yes. I have reviewed Mr. Johnson's testimony, Exhibit No. 10, Schedule 1, Company workpapers that support the exhibit and Company responses to Staff production requests.

Q. What are the primary reasons for the proposed power supply adjustments?

A. There are two primary reasons for the 67 proposed adjustments to the 2002 test year power supply revenue and expenses. The majority of the adjustments are associated with contracts. These can be due to the expiration of an existing contract or the initiation of a new contract, or due to specific, projected or estimated changes in contract rates or charges. The remaining changes result from the dispatch simulation model, and mostly include projected fuel expenses.

Staff Exhibit No. 128, entitled 2002 Test

Year Power Supply Adjustments, provides a categorical breakdown of total Company power supply expense and revenue adjustments. Expenses have been reduced by $85.9 million and revenues have been reduced by $55.4 million for a net decrease in revenue requirement of $30.5 million from the 2002 test year.

Q. Please generally describe the types of power supply adjustments summarized in Staff Exhibit No. 128.

A. Avista has made 67 pro forma power supply adjustments to 2002 test year actuals to reflect power costs for the twelve-month period beginning September 1, 2004 and ending August 31, 2005. Fifty-two of these adjustments are to test year expenses, while 15 adjustments are to test year revenues. Many of the adjustments are associated with changes in wholesale power contracts from 2002 through August 2005. Some of these adjustments reflect new or expiring contracts, while others reflect contractual rate and cost changes for services purchased, services rendered and acquisition of fuel supplies over the same period. In some cases, adjustments are based on specific contractual rates applied to historical averages or estimates for such things as generation or transmission quantities. The remaining adjustments have been categorized as power supply, and are the result of output from the Company's dispatch simulation model under normal load and water conditions.

Q. What primary criterion did you use to decide whether a proposed adjustment is reasonable?

A. The primary criterion is whether the adjustment is known and measurable.

Q. Are the power supply adjustments proposed by the Company and presented by Mr. Johnson reasonable?

A. I have reviewed the workpapers provided by the Company for each of the proposed power supply adjustments presented by Mr. Johnson and recommend that they be approved as proposed. There is little question that the specific changes such as new contracts, expired contracts, and contract-specific changes in rates or charges occur at a date certain and are therefore known and measurable. When expense and revenue adjustments shown on line 4 of Staff Exhibit No. 128 are combined, this category of adjustments represents approximately a $7.09 million <u>increase</u> in power supply revenue requirement (Net adjustment in power supply costs = Net adjustment in expenses - Net adjustment in revenues, or -$11.172 million - (-$18.260 million) = $7.088 million).

When the expense and revenue adjustments shown on line 8 that represent estimated, projected and miscellaneous contract changes are combined, they represent a <u>decrease</u> in power supply expenses of $34.08 million. Although these changes are not all specifically stated within a contract, I believe they represent reasonable estimates based on historic averages, projected third party budgets or historic service costs or revenues under existing contracts.

Power Supply adjustments, the final category of expense and revenue adjustments, are from the dispatch simulation model and are shown on lines 10 and 11 of Staff Exhibit No. 128. After analysis of the simulation model, examination of Company workpapers and review of production request responses, I believe that the adjustments for short-term sales and purchases, and fuel price changes for thermal resources are reasonable. When added together, this category of adjustments represents a decrease of $3.53 million. I will discuss the dispatch simulation model and the associated adjustments in more detail later in my testimony.

Q. How did you evaluate the Company's proposed adjustments for contracts?

A. I reviewed the workpapers provided by the Company, which in some cases consisted of the contracts themselves and in other cases consisted of excerpts from the contracts showing the rates and terms that would affect power supply costs. The workpapers showed beginning and termination dates of the contracts, the quantities and delivery schedules, and the rates for purchase or sale.

Q. Are there some contracts for which adjustments have been made where a precise rate is not specified?

A. Yes, there are some. For those contracts the adjustments were based on estimates made by the contracting parties.

Q. There appear to be very large power supply adjustments in both expenses and revenues in the "miscellaneous" category (line 7) of your Staff Exhibit No. 128. Please explain why these adjustments are so large.

A. Nearly all of the adjustments in this category, both on the expense and the revenue side, are attributable to gas that was purchased, but not consumed, for generation during the 2002 test year. The pro forma expense for this gas is zero since it is assumed that all gas purchased will be used for generation. Similarly, the pro forma revenue for this gas is also zero since there would normally be no gas to sell.

Q. The second most noticeable adjustments are in the "short-term purchases/sales" category (line 10) of your Staff Exhibit No. 128. Please explain why these adjustments are so large.

A. The short-term market purchases and sales adjustments are based on output from the dispatch simulation model (AURORA). The adjustments are the combined effect of differences from the 2002 test year in both the quantities of purchases and sales, and the prices of those purchases and sales. In general, there would be fewer short-term purchases and more sales in a normal year. This reflects the fact that the CS2 plant would be available in a normal year, and the fact that 2002 was below normal for hydro generation.

Q. The final category of large adjustments is in fuel expenses (line 11 of Staff Exhibit No. 128). Please explain this adjustment.

A. Fuel expense adjustments are based on the results of the Company's system dispatch model. The majority of the fuel expense increase is associated with operation of the CS2 plant. The Boulder Park and Kettle Falls CT projects also contribute to this adjustment. Note on Staff Exhibit No. 128 that the increase in fuel expense is more than offset by a net decrease in the cost of short-term purchases and sales.

Q. Do you believe it is appropriate to pro form the normalized 2002 test year power supply expenses to the period of September 1, 2004 through August 31, 2005?

A. Yes, I believe that it is appropriate to allow adjustments that reflect power supply cost during the period proposed for several reasons. First, as I previously discussed, all of the adjustments must be reasonably known and measurable to be considered reasonable. Second, the adjustments must be based strictly on test year loads and be independent of future retail load conditions. Finally, by the time the rates go into effect in this proceeding, we will be at the beginning of the pro forma period and the test year will be more than two years old.

Q. Is it unusual in a general rate case to pro form test year power supply expenses to a period more than two years later than the test year, in this case from a 2002 test year to a pro forma period of September 1, 2004 through August 31, 2005?

A. No. In Avista's last general rate case, Case No. WWP-E-98-11, the Company used a 1997 test year and a pro forma power supply period of July 1, 1999 through June 30, 2000. Thus, the pro forma period followed the test year by about two and a half years.

Q. By using a pro forma power supply period of September 1, 2004 through August 31, 2005, do you believe there is any potential for a mismatch between revenues and expenses?

A. There is always a potential for a mismatch of revenues and expenses. That is why we typically use a historical test year and try to limit adjustments as much as possible. In using a historic test year and making prospective adjustments, it is very important to make only those adjustments that are known and measurable. I have carefully reviewed each of the power supply adjustments proposed by the Company and believe all of them are reasonably known and measurable.

Q. But isn't it possible that the Company's power supply adjustments include known expense increases and known revenue decreases due to either new or expired contracts, but not include potential revenue increases due to unknown future events and prices?

A. If Avista has contracts that expire and are not replaced during the pro forma period, the dispatch simulation model will either buy or sell generation to replace the effect of the contract. Thus, for example, if a power sales contract expires before the end of the pro forma period leaving Avista with surplus generation for some period of time, the system dispatch model will simply sell the surplus into the market at whatever prices the model computes. Thus, the revenue lost when the contract expires is replaced by revenue determined by the system dispatch model. Similarly, if a purchase contract by

Avista expires, the model will purchase replacement resources from the market at computed prices. Although the purchase and sales prices computed by the model are not precisely known and measurable, they are as accurate as can be determined, short of having a contract in-hand. Moreover, they are no less accurate than the normalized fuel expenses.

Q. According to Mr. Storro's testimony at page 4, lines 6-9, Avista's annual net resource energy position does not become deficient until 2008 and beyond, and the Company's capacity position is either surplus or nearly balanced through 2007. Is it possible that the Company's surplus is too large, resulting in increased costs but not proportionately increased revenues?

A. It is important to realize that the Company's surplus condition is on an annual basis, and that there are times during the year when the surplus is either greater or less than the annual average. Avista operates its own resources to make economy sales in the market whenever its resources are not needed to meet its own load. However, if those resources cannot be economically operated to make off-system sales, they sit idle. Nevertheless Avista still may need all of its resources at times, and must always maintain a required reserve margin. (Avista currently maintains a reserve margin of about 15%

based on forecasted peak loads. In addition, Avista is required by the Western Electricity Coordinating Council to maintain an operating reserve equal to 5% of its hydro generation and 7% of its thermal generation capacity). Having too great of a surplus can indeed cost the Company and its ratepayers more. However, I do not believe that Avista has an unacceptably large surplus. Further, I believe the planning criteria used by the Company for deciding whether and when to acquire new resources is appropriate.

Q. Is it unusual to have 67 power supply expense and revenue adjustments in a general rate case?

A. No. In Avista's last general rate case there were 97 power supply adjustments. As I stated earlier, the majority of the adjustments in this case are contractually related, and the remaining adjustments are pro forma fuel cost adjustments.

DISPATCH SIMULATION MODEL

Q. Has Avista done anything differently from its 1997 general rate case in terms of analysis using a dispatch simulation model?

A. Yes. The primary difference is that the Company is now using the AURORA model. AURORA dispatches resources on an hourly basis, unlike the previous model that used a monthly time step. An hourly dispatch more accurately reflects the true system dispatch of Avista's resources and of other generation resources throughout the region. The use of hourly data also more accurately recognizes hourly load variations and properly evaluates the costs and benefits of peaking resources. In my opinion, the adoption of an hourly dispatch model is a substantial improvement over prior system dispatch models, and I am more comfortable with the results it produces.

Q. You stated that the power supply adjustments proposed by Mr. Johnson were reasonable. How did you evaluate the adjustments that result from running the dispatch simulation model?

A. The first step in evaluating the power supply expense and revenue adjustments was to replicate the Company's results using the AURORA model. Through its software licensing agreement, Avista has provided Staff with a copy of the model. Avista has also provided Staff with a complete copy of all input data that it used in its analysis. By replicating the Company's results, I was able to better understand the relationships between energy demand, supply energy and market conditions throughout the region. I then evaluated the hydro generation and regional resource input data provided mostly by third parties, the long-term contract demand obligations as adjusted in the pro forma test year, the monthly energy as calculated by the model for short-term purchases and sales, and the generation and cost for each Company-owned thermal resource. The final step was to evaluate the effect of different natural gas prices on the annual fuel cost for the Company's thermal resources.

Q. How do you know that the hydro conditions assumed by the model represent normal water conditions?

A. In the model, hydroelectric generation for the Northwest was based on the Northwest Power Pool's 2000-2001 Headwater Benefits Study. The study provides generation estimates for northwest hydroelectric plants, including Avista's plants, utilizing current regulation and sixty water years (1929-1988) of historical stream flows. Because AURORA dispatches resources throughout the WECC, data sets for plants outside of the Northwest (e.g. Canada and California) were also used. These data sets were provided by EPIS, the developer of AURORA, and are based on information from Canadian sources and from the U.S. Department of Energy. Because the hydro data used in this rate case has been developed by independent sources for a variety of uses by many different utilities, I believe it fairly reflects normal water conditions and produces unbiased results.

Q. It would seem that the results of the dispatch simulation model would be highly dependent on the fuel price assumptions used in the model. Did you review Avista's fuel price assumptions and do you believe they are reasonable?

A. It is true that the results of the dispatch simulation modeling are highly dependent on the fuel price assumptions used. For its analysis, Avista used actual contract prices for its coal plants and for its wood-fired Kettle Falls plant. For its gas-fired plants, the Company used Henry Hub NYMEX natural gas forward prices on December 10, 2003 for the power supply pro forma period. Avista then adjusted the Henry Hub prices using basis differentials intended to capture ancillary costs such as transportation and taxes. A different set of gas prices was derived for Coyote Springs 2, Rathdrum, and the combination of Boulder Park, Northeast and the Kettle Falls CT. The source used by Avista for these prices was the same system the Company uses to make gas-fired resource dispatch decisions.

Because the modeling results are so highly dependent on gas prices, I investigated gas price changes and their effect on annual expenses. I first examined a historical record of NYMEX forward prices for delivery in each month of the pro forma period. I reviewed historical daily NYMEX forward prices from April 2003 - April 2004 to determine whether the December 10, 2003 prices used by

Avista were unreasonably high or low. In my judgment, Avista did not choose a particularly high or low priced day. Generally, gas prices have steadily increased since December 10, 2003 when Avista chose prices for its analysis.

Nevertheless, to analyze the effect of gas prices on net power supply costs; I estimated gas prices that were lower and higher than the prices used by Avista. In the low price scenario, I selected prices on May 1, 2003 because they were nearly the lowest of any day in the past twelve months. For the pro forma period, the prices averaged about $4.77 per MMBtu. For the high gas price scenario, I selected futures prices on May 5, 2004 because they were close to the highest on any day in the past twelve months. The average price in the pro forma period under the high price scenario was approximately $6.09 per MMBtu. Using these high and low gas price scenarios, I determined a corresponding range of thermal fuel costs to be $46.32 million to $63.49 million. The thermal fuel cost computed by Avista using its December 10, 2003 fuel prices is $50.0 million. Based on the range I computed for high and low gas prices, I concluded that the gas prices Avista used in its modeling are reasonable.

Q. How critical is it that Avista use accurate gas prices in determining its net power supply costs?

A. Of course, it is desirable to use gas prices that are close as possible to what the Company will actually encounter. It is impossible to know these prices in advance, however. Nevertheless, if gas prices are estimated too high or too low, deviations in actual net power supply costs will be captured in the Company's annual power cost adjustment (PCA). Under the PCA, Avista is entitled to recover or refund to customers up to 90 percent of deviations from normal. This sharing between the Company and its customers helps to minimize the built-in incentive for Avista to establish its base net power supply costs too high. Again, I do not believe Avista chose to use December 10, 2003 gas prices in an effort to set its base net power supply costs high. Instead, I believe the gas prices chosen by Avista are reasonable.

Q. Do you recommend any changes in the thermal fuel adjustments proposed by the Company?

A. No. I believe that the dispatch simulation model adequately estimates the amount of energy that will be generated at each resource under normal water conditions. I also believe that the fuel price changes proposed by the Company are reasonable based on my review of Company workpapers.

Q. Does the dispatch simulation model include speculative sales or purchases?

A. No. The dispatch simulation model includes only Avista's hourly native loads, so resources are dispatched to meet only those loads. However, whenever Avista has resources of its own that can be operated economically to meet other loads in the region, they will be operated and the revenues will accrue to Avista and its customers. Similarly, Avista regularly makes off-system purchases whenever its own resources are insufficient to meet load. These off-system purchases and sales are not speculative and therefore are appropriately included in power supply modeling.

COYOTE SPRINGS 2

Q. When did Avista first identify a need for the Coyote Springs 2 project?

A. In July 2000, Avista submitted an update to its 1997 Integrated Resource Plan (IRP). The updated 1997 IRP served as the basis for a Request for Proposals that the Company intended to release in August 2000. In the 1997 IRP update, Avista's load-resource balance showed that the Company was deficit, both for energy capacity, beginning immediately and extending throughout the entire planning horizon. Deficits in 2000 were 395 MW of peak capacity and 237 aMW of energy. One of the primary reasons for the deficits was the sale of the Company's share of the Centralia plant. Avista had a contract to purchase output from Centralia after the sale, but that contract expired at the end of 2003. A second reason for the expected deficits was a decreased reliance on long and short-term contracts, in part due to their risk and the recent volatility in market prices. I believed that the Company's need for new resources was sufficiently demonstrated in the 1997 IRP update and I supported the Company's decision to issue a Request for Proposals.

Q. Do you believe the RFP issued by Avista was fair?

A. Yes, I believe the RFP was fair. Staff reviewed preliminary drafts of the RFP prior to its release and provided comments to Avista. All of Staff's comments, both written and verbal, were addressed by Avista in the preparation of the final draft RFP. Avista then submitted the draft RFP and its 1997 IRP Update to the Commission for comment. Commission Staff commented noting that it believed that issuing the RFP was appropriate. The Commission issued Order No. 28542 noting that the Company's filings of its 1997 IRP Update and the RFP were informational and were not required by statute or Commission Order. The Company solicited only comment; therefore, Commission approval was not necessary. The Commission commended Avista for soliciting public input into its RFP process.

Avista's RFP was an "all source" competitive bid based on the Company's identified need for 300 MW of new electric power starting in 2004. The 1997 IRP Update described the Company's loads and resources, provided an overview of technically available resource options, and demonstrated need for resources.

In its filing with the Commission, the Company stated that it would consider any offer of resources including but not limited to, energy and capacity, energy efficiency, turnkey plans, construction—for Avista—of a generating plant on a site provided by the bidder, and construction by a bidder on a site furnished by Avista.

I believe that the RFP was fair in all respects, and not intended to favor specific proposals, locations, technologies or bidders.

Q. Briefly describe the response Avista received in response to the RFP.

A. Thirty-two proposals were received from 23 bidders for a total of 2,700 MW of resources in response to the all-resource RFP. The proposals included 24 offers for new generation, six of which were for renewables, one customer-owned emergency generation proposal, and seven energy efficiency projects.

Q. Do you believe that the evaluation criteria developed and used by Avista were fair to all proposals?

A. Yes. Avista went to great lengths to insure that the evaluation criteria it developed were fair and impartial. Besides seeking input from the Idaho and Washington Commission Staffs, it retained R.W. Beck, an engineering consulting company, to also review the evaluation criteria. R.W. Beck made recommendations on the evaluation criteria and on the assumptions to be used in analyzing proposals, and on the dispatch modeling and economic analysis used by Avista.

Q. Do you believe it was appropriate to consider the Coyote Springs 2 project as an alternative, since rights to develop the project were owned at the time by Avista Power, an unregulated Avista Corp. subsidiary?

A. Yes, I do believe it was appropriate. I participated in meetings with Avista and with a representative from the Washington Commission Staff in which this issue was specifically discussed. My opinion and the opinion of the Washington staff member was that CS2 should be considered as an alternative as long as the project assets at the time (permits, site, turbine contract, rights to develop, etc.) would be transferred at cost to Avista Utilities. Early on in the proposal evaluation phase, it was apparent that the CS2 project could be a very competitive proposal. It was felt that excluding it might eliminate what could ultimately be Avista's best and least cost option.

Q. Do you believe there was any impropriety in the transfer of rights to the CS2 project from Avista power to Avista Utilities?

A. No, because the transfer was made at cost. Staff auditors have reviewed the transaction and have assured me that the transfer was indeed at cost. Neither Avista Power nor the shareholders of Avista Corp. made any profit from the transfer.

Q. What was Staff's involvement in the RFP process?

A. I participated on behalf of the Idaho Commission Staff. I reviewed and helped develop evaluation criteria, and reviewed the results of Avista's analysis of proposals. I participated in several meetings with Avista and a representative of the Washington Commission staff to review Avista's evaluation and ranking of the proposals. We reviewed the Company's first round screening results and provided input into the decision about which projects should move on to the second round of screening. We also identified things we believed needed further investigation before further evaluation and ranking could take place. During the final screening process, we reviewed in detail Avista's economic analysis as well as all the other factors that were used in assessing the proposals. I also attended a final meeting just days before Avista staff made their recommendation to the Board of Directors.

Q. Are you convinced that Avista chose the best, least cost proposal?

A. Yes, I am. The Company's selection of CS2 as a resource from its 2000 all-resource Request for Proposals process was reasonable.

Q. Do you believe it was reasonable to sell half of CS2 to Mirant?

A. Yes, I do believe it was reasonable, given the financial challenges facing the Company at the time. I reviewed the analysis done by the Company of the options available at the time. Although it would have been desirable to have more interested bidders in the plant, I believe that the Company's analysis supports the decision to sell half of the plant to Mirant.

Q. Avista witness Lafferty's testimony includes extensive discussion of the litany of problems experienced during the construction and start-up of CS2, along with the costs associated with those problems. Do you believe that the cost overruns that resulted from these problems should be allowed in rate base?

A. The problems and associated cost overruns seemed to be associated primarily with two factors, the bankruptcy of Enron and ultimately of NEPCO, its construction subsidiary, and failures of the generator step-up (GSU) transformer.

I do not believe the bankruptcy of Enron and NEPCO could have ever been envisioned at the time construction on the project began. There was virtually nothing Avista could do other than try to mitigate the effects on the CS2 construction costs and schedule. I believe Avista made a good effort to keep costs under control and to minimize construction delays following the bankruptcies; therefore, I do not believe Avista or its shareholders should be held accountable for any cost overruns and delays caused by the bankruptcies.

With regard to the repeated GSU transformer failures, I believe that these too were beyond the control of Avista. Decisions about the transformer design and which manufacturer to select were not unreasonable. Whenever problems were encountered, it appears Avista did everything it could to make repairs or acquire a replacement. The Company also appears to have diligently exercised warranties and pursued insurance claims.

The cost overruns associated with these problems have been estimated by Avista to be approximately $15 million. This amount represents 16 percent of the total original project cost estimate of $93.9 million. Staff does not oppose inclusion of these costs in rate base for the CS2 plant.

KETTLE FALLS CT

Q. Why did Avista build the Kettle Falls gas-fired combustion turbine (CT) project?

A. The Kettle Falls CT project was one of at least five potential generation projects identified as possible solutions to help mitigate the effect of very low water conditions and extremely high and volatile electric prices that occurred during the June 2000 through December 2001 period. Eventually the Company decided to pursue the Kettle Falls CT project and the Boulder Park project, but not pursue three small projects involving installation of natural gas or diesel-fueled generators at other locations. Two gas-fired engine generators like those installed at Boulder Park were purchased by Avista for installation at the Spokane Industrial Park, but were never installed after power prices receded in late 2001. Recovery of the cost of these generators is not being requested in this case.

Q. Have you reviewed the final cost of the Kettle Falls CT project?

A. Yes. The final cost of the Kettle Falls CT project as verified by Staff auditors is $9.2 million, or approximately 8.2 percent above the estimated project cost of $8.5 million.

Q. It appears the project exceeded its cost estimate by nearly $700,000. What does Avista attribute the cost overruns to?

A. There are two primary reasons identified by Avista. First, $543,000 in additional costs were incurred because of additional work that had to be completed by the project contractor. Most of this work was associated with the construction cost of the turbine building. Second, an additional $153,000 was incurred directly by Avista for work outside of the scope of the contractor's responsibility. Of this amount, $133,000 was paid to the contractor in accordance with contract requirements for exceeding the performance requirements of the turbine.

Q. Do you recommend that the full final cost of the Kettle Falls CT project be allowed in rate base?

A. Yes, I do. Despite the fact that the final project costs exceeded its original estimate and took a little longer to complete than expected, I believe the cost overruns were within a reasonable range and not unusual for a project of this type.

BOULDER PARK

Q. Was Boulder Park or an equivalent plant included in Avista's 1997 or 2000 IRPs before the Company made its decision to pursue the project?

A. No. The need for such a plant was not identified in any of the Company's previous IRPs. Avista decided to pursue the project primarily in response to the extreme low water conditions and market prices in 2000-2001.

Q. Do you believe it was reasonable for Avista to develop the Boulder Park project?

A. Yes, I do. Market prices at the time were extremely high and no one knew if or when such high prices might subside. Most utilities in the Northwest were pursuing a variety of options for relief from the high prices including diesel generation, gas-fired generation, customer buy-backs and demand management programs. Avista also considered many of these options, and the Boulder Park project appeared to be one of the Company's most cost effective alternatives. I thoroughly reviewed the Company's analysis that it completed at the time a decision was made to pursue the project. At that time, I believe a decision to proceed was reasonable.

Q. What was the Company's estimated cost for Boulder Park? When did the Company expect to complete construction?

A. When the project was first proposed, Avista estimated the construction cost to be $21.0 million. On

June 17, 2001, Avista revised its estimate upward to $23.65 million. The original estimated completion date was September 1, 2001.

Q. It appears that there were considerable cost overruns and delays on the project. Have you reviewed the information provided by the Company in response to Staff's production requests concerning cost overruns and delays?

A. Yes, I have. The final cost of Boulder Park was approximately $32.1 million. This is $11 million more than initially projected, and represents a greater than 50% cost overrun. Completion of construction was delayed by eight months until May 2002.

Q. What reasons does Avista give for the cost overruns and delay in completion?

A. In response to production requests, Avista states that:

> The excess costs for the Boulder Park project generally stemmed from the fast track design-build approach that the Company chose in order to bring small generation on line as quickly as practical in order to mitigate the high prices and volatility in the electric power market during the energy crisis. Although not new technology for the power industry, the natural gas fired reciprocating engine generators were the first project of its kind for Avista, which contributed in part to actual construction costs being higher than the original estimates.

Avista provided a summary by cost category of the amounts of the cost overruns, along with a brief description of the reasons for the cost variations in each category. I have included this summary as Staff Exhibit No. 129.

Q. Do you believe the explanations cited by Avista for the cost overruns are reasonable?

A. I believe that some of the explanations are reasonable. Avista clearly did not anticipate many of the problems encountered in the project's construction or many of the requirements imposed on the project by other agencies. For example, the Company cites incomplete construction plans being provided by the engine generator manufacturer, handicapped building access requirements, road width requirements, paved instead of graveled site grounds, building soundproofing requirements and construction plan approval delays as among the many unexpected factors. I agree that many of these delays and requirements could not have been anticipated.

Nevertheless, it is simply impossible to ignore that the final project cost exceeded the initial estimate by nearly 53 percent. While many of the causes of cost overruns could not be anticipated, I believe some of them could have been if Avista had better planned and managed the project. Blaming a fast track construction process for cost overruns might make sense if the project had actually been completed on a fast track schedule, but the fact is that construction took eight months longer than expected. The higher costs due to the fast track schedule apparently cost the Company quite a lot but gained nothing.

It is common to include a contingency amount in the cost estimate for large construction projects to insure that funds are available in the event of unplanned problems, circumstances or conditions. The amount of the contingency can vary considerably for construction projects depending on many things such as material and equipment costs, installation complications and unknown site conditions. Contingency amounts for projects similar to this one are typically in the range of 5-15 percent. In fact, CS2 and Kettle Falls contingencies totaled 16 and 8 percent, respectively. Avista may not have any experience in building this particular type of plant, but it should have some experience with building practices and requirements in Spokane County, a place where it has built many things.

The explanations put forth by Avista may be understandable, but the excessive cost overruns should primarily be the responsibility of Avista. I believe ratepayers should be able to expect the utility to have the ability to construct projects at least cost. Construction of new projects cannot simply be a blank check signed by ratepayers. It is reasonable to expect the utility to have the expertise and experience to construct and manage any project it undertakes at a reasonable cost.

Q. Do you recommend that all of the cost of the Boulder Park plant be allowed in rate base?

A. No, I do not. I recommend that ten percent of the final project cost be disallowed.

Q. What is the basis for recommending ten percent disallowance?

A. In reviewing Staff Exhibit No. 129, three particular cost categories stand out. First, the final construction management cost of $2,159,000 was 2.25 times the revised project estimate. This additional cost was primarily due to the contractor being required to spend twice the amount of time working on the project. The second cost category that stands out is $1,110,000 for Avista's project management, engineering and project commissioning. There was no amount included for these costs in the revised estimate. Finally, an additional $912,714 was incurred because of the additional time required to complete the project. The total cost overrun in just these three cost categories comes to $3,221,714, approximately ten percent of the total final project cost Undoubtedly, some of the cost overruns in these categories would have occurred due to reasonable construction delays and problems. However, it is also likely that there are some unreasonable cost overruns spread throughout nearly every cost category. Consequently, I believe a ten percent disallowance from rate base is a fair amount. The effect of a ten percent disallowance from rate base is a reduction in annual revenue requirement of approximately $205,000 on an Idaho jurisdictional basis. Staff witness Patricia Harms further discusses this adjustment in her testimony.

I might also add that using the initial construction cost estimate as the basis for judging the reasonableness of the final construction cost is not necessarily always fair. The initial estimate could be low or inaccurate.

Q. Have you examined any other evidence to determine a reasonable cost for gas fired reciprocating engines similar to Boulder Park?

A. Yes, although cost information for these types of engines is somewhat difficult to obtain because there are few utilities or public entities that have recently installed these types of units. Normally, units like these are installed by non-public entities such as hospitals, institutions and industries for cogeneration or backup purposes. Nevertheless, I was able to obtain some information for comparison purposes. Six different recent reports all reference the same source for cost figures. Thus, I have included excerpts from only one report as Staff Exhibit No. 130. As second source citing a cost range of $350 to $600 per kW is included as Staff Exhibit No. 131. As shown by Staff Exhibit No. 130, total plant costs range from $695 per kW for the largest units to $1030 per kW for the smallest units. Boulder Park consists of six units similar in size to the largest unit shown in the exhibit. Boulder Park's total plant cost came to $1303 per kW. The initial estimate of the plant cost was approximately $850 per kW. It is absolutely true that actual costs for a specific plant could vary quite significantly from the estimates shown in the exhibit; however, Boulder Park's cost seems exceptionally high by comparison. Even with the ten percent disallowance recommended by Staff, Boulder Park's cost would still far exceed the estimates from other sources.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

2002 TEST YEAR POWER SUPPLY ADJUSTMENTS
TOTAL SYSTEM
($1000)

Line No.	TYPE OF CHANGES	EXPENSES	REVENUES	NET ADJUSTMENT
1	**SPECIFIC CONTRACT CHANGES**			
2	NEW AND EXPIRED CONTRACTS	-$12,016	-$18,546	$6,530
3	CONTRACT SPECIFIC RATE	$844	$286	$558
4	SUBTOTAL	-$11,172	-$18,260	$7,088
5	**CONTRACT RATE/REV CHANGE**			
6	ESTIMATED/PROJECTED	$5,070	$1,523	$3,547
7	MISC	-$78,810	-$41,184	-$37,626
8	SUBTOTAL	-$73,740	-$39,661	-$34,079
9	**POWER SUPPLY**			
10	SHORT-TERM PURCHASES/SALES	-$36,203	$2,530	-$38,733
11	FUEL	$35,201	$0	$35,201
12	SUBTOTAL	-$1,002	$2,530	-$3,532
13	**TOTAL NET ADJUSTMENT**	-$85,914	-$55,391	-$30,523

Exhibit No. 128
Case No. AVU-E-04-1/
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R. Sterling, Staff
6/21/04

Summary of Costs
Boulder Park Generating Station

Part I - Wartsila Costs	7-17 est.	actual	difference
Wartsila Reciprocating Engine/Generators (Units 1 - 6)	$ 13,300,000	$ 13,300,000	$ -
Change orders	$ -	$ 208,000	$ 208,000
Wartsila Subtotal	*$ 13,300,000*	*$ 13,508,000*	***$ 208,000***
Part II - Contractor Construction Costs			
Construction Management (KBI)	$ 960,000	$ 2,159,000	$ 1,199,000
Buildings and Sound Enclosures (Furnish and Install)	$ 1,250,000	$ 2,228,000	$ 978,000
Ventilation/Exhaust/Duct System (fabricate & install)	$ 1,170,000	$ 1,299,000	$ 129,000
Mechanical equipment Installation and commissioning	$ 1,130,000	$ 2,712,000	$ 1,582,000
Electrical equipment Installation and commissioning	$ 1,720,000	2,546,000	$ 826,000
Contract Construction Subtotal	*$ 6,230,000*	*$ 10,944,000*	***$ 4,714,000***
Part III - Avista Construction Costs			
Site Work	$ 220,000	$ 410,000	$ 190,000
Gas System	$ 160,000	$ 103,000	$ (57,000)
Substation/Transmission/Distribution/Communication	$ 1,136,000	$ 1,488,000	$ 352,000
Permits/Property Acquisition/Legal Fees	$ 450,000	$ 280,000	$ (170,000)
Miscellaneous Items			
Fire Detection & Suppression Systems		$ 237,000	$ 237,000
Electrical and mechanical systems		$ 415,000	$ 415,000
Emission Testing		$ 35,000	$ 35,000
Spare Parts and Tools		$ 100,000	$ 100,000
Avista Commissioning/Management/Engineering		$ 1,110,000	$ 1,110,000
Avista Subtotal	*$ 1,966,000*	*$ 4,178,000*	***$ 2,212,000***
Subtotal (Wartsila, Contractor, and Avista)	**$ 21,496,000**	**$ 28,630,000**	**$ 7,134,000**
Washington State Sales Tax (8.1%)	$ 1,772,546	$ 2,080,000	$ 307,454
B&O Tax	-	$ 54,000	$ 54,000
AFUDC	$ 387,286	$ 1,300,000	$ 912,714
TOTAL (Units 1 to 6)	**$ 23,655,832**	**32,064,000**	**$ 8,408,168**

Boulder Park Generating Station
Cost Summery Variance Details

Part I – Wartsila

The project had 13 Change orders issued for a total of $208,000. The major cost increase was $123,000 to cover the additional time Wartsila had to spend on the site over and above that which they contracted for.

Part II – Contractor Construction Costs

The total contractor construction cost over run was $4,714,000. This was primarily the extra cost associated with the following:

a. Construction Management. The project took much longer than anticipated to complete thereby increasing the construction management costs by approximately $600,000 for supervision labor and $400,000 for additional purchasing and construction markups on the overruns on materials and subcontractors. Change orders for engineering changes totaled approximately $200,000. Total overrun from estimate is $1,199,000.
b. Buildings and Sound Enclosures. The original estimate did not include the consumables building ($150,000), special inspections ($80,000), nor control room building ($500,000). The original building estimate from the consultant was lower than the actual cost by $400,000. The sound enclosures overran $60,000 due to design changes. The total overrun on buildings was $978,000.
c. Ventilation/Exhaust/Duct systems. Change orders to add ventilation air louvers and piping/sheeting changes added $129,000 total.
d. Mechanical equipment installation and commissioning. This was the single largest overrun on the project. The mechanical piping work ran $977,000 over due to the complexity of the piping as required versus the simple piping runs as bid from the minimal design prints. The exhaust stack was not in the original design and added $200,000. The exhaust duct insulation was not known in the original design and added $195,000. The foundation work associated with the auxiliary work outside the main building was not in the original estimate due to unknowns and underestimates of what was actually needed thereby adding $275,000. Commissioning costs were less here than estimated but resulted in increased Avista commissioning costs in Part III. Total cost overrun here was $1,582,000.
e. Electrical equipment installation and commissioning. The total overrun was $826,000. This was due to additions to the scope of work (ie. fire detection system) as well as the lack of electrical design especially in the control wiring.

Part III – Avista Construction Costs

The total Avista construction cost over run was $2,212,000. This was primarily the extra cost associated with the following:

a. Site work. Road work was larger and more difficult than expected because Spokane County required a 24' road instead of a 20' road ($35,000). Site work was larger and more difficult than expected due to rocks, larger footprint of buildings and auxiliaries, as well as fire and water system increases ($130,000). The fence work was overlooked in original estimate ($25,000). Total overrun here was $190,000.
b. Gas system. Relocating the station further east shortened the gas run and was $57,000 less than estimated.
c. Substation/Transmission/Distribution/Communication systems. The substation transformer was more expensive than expected, the substation work was more extensive, but the transmission/distribution work was not as extensive as predicted for a total overrun of $220,000. The communication system was far more extensive and complicated than originally anticipated due to microwave not feasible and fiberoptic being required to handle the load thereby costing an additional $132,000.
d. Permits/Property/Legal. The land was $150,000 less than expected and the legal was $20,000 less than expected for a cost underrun of $170,000.
e. Miscellaneous. These were not included in the original estimate. The fire detection and suppression systems were $237,000; electrical and mechanical system work was $415,000 (broken down to control systems @ $160,000; larger power cables and terminations @ $35,000; extra grounding inside station @ $20,000; work platforms @ $150,000; handicap access ramp @$50,000); emission testing was $35,000; spare parts and tools was $100,000; and the Avista commissioning/management/engineering was $1,110,000. The extra labor costs were due to the fact that to get this project completed, Avista essentially took over from the construction management firm the commissioning and final engineering.

Taxes – The extra sales tax was from the increase in the cost of the project. The B&O taxes were not included in the original estimate. The extra AFUDC was accrued due to the extra time the project took to complete.

Boulder Park Generation Station
CAR data-backup 2-1-02

Major Changes from original handwritten CAR form:

Original estimate = $23.5M
Est. 1-30-02 = $31.5M
$ 8.0M required to complete project.

Major changes in scope of work:

- Extra time on project for Wartsila, KBI, contractors, and Avista construction personnel
- Extra AFUDC accumulated due to increase in length of construction process
- Control building size increased 25%
- Handicapped access required by Spokane County
- Complete cooling system containment and oil system containment required by Spokane County
- Air Handling system added to achieve cooling and charge air requirements
- Extra catalyst required to achieve acrilyn and formaldehyde limits for SCAPA
- Quieter radiator fans and silencers from Wartsila to meet sound limits
- Additional piping required to handle unforeseen complexity of mechanical systems
- Additional electrical work to handle unforeseen complexity of electrical systems(especially control systems)
- Road building changed from 14' driveway to 24' road complete with paving to satisfy Spokane County requirements /plus extra rock problems encountered
- Site grading size increased 20%/ extra rock problems encountered
- Added 115 Kv transmission line work
- Increases in Washington State Sales Tax and B&O tax

Estimated total increase for above section = $5.7 M

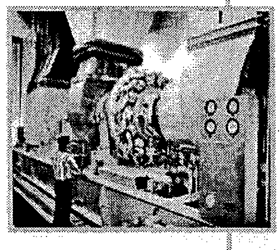
Major portions of work not included in original estimate;

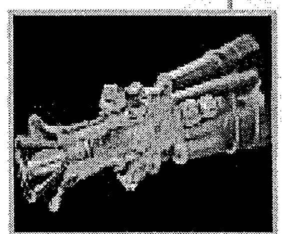
- Communication system to tie plant into remote operating facility
- Work platforms and cell hoists
- Fire & gas detection system
- Fire suppression system
- 10" fire line and hydrants/ " water line
- Remote and air handling computer control systems
- Security system
- Annunciator system
- Interior painting and insulation
- 4/0 power cable & terminations
- emergency shutdown generator and connections
- interior building grounding system
- emission testing
- Commissioning (Avista labor)
- Operations training for Avista personnel
- Avista Management and Engineering time

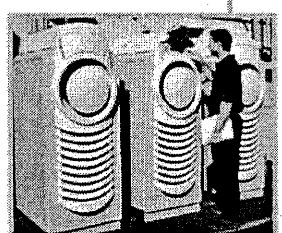
Estimated total increase for above section = $2.3 M

Gas-Fired Distributed Energy Resource Technology Characterizations

Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable







A joint project of the Gas Research Institute (GRI) and the

NREL National Renewable Energy Laboratory

Prepared for the Office of Energy Efficiency and Renewable Energy

November 2003 · NREL/TP-620-34783

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U.S. Department of Energy
Energy Efficiency and Renewable Energy

November 2003 • NREL/TP-620-34783

Gas-Fired Distributed Energy Resource Technology Characterizations

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Contract No. DE-AC36-99-GO10337

4.3 Performance and Efficiency Enhancements

Brake Mean Effective Pressure (BMEP) and Engine Speed

Engine power is related to engine speed and the Brake Mean Effective Pressure (BMEP) during the power stroke. Reciprocating engines can produce more power from a given displacement volume (cubic inches or liters) by increasing engine speed and/or the pressure inside the engine's cylinders. BMEP can be regarded as an "average" cylinder pressure on the piston during engine operation, and is an indication of the specific load on an engine. Engine manufacturers often include BMEP values in their product specifications. Typical BMEP values are as high as 230 psig for large natural gas engines and 350 psig for diesel engines. Corresponding peak combustion pressures are about 1,750 psig and 2,600 psig, respectively. High BMEP levels indicate high specific power output, and generally result in improved efficiency and lower specific capital costs and maintenance costs.

BMEP can be increased by introducing larger volumes of combustion air and fuel into the engine cylinders through improved turbocharging, improved after-cooling, and reduced pressure losses through improved air-passage design. These factors all increase air charge density and raise peak combustion pressures, translating into higher BMEP levels. However, higher BMEP increases thermal and mechanical stresses within the engine combustion chamber and drive-train components, along with a potential increase in the tendency for detonation, depending on fuel type. Proper design and testing is required to ensure continued engine durability and reliability.

Turbocharging

Essentially, all modern industrial engines above 300 kW are turbocharged to achieve higher power densities. A turbocharger is basically a turbine-driven intake air compressor. The hot, high-velocity exhaust gases leaving the engine cylinders power the turbine. Very large engines typically are equipped with two large or four small turbochargers. On a carbureted engine, turbocharging forces more air and fuel into the cylinders, increasing engine output. On a fuel-injected engine, the mass of fuel injected must be increased in proportion to the increased air input. Cylinder pressure and temperature normally increase as a result of turbocharging, increasing the tendency for detonation for both spark ignition and dual-fuel engines and requiring a careful balance between compression ratio and turbocharger boost level. Turbochargers normally boost inlet air pressure by a factor of 3 to 4. A wide range of turbocharger designs and models is used. Heat exchangers (called after-coolers or inter-coolers) are often used to cool the combustion air exiting the turbocharger compressor to keep the temperature of the air to the engine under a specified limit and to increase the air density.

4.4 Capital Cost

This section provides estimates for the installed cost of natural gas spark-ignited, reciprocating engine-driven generators. Two configurations are presented: power-only and CHP. Capital costs (equipment and installation) are estimated for the five typical engine genset systems ranging from 100 kW to 5 MW for each configuration. These are "typical" budgetary price levels to the end user. Installed costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements,

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emissions control requirements, prevailing labor rates, and whether the installation is a new or retrofit application.

In general, engine gensets do not show the economies of scale that are typical when costing industrial equipment of different sizes. Smaller genset packages are often less costly on a specific cost basis ($/kW) than larger gensets. Smaller engines typically run at a higher speed (rpm) than larger engines and often are adaptations of high-production-volume automotive or truck engines. These two factors combine to make the small engines cost less than larger, slower-speed engines.

The basic genset package consists of an engine connected directly to a generator without a gearbox. In countries where 60 Hz power is required, the gensets run at speeds that are multiples of 60 – typically 1,800 rpm for smaller engines and 900 or 720 rpm for large engines. In areas where 50 Hz power is used, such as Europe and parts of Japan, the engines run at speeds that are multiples of 50 – typically 1,500 rpm for smaller high-speed engines. The smaller engines are skid-mounted with a basic genset control system, fuel system, radiator, radiator fan, and starting system. Some smaller packages come with an enclosure, integrated heat-recovery system, and basic electric-paralleling equipment. The cost of the basic engine genset package plus the cost for added systems needed for the particular application or site comprise the total equipment cost. The total installed cost includes total equipment cost, plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning, and startup), and contingency.

Table 3 provides cost estimates for current power-only systems. The estimates are based on a simple installation with minimal site preparation required. These cost estimates are for base-load or extended peaking operation and include provisions for grid interconnection and paralleling. The package costs are intended to reflect a generic representation of popular engines in each size category. The engines all have low emission, lean-burn technology (with the exception of the 100 kW system, which is a rich burn engine that would require a three-way catalyst in most urban installations). The interconnect/electrical costs reflect the costs of paralleling a synchronous generator, although many 100 kW packages available today use induction generators that are simpler and less costly to parallel.[19] However, induction generators cannot operate isolated from the grid and will not provide power to the site when the grid is down. Labor/materials represent the labor cost for the civil, mechanical, and electrical work – as well as materials such as ductwork, piping, and wiring – and is estimated to range from 35% of the total equipment cost for smaller engines to 20% for the largest. Project and construction management also includes general contractor markup and bonding, as well as performance guarantees, and is estimated to range from 10% of the total equipment cost for small engines to 8% for the largest engines. Engineering and permitting fees are estimated to range from 5% to 8% of the total equipment cost depending on engine size. Contingency is assumed to be 5% of the total equipment cost in all cases.

[19] *Reciprocating Engines for Stationary Power Generation: Technology, Products, Players, and Business Issues*, GRI, Chicago, IL and EPRIGEN, Palo Alto, CA: 1999. GRI-99/0271, EPRI TR-113894.

Table 3. Estimated Capital Cost for Typical Reciprocating Engine-Generators in Grid-Interconnected Power-Only Applications (2003)

Cost Component	System 1	System 2	System 3	System 4	System 5
Nominal Capacity (kW)	100	300	1,000	3,000	5,000
Cost ($/kW)					
Equipment					
Genset Package	400	350	370	440	450
Interconnect/Electrical	250	150	100	75	65
Total Equipment	650	500	470	515	515
Labor/Materials	228	175	141	103	103
Total Process Capital	878	675	611	618	618
Project and Construction and Management	66	50	47	40	25
Engineering and Fees	53	40	38	26	26
Project Contingency	33	25	24	26	26
Total Plant Cost (2003 $/kW)	$1,030	$790	$720	$710	$695

Source: Energy and Environmental Analysis, Inc., estimates

Table 4 shows the cost estimates on the same basis for combined heat and power applications. The CHP systems are assumed to produce hot water, although the multi-megawatt size engines are capable of producing low-pressure steam. The heat recovery equipment consists of an exhaust heat exchanger that extracts heat from the exhaust system, a process heat exchanger that extracts heat from the engine jacket coolant, a circulation pump, a control system, and piping. The CHP system also requires additional engineering to integrate the system with the on-site process. Installation costs are generally higher than power-only installations due to increased project complexity and the higher performance risks associated with system and process integration. Labor/materials, representing the labor cost for the civil, mechanical, and electrical work – as well as materials such as ductwork, piping, and wiring – is estimated to range from 55% of the total equipment cost for smaller engines to 35% for the largest CHP installations. Project and construction management is estimated to be 10% of the total equipment cost for all engines. Engineering and permitting fees are estimated to range from 10% to 8% of the total equipment cost depending on engine size. Contingency is assumed to be 5% of the total equipment cost in all cases.

Table 4. Estimated Capital Cost for Typical Reciprocating Engine-Generators in Grid-Interconnected CHP Applications (2003)

Cost Component	System 1	System 2	System 3	System 4	System 5
Nominal Capacity (kW)	100	300	1,000	3,000	5,000
Cost ($/kW)					
Equipment					
Genset Package	500	350	370	440	450
Heat Recovery	incl.	180	90	65	40
Interconnect/Electrical	250	150	100	75	65
Total Equipment	750	680	560	580	555
Labor/Materials	413	306	240	220	210
Total Process Capital	1,163	986	800	800	765
Project and Construction and Management	75	70	56	58	55
Engineering and Fees	75	70	56	48	44
Project Contingency	38	34	28	28	28
Total Plant Cost (2003 $/kW)	$1,350	$1,160	$945	$935	$890

Source: Energy and Environmental Analysis, Inc., estimates

4.5 Maintenance

Maintenance costs vary with engine type, speed, size, and number of cylinders, and typically include:

- Maintenance labor
- Engine parts and materials, such as oil filters, air filters, spark plugs, gaskets, valves, piston rings, electronic components, and consumables (such as oil).
- Minor and major overhauls.

Maintenance can be done either by in-house personnel or contracted out to manufacturers, distributors, or dealers under service contracts. Full maintenance contracts (covering all recommended service) generally cost 0.7 to 2.0 cents/kWh, depending on engine size, speed, and service, as well as customer location. Many service contracts now include remote monitoring of engine performance and condition and allow predictive maintenance. Service contract rates typically are all-inclusive, including the travel time of technicians on service calls.

Recommended service is comprised of routine short-interval inspections/adjustments and periodic replacement of engine oil and filter, coolant, and spark plugs (typically at 500 to 2,000

DISTRIBUTED ENERGY
THE JOURNAL FOR ONSITE POWER SOLUTIONS

What's Up With Lean-Burn Natural-Gas Gensets

The federal government is sponsoring development of a new era of lean-burning gas reciprocating engines, but what's up with the immediate future?

BY PENELOPE GRENOBLE O'MALLEY

sidebar
Exhaust-Gas Recirculating Aftertreatment

graph
Cost of Electricity Comparison

Convinced that reciprocating engines fired by natural gas will play a major role in the future of distributed energy but that key technology challenges remain to be addressed, the United States Department of Energy has set the goal of a more efficient and cost-effective lean-burn gas engine within the next five to seven years. The goal for this new era is a fuel-to-electricity conversion efficiency of at least 50% (30% higher than what's currently available), NOx emissions of 0.1 g/bhp/hr. (a 95% reduction, which still will need aftertreatment to meet tough air-quality standards in such places as California's South Coast Air Quality Management District), installed capital costs of $400-$540/kWe and significant reduction in maintenance costs. The program is called Advanced Reciprocating Energy Systems (ARES) and so far has the support of the major engine manufacturers working in concert with the national laboratories and selected universities to expand the use of reciprocating engines for distributed-generation (DG) applications.

According to former ARES Program Manager Joe Mavec, the project was launched in September 2001 and will proceed over three phases with research on advanced materials, fuel- and air-handling systems, advanced ignition and combustion systems, catalysts, and lubricants. Phase I is scheduled for completion during 2004-2005, while the deadline for final Phase III is 2009-2010. Cummins Power Generation, Caterpillar Inc., and Waukesha Engine Dresser Inc. have received Phase I grants and are "following individual research paths," as John Hoeft, director of marketing for Waukesha, puts it, based on each company's marketing target. "At Waukesha we're working on the 1-megawatt-size product," says Hoeft, "and we're looking at a redesign of our VGF [engine], our V16 platform to get there."

A non-nonsense, long-established, and extensively used power-generating technology that requires fuel, air, compression, and a combustion source, reciprocating engines fall into two categories: spark-ignited engines fueled by natural gas and compression-ignited engines that run on diesel fuel. Gas engines are currently available in two versions: rich-burn and lean-burn, the latter made commercially viable when microprocessors made it possible to efficiently control critical fuel flow and fuel-air gas mixture plus ignition timing. In a lean-burn engine, excess air is introduced into the engine with the fuel, which reduces the temperature of the combustion process, which in turn reduces by almost half the amount of nitrogen oxide produced compared to rich-burn engines. And because excess oxygen is available, combustion is more efficient, producing more power with the same amount of fuel.

"Distributed-power applications favor

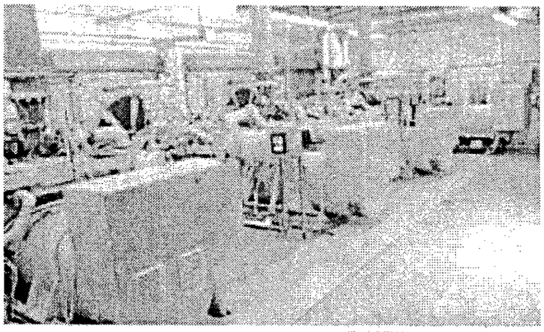

PHOTO: CATERPILLAR

natural-gas technologies first and foremost because they deliver low air emissions," says Caterpillar's Gas Product Marketing Manager Michael Devine. "Diesel-fueled systems still dominate in standby and short-run installations, but right now gas is better at combining availability, price, and environmental compliance. Gas-fueled generator sets can be on-line and producing power within three to six months of when they're ordered at a cost that varies from about $350 to $600 per kilowatt."

Devine says Caterpillar has already hit the market with ARES-style improvements. "The G3500C engine program and its advanced gas-engine control module is an offshoot of ARES. The new control system solves some of the challenges that have typically affected the efficiency of lean-burn engines, including maintaining air-fuel ratio and constant emissions control."

Technological advances aside, choosing a natural-gas learn-burn generator set from what's now available requires a thorough assessment of the amount and duration of power to be generated, which must in turn be balanced against installed cost, engine efficiency, and emissions control. While large-scale DG applications have sometimes favored 24/7 cogeneration systems, Devine reports that smaller industrial users and some utilities are opting for selective usage, sometimes running as few as 500 hr./yr.

But Stan Price, project manager for Northern Power Systems Inc. in San Francisco, CA, wonders about such short-hour applications. "We try to select equipment so that it runs at least 4,000 to 4,500 hours a year as close to its full rating as possible. If the capacity factor is below 60%, I begin to wonder whether the economics are going to make sense for the customer. What's got to drive the decision to put in a genset for, say, 1,200 hours a year is the fact that loss of power during an interruptible period is very expensive in terms of lost product. The company is not just saving money on electricity, they're saving on product costs."

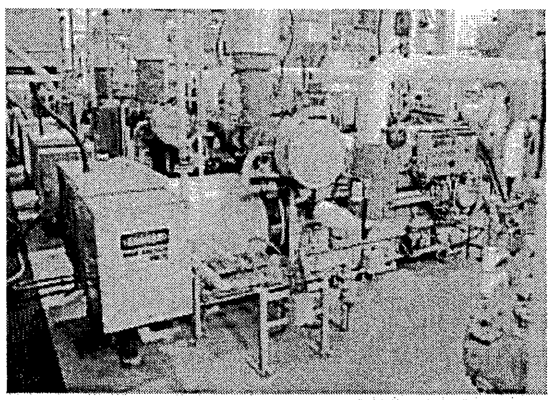

PHOTO: CATERPILLAR

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At Waukesha, Hoeft thinks the choice of an engine begins with emissions requirements. "Once you look at kilowatt size, you make your decisions based on the product mix and meeting the emissions requirements, then on how much efficiency you want. It's a tradeoff between emissions and efficiency and first [installation] costs."

Chach Curtis, vice president of onsite generation for Waitsfield, VT-based Northern Power Systems, notes that while lean-burn engines have become the industry standard - particularly in Europe because they are typically anywhere from 3 to as much as 10% more efficient in converting fuel to electricity - there also is a market for rich-burn engines. "In states like California and New Jersey and New York and now Massachusetts, both systems are going to need some kind of aftertreatment. For the rich-burn engines, it's a cheaper, simpler process. So, in these states, you have to look at the higher cost of aftertreatment to meet emissions standards on a lean-burn engine versus how much additional savings you're going to generate from the higher electrical efficiency a lean-burn system is going to give you. Then you have to determine if that's going to pay for itself in a reasonable timeframe. If not, the customer might be better off with a rich-burn engine and saving some money up-front on the emissions equipment.

"A year ago you could install a lean-burn engine in Massachusetts without the tougher area-based SCR [selective catalytic reduction]. And, in California, although they've extended the incentive program to the end of 2007, they've lowered the emission requirements in order to qualify."

As Curtis points out, the only aftertreatment technology currently on the market to bring lean-burn engines into compliance where NOx standards are tight is SCR, which some end users are uncomfortable about utilizing for cost and safety reasons. But because the major manufacturers are solidly behind lean-burn technology, they are quick to play down states where higher emission standards can make compliance costly, and the industry itself is looking for new aftertreatment technologies to come on-line that will eliminate the perceived risk of storing and using the ammonia that's added to a lean-burn engine exhaust stream. "Within the next two or three years, you're going to see exhaust gas-circulation technologies emerging for lean-burn [engines] that will bring them down into compliance," says John Kelly, director of distributed energy for the Gas Technology Institute (GTI) in Chicago, IL. But Ritchie Priddy of Attainment Technologies LLC in New Iberia, LA, says that time is already here (see sidebar).

At Caterpillar, Devine agrees that meeting local emissions standards is one of the factors that needs to be considered in what he calls "the economic equation" to determine whether generating your own electricity is competitive against purchasing power from a utility. "When a user is trying to determine the cost of operation for a gas engine, they usually think of the installed first cost of the system, the fuel and maintenance costs, but they also need to figure the cost of meeting the local emissions regulations, which can be met either inside the engine or outside the engine. With rich-burn engines, there is just enough air to mix with the right amount of required fuel to make the power required. Given that nitrous oxide is created in the exhaust stream in the presence of heat, the higher the temperature and the longer the exposure to that heat, the more NOx will be created. To minimize exhaust emissions, a three-way catalyst is then used to convert the exhaust gas into essentially water and nitrogen. This type of system is similar to automotive systems used today - you end up with very high exhaust-gas temperatures, and because of the way this type of engine consumes fuel, your efficiency is typically in the 33% to 35% range. A lean-burn engine deals with most emissions in the engine. You still have the same amount of fuel introduced into the cylinder to make the required power, but you're putting excess air into the cylinder with the fuel. You're distributing the same amount of heat over a larger volume, so your exhaust-gas temperatures are lower, greatly reducing the formation of NOx. In areas where very low exhaust emissions are required, a simple oxidation catalyst or SCR may be used to meet the local standards. An added benefit of lean-burn engines is that the lower exhaust-gas temperatures translate into higher power density, longer maintenance intervals, and lower owning and operating costs."

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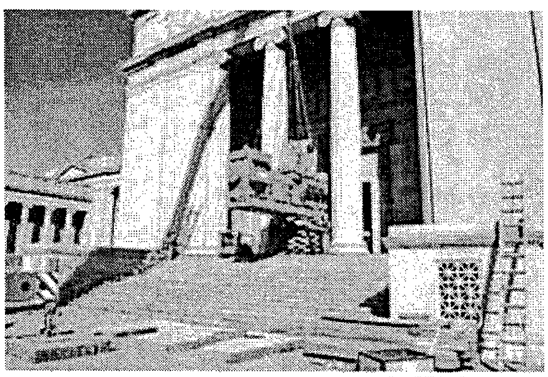
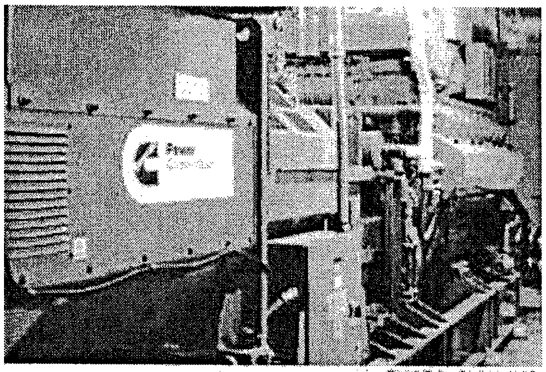


PHOTO: CUMMINS

After installation, a 1.75-MW cogeneration system at the Chicago Museum of Science and Industry will provide up to 80% of the museum's heat, hot water, and electricity.

Herman Van Niekerk, vice president of engineering at Cummins, agrees that a fundamental difference between rich-burn and lean-burn engines is that the lean-burn is more fuel-efficient, but he adds a qualifier. "As the engine gets bigger, the gap in performance and efficiency gets wider. The newer lean-burns are 39% efficient or better, while the rich-burns are about 32%. With that sort of efficiency gap, you can afford to do all sorts of aftertreatments to meet emissions requirements. But if you get down to 300 kilowatts or less, then the advantage of having lean-burn over rich-burn is not that great. You may [gain] two percentage points of efficiency with lean-burn, but you have the cost of the aftertreatment. I've done several feasibility studies on lean-burn projects in which a small unit just doesn't cut it.

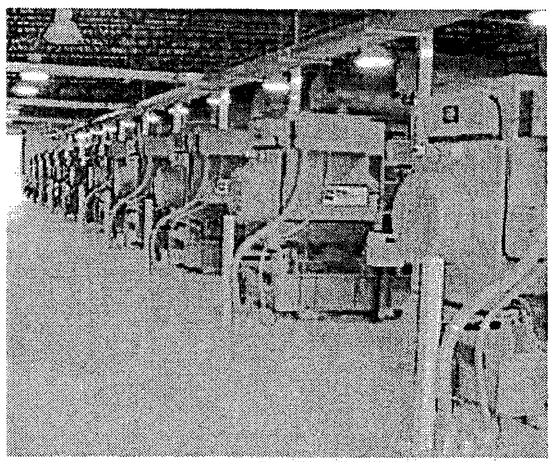


The Cummins lean-burn generator set produces up to 1.75 MW/hr. of electricity and 4,000 lb./hr. of steam.

"Otherwise it's a purely economical situation. We run a feasibility study with the data we get from the utility company - every 15 minutes of use - and from the customer about his site, including his thermal load profile and if it's a cogeneration project. Then we'll model an engine on the resulting load curve and simulate real-life conditions for an entire year so we will know exactly what will happen if we try to generate power on the customer's site. This makes it easy for us to then compare rich-burn and lean-burn engines of different sizes and from different manufacturers.

"This process also gives me a financial model, which allows me to give the customer a full financial-impact study on what it will take to do the job. Some customers want a simple payback in two to three years. Others want to borrow the money. Our program will take the cash flow from construction to ten years and calculate the return on investment. Customers must be clear on these questions before any of the modeling work can be done."

A case in point is a large automobile manufacturer headquartered in Torrance, CA, that elected a simple payback, Van Neikerk says. The company installed a combined heat and power system that uses a Cummins 1.2-MW natural gas-fired generator with a 250-ton Trane absorption chiller. Modeling convinced decision-makers that a CHP unit was environmentally and economically responsible, says Garth Sellers, manager of national facilities services. "We knew that we wanted to generate power, especially with the cost of energy in California. We also knew we wanted to use the byproduct of heat. Eventually we determined that we could use the heat in an absorption chiller to produce air conditioning, which we needed. We generate enough electricity to fully supply our central plant in Torrance during the summer months. During the winter months and in the evenings and on weekends, we supply several other buildings on campus. Our goal is to run the generator at 100% load, 98% of the time."



At Northern Power, Pace points out that there are advantages to cogeneration besides what's obvious. "Being an official cogenerator based on the Public Utility Code [means] that you can apply for incentives, and most utilities have a special gas tariff rate for cogeneration, which in some cases is significantly less than the tariff for normal boiler heating gas. But one thing you have to be careful of is the quality of waste heat you need. Some processes use 150 psi of steam, and recip engines are not good matches for waste heat at 150-pound steam because they don't have the required amount of waste heat at a high enough temperature. Some manufacturers are more restrictive than others as to how hot they allow certain waste heat streams to be. Some will limit water-jacket heat to 185¡, others will let it go up to 210¡, and some [will let it go] as high as 240¡. So understanding the basic energy balance of the engine and the quality of the heat is important in understanding how you match that specific engine to the process."

"From our perspective at GTI," says Kelly, "although heat recovery helps, the really big impact on decision-making is the electricity cost in the region. That's the number-one driver. With utilities having peak and off-peak rates, if you manage the situation correctly, you can be very economical. At GTI, for example, we run 9 a.m. to 6 p.m. every day, and the payback on our system is maybe four and a half years. We believe this is the optimum solution because it also takes care of the electrical utility. When we're not running at night, they get to sell their base, but we're shaving their peak."

"Whether you're only going to run at peak periods depends on what your nighttime rates are and what your fuel costs are," says Van Niekerk. "If you can generate cheaper than what you would otherwise pay for electricity - if you compare both thermal and electric - you always run the genset 24/7, and it pays every time. Because even if you only save a penny per kilowatt-hour, on a megawatt unit, that's almost $100,000 a year. Because deciding when to run or not is a really tight calculation, at Cummins we also provide a real-time monitoring and analysis system that will actually look at fuel costs and at electrical rates and then advise the customer during off periods to stop the generator until fuel prices come down."

Except for waste heat, all of these factors were figured into decision-making when the research and development operation of a major global manufacturing company based outside of Chicago decided on self-generation. According to its facilities manager, the company was experiencing major problems with quality and reliability in the power it received from its local utility. During summer hot spells, the load could be down by as much as 15%. The company already had installed its own internal distribution network for power it bought off the grid and its own double-redundant diesel-powered system for backup at its corporate data center. Once the decision was made to generate power on-site, the company brought in Nicor Solutions, which helped develop the onsite power plant, eventually built the facility, and then leased it to the client, who runs it on a typical peak-shaving profile, 9 a.m. to 6 p.m. The company chose two Waukesha VHP 5904-LTD 1- to 25-kW gensets but left enough room in the building that houses them to add a third unit. "We chose Waukesha," says the facilities manager, "primarily because of their availability in the market, because of their operating history, and [because of] the fact that they're a relatively simple and straightforward engine. In my mind, other new technology being offered hadn't been proven. We also liked the fact that the company is relatively close in case anything happens." Keeping track of fuel costs is critical to efficient operation. "I'm always looking two years ahead, and when I see that the price of gas in 2006 is reasonable, I buy a contract and lock in the price. A lot of people do this, but they don't constantly monitor the market. We have settled into a procedure, which takes me a minute each morning to look at where our electricity prices are and then at what our natural-gas prices are, and then we make a determination: Does it make sense for me to buy energy, leave my plant idle, and sell my natural gas, or does it make sense to generate electricity on-site?"

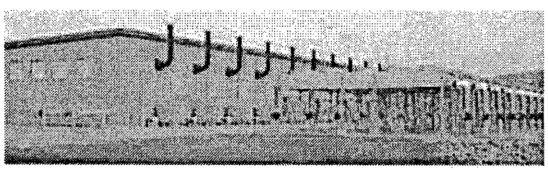


PHOTO: ATMOS POWER SYSTEMS

Devine agrees that equipment and operating costs have to be balanced against what he calls "power reliability and power quality," and any bottom-line economic assessment must consider added costs, such as standby charges, exit fees, and additional incremental costs, for interconnection. He points to industrial operations, such as Kuntz Electroplating Inc. in Kitchener, ON, where seconds-long interruptions in utility-supplied power stopped production for as long as an hour. The company also was experiencing voltage disruptions during periods when high-demand equipment came on-line, and the resulting damage in solid state processing control could cause repairs that could shut down production lines for as long as 45 minutes. To solve these problems, Kuntz installed five Cat G3516 generator sets for a 4.075-MW capacity. When the system is operating at the rated load, it carries roughly 65% of the plant's total electrical load; control switchgear sheds noncritical loads in case of utility power interruptions. The company also recovers heat from engine exhaust and jacket water/oil cooler circuits to help satisfy a process heat load of 18 million Btu /hr. for parts cleaning and electroplating tanks.

Caterpillar also is working with utilities, such as Herber Light and Power (HL&P), a municipal electric utility in Herber City, UT, to install its own DG systems rather than rely on customers to pick up peak-time power demands. Devine explains, "When power shortages hit California in the summer of 2000, HL&P was prepared. By increasing run time on its distributed-generation resources, which consisted of natural-gas- and diesel-engine-driven generator sets, HL&P avoided purchasing wholesale power at prices that rose from the typical $20 per megawatt-hour to as high as $200 per megawatt-hour at peak-demand hours. After the crisis passed, HL&P took further steps to protect reliability and stabilize prices, investing in three new advanced gas-fueled generator sets rated at a combined 5.52 megawatts. With those new units on-line as of July 2002, the distributed-generation facility has nine gas and two diesel units delivering 11.97 megawatts of capacity. It provides economical load following year-round and shields HL&P customers against future swings in wholesale power prices. In case of a major wholesale supply interruption, the facility could carry a substantial share of HL&P's load, keeping the majority of its customers in service."

Houston, TX-based Atmos Power Systems (APS) designs and installs plants for peak shaving, shoulder, and interruptible load applications. "Historically," says APS Vice President Larry Moore, "utility-provided power during peak- and shoulder-load operations has always been the most expensive due to demand charges. APS builds the power-generating facility and offers its customers long-term leases that allow them to build an equity position in the generation plant during the term of the contract." One of APS's clients is a food-processing operation in the Southeast where a large portion of the facility's electricity portfolio was on an interruptible basis, which meant that the utility had the right, given notice, to reduce power demand by a certain amount. In the face of increasing demands on the utility that supplied its power, the company wanted to firm up its power delivery and reduce high demand charges.

"The decision we had to make," says the company's energy manager, "was [this]: Do we continue to take interruptible power, or do we take the interruptible part of our portfolio and make it firm? But under most utilities, the real benefit of interruptible power versus firm power is that you don't pay the high demand charges. So in effect the demand portion is much cheaper. So we weighed the increased cost of firming up our interruptible service against the cost of turning those generators. In effect we were firming up our power because we had generation on-site."

APS installed a 20-MW plant using 12 Cummins QSV lean-burn generator sets, which environmentally were permitted to operate 1,200 hr./yr., and then leased the plant to the customer. Power is generated at 13,800 V and is connected directly to the customer's substation. The company's energy manager acknowledges that leasing the facility rather than bearing the capital cost of building the plant was attractive but that the company hasn't completely ruled out buying the lease.

With these kinds of numbers, Moore says APS is enthusiastic about the DG market, which he also predicts will include a combination of utilities and end users. "Utilities benefit from DG power plants installed in areas of system weakness," says Moore, "by being able to defer capital budget items to upgrade their transmission infrastructure."

Besides emissions, Moore thinks that noise management and equipment maintenance are two factors that have to be considered from the get-go. "In these kinds of lightly loaded applications, the life expectancy of a system like we put in with the 12 Cummins gensets is 40 years, after which the engines will be overhauled and allowed to operate for another 40 years. The key is proper maintenance, which Cummins supplies. The only thing we require of our customers is that someone walk through and do a periodic check once a day to make sure everything is running smoothly, that there's no oil on the floor, no antifreeze. This has the added benefit that, if five years down the road the customer decides they want to purchase the power plant, they have people who are qualified and know how it works and are familiar with its operating history."

GTI recommends that anyone considering distributed energy develop maintenance specifications and put them out to bid at the same time they bid the project. Van Niekerk describes Cummins's "bumper-to-bumper" guarantee as "a fixed feed per kilowatt-hour. The customer knows exactly what it's costing him to generate electricity. For a penny or a quarter of whatever that number is per kilowatt-hour, we provide full warranted maintenance and a monitoring system, which automatically calls out so everybody knows what's going on and if there are any problems."

Journalist **PENELOPE GRENOBLE O'MALLEY** *is a frequent contributor to environmental publications.*

Exhibit No. 131
Case No. AVU-E-04-1/
AVU-G-04-1
R. Sterling, Staff
6/21/04 Page 6 of 6

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21ST DAY OF JUNE 2004, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. AVU-E-04-1/AVU-G-04-1, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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