November 9, 2004

Mr. Ed Regan
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Gainesville Regional Utilities
301 S.E. 4th Avenue
Post Office Box 147117
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Subject: **High-Level Independent Review of the Preliminary Integrated Resource Plan**

Dear Mr. Regan:

As you requested, R. W. Beck, Inc. ("R. W. Beck") has prepared a high-level independent review of the preliminary Integrated Resource Plan ("IRP"), dated December 2003 (the "2003 IRP Proposal") requested by the Gainesville Regional Utilities ("GRU") and the sensitivity case matrix dated August 17, 2004 (the "2004 Sensitivity Case Matrix"). The 2004 Sensitivity Case Matrix includes a set of sensitivity cases supporting GRU's latest IRP proposal ("2004 IRP Proposal"). The purpose of the high-level review is to provide GRU with an independent assessment of the assumptions and methodologies used in developing the 2003 IRP Proposal and 2004 Sensitivity Case Matrix for reasonableness and suggest areas where revised assumptions are indicated to represent current conditions, where additional work is warranted, and where an in-depth review may be justified.

R. W. Beck has reviewed documents and an analysis supplied by GRU, has requested and received supporting data, and has conducted interviews with various members of GRU to clarify various aspects of the studies and analyses which supported the 2003 IRP Proposal and 2004 Sensitivity Case Matrix. As a part of the assignment, R. W. Beck reviewed (i) the history leading up to the 2003 IRP Proposal; (ii) the basis for the forecast of load and energy requirements; (iii) the effects of conservation; (iv) the generating reserve requirements; (v) the forecast of fuel prices and certain environmental matters; (vi) the technology screening, and (vii) the electric generation economic analysis. The results of the review are summarized herein.

INTRODUCTION AND HISTORY

The purpose of the initial IRP was to determine the type and amount of additional electrical generating capacity that GRU would need through 2022, subject to the following stated objectives:

(i) Conserve natural resources;

(ii) Reduce total air emissions;

(iii) Reduce the carbon intensity of electricity generated;

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(iv) Enhance the local economy;

(v) Assure reliable energy supplies; and

(vi) Minimize revenue requirements (the cost of electricity to customers).

After evaluating the eight potential supply options and certain demand side options, a preliminary 2003 IRP Proposal was presented by GRU to the City for review, consideration and approval. The 2003 IRP Proposal included the following considerations and refinements:

(i) 1.8 MW of energy conservation programs in addition to the existing programs;

(ii) The introduction of demand response incentives;

(iii) The use of reclaimed water from GRU's wastewater system;

(iv) Up to 30 MW of biomass capacity from utilizing waste wood as fuel;

(v) 34 MW of natural gas-fueled combined-cycle capacity;

(vi) A 206 MW (34 percent) undivided ownership interest in a 557 MW, super critical coal fueled unit to be constructed at the Deerhaven Generating Station with the remaining 351 MW of capacity to be owned and financed by other electric utilities; and

(vii) Retrofitting Unit No. 2 at the Deerhaven Generating Station resulting in an estimated net emission reduction at the Deerhaven Generating Station.

Since the 2003 IRP Proposal was prepared, the City Commission decided that GRU should not participate in a jointly owned unit to be located at the Deerhaven Generating Station. This decision removed from consideration the development of a larger, more cost effective coal fueled unit which would be jointly owned by GRU and others. This action resulted in GRU evaluating the economic, environmental, social and political aspects of a smaller, but wholly owned coal fueled generating unit. During this time period, GRU revised its load forecast and fuel price forecast to reflect then known changes and more current conditions (the "2004 Updated Load Forecast" and "2004 Updated Fuel Price Forecast"). Consequently, numerous financial analysis "cases" were developed reflecting these changes and have been identified as the "2004 Sensitivity Case Matrix." Based on the results of the 2004 Sensitivity Case Matrix, the 2004 IRP Proposal was developed. The 2004 IRP Proposal included the following changes:

(i) The 34 MW of natural gas-fueled generation was replaced with 77.5 MW of gas-fueled generation planned for 2022;

(ii) Joint ownership of a 206 MW interest in a 557 MW super critical coal fueled unit was replaced with a 220 MW Circulating Fluidized Bed ("CFB") coal fueled unit to be constructed at the Deerhaven Generating Station and to be wholly owned by GRU.

LOAD FORECAST

The load forecast used for the 2004 Sensitivity Case Matrix analysis is consistent with that contained in GRU 2004 Ten-Year Site Plan, with projections through 2023. The methodologies used for these forecasts, as explained in the respective Ten-year Site Plans, is based on econometric regression models that project numbers of customers and average use per customer for each retail customer class and for wholesale sales to Clay Electric Cooperative and the City of Alachua.[1]

In addition to the Base Case energy and demand forecast, GRU has developed High and Low forecasts for use in the 2003 IRP Proposal and the 2004 Sensitivity Case Matrix. GRU has developed banded forecasts around the base forecast of load and energy. Forecasts from 1992 through 2003 were analyzed to develop statistical estimates of forecast error. The banded forecasts represent 68 percent ("One-Sigma") and 95 percent ("Two-Sigma") confidence intervals from the base forecast for peak summer demand and net energy for load.

The projected compound annual growth rate for the Base Case net energy for load and peak summer demand are approximately 2.33 percent and 2.34 percent, respectively, over the period 2004 through 2013 and approximately 2.05 percent and 2.09 percent over the period 2004 through 2023. These projected growth rates are comparable with load growth projected for similar municipal electric utilities in Florida, such as Jacksonville Electric Authority (2.3 percent annual growth rate for years 2004 through 2013), the Florida Municipal Power Agency (2.4 percent annual growth rate for years 2004 through 2013), and Lakeland Electric (2.3 percent annual growth rate for years 2004 through 2013).

Based on the information summarized above, we believe that the load forecast methodology used by GRU is typical of that used by the industry and is generally reasonable for purposes of developing the 2003 IRP Proposal and 2004 Sensitivity Case Matrix analyses.

We understand that contracts for wholesale sales to the City of Alachua and Clay Electric Cooperative are scheduled to expire in 2007 and 2013, respectively. These sales and their respective impacts on peak demand requirements are assumed to continue throughout the IRP analysis period. Because these sales make up approximately 8.5 percent of the total peak demand requirements projected by 2013, it was suggested that GRU perform sensitivity analysis to investigate the impact to resource plans should these contracts expire at the end of their current contract terms.

GRU responded to this request by modeling low forecast cases, developed by subtracting these wholesale loads from One Sigma and Two Sigma load and energy forecast. The results of this work found that the CFB option was still the lowest net present value revenue requirements plan, for both the 20 year and 50 year analysis periods.

[1] GRU currently engages in partial-requirements wholesale sales to the City of Starke, Florida. This sale is projected to end in December, 2006, and, as such, was not modeled beyond 2006.

DEMAND-SIDE MANAGEMENT

As documented in Section F of the 2003 IRP, it is our understanding that in 1995 GRU evaluated the cost-effectiveness of incremental demand and energy reductions that might be derived from demand-side management ("DSM") and conservation programs ("DSM Programs"). This analysis utilized three tests commonly recognized by the electric utility industry: (i) the Participant Cost Test; (ii) the Rate Impact Measure Test; and (iii) the Total Resource Cost Test. From this analysis, GRU identified eleven new potential DSM Programs (referenced in Table F-9 of the 2003 IRP). GRU has added the 7 most cost effective programs from this list to their existing DSM Programs and these programs were approved for the FY 2005/2006 budget. GRU projects that these programs could result in an additional 1.8 MW of summer peak reductions. These additional DSM Programs are reflected in the 2004 Ten-Year Site Plan load forecast.

The 2003 IRP Proposal recognizes that the DSM analysis should be updated once an IRP supply plan has been finalized so that projections of costs can be used in the DSM analysis that more accurately reflect current supply planning assumptions. We agree that for purposes of an IRP, the Rate Impact Measure Test is the appropriate metric for evaluating DSM alternatives. We also agree that the DSM analysis should be updated to reflect the most current IRP assumptions, and we suggest that periodic re-evaluation of DSM Programs is appropriate.

GENERATING CAPACITY RESERVE REQUIREMENTS

For planning purposes, GRU utilizes a 15 percent generating reserve capacity margin criteria. This is the same or similar to planning reserve margins used by other non-investor owned, generating Florida utilities. The Florida Public Service Commission and investor owned generating Florida utilities have agreed that investor owned utilities should maintain a minimum 20 percent generating capacity reserve margin.

Using recognized industry practices, GRU has a relatively large worst single contingency case based on the loss of its largest generating unit, Unit No. 2 at the Deerhaven Generating Station. Deerhaven Unit No. 2 has a net summer rating of 228 MW and represents approximately 49 percent of the 2004 summer peak demand. Without further study, there is a question that using a 15 percent generating reserve margin criteria may not capture the benefits of smaller generating resources that may have a lower single contingency risk. However, GRU has four (4) interconnections with the Florida transmission grid, two of which reportedly have import capabilities (approximately 224 MW) that are each equal to the summer rating of the Deerhaven Unit No. 2. The remaining two interconnections have a reported capacity of 168 MW combined. Taking into account the interconnection arrangements mitigates the concern of an unscheduled outage of Unit No. 2 at the Deerhaven Generating Station.

In keeping with industry practices, GRU routinely performs Loss of Load Probability ("LOLP") studies that project a LOLP of less than one day in 10 years when interconnections are recognized in the model. This is a recognized industry standard for reliability. Based on this information, the interconnectivity of GRU makes the loss of a large (relative to GRU load) unit less of an issue. Therefore, it is believed the 15 percent reserve criterion is a reasonable capacity planning reserve margin criterion for purposes of the 2003 IRP Proposal and the 2004 Sensitivity Matrix.

In the 2004 IRP Proposal, GRU assumed that five units retire in 2011, 2018, 2019 and 2022. The retirements of these units are based on an assumed maximum life span of 50 years as compared to an economic decision that would consider life extension. Since these units are older steam and combustion turbine peaking type units, it is not likely that the assumed retirements of these units would impact the economics of ultimately installing the CFB. GRU may want to run a sensitivity case without retirements to determine if the on-line date of 2011 for the CFB would be affected by this retirement assumption.

FUEL PRICE PROJECTIONS

The 2004 IRP Proposal includes the installation of a 220 MW CFB, the selection of which is affected by the assumptions regarding gas, coal, and pet coke prices. R. W. Beck has focused its review of fuel price projections on two fuel types namely, gas and coal. GRU's forecasted coal, gas and pet coke prices for 2011 and 2025 are summarized below:

GRU 2004 Fuel Price Forecast for Sensitivity Case Matrix

	Delivered 2.7% Sulfur Coal ($/MMBtu)			**Delivered PET Coke ($/MMBtu)**			**Delivered Gas ($/MMBtu)**		
	Low	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
2011	1.99	1.99	2.35	.79	1.06	1.59	5.39	6.64	8.08
2025	2.54	2.81	3.80	1.24	1.65	2.48	9.24	12.48	16.62
% of Base in 2011	100%	--	118%	75%	--	150%	81%	--	122%
% of Base in 2025	90%	--	135%	75%	--	150%	74%	--	133%

GRU's projected prices for natural gas include monthly price projections through 2005 from the U.S. Department of Energy, Energy Information Administration ("EIA"), Short Term Energy Outlook, April 2004 (the "STEO"). The average monthly price for 2005 from the STEO was escalated through 2025 based on the rate of change in annual prices from the Annual Energy Outlook 2004 ("AEO2004"). GRU's costs for transporting natural gas are added to the above commodity prices to yield a forecast of delivered natural gas prices. The AEO2004 is published in 2002 dollars (real dollars), and GRU inflates the AEO2004 prices to nominal dollars using the GDP Chain-Type Price Index published in AEO2004 (Table B20) for purposes of deriving the escalation factors. Since GRU adjusts its starting point from the AEO2004 values based on the STEO projections, the long term prices in GRU's forecast are higher than the end points published by EIA in the AEO2004. At the time AEO2004 was published, EIA was projecting a downturn in prices from 2003 through 2004 and 2005. STEO estimates and projections do not indicate this downturn, and in fact prices have steadily increased since 2003. This was the basis for GRU adjusting gas prices upward and using the rates of changes in prices generated by the National Energy Modeling System (the “NEMS”) in AEO2004 for GRU’s forecast. As a result, the projected upturns and downturns projected by the NEMS through the long term horizon are reflected in GRU’s projections although the starting point is higher.

While it is realized that the starting projections in the AEO2004 forecast seem low compared to recent gas prices, we believe that the methodology of applying growth rates for the AEO2004 forecast for 2006 onward to a 2005 price for gas from the STEO may result in a price forecast that is higher than EIA intended..

As can be calculated from the table above, the spread between the base 2.7 percent sulfur coal and gas price in the 2004 Updated Fuel Price Forecast is projected to be $9.67 dollars per MMBtu in 2025. The AEO2004 projected gas prices and coal prices result in a projected spread of approximately $7 dollars per MMBtu in 2025. This compares approximately with GRU’s projected spread between base coal and the low band natural gas prices of $6.70 dollars per MMBtu in 2025. We believe this long-term spread represents a more reasonable base case fuel price projection. Based on this assumption, we suggested that GRU should run additional sensitivity cases to reflect an adjusted base gas price scenario based on a GRU Weighted Average Cost of Gas fuel price that escalates somewhat uniformly between the 2005 base price and the 2025 low price forecast, thereby achieving approximately a spread between coal and gas more consistent with that contained in the AEO2004 forecasts. GRU tested this scenario. We further suggest that low and high bands price forecasts be evaluated that are approximately 81 percent and 122 percent of the adjusted base forecast by the year 2011, and 74 percent and 133 percent of the adjusted base forecast in the year 2025.

GRU’s forecasts of coal prices include banded (low/base/high) forecasts for compliance coal used in Deerhaven Unit 2, and banded forecasts for three alternate grades of coal (0.7 percent, 1.8 percent and 2.7 percent sulfur contents, respectively) for modeling in a CFB unit. Similarly, a banded forecast for petroleum coke, which could be blended with coal in a CFB unit, was developed. A CFB unit is also modeled to include wood as a fuel, and for planning purposes, GRU assumes the cost of wood will equal the cost of its least expensive (2.7 percent sulfur) coal. As with natural gas, GRU’s delivered coal price forecasts include a component for commodity coal and a component for transporting coal to the Deerhaven site. GRU’s short-term commodity compliance coal prices were projected through 2006 based on contractual arrangements already in place with coal suppliers. Estimates of coal prices for 2004 for the alternate grades of coal not currently used by GRU were based on an analysis of current prices paid by other utilities in Florida obtained from Platt’s CoalDat. Hill & Associates Short Term Coal Supply Forecast provided short term projections through 2006 for the alternate grades of coal. GRU’s cost of transporting coal is based on a long term contract with CSX through 2019. Freight rates are escalated based on the Rail Cost Adjustment Factor (“RCAF”), weighted for the adjusted and unadjusted components. GRU has not found an external forecast for the RCAF. GRU escalates the RCAF based on a time-trend of historical values. The long term commodity coal prices for all coal types are escalated using AEO2004 escalation rates for U.S. average minemouth coal prices.

The coal price forecasts include low and high bands for 2.7 percent sulfur coal that are approximately 100 percent and 118 percent of the base price in 2011 and 90 percent and 135 percent of the base price in 2025. The CFB fuel mix is projected to contain 13.7 percent wood fuel, 54.9 percent petroleum coke, and 31.4 percent of 2.7 percent sulfur coal. The delivered price of petroleum coke is projected to be $1.06 dollars per MMBtu in 2011, increasing to $1.65 by 2025. The combination of petroleum coke and 2.7 percent sulfur coal is projected to result in fuel costs which are beneficial for the economics of the CFB selection. The use of petroleum coke has an attendant price risk associated with it. The petroleum coke market is, and has been, a thin market tied to the petroleum processing industry. Since petroleum coke is a byproduct of petroleum processing, there is always a potential for changes to petroleum coke supplying and/or quality due to advances in petroleum processing technology which adds further uncertainty to long-term supply. GRU may want to consider reducing its reliance on petroleum coke due to potential price and supply risks. GRU should consider the economics of the CFB alternative assuming a lower mix (e.g., 20 percent) of petroleum coke with high sulfur coal.

In general, the coal fuel price forecast appears reasonable. The escalation for the commodity price of compliance and 2.7 percent sulfur coal is projected to escalate annually from 2007 to 2025 at approximately 2.9 percent in nominal dollars which is consistent with the AEO2004 projected real escalation rate of -0.2 percent for mine mouth coal. We believe that the gas and coal price forecast utilized by GRU results in too large of a spread between coal and gas prices compared to AEO2004 projections because the gas price escalation starts from a higher base price without allowing for market correction from current high prices. We believe that reducing the gas price escalation as explained above will result in relative coal and gas prices that are more consistent with the AEO 2004 long-term forecast. The high and low bands cover a reasonable range about the base price, although it is noted that the low band coal price forecast is not different from the base coal price forecast until 2011.

ENVIRONMENTAL

One of the objectives of the 2003 IRP Proposal is to reduce air emissions. The major regulated air emissions are sulphur dioxide (“SO_2”), nitrogen oxide (“NO_X”) and particulate matter (“PM”). As a part of the 2003 IRP Proposal, GRU has proposed to install additional emission controls on its existing coal fueled Unit No. 2 at the Deerhaven Generating Station. In addition, the 2004 IRP Proposal considers the installation of a 220 MW CFB coal fueled unit with a selective non-catalytic reduction (“SNCR”) system for NO_X removal. The SO_2 removal in the CFB is primarily done in the bed by injecting limestone. A fabric filter for particulate and a polishing scrubber for SO_2 for the CFB is included in the plan. The additional controls proposed for the Deerhaven Unit No. 2 includes selective catalytic reduction (“SCR”) system for NO_X emissions and a flue gas desulphurization (“FGD”) for SO_2 and a fabric filter for PM control. The 2004 IRP Proposal with both the proposed CFB and the Deerhaven Unit No. 2 retrofit is projected by GRU to reduce overall SO_2 emissions from 6,992 tons/year to 2,980 tons/year, and overall NO_X emissions are projected to decrease from 3,316 tons/year to 1,316 tons per year[2].

The emissions reductions for SO_2 for the combined Deerhaven Generating Station No. 2 retrofit and the CFB project are based on Table J-7 of the 2003 IRP. It is assumed by GRU in this calculation that the SO_2 control efficiency is 97.5 percent. Although this projection of efficiency appears to be at the high end of the range for this control technology, GRU has provided information to substantiate that this level of control is achievable.

The recent Best Available Control Technology ("BACT") limits for controlled emissions shown on Table J-1 which were assumed for the 2003 IRP Proposal are reasonable for purposes of the 2003 IRP Proposal.

Since the 2003 IRP Proposal, GRU now assumes that the Deerhaven Unit No. 2 retrofit is likely to be required regardless of what other new generation alternatives are undertaken. GRU has stated that there are several regulatory actions by the U.S. Environmental Protection Agency ("EPA") in the final proposal steps that will likely result in additional control requirements for the Deerhaven Unit No. 2. These proposal rules include the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR"), and the Best Available Retrofit Technology Rule ("BART") either of which could lead to the Deerhaven Unit No. 2 requiring a FGD scrubber and most likely an SCR or the purchase of sufficient allowances for SO_2, NO_X and mercury. GRU has stated that based on the strong public sentiment toward emission reduction at the Deerhaven Generating Station the most acceptable alternative for GRU may be to reduce emissions by adding control systems rather than purchasing allowances.

The assumption regarding the Deerhaven Generating Station, Unit No. 2 retrofit, would indicate that a potential scenario could involve a gas-only build case with the Deerhaven Generating Station, Unit No. 2 retrofit. Such a case would be expected to have fewer emissions than the CFB/Deerhaven Generating Station retrofit case although it would result in higher electricity costs to GRU customers.

The 2004 Sensitivity Case Matrix included a number of cases relating to the cost of CO_2 allowances. The IRP that includes the proposed CFB, will likely result in more carbon dioxide emissions than a gas-only alternative. Although CO_2 is not controlled at this time, there is reason to believe that emission controls and associated costs (the so called "carbon tax") may be mandated in the future. The 2004 Sensitivity Case Matrix included cases that ranged from a $50 dollars per ton to $200 dollars per ton carbon tax. GRU has informed us that this analysis was based on a dollar per ton of carbon. These assumptions would equate to a dollar per ton of CO_2 in the range of $14 to $55 dollars. It is believed that the price range used in the 2004 Sensitivity Case Matrix for the potential carbon tax was sufficiently high enough to cover the upper range of the potential costs associated with a potential carbon tax. The projected carbon

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[2] *"Planning Study of the effects of Gainesville's Long-Term Electrical Energy Supply Plans on Ambient Air Quality and Greenhouse Gas Emissions"* dated September 30, 2004.

controls for coal and gas are shown on Figure J-1 in the 2003 IRP Proposal, and we believe the projected emissions for coal and gas technologies appear to be in the proper range.

TECHNOLOGY SCREENING

The screening methodology involved screening a broad range of ideas for ways to meet Gainesville's long-term energy needs identified from a public outreach program by considering the following factors:

i. Long-term capacity;
ii. Economic;
iii. Economic and societal;
iv. Fuel price volatility;
v. Fuel transportation security;
vi. Fuel storage ability;
vii. Grid Independence;
viii. Reduction of local emissions; and
ix. Local economic benefits.

We reviewed the technology screening in detail and noted that F class combined cycle units had not been included in the economic analysis computer model as an option. GRU has incorporated this suggestion.

ELECTRIC GENERATION ECONOMIC ANALYSIS

Based on the technology screening, GRU developed more detailed cost and operating characteristics for potentially feasible alternatives to be considered in the 2003 IRP Proposal. These cost and operating characteristics are summarized on Tables L-1 and L-2 of the 2003 IRP Proposal. We performed a high level review of the capital costs, variable and fixed operation and maintenance costs and heat rates in the 2003 IRP Proposal on Table L-2. We have focused our review on the combined cycle, combustion turbine, pulverized coal, and CFB coal cost projections and found them to be in the general range that is typical in the industry for a planning study.

In the 2003 IRP Proposal on Table L-2, the Deerhaven Generating Station CFB with the retrofit to Unit No. 2 it was projected to have a capital cost of $1,832 dollars per kW, and a heat rate of 9,910 Btu/kWh. GRU has stated that in the analysis supporting the Sensitivity Case Matrix, these assumptions were revised to be $1,762 dollars per kW and a 9,653 Btu/kWh heat rate. The lower heat rate is based on a report prepared by Black & Veatch Report dated March 2004. The CFB heat rate is subject to final design and manufacturer warrantees, and as such, should be modeled in a sensitivity case that reflects a potentially higher heat rate.

In performing the economic analysis, GRU made certain financial assumptions which are summarized on Table M-1 of the 2003 IRP. GRU has assumed that its discount rate for evaluating the IRP is 7.0 percent which is based on an 80/20 weighting of its assumed annual 6.5 percent tax exempt interest rate and an assumed customer provided annual interest rate of 9 percent. The estimated 9 percent represents the cost of funds for the portion of construction costs that are funded by customers through the Utility Plant Improvement Funds ("UPIF").

GRU has assumed that construction interest is capitalized during the construction period to avoid prematurely increasing the rate base and financially burdening customers before a project enters commercial service. Capitalized interest during construction for solid fuel plants, combined cycle, and simple cycle are projected to be 15.48 percent, 10.24 percent and 5.44 as a percent of construction costs. General inflation for the cost of capital equipment, fixed and variable operation and maintenance expense is projected to be 3.0 percent per year. A book life of 35 years was assumed for all new generation additions. The carrying charge used in the economic analysis is based on calculating the capital recovery factor over the book life plus fixed charges (insurance, etc.) and adjusted for capitalized interest.

The capitalized interest for the solid fuel alternative such as the CFB is greater due to the longer construction period; therefore, the solid fuel alternatives are more sensitive to changes in interest rates than the gas fueled alternatives. Typically, a construction loan is refinanced with a long-term instrument when the project becomes commercial. Since this would take place in the 2011 time frame, it seems appropriate to prepare sensitivity cases regarding future long-term interest rates. We suggested that GRU prepare a set of sensitivity cases assuming an annual tax exempt interest rate of up to 7.5 percent. The higher interest rate case was run which indicated that the CFB was still the lower cost alternative. We believe that the financial assumptions used by GRU are reasonable for planning purposes.

For evaluating the various generation alternatives and arriving at an integrated resource plan GRU used the computer modeling system called *"Electric Generation Expansion Analysis System"* ("EGEAS") which was developed by the Electric Power Research Institute. The primary purpose of EGEAS is to find the best possible integrated resource plan for meeting forecasted electric load and energy by either expanding an electric system's capacity, retiring units, and/or reducing load via demand side management. The model seeks a solution which optimizes a specified objective function. For purposes of the 2003 IRP Proposal and the 2004 Sensitivity Case Matrix, the objective function is to minimize revenue requirements (customer costs) on a net present value basis over the period 2004 through 2023 and the extension period. The EGEAS model is a generally recognized and accepted model for use in the electric power supply industry. The use of the EGEAS model for developing the 2003 IRP Proposal and the 2004 Sensitivity Case Matrix was a reasonable approach.

Based on the EGEAS methodology and other analyses, the theoretical optimum amount and timing of additional intermediate and base alternatives are shown on Table N-2 of the 2003 IRP Proposal. This plan showed 34 MW of a 7FA combined cycle unit and 206 MW of a 557 MW supercritical unit constructed at the Deerhaven Generating Station site. The output served as the basis for the 2003 IRP Proposal. EGEAS modeling also indicated four potentially feasible solid fuel options in order of lowest to highest cost per MWh included a 557 MW, or 425 MW supercritical boiler coal unit at the Deerhaven Generating Station, a 220 MW CFB at Deerhaven, and a 557 MW supercritical boiler unit at a green field site. All of these alternatives except the 220 MW CFB unit involved joint participation with other parties. Since the City Commission decided that GRU should not participate in a jointly-owned unit to be located at the Deerhaven Generating Station, the lowest cost per MWh remaining alternative was the 220 MW CFB unit at the Deerhaven Generating Station to be solely owned by GRU.

GRU prepared the 2004 Sensitivity Case Matrix to further refine its 2003 IRP Proposal based on the use of a 220 MW CFB unit at the Deerhaven Generating Station. The EGEAS model was utilized to develop optimum plans under various sets of assumptions. Cases were run for a matrix of assumptions sets including high, base, and low load forecasts, versus base, high coal/low gas, high and low fuel prices as shown below:

	Fuel Price			
Load	**Base**	**High Coal/Low Gas**	**High**	**Low**
Base	X	X	X	X
High	X	X	X	X
Low	X	X	X	X

The high load and low load cases were run assuming both one and two standard deviation units below or above the mean designated by the notation ("Low-One Sigma") or ("Low-Two Sigma"). The cases were run with and without "30 years end effects". The "30 years end effects" are projected in order to capture the cost impacts beyond the study period that might result from capital left unused at the end of the planning period or shifts in the relative economics of units caused by differences in escalation rates for various cost components. The 220 MW CFB was installed in every case except when the high coal, low gas was assumed without "end effects." The "end-effects" associated with the 2004 Sensitivity Case Matrix represent a continued escalation of the previously mentioned spread between coal and gas prices in the year 2023. We believe that due to the uncertain nature of fuel prices in 2025 and beyond the "end effects" should be based on the assumptions that spreads between fuel prices in 2023 not be escalated.

Sensitivity cases were also run for the matrix of load and fuel price assumptions with the additional assumption of either a 20 percent increase in capital costs or carbon taxes of $50 dollars, $100 dollars and $200 dollars per ton of carbon. We noticed that the sensitivity cases that had been performed to date had a significant omission with respect to the gas only cases. This omission was the cost of Deerhaven 2 emission controls for cases that did not pick the CFB option. GRU has been requested and reran these sensitivity cases. The following describes the results obtained which when this omission was corrected. For the 20 percent increase in capital cost, the 220 MW CFB was installed in all cases, except that the timing of the CFB was delayed 3 years under the high coal/low gas fuel prices under low load – Two Sigma conditions. For cases assuming a $50 dollars per ton carbon tax, the CFB was selected, but delayed 2 to 3 years under the high coal/low gas case and low fuel price cases, under low load Two-Sigma conditions. As expected, the cases involving carbon taxes of $100 dollars per ton and $200 dollars per ton resulted in cases where the CFB was not selected.

The 2004 Sensitivity Case Matrix prepared by GRU covers a wide range of assumptions regarding fuel prices, load conditions and carbon tax assumptions. However, we believe that additional sensitivity cases should be developed which would provide additional insight to the sensitivity to interest rates. Also, a potentially lower cost option than the market might be a gas only build case. As stated above, we noted that GRU's market cases omitted the cost of retrofitting Deerhaven 2. Finally, and as also described earlier, we suggested examination of cases that constrain the long term spread between gas and coal prices (the "adjusted base case"). In response to these concerns, GRU prepared the following cases.

Cases	Description
1	Low Load & Energy – 2 SIGMA, Low Fuel – Gas Only with Deerhaven Retrofit
2	Low Load & Energy – 2 SIGMA, High Coal/Low Gas – Gas Only with Deerhaven Retrofit
3	Base Load & Energy, Low Fuel – Gas Only with Deerhaven Retrofit
4	Base Load & Energy, High Coal/Low Gas - Gas Only with Deerhaven Retrofit
5	Base Load & Energy, Adjusted GRU Fuel, 7.5% Interest - Gas Only with Deerhaven Retrofit
6.	Base Load & Energy, Adjusted GRU Fuel, 7.5% Interest - CFB with Deerhaven Retrofit
7.	Base Load & Energy, Adjusted GRU Fuel, 6.5% Interest - Gas Only with Deerhaven Retrofit
8.	Base Load & Energy, Adjusted GRU Fuel, 6.5% Interest - CFB with Deerhaven Retrofit

The primary purpose of the first four cases was to determine how the best gas-only case, using larger less expensive per kW, F-Class technology would compare to the CFB cases, under sensitivity cases that would tend to favor gas alternatives, on a year by year cumulative net present value basis. These specific sensitivity cases were chosen because they represent situations where gas alternatives would be the most likely to be favorably compared to the CFB alternatives.

The results of these additional scenarios are summarized below. In cases 1 through 6, the gas only build cases are projected to be more expensive on a NPV of revenue requirements, even excluding EGEAS end effects. When cases 7 and 8, which assume the adjusted fuel price forecast, are compared to the previous base fuel price forecast scenarios, the difference between the gas only build and CFB case is reduced by $53.8 million NPV. This finding is substantial enough to suggest that GRU perform additional analysis with similar adjustments applied to the high and low fuel price forecasts.

Sensitivity Cases

Case 1 — Low Load & Energy – 2 SIGMA, Low Fuel Without Adjustment

Gas Only	CFB
1,289.0	1,223.1

Case 2 — Low Load & Energy – 2SIGMA, High Coal, Low Gas Without Adjustment

Gas Only	CFB
1,350.0	1,307.4

Case 3 — Base Load & Energy, Low Fuel Without Adjustment

Gas Only	CFB
1,377.7	1,301.6

Case 4 — Base Load & Energy, High Coal, Low Gas Without Adjustment

Gas Only	CFB
1,439.9	1,389.3

Cases 5 and 6 — Base Load & Energy, Adjusted Fuel Price, High Bond Interest Rates (7.5%__)

Gas Only	CFB
1,482.0	1,387.9

Base Case (Already Done)

Base Load and Energy	Base Fuel Price
Gas Only	CFB
1529.6	1,370.9

Cases 7 & 8

	Base Load and Energy	Adjusted Fuel[3]
	Gas Only	CFB
	1,4722	1,374.5
Difference	-57.4	+3.6

The results of the Sensitivity Case Matrix and the additional cases performed to date indicate that the 220 MW CFB alternative is a robust alternative that is selected over gas fueled alternatives to be included in GRU's optimum plan over a wide range of assumptions regarding fuel prices, load and energy, capital costs and interest rates. R. W. Beck has identified a number of additional sensitivity analyses that should be performed to test and further define the boundaries of this robustness.

[3] R. W. Beck suggested adjustment to GRU base fuel price.

CONCLUSIONS

Based on our review of the 2003 IRP Proposal, the 2004 Sensitivity Case Matrix, other supporting documents supplied by GRU, and discussions with GRU, R. W. Beck has the following conclusions:

1. The load forecast methodology used by GRU is typical of that used by the municipal utility industry and is generally reasonable for purposes of developing the IRP Proposal and 2004 Sensitivity Case Matrix.
2. We agree that for purposes of an IRP, the Rate Impact Measure Test is the appropriate metric for evaluating DSM alternatives. We also agree with GRU that the DSM analysis should be updated to reflect the most current IRP assumptions.
3. The 15 percent capacity reserve criteria used by GRU is a reasonable capacity planning reserve margin for purpose of the 2003 IRP Proposal and the 2004 Sensitivity Case Matrix.
4. The assumed use of petroleum coke in the CFB has attendant risks associated with fuel supply, pricing, and operating costs. For planning purposes, GRU may want to consider a lower percentage mix for CFB fuel in the range of 20 percent versus 50 percent by weight (54 percent by heat).
5. GRU's 2004 Fuel Price forecast results in a spread between natural gas and coal prices that is larger than AEO2004 projections. We believe that GRU's base gas price forecast is high. GRU should develop a base, low and high band set of natural gas projections, with a gas and coal price spread for the base case more in line with the spreads indicated in the AEO2004 forecast.
6. The high and low bands for coal fuel and gas fuel cover a reasonably wide range about the base price for purposes of fuel price sensitivity, although as described in item 5, the base gas and coal fuel prices have too wide of a price spread. GRU's low gas and high coal price forecast are reasonable for planning purposes.
7. The assumptions regarding capital costs, fixed operating costs, heat rates and variable operation and maintenance for combined cycle, combustion turbine, pulverized coal, and CFB coal generating units as shown on Table L-2 of the 2003 IRP Proposal with adjustments to the CFB option are reasonable for long-term planning purposes, although we believe that additional sensitivity cases should be considered using a higher CFB heat rate.
8. The EGEAS computer model used by GRU is a standard planning model used in the industry for planning electric generation, and the general use of the model by GRU in developing an economic generation plan was reasonable.
9. The technology screening by GRU summarized in Figures I-1 through I-3 for the 2003 IRP Proposal covered a wide range of technologies and arrived at a reasonable set of technologies for the more detailed economic analysis

10. The financial assumptions used for the 2004 Sensitivity Case Matrix as described herein are reasonable for planning purposes.
11. Based on the EGEAS runs and sensitivity analyses performed to date, including cases requested by R. W. Beck, the 2004 IRP Proposal, that includes the 220 MW CFB is a robust plan over a wide range of assumptions including fuel costs, capital costs, interest rates, and environmental costs and is consistently projected to be lower in cost than alternative plans involving gas-only resources. R. W. Beck has identified a number of additional sensitivity analyses that should be performed to test and further define the boundaries of this robustness.
12. Based on the assumption that the Deerhaven Generating Station, Unit No. 2 Retrofit will be accomplished with both the CFB and gas only alternatives, both the gas only alternative and the CFB alternative are projected to result in reduced emissions compared to current operations. The gas only alternative is expected to result in lower emissions in comparison to the CFB alternative, but results in higher projected power costs.
13. GRU should consider preparing a sensitivity case matrix which would include all of the previous types of sensitivity cases with the following adjustments:
    - i. The reduced percentage of petroleum coke as described in conclusion 4;
    - ii. A revised base gas price forecast as described in conclusion 5;
    - iii. The CFB heat rate as described in conclusion 7;
    - iv. An adjustment to the "end effects" methodology to freeze the fuel price differentials in the last year of the study (2023); and
    - v. A high and low band gas price forecast that cover a reasonably wide range about the revised base gas price.

Respectfully submitted,

R W Beck, Inc.