



***GE Power Systems***

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# ***Economic Evaluation of Plant Upgrades Using Plant Optimization Software***

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# ***Economic Evaluation of Plant Upgrades Using Plant Optimization Software***

## Abstract

Equipment vendors typically quote the performance gain that can be expected from an equipment upgrade, but often cannot calculate the impact of the upgrade on overall power plant economics. The economic benefit from equipment upgrade results from the interaction of many complex economic and plant performance parameters.

To calculate the economic benefit of an upgrade the analysis must account for configuration and performance characteristics of the power plant; operational profile; electric sales and fuel purchase contract stipulations; and prices of fuel, electricity, makeup water and other variable costs.

This paper describes the application of plant optimization software (Plant Playback™) to perform plant upgrade benefit analysis at a combined-cycle power plant.

## Introduction

Equipment vendors typically quote the expected performance gain that can be achieved from an equipment upgrade, but often cannot calculate the impact of the upgrade on overall power plant economics. The payback from equipment upgrades results from the interaction of many complex economic and plant performance parameters. To calculate the economic benefit of an upgrade the analysis must account for:

- Configuration and performance characteristics of the power plant
- Operational profile (i.e., expected variations in loads and ambient conditions)
- Electric sales and fuel purchase contract stipulations
- Prices of fuel, electricity, makeup water and other variable costs

Plant optimization software (Plant Playback™) contains the necessary plant economic and performance models to perform the benefit evaluation. An optimizer contains mathematical models of the power plant performance, and of the economic revenue and cost streams associated with the plant. This model can be exercised in the “what-if” mode to simulate the plant yearly budget with and without the upgrade. The benefit of the upgrade is the difference in the yearly operational profits calculated with and without the upgrade.

Optimization software is well suited for plant operational economic analysis because the optimization automatically determines the proper plant operational mode and plant control settings. For example, if the price of electricity is high, the optimizer will automatically turn on duct burners or peak-load the plant. At part load, the optimizer will turn off inlet coolers, and set the gas turbine power levels at the most economic levels. If a traditional heat balance code were used, the software user would need to specify the duct burner fuel flows and the gas turbine power levels.

Often electric sales and fuel purchase contracts are tiered. That is, the price changes with volume. In addition, some plants run at fixed load levels while others can vary production with economic conditions. The economic value of an upgrade is strongly dependent upon the type of electric sales contracts in place. The optimization software includes modeling of these contract features and predicts the plant revenues and expenses as operations change. The interaction of price levels and plant performance is a key feature of the optimization.

The procedure to perform an upgrade analysis is:

1. Build a plant performance model
2. Test the model by comparison to plant

- data or vendor performance curves
- 3. Predict a yearly budget for the facility
- 4. Upgrade the plant model and rerun the yearly budget prediction
- 5. Compare the plant budgets with and without the upgrade to compute the benefit

## Build Plant Model

The first step in thermo-economic analysis is to build an accurate performance model of the power plant. Building a plant model when using the Plant Payback™ software involves inputting reference data, performance curves and coefficients that specify the equipment performance over a range of operating conditions. To build a power plant model, one starts with the gas turbine, then proceeds to the HRSG (heat recovery steam generator) and the steam turbine/condenser. The paragraphs below describe the input data that is required to model a combined-cycle power plant.

## Plant Configuration

Plant Payback™ software models a combined-cycle power plant that consists of gas turbines, heat recovery steam generators, steam turbines, condensers, auxiliary boilers and process steam loads. The user configures a plant model by using the “Plant Wizard” to set the numbers of gas turbine, steam turbines, auxiliary boilers, and steam loads.

The plant schematic of *Figure 1* illustrates the equipment modeled by the Plant Payback™ software. The notation (i) on the diagram indicates that that equipment may have a number of replications. Thus, a Plant Payback™ model may have any number of gas turbines, HRSGs, steam turbines/condensers, auxiliary boilers at three different pressure levels, and process steam loads at three different pressure levels. Each replication of plant equipment is modeled with its own set of performance data, and may operate at different operating conditions from the other replications. The HRSGs are limited to producing steam at up to three pressure lev-

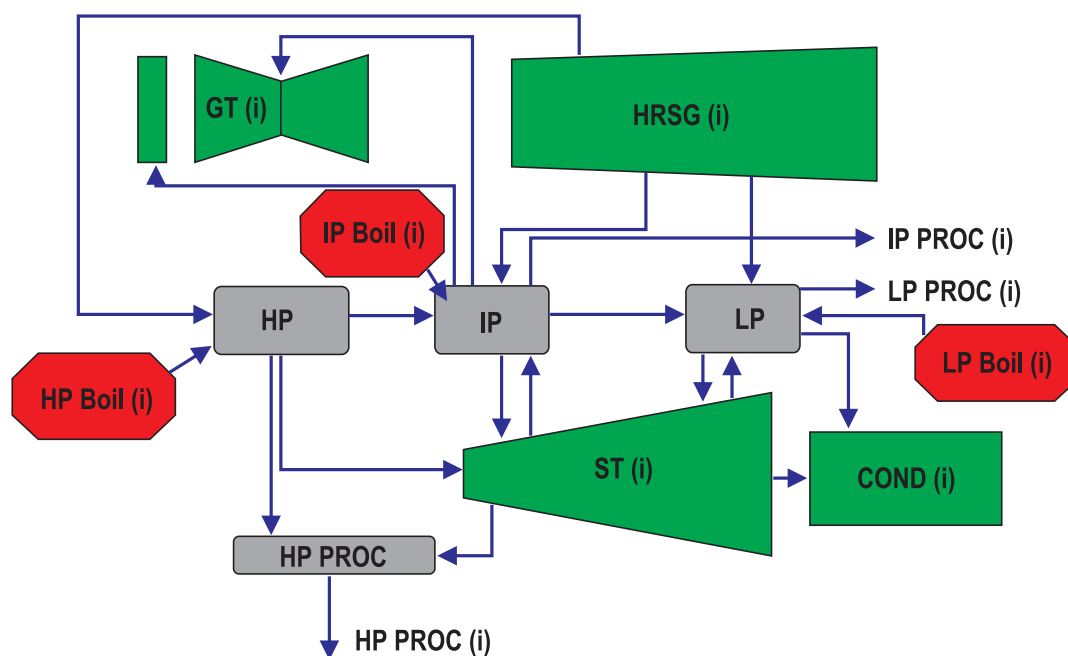


Figure 1. A general plant schematic modeled in the Plant Payback™ software

els (HP, IP and LP), and the steam turbines may only accept admissions from those three pressure levels. The steam turbines may exhaust steam to four different pressure levels (HPPROC, IP, LP and Cond). A complete set of bypass flows and letdowns is allowed so that steam may be directly transferred from a given pressure level to any other, lower pressure level.

### Gas Turbine Model

The gas turbine performance model requires the user to supply the following data:

1. Rating of the gas turbine performance at a reference inlet air temperature. Included in this data are the following:
  - Inlet temperature
  - Gross power
  - Gross heat rate
  - Exhaust temperature
  - Exhaust gas flow rate
  - Steam/water-injection rate
2. Baseload performance curves relating air inlet temperature to the baseload values of:
  - Gross power
  - Gross heat rate
  - Exhaust temperature
  - Exhaust gas flow rate
3. Part-load constants that specify how the heat rate, exhaust temperature and exhaust flow change as the engine power is reduced below the baseload value. Some of the important constants that must be input are:
  - Fuel flow fraction at zero load
  - Control action used to reduce power: inlet guide vane (IGV) or underfiring
  - Change in exhaust temperature per degree of IGV control

- Change in exhaust temperature per MW of underfiring
- Change in exhaust temperature per MW of peak (over) firing
- Change in power, heat rate, and exhaust temperature per unit steam injection
- Curve of exhaust flow change vs. IGV angle

This set of reference values and performance curves uniquely determines the gas turbine performance anywhere within the turbine's allowable range of operation. Additional inputs specify the existence and performance constants of inlet cooling, inlet chilling and/or inlet heating.

### HRSG Model

The exhaust of the gas turbine and the duct burner are the energy sources for steam generation in the heat recovery steam generator (HRSG). The Plant Payback™ user must input HRSG rating data, which specifies the reference steam generation of the HRSG at the reference gas turbine exhaust conditions and at a reference duct burner fuel energy input rate. In addition, the user must input coefficients that specify the change in steam generation per unit change in the gas turbine exhaust temperature and exhaust flow rate. The user also inputs a curve of duct burner fuel conversion efficiency (energy that goes to steam production divided by total fuel input energy) vs. duct burner load level as a fraction of the maximum fuel flow rate.

### Steam Turbine Model

The steam turbine power generation is modeled as a linear function of the flows into and out of the steam turbine plus a constant times the change in condenser pressure plus a steam turbine exhaust loss term. Linear coefficients must be inputted to model the change in steam

turbine power per unit change in inlet (throttle) pressure, inlet (throttle) flow, admission flow rates, extraction flow rates and condenser pressure. A curve of the exhaust pressure loss (MW) versus exhaust flow rate is also a required input.

## Economic Model

The Plant Payback™ optimization software considers plant revenues and expenses and then predicts the plant operating condition that maximizes operational profits. The user may model contracts to buy fuel and make-up water, and to sell electricity, gas and/or steam (*see Table 1*). Each contract stipulation is modeled simply by specifying a price and maximum and minimum quantities. Each of the revenue and expense streams may be modeled by inputting contract stipulations.

Variable maintenance costs are inputted as hourly costs associated with operation of gas turbines, steam turbines and auxiliary boilers. Peak firing the gas turbines increases maintenance costs by a user input cost per MWh of over-firing.

<b>Revenues</b>
Sales of Electricity
Sales of Steam
Sales of Gas Fuel
<b>Expenses</b>
Cost of Fuel (three types allowed per model)
Purchases of Electricity
Purchases of Make-up Water
Variable Maintenance Costs
Fixed Costs

**Table 1.** Revenues and expenses considered in a Plant Payback™ model

## Operational Limits

A very important element in optimization modeling is the specification of operational limits,

which become mathematical constraints on plant operation. Operational limits constrain the optimization such that it does not suggest plant operation where the plant operator cannot actually run the plant. The maximum gas turbine power may be set by limits on the generator, the minimum power level may be an environmental constraint imposed by a regulatory body. The Plant Payback™ software user is able to input a maximum and a minimum allowed value for most of the heat balance values calculated by the software.

## Test Model vs. Data

Once the necessary performance data has been supplied, the model is ready to be tested. The objective of the optimization modeling is to be able to predict overall plant thermo-economics, not just equipment performance. Thus, the plant model needs to be checked against overall power plant performance data to confirm that the optimizer can accurately predict overall plant performance.

The ideal test methodology is to acquire measured data from the operating power plant over a wide range of operating conditions. Data on a hot day, cold day, at full load and at part-load is desirable for this evaluation. The model is checked against plant data by manually inputting values into Plant Payback™ for parameters that are controlled by plant operators (inputs in the table below) and then comparing predicted outputs from Plant Payback™ to measured data.

*Table 2* lists Plant Payback™ inputs and outputs for testing of optimizer predictions vs. plant data.

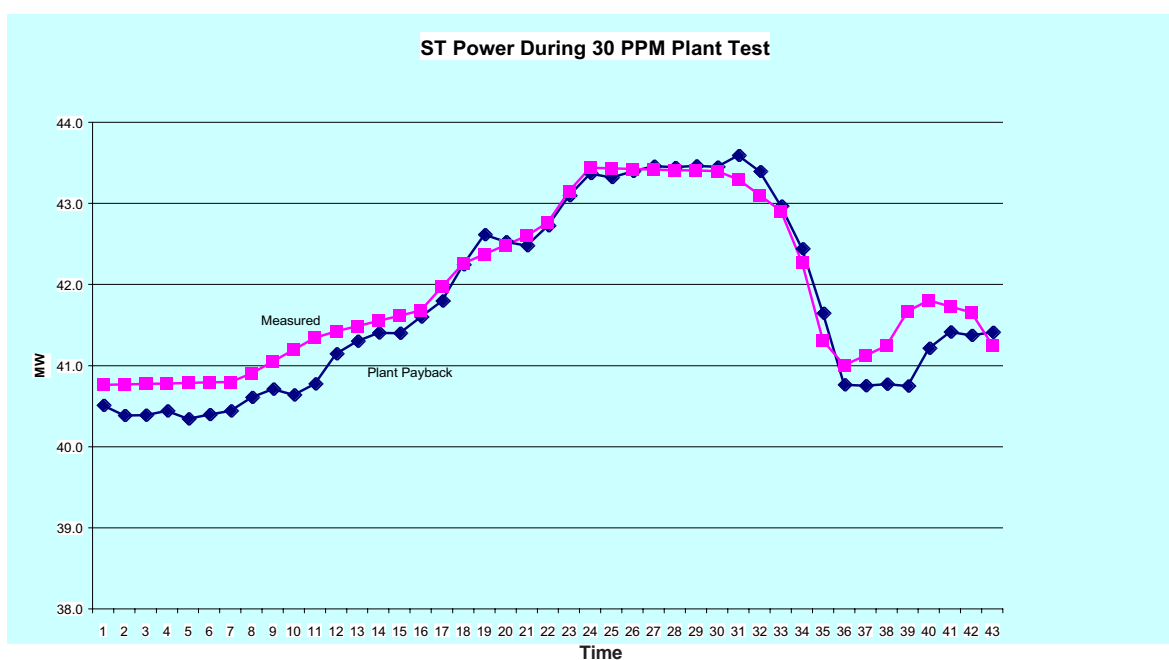
*Figure 2* illustrates the comparison of Plant Payback™ software predictions to plant test data. At a power plant in Florida, the gas turbine steam injection rate was changed over time. Measured values of the inlet air tempera-



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Measured Parameter	Plant Payback™ Model Status
Inlet Air Temperature to Gas Turbine	Input
Steam/Water Injection Rate to Gas Turbine	Input
Gas Turbine Gross Power	Input
Duct Burner Fuel Energy Input Rate	Input
Process Steam Mass Flow Rates	Input
Auxiliary Boiler Fuel Energy Input Rates	Input
Gas Turbine Heat Rate	Output
Gas Turbine Exhaust Temperature and Flow	Output
Steam Production Rate in HRSG	Output
Steam Turbine Power	Output
Condenser Pressure	Output
Overall Plant Net Power	Output
Overall Plant Net Heat Rate	Output
Auxiliary Boiler Steam Production Rate	Output

**Table 2.** Inputs and outputs used in Plant Payback™ when comparing predictions to plant data



**Figure 2.** Comparison of predicted to measured steam turbine power during a plant test

ture, gas turbine power, and steam/fuel ratio were inputted to Plant Payback™. An optimization case was executed with input data taken at five-minute intervals during the plant test. Predicted (output) steam turbine power from Plant Payback™ was compared to measured plant data.

In general, the Plant Payback™ software should be able to predict overall plant power and heat

rate to within 1% of the actual plant data. GE Enter Software has compared optimizer predictions to measured data from over forty combined-cycle power plants, and found that this level of accuracy may be achieved. If no plant test data is available, the optimization model can be compared to vendor predictions of overall plant performance at various operating conditions.

## Yearly Budget Analysis

The power plant yearly budget analysis is performed by predicting plant thermo-economics at a selected number of anticipated plant operating conditions over each month of the year. These predictions are combined to form a monthly budget. This monthly budget process is repeated over the 12 months of the year to result in the yearly budget.

The budget analysis needs to account for the complete operational profile of the power plant. Does the plant run at full load during the day, and at reduced load at night? Do process steam demands vary over the year of operation? Do electric prices occasionally peak at high values a few days per month or year? Can the plant sell to a spot market or is the plant load set by contract with the electric customer? All of these possibilities must be considered in a budget analysis.

### Example Plant Monthly Budget Analysis

To illustrate budget analysis methodology, a budget was prepared for a sample power plant.

This plant consists of two gas turbines rated at approximately 210 MW and a 213 MW steam turbine. It has duct burners on the HRSG and a process steam load supplied with steam from the IP steam header.

The yearly budget was simulated using three analysis cases per month resulting in a total of 36 cases to simulate the year of operation. The three cases per month modeled typical daytime operation, typical nighttime operation and operation during high spot prices of electricity. *Figure 3* shows a list of analysis cases used.

The user inputs for the analysis cases are summarized in *Figure 4*. Over the course of the year ambient temperatures change with the seasons, and process loads change on a monthly basis. The plant has three customers who might purchase electricity. The first customer pays a price of \$50 per MWh and demands 600 MW during the day, but only pays a price of \$35/MWh at night for a demand of 400 MW. The second customer pays a price of \$25/MWh, and will purchase any amount up to 100 MW during the day but zero at night. The third customer rep-

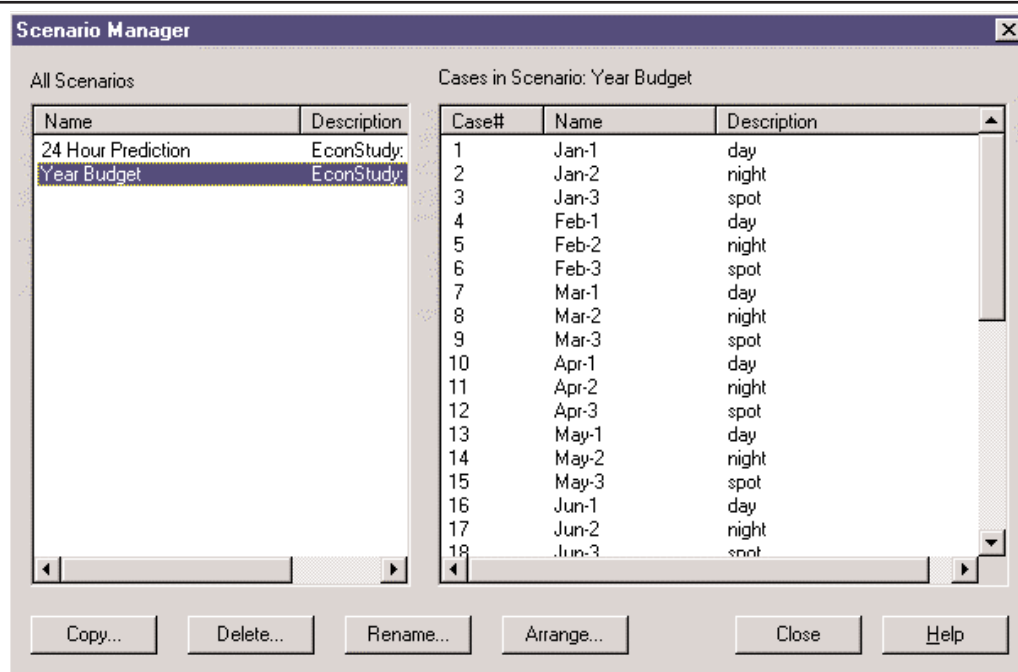


Figure 3. Screen showing 18 of the 36 analysis cases used for yearly budget

# Economic Evaluation of Plant Upgrades Using Plant Optimization Software

The figure shows two screenshots from the CogenBudget software. The top screenshot is titled "CogenBudget - Year Budget: Summary Inputs" and the bottom is "CogenBudget - Year Budget: Summary Outputs". Both tables have columns for months Jan-1, Jan-2, Jan-3, Feb-1, Feb-2, Feb-3, Mar-1, Mar-2, and Mar-3.

Variable Name	Units	Jan-1	Jan-2	Jan-3	Feb-1	Feb-2	Feb-3	Mar-1	Mar-2	Mar-3
Max Plant Net Power	MW	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt
Max Plant Fuel Energy	MBtu/h	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt
Tamb	C	3	0	4	4	1	5	8	2	9
Pamb	BARA	1,014	1,014	1,014	1,014	1,014	1,014	1,014	1,014	1,014
Rel Hum	%	60	60	60	60	60	60	60	60	60
**** Electric Sales ****										
Electricity Sales Price 1	\$/MWh	50	35	50	50	35	50	50	35	50
Electricity Sales Price 2	\$/MWh	25	25	25	25	25	25	25	25	25
Electricity Sales Price 3	\$/MWh	100	100	100	100	100	100	100	100	100
Min Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
Min Electricity Sold 2	MW	0	0	0	0	0	0	0	0	0
Min Electricity Sold 3	MW	0	0	0	0	0	0	0	0	0
Max Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
Max Electricity Sold 2	MW	100	0	100	0	0	0	0	0	0
Max Electricity Sold 3	MW	0	0	80	0	0	80	0	0	80
**** IP Process Steam ****										
IP Process Stm Flow 1	kg/s	50	50	50	55	55	55	40.00005	40.00005	40.00005
IP Steam Stm Price 1	\$/MBtu	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
**** Gas Turbine ****										

Variable Name	Units	Jan-1	Jan-2	Jan-3	Feb-1	Feb-2	Feb-3	Mar-1	Mar-2	Mar-3
**** Plant ****										
Plant Profit	\$/h	12743.13	-545.5156	18713.69	12436.19	-497.0801	18531.66	12403.02	-579.707	17729.0
Total Revenues	\$/h	32260.4	14761.86	38761.86	30838.08	14838.08	38606.58	30609.6	14609.6	37550.7
Total Costs	\$/h	19517.27	15307.37	20048.17	18401.89	15335.16	20074.92	18206.58	15189.31	19821.7
Plant Gross Power	MW	668.7559	408.1198	688.8964	608.6727	408.1296	686.5883	608.6796	408.1179	678.310
Plant Net Power	MW	659.9419	400	680	600	400	677.685	600	400	669.411
Plant Heatrate Net HHV	Btu/kWh	6788.963	8120.681	6817.065	6923.063	8140.982	6851.883	6827.769	8034.278	6825.85
**** Electric Sales ****										
Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
Electricity Sold 2	MW	59.94192	0	0	0	0	0	0	0	0
Electricity Sold 3	MW	0	0	80	0	0	77.68501	0	0	69.411

Figure 4. Input and output summary screens display results of yearly budget analysis

resents spot electric prices, which are modeled at a price of \$100/MWh, and are limited to 80 MW during peak electric periods.

Each gas turbine was assessed an hourly maintenance charge of \$200, and the steam turbine has an hourly maintenance cost equal to \$100. These maintenance costs are intended to account for equipment overhauls, whose cost is associated with hours of operation. The plant was modeled with a fixed cost of \$4500/hr, which is intended to account for capital and overhead costs that do not vary with the mode of operation of the plant.

These three electric customers are the driving force that resulted in three analysis cases per month. The first case per month (daytime operation) has both minimum and maximum demand from electric *Customer 1* set to 600 MW. This forces the plant to sell exactly 600 MW to that customer at a price of \$50/MWh.

The second analysis case per month (nighttime operation) forces 400 MW to be sold to *Customer 1* at a price of \$35/MWh. The maximum night-

time loads to *Customer 2* and *Customer 3* are set to zero. Thus, no electricity is sold to these two customers at night.

Finally the third analysis case per month (spot electric operation) forces 600 MW to be sold to *Customer 1* (at a price of \$50/MWh), and allows up to 100 MW (at \$25/MWh) to *Customer 2* and up to 80 MW (at \$100/MWh) to *Customer 3*. The inputs to the Plant Payback™ software for all these cases are shown on Figure 4 in the window labeled “Summary Inputs.” Figure 4 also shows some of the calculated results in the window labeled “Summary Outputs.”

The advantage of using optimization is demonstrated in the above analysis. The software user only needs to prepare a plant model and input ambient conditions, process load demands and electric contract specifications in order to calculate the predicted plant economics. The optimization solver automatically sets the power level on the gas turbines, and turns on the duct burners when economic (increases plant profit). In effect, the optimization performs the

function of plant operators, freeing the software user from that task.

Looking at the predicted results for January, notice that during daytime operation, the Plant Payback™ software runs the plant at 656 MW, which is baseload on the gas turbine engines, and the plant heat rate is 6789 Btu/kWh. At night, the plant is forced to run at 400 MW. In this case, the Plant Payback™ software sets the optimal power levels on the gas turbines at 146.9 MW and 152.6 MW respectively. These power levels result exactly in a plant net power of 400 MW and achieve the maximum operational profit at that load level. Notice that Engine Number Two is operated at a higher power than Engine Number One. This is as expected because Engine Number Two is rated at 211 MW and 9850 Btu/kWh at an ambient temperature of 21°C, while Engine Number One has a lower power generation capability, 210 MW, and a poorer efficiency, 9870 Btu/kWh.

When spot electricity can be sold at a price of \$100/MWh, the Plant Payback™ software automatically turns on duct burners so as to sell more electricity. Eighty MW are sold to electric Customer 3. Notice that the plant heat rate degrades to 6817 Btu/kWh when the duct burners are utilized, but plant profits increase (as do costs and revenues). The optimization maximizes plant profit; it does not minimize plant costs.

The predicted plant power during spot electric operation in February (case Feb-3) is only 677.7 MW even though 80 MW could be sold on the spot market at a price of \$100/MWh. Thus, only 77.7 MW are sold to the spot market. This is because the maximum plant net power with the duct burners at maximum firing is only 677.7 MW at the higher process steam load and warmer ambient temperatures in February vs. January.

Notice, also, that the plant does not sell electricity to electric customer number two at a price of \$25/MWh in February. It was economical to sell at this price in January but not in February. This is because the plant incremental heat rate is better in January than in February.

### **Yearly Budget Calculation**

The 36 analysis case results must be combined together to estimate the yearly budget. This analysis is most easily done in a spreadsheet. All of the scenario results were exported to Microsoft® Excel (via the “Export to Excel” selection under the “Tools” menu within the Plant Payback™ software). The economic figures predicted by Plant Payback™ are for one hour of plant operation. To calculate the monthly revenues, costs and profits, the three cases of operation for each month must be multiplied by the number of hours of operation at each mode. Excel was used to perform the calculations. For the purposes of this example, each month was assumed to consist of 730 hours of plant operation. The yearly budget calculation used 350 hours per month of daytime operation, 300 hours per month of nighttime operation and 80 hours per month of spot price operation.

### **Yearly Budget Analysis of Upgraded Plant**

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The procedure for performing the plant budget analysis after the gas turbine upgrade is simply to enter a new set of gas turbine reference data and then repeat the yearly budget analysis described above. *Figure 5* shows the gas turbine ratings before and after the upgrade. The upgrade considers a 6 MW power increase and a 2% reduction in gas turbine heat rate.

The yearly budget after the upgrade was calculated using the same yearly budget scenario that was used before the upgrade; only the gas tur-

	Variable Name	Units	1	2
**** Gas Turbine ****				
1	Ref GT Gross Pwr NG	MW	210	211
2	GT HeatRate Gas Ref	Btu/kWh	9875	9850
3	Ref H2O NOx Inj NG	ratio	0	0
4	GT Texh Ref	C	580	576
5	Ref Total H2O Inj	kg/s	0	0
6	Ref GT Exh Flow	kg/s	508	507
7	Ref GT Tin	C	21	21

	Variable Name	Units	1	2
**** Gas Turbine ****				
1	Ref GT Gross Pwr NG	MW	216	217
2	GT HeatRate Gas Ref	Btu/kWh	9677	9653
3	Ref H2O NOx Inj NG	ratio	0	0
4	GT Texh Ref	C	583	579
5	Ref Total H2O Inj	kg/s	0	0
6	Ref GT Exh Flow	kg/s	508	507

**Figure 5.** Gas turbine ratings showing power and heat rate before and after the upgrade

bine properties were changed. The benefits of the gas turbine upgrade come from two primary factors. First the plant heat rate is lower, which results in cost savings at all operating points throughout the year. During most of the year the plant operates at either 600 MW or 400 MW. (See Figure 6). There is little benefit to the increased power generation capacity of the upgrade when the plant runs at the same power level as before.

However, the power generation capacity increase does come into play during spot electric pricing. In this case, the plant is now able to sell the maximum spot electric generation equal to 80 MW. This is considerable benefit. In the original budget analysis the plant was to generate approximately 618 MW during August; but after the upgrade, the plant can run at 630 MW during August. Note that the plant power increased only 12 MW on a hot August afternoon. This seems low because the gas turbine ratings were increased by 12 MW, and one would expect the steam turbine power to also increase due to the higher exhaust temperature of the upgraded turbines. Unfortunately, the high ambient temperature in August lowers the gas turbine power, and reduces the impact of the upgrade (on an absolute basis, but not on a relative basis). The benefit is approximately \$1100 per hour during spot electric price oper-

ation in August. Note that the analysis assumed 62 hours of spot electric operation per month, 300 hours of nighttime operation and 350 hours of daytime operation per month.

The yearly benefit of the upgrade is equal to the change in yearly plant operating profit. The benefit was calculated to equal \$1,592,052 per year. Operating profits increased from \$66,050,600 to \$67,642,652 per year.

## Summary and Conclusions

Plant thermo-economic modeling combined with optimization on plant operational profit offers several advantages for plant upgrade analysis. The prediction of the savings or benefit from a plant upgrade can account for the changes in plant operation that are likely to occur because of the upgrade. The optimization automatically picks the plant operating mode and sets plant controllable parameters such as engine power levels, power augmentation steam injection, peak firing, duct firing and operation of auxiliary boilers. Since the software automatically sets the plant operating mode the analysis is much faster to perform and the user is able to concentrate on understanding the results instead of performing the analysis. Often the optimization will run the power plant in a manner that the user never envi-



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sioned. As a result, savings (benefits) may be realized which are greater than the user may have anticipated. Thus, the benefit calculation for a power plant upgrade will be more accurate than a benefit calculation that assumes a plant operational mode for the upgraded plant, but does not determine the optimal way to operate the upgraded power plant.

Optimization modeling (such as the Plant Payback™ software) is able to predict power plant power generation capability and heat rate with a precision of 1% over a wide range of operating conditions. GE Enter Software has proven this by comparison of optimization predictions to plant measured data at nearly forty combined-cycle power plants.

Variable Name	Units	Jan-1	Jan-2	Jan-3	Feb-1	Feb-2	Feb-3	Mar-1	Mar-2	Mar-3
4 Max Plant Fuel Energy	MBtu/h	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt	Opt
5 Tamb	C	3	0	4	4	1	5	8	2	9
6 Pamb	BARA	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014
7 Rel Hum	%	60	60	60	60	60	60	60	60	60
**** Electric Sales ****										
8 Electricity Sales Price 1	\$/MWh	50	35	50	50	35	50	50	35	50
9 Electricity Sales Price 2	\$/MWh	25	25	25	25	25	25	25	25	25
10 Electricity Sales Price 3	\$/MWh	100	100	100	100	100	100	100	100	100
11 Min Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
12 Min Electricity Sold 2	MW	0	0	0	0	0	0	0	0	0
13 Min Electricity Sold 3	MW	0	0	0	0	0	0	0	0	0
14 Max Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
15 Max Electricity Sold 2	MW	100	0	100	0	0	0	0	0	0
16 Max Electricity Sold 3	MW	0	0	80	0	0	80	0	0	80
**** IP Process Steam ****										
17 IP Process Stm Flow 1	kg/s	50	50	50	54.99998	54.99998	54.99998	40.00005	40.00005	40.00005

CogenBudget Upgraded -- Year Budget: Summary Outputs										
Variable Name	Units	Jan-1	Jan-2	Jan-3	Feb-1	Feb-2	Feb-3	Mar-1	Mar-2	Mar-3
**** Plant ****										
1 Plant Profit	\$/h	12986.2	-520.869	18971.7	12584.8	-471.435	18968.8	12547	-558.743	18797.2
2 Total Revenues	\$/h	32581.2	14761.9	38761.9	30838.1	14838.1	38838.1	30609.6	14609.6	38609.6
3 Total Costs	\$/h	19595.1	15282.7	19790.2	18253.3	15309.5	19869.3	18062.6	15168.3	19812.4
4 Plant Gross Power	MW	681.592	408.096	688.852	608.648	408.106	688.868	608.654	408.095	688.89
5 Plant Net Power	MW	672.774	400	680	600	400	680	600	400	680
6 Plant Heatrate Net HHV	Btu/kWh	6693.32	8102.73	6706.1	6850.58	8122.29	6740.11	6757.55	8019.02	6715.56
**** Electric Sales ****										
7 Electricity Sold 1	MW	600	400	600	600	400	600	600	400	600
8 Electricity Sold 2	MW	72.7744	0	0	0	0	0	0	0	0
9 Electricity Sold 3	MW	0	0	80	0	0	80	0	0	80

Figure 6. Predicted plant budget after the gas turbine upgrade is shown on summary screens

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