Optimization of a CHP Power Plant Group – A Case Study

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ABSTRACT

Combined Heat and Power (CHP) systems generate electricity and thermal energy in a single integrated system. Because CHP captures the heat that would be rejected in traditional separate generation of electric or mechanical energy the total efficiency of these integrated systems is much greater than from separate systems.

The most efficient CHP systems are those that satisfy a large thermal demand while producing relatively less power. CHP plants contain multiple thermal and electric producers so it is advantageous to know how to load these pieces of equipment so that the electric and thermal demands are satisfied in the most economical manner.

Sometimes instead of having one plant there may be a group of plants acting as one large CHP, however, each plant in the group acts as its own profit center.

This paper discusses a case where three plants that are owned by the same company must supply hot water to the city for heating, steam to an industrial plant and sell power to the grid. One of the plants has contracts to supply the hot water and process steam; one plant gets dispatched from the grid and must satisfy this demand but can also make hot water and steam as byproducts and sell them to the first plant. The third plant can sell power to the grid and can make hot water as a byproduct and sell it to the first plant. All of the plants can sell as much power as they want providing that by the end of the year all power sold came from a process that was at least 75% efficient and that a yearly CO^2 cap was not violated. This paper discusses the optimization that found how to load all these plants so that maximum overall profit was obtained while considering these constraints. It also discusses the day-ahead unit commitment and gas usage prediction system that were required.

Introduction

Fossil power plants that burn coal, oil and natural gas do not convert all of their available energy into electricity. By capturing the excess heat, Combined Heat and Power (CHP) plants use heat that would be wasted in a conventional power plant, potentially reaching an efficiency of up to 89%, compared with 55% [1] for the best conventional plants. This means that less fuel needs to be consumed to produce the same amount of useful energy. Also, less pollution is produced for a given economic benefit.

The most efficient CHP systems are those that satisfy a large thermal demand while producing relatively less power and when the heat can be used on site or very close to it. Overall efficiency is reduced when the heat must be transported over longer distances. This requires heavily insulated pipes, which are expensive and inefficient; whereas electricity can be transmitted along a comparatively simple wire, and over much longer distances for the same energy loss.

Thus, CHP plants are often used for district heating. District heating - also referred to as district- or city heating – is a type of heating system which has supplied several buildings up to entire cities and even entire regions with heat for more than 130 years. This heat demand is satisfied by a CHP plant that is centrally located. In general, water and in special cases even steam is utilized as a heat conductor, which supplies the consumers over a pipe line network with heat for heating, for service water heating, for process steam utilization and even for cooling purposes.

CHP plants contain multiple thermal and electric producers so it is advantageous to know how to load these pieces of equipment so that the electric and thermal demands are satisfied in the most economical manner.

Energy management for process industries has drawn attention for a long time and has been discussed by Kaya and Keyes [2,3,4]. The methods for optimizing the distribution of steam and power generation within a cogeneration plant was outlined by Putman [5] using a real time on-line linear programming (LP) technique in which the LP matrix reflected the interconnections in the steam and power networks, the turbo-generator models and their sets of constraints, together with the effective costs of live steam and purchased power. The solution showed the loads to be assigned to each turbo-generator; the amount of power to be drawn from the tie-line; and the extraction flows at various pressures from each steam turbo-generator; in order that the combined demands of the manufacturing process for power and steam can be satisfied at least cost, and within the set of constraints. One of these is often the tie-line demand limit.

These same principals apply to CHP plants. Sometimes instead of having one plant there may be a group of plants acting as one large CHP, and each plant in the group acts as its own profit center. Regardless, an overall optimization can be performed.

This paper discusses a case where three plants that are owned by the same company must supply hot water to the city for heating, steam to an industrial plant, and sell power to the grid. One of the plants has contracts to supply the hot water and process steam; one plant gets dispatched from the grid and must satisfy this demand but can also make hot water and steam as byproducts and sell them to the first plant. The third plant can sell power to the grid and can make hot water as a byproduct and sell it to the first plant. All of the plants can sell as much power as they want providing that by the end of the year all power sold came from a process that was at least 75% efficient and that a yearly CO^2 cap was not violated. This paper discusses the optimization that found how to load all these plants so that maximum overall profit was obtained while considering these constraints. It also discusses the day-ahead unit commitment and gas usage prediction system that were required.

Multi-Plant Configuration

The CHP facility discussed in this paper is comprised of three plants as shown in Figure 1 below. The first plant contained in this set of three plants is known as the DE plant. It is comprised of three boilers that produce 8.5 bar steam. There are two high pressure steam boilers that make 40 bar steam. There are also 3 hot water boilers. The throttle of the steam turbo-generator (STG) is supplied from the 40 bar steam header. The extraction from the STG is fed into a heat exchanger to produce hot water. Steam from the 8.5 bar header must be sent to an industrial plant to satisfy its process demand and it can also be fed into a heat exchanger to produce hot water. This plant within the set of three must provide hot water to the city for heating and must supply steam to the industrial plant. It can also sell power to the grid. The hot water and steam demands can be satisfied from the equipment within the DE plant or it can be purchased from one of the sister plants contained in the facility. The steam and hot water boilers in this plant can be fired with gas or oil.

The second plant inside the facility is known as the DKCE plant. This is a combined cycle unit consisting of one gas turbine whose hot exhaust feeds a Heat Recovery Steam Generator (HRSG). The HRSG makes steam that feeds a steam turbine. There is a common generator for the gas and steam turbines. Extraction steam from the steam turbine can be used to help satisfy the 8.5 bar steam demand of the DE plant. In addition the extraction steam can feed a heat exchanger to produce hot water that can be used to satisfy the hot water demand of the DE plant. This plant is dispatched from the grid and must satisfy this power demand. Any steam and hot water produced can be sold to the DE plant. Gas is the only fuel that can be used in this plant.

The third plant contained in this facility is known as the DGE plant. This plant is comprised of six Caterpillar CAT 3520C gas motors. These gas motors make a fixed amount of electric power when they are running and the heat from the running motors can be used to make hot water. This hot water can be sold to the DE plant and used to help satisfy the city's hot water demand. This plant can sell as much power as it wants to the grid. Unlike the other two plants inside the facility It has no demand that must be satisfied.

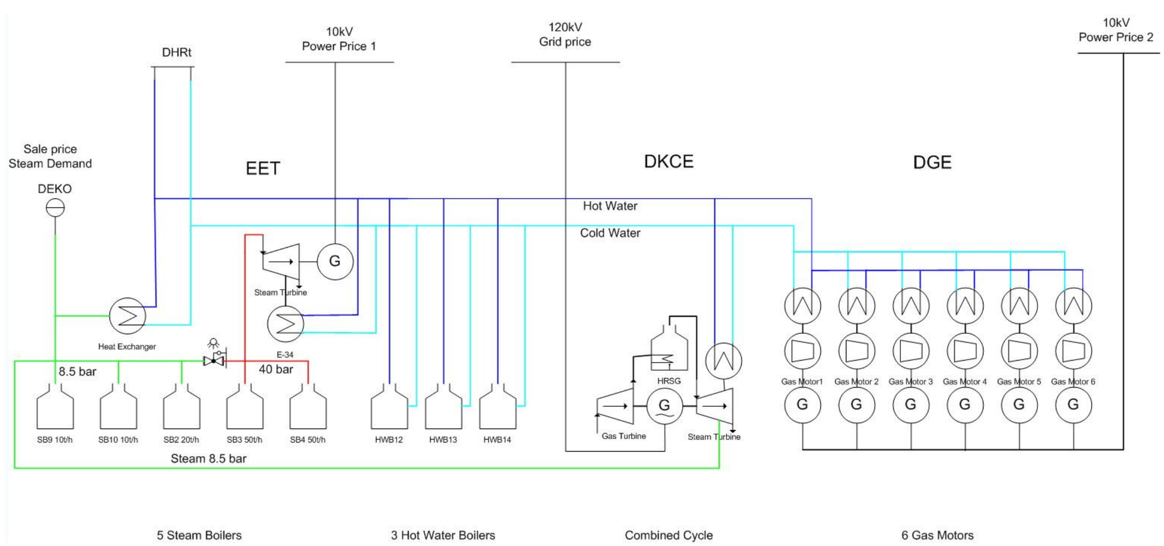

Figure 1

CHP Plant Needs and Goals

This CHP facility had to satisfy the hot water demand of the city. It also had to satisfy the industrial plants process steam demand. The DKCE plant had to satisfy a grid power demand. However, the DGE plant could sell as much power as it wanted and the DE plant could also sell as much power as it wanted. The CHP facility got paid for the power it sold but at the end of the year it had to prove that all the power it sold came from a process that was at leas 75% efficient. If the power sold did not come from a process at least 75% efficient it had to pay a large penalty. In addition, the plant had to ensure that the CO^2 yearly cap was not violated. Hence, the facility needed an optimization program that would tell them how to load the equipment in all the plants so that the process water and steam demands were satisfied and so they sold the proper amount of power ensuring that overall profit of all three plants was maximized. This had to be an optimization of maximizing profit rather than minimizing cost otherwise the optimum solution would be to not sell any power thus minimizing the cost.

In addition, this facility also had to predict its gas usage a day ahead. The amount of gas that would be consumed was a function of the hot water demand, steam demand and the amount of power that must be sold. The water demand varied on the weather conditions and the steam demand varied based on the industrial plants production schedule. Thus there was a need to be able to forecast the water demands based on forecasted weather conditions. The amount of power to sell had to be constrained based on the overall efficiency of the process making the power and the amount of CO^2 gas being produced. The efficiency and CO^2 gas yearly targets could not be violated, so efficiency and CO^2 gas tracking programs were required. Figure 2 below diagrams the major components of this energy optimization system along with the inputs to each module and the outputs of each function.

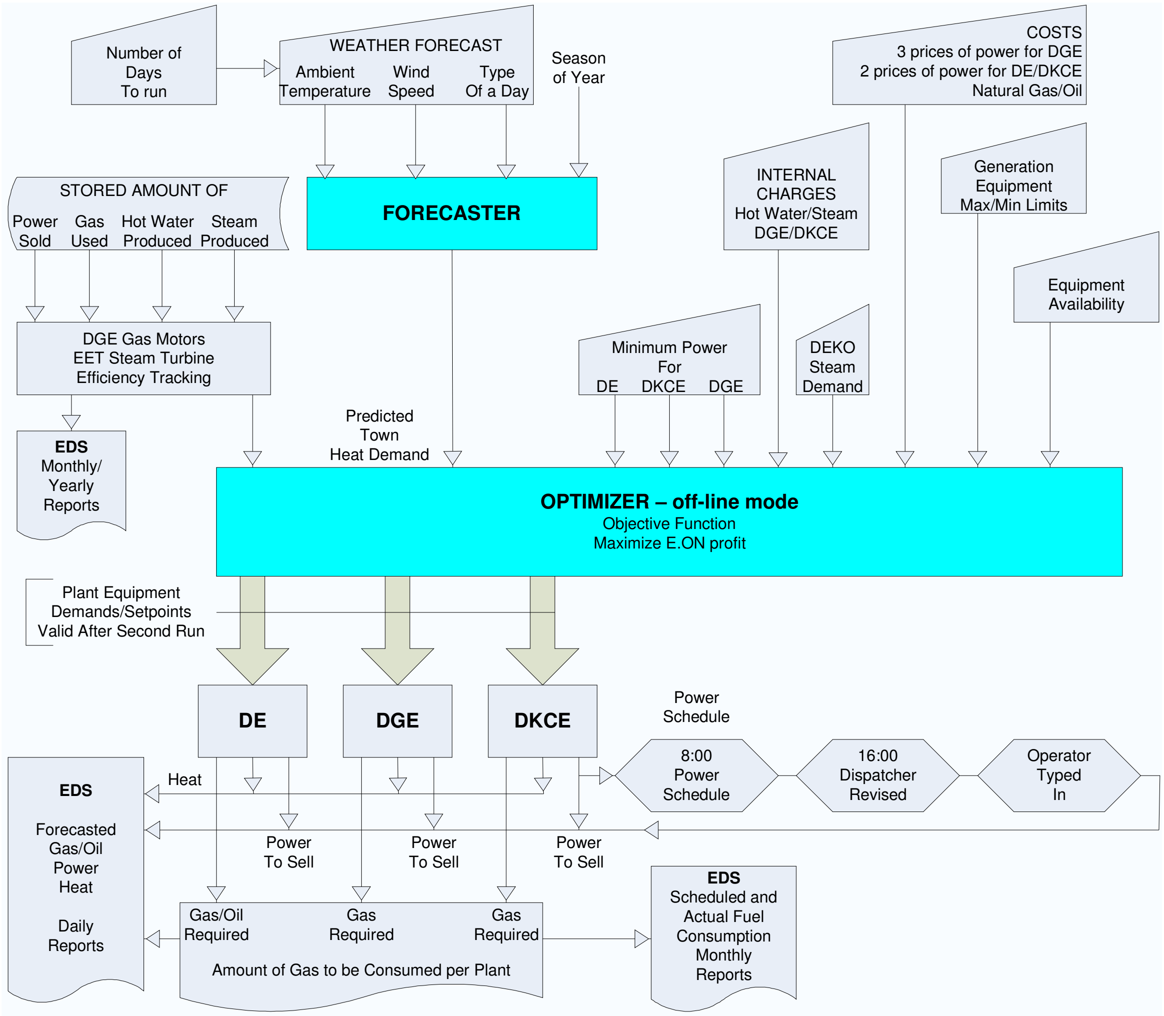
Number of Days To run
WEATHER FORECAST
Ambient Temperature
Wind Speed
Type Of a Day
Season of Year
COSTS
3 prices of power for DGE
2 prices of power for DE/DKCE
Natural Gas/Oil
STORED AMOUNT OF
Power Sold
Gas Used
Hot Water Produced
Steam Produced
FORECASTER
INTERNAL CHARGES Hot Water/Steam DGE/DKCE
Generation Equipment Max/Min Limits
Equipment Availability
DGE Gas Motors
EET Steam Turbine
Efficiency Tracking
Minimum Power For
DE DKCE DGE
DEKO Steam Demand
EDS Monthly/ Yearly Reports
Predicted Town Heat Demand
OPTIMIZER – off-line mode
Objective Function
Maximize E.ON profit
Plant Equipment Demands/Setpoints Valid After Second Run
DE
DGE
DKCE
Power Schedule
8:00 Power Schedule
16:00 Dispatcher Revised
Operator Typed In
EDS
Forecasted Gas/Oil Power Heat
Daily Reports
Heat
Power To Sell
Power To Sell
Power To Sell
Gas/Oil Required
Gas Required
Gas Required
Amount of Gas to be Consumed per Plant
EDS
Scheduled and Actual Fuel Consumption Monthly Reports

Figure 2

System Configuration

Each of the plants in the CHP facility had its own control system, but the energy optimization system had to be common. The energy optimization system had to be able to send and receive data from all three control systems. Since each control system was different there was a need to provide a common interface so that the operators at each plant would have a common interface. In order to achieve a standard interface for the operators at all three plants a web based interface was used. An Enterprise Data Server (EDS) historian was supplied that could send and receive data to each of the three plants control systems. The EDS contained its own graphic and reporting packages and also web portal software. By having a web based interface any PC that had a network connection to the EDS could be used to view and interact with the energy optimization system. Figure 3 below shows the system architecture.

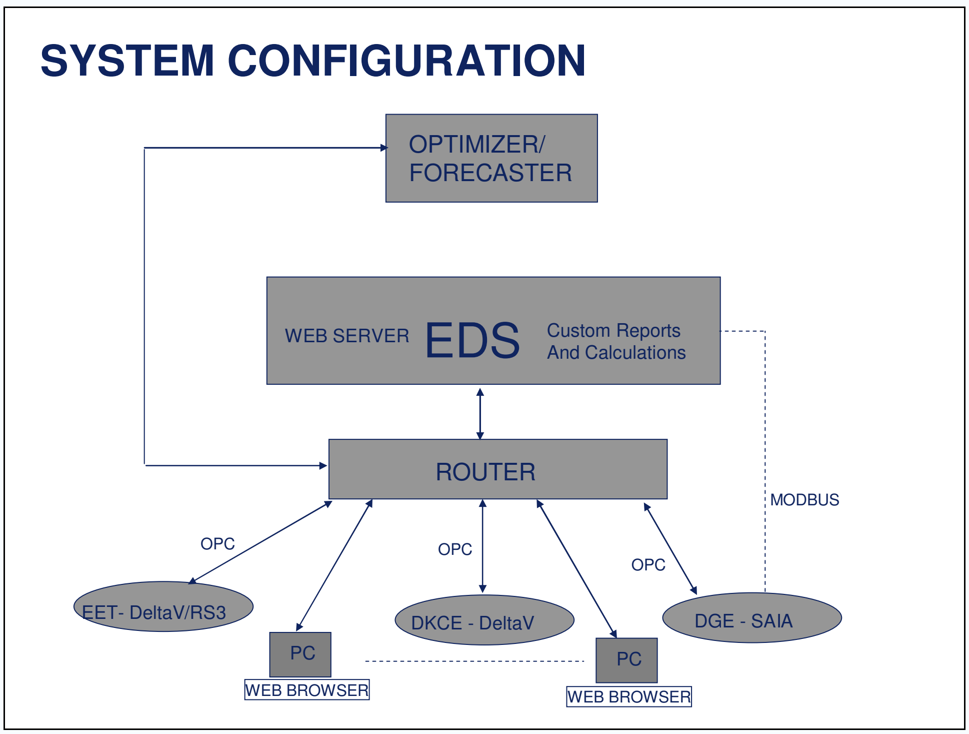

Figure 3

Economic Optimizer

The optimization program included in the energy optimization system continuously advised the operators how to run the plant so that current plant conditions were satisfied in such way as to yield maximum profit. In addition, it is used in the daily prediction of gas usage and it is also used to allow engineering personnel to perform “What If” calculations. In general it has three modes of operation, Offline, Online and prediction. These three modes and their usage are discussed below.

Offline mode

The optimizer is a general purpose solver for the mixed integer linear/nonlinear optimization problems. The software provides the user with abilities to find a solution of *x* (a.k.a. a vector of independent decision variables) in the feasible regions (which are determined by a set of equality/inequality constraints), such that the local or global minimum (or maximum) value of the objective function *J*, which is a function of *x*, is obtained.

The mathematical form of the optimization problem can be stated as follows:

$$\underset{x}{Min} \quad J = f(x)$$

$$s.t. \quad \begin{cases} g(x) \le 0 \\ h(x) = 0 \\ x_{i,\min} \le x_i \le x_{i,\max} \end{cases}$$

where x_i is either an integer or a real number.

To construct an optimization problem for the software to solve, all the coefficients in f(x), g(x), and h(x) need to be specified. Different values of those coefficients determine different ‘cases’ or ‘scenarios’ of the same optimization problem. For example, in the economic dispatch problem when the heat demand (most likely a coefficient in *g(x)* or *h(x)*) is changed, the optimal solution of *x* may be changed, and as a result, the optimization problem needs to be solved again. The new heat demand coefficient can be changed manually in the offline calculation.

The off-line program allows the user to build different plant models so that "What If" analysis can be performed. With the offline program the user manually enters costs, heat demands, steam demands, power demands, takes equipment out of service etc. This can all be done without effecting the operation of the plant.

The offline program is used to build the plant model that will run online and as part of the prediction program. This is a model that represents the existing plant (in this case set of plants). This model is run in an offline mode by manually entering plant demands and costs to ensure the model is correct. This model can be run with manually entered projected heat, steam and electrical demands to provide recommended equipment selection and loadings to operators.

Models can be built that do not reflect the plant. For example, a model might be built that contains an extra CTG/HRSG, gas motor or condensing STG to see what economical impact it may have. The optimization software is loaded onto one PC and this becomes the server. The offline interface can be run from any PC that has a network connection to the server. The offline program is run from the client PCs using Internet Explorer. The IP address of the server is entered into the address bar and the interface is displayed. Once proper user name and password is provided user has to select the model developed for offline optimization. Final step is displaying dedicated window where user can enter specific plant conditions and run optimizer to find the solution. The display developed for this project is shown in Figure 4 below.

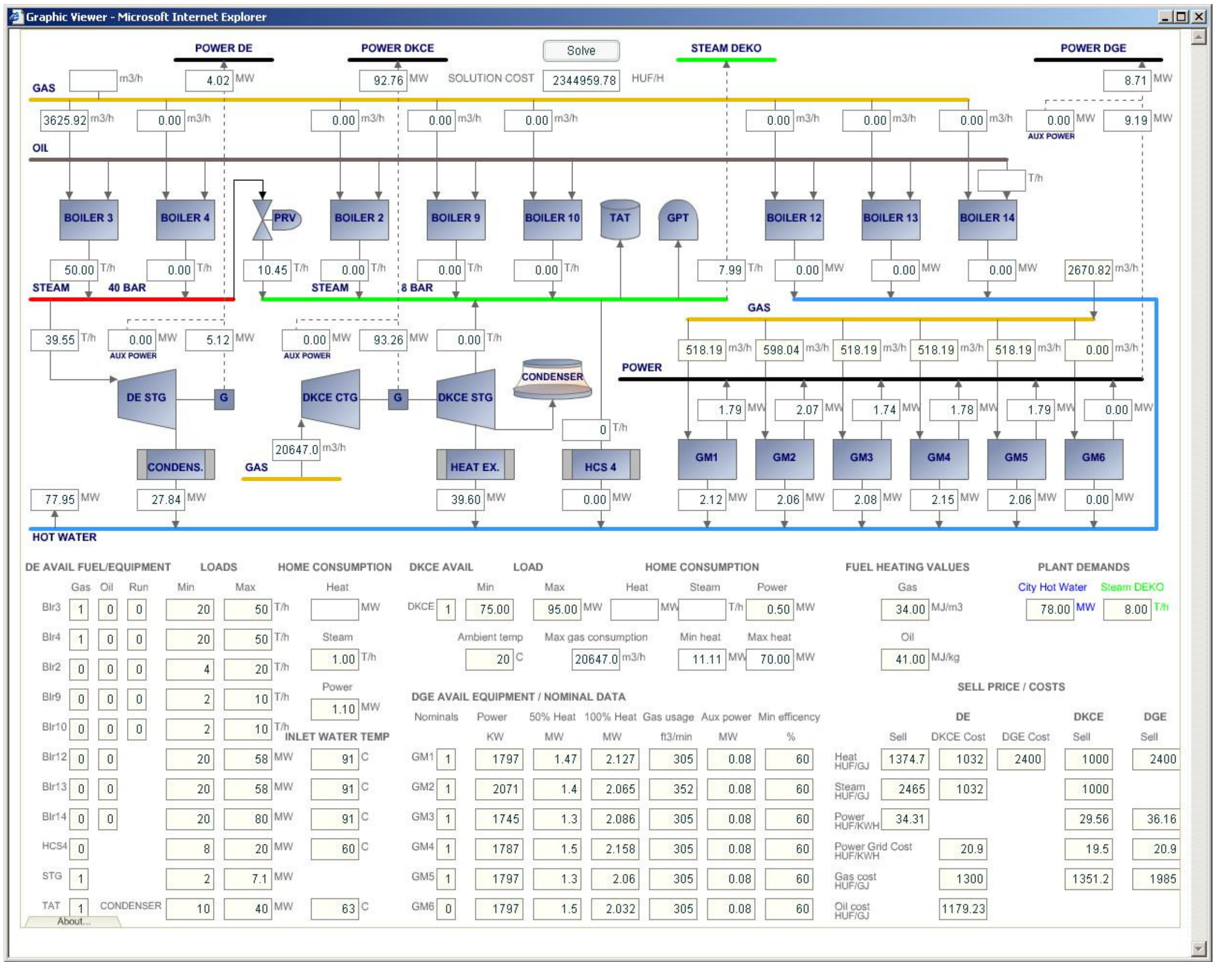

Figure 4

Online mode

The online program is tailored to satisfy a specific optimization problem and runs continuously as a Windows service. The online program runs every couple of seconds (configurable from offline GUI) and compares demands and actual generation capacities such as hot water demand, steam demand, power demand, equipment availability, steam, hot water power generation etc. If there was a major change in plant conditions the optimization program runs immediately. If the plant is remaining stable the program runs every couple of minutes (tunable value).

When the online program decides it must run the optimization, the program obtains the base plant model from the server's database that was constructed from the Offline program. It then replaces the costs, hot water, steam demands, power demands etc. with actual plant parameters from the DCS that were gathered by the EDS, and carries out the optimization calculation. If the solution is feasible, the optimum values for the variables are updated on the control system along with the status. However, if there is an unfeasible solution only the status is updated on the DCS. The unfeasible solution lets the operator know that the values of the variables have not been updated and the current form of the optimization problem cannot be solved. When this occurs the online optimization problem will be saved into the database so it can be analyzed by using the offline program. It should be noted that the online updated plant models can be saved even if it had a feasible solution.

The online optimization runs in ADVISORY mode - the results are not implemented as supervisory setpoints in the control system. When the model is running on-line it will find the best solution for the pieces of equipment that are currently running in the plant. The results of optimization will be stored in EDS database and made available to the operator throughout graphic interfaces that can be accessed via the web browser and are used to advise the operator on how to load the equipment to achieve maximum profit.

Prediction Mode

When the prediction program invokes the optimizer the optimizer obtains the base plant model from the optimizer's database that was constructed from the Offline program. It then replaces the costs, hot water, steam demands, power demands etc. with the predicted values stored in the EDS database. The optimizer will receive availability flags for each piece of plant equipment when it runs from within the prediction program. If a piece of equipment is available then the optimizer is allowed to select that piece of equipment. During the prediction process the optimizer determines which pieces of equipment should be ON or OFF to meet the forecasted demands. The results of the prediction are very useful for providing a unit commitment profile for the operator. Please note that only the optimizer that runs inside the prediction program determines which pieces of equipment should be running. The on-line optimizer discussed above determines the best solution for the equipment the operator has chosen to have running. If the operator decided to run equipment other than what was recommended from the prediction program he will then see the best way to operate that equipment set.

Plant Model

The plant model is comprised of the following types of variables:

Coefficients – these are variables that are not modified during the optimization process or calculated. These were:

- Equipment availability
- Minimum and Maximum constraints for manipulated variables
- Water and steam demands
- Costs and sale prices
- Heating Values of fuel
- Temperatures

Manipulated Variables – these are variables that the optimizer can adjust. Examples are:

- Boiler oil and gas flows
- CTG fuel flow
- PRV steam flows
- Equipment ON/OFF
- Gas motor heat recovery mode
  - 100% recovery
  - 50% recovery
- Purchased Power

Dependent Variables – these are variables that are calculated from some combination of manipulated variables, coefficients, and other dependent variables. Examples are:

- Equipment models for:
  - Hot water boilers
  - Steam boilers
  - Heat exchangers
  - Combined cycle unit
  - Gas motors
- Balances
  - Water
  - Steam
  - Power

Constraints

The variables discussed above will have minimum and maximum constraint. Examples are:

- Equipment Minimum and Maximum operating ranges
- Water and steam demands
- Efficiencies
- Equipment availability

All of the individual models of equipment contained in the DE, DKCE and DGE plants were developed from actual plant data. The plant data was regressed to develop the equipment models. Thus the accuracy of the models depends on the quality of the plant data.

For this facility models were developed for each boiler and each heat exchanger. A model was developed for the STG in the DE plant. The combined cycle unit in the DKCE plant was modeled. The gas motors made a fixed amount of power when they were on and each motor could run in 50% or 100% heat recovery mode. A model was developed for each gas motor. In a plant such as this there are multiple pieces of equipment and multiple fuels that can be used. Not all pieces of equipment were required to be on. The mixed integer programming feature of the optimizer was very useful for solving this selection process. Binary manipulated variables (MV) were created. The optimizer could turn pieces of equipment on and off. The binary MV's were incorporated into the individual equipment models so that when a piece of equipment was turned off its output would be zero.

Objective Function

All of the individual equipment models that make up the overall plant model are a set of simultaneous equations. The optimizer adjusts the manipulated variables in such a way that the solution to the set of equations either minimizes or maximizes an objective function. In this case the goal was to maximize overall profit. Therefore, the objective function had to be an equation that represented the overall profit of the CHP facility. This was defined by the following equation:

MAXIMUM (DE_Profit + DKCE Profit + DGE Profit)

Profit can be defined as sales minus cost. The profit in the DE plant was equal to the revenue earned from the sale of water, power and steam. The total cost came from the fuel used by the DE plant equipment plus the cost of buying steam and water from the DKCE and DGE plants. The DKCE plant had revenue from the power it sold to the grid and any water and steam that it sold to the DE plant. The cost was only applied to the fuel that it used. The DGE profit is similar to the DKCE plant. Revenue resulted from the sale of power plus any hot water it sold to the DE plant minus the cost of gas used in the gas motors.

Hot Water Forecast

The contract between the city and the CHP plant determines the overall amount of incremental heat energy to be delivered to the town. The incremental water demand is forecasted and the steam demand is determined from the production schedule of the industrial plant but the power amount must be the amount that yields maximum profit. Therefore, the energy optimization system provides the ability to forecast the incremental hot water demand. The CHP operator enters the ambient temperature, wind speed and type of day so the hot water can be forecasted.

The hot water forecast is predicted by a neural network model that was developed based on historical hourly data such as heating loads and meteorological data that included ambient temperature, wind speed, and type of a day.

The hot water had to be forecasted so that the gas consumption for the next day could be estimated. In order to forecast the optimization program was run to determine how much gas was required to not only satisfy the incremental water demand but also to determine the best way to satisfy the required steam demand and the amount of gas that should be burnt to make the optimum amount of power. The results of running the optimization program using predicted water and steam demands were used to estimate gas usage and provide a unit commitment profile to the operator.

The hot water demand for the on-line program was determined by the desired water temperature. The operator entered the desired temperature of the water. The desired enthalpy of the water was calculated using the entered temperatures and the fixed water pressures. This enthalpy multiplied by the current water flow yielded heat. This is the final heat in water. To calculate the incremental heat, the heat in the return water must be subtracted. The heat in the return water was calculated by multiplying the water flow by the enthalpy of the water at the return water temperature. The incremental heat was then converted to MW and this became the MW heat demand used the optimization program. If the temperature of the water had to be adjusted the operator changed the temperature values and the program automatically determined how to load the equipment to satisfy the new hot water MW demand.

Since some forecasts are daily (midnight to midnight) and some are from 6:00 to 6:00 and some are for 48 hours rather than 24 hours, the operator was able to request a forecast for any time period. He entered the starting day at mid-night and the number of days to forecast. If the operator did not enter enough prediction information for the requested forecast he received an error message indicating this.

Gas Forecasting

The CHP facility must forecast the amount of gas that will be consumed a day ahead. The amount of gas required depends on the amount of hot water and steam that must be supplied and the amount of power that should be sold. The water demand is forecasted and the steam demand is determined from the production schedule of the industrial plant but the power amount must be the amount that yields maximum profit.

The hot water was forecasted as discussed above. The steam demand was entered in T/h from the industrial plant production schedule and any minimum power demands were entered. In addition the operator has the ability to enter equipment availabilities, fuel availabilities, and all associated costs, such as fuel cost, internal water and steam costs and sale prices. From this information the optimizer determined the amount of power that each of three plants should produce and the amount of gas required by each plant.

For gas forecasting the Forecaster/Optimizer has to be executed a number of times. On each turn it calculated hourly-based gas consumption for each piece of equipment. Additional calculations programmed in the EDS summarized forecasted gas consumption for all equipment of each particular plant.

The gas forecast was for a day defined to be 6:00 AM to 6:00 AM. The day forecast for power was for a time period of midnight to midnight. In order to be able to handle two different day periods the forecasts were performed as follows:

The operator entered the ambient temperature, wind speed, type of day, steam demand (T/h), and minimum power demands for each plant (MW) for a 30 hour period – (schema valid from Monday to Thursday). Typically, this was performed by the operator at 8:00 AM. The forecasted results were sent to the utility by CHP personnel and the dispatcher informed the CHP facility what power demands they required. At 4:00PM the operator revised the forecast data based on the information received from the dispatcher and the forecast was re-run. The result of this forecast was used to determine the gas consumption and amount of power to be sold.

Since power forecasts must be in terms of demand periods instead of hours the forecast ran in 15 minute increments instead of hours.

Efficiency Tracking

The six gas motors owned by DGE and the steam turbine owned by DE have a special status according to the local country legislation. At present the electric power generated by this equipment must be purchased at a predetermined supported price subject to certain indicators of generating meeting conditions set forth in provisions of the law. The CHP facility can produce as much power as possible from the gas engines in the DGE facility; however, the power produced from these engines must maintain a minimum monthly efficiency of 65% and a minimum yearly efficiency of 75%. This regulation means that over the heating season the motors run at full capacity with efficiency over 80%, which allows a heat drop mode of operation during the intermediate and summer period. The back pressure steam turbine in the DE facility must maintain a minimum monthly efficiency of 65%.

These efficiencies became constraints in the optimization program. The energy optimization system tracks the efficiency for the 6 gas engines and the steam turbine. The tracking for gas engines is done by storing the amount of power sold, amount of gas used and hot water produced from these pieces of equipment so a year-to-date efficiency can be calculated at anytime by dividing the total energy produced (power and water) by the energy consumed (gas). The DE back pressure turbine efficiency calculations will calculate year-to-date efficiency by considering power, water and steam.

A program in the EDS keeps track of the year to date efficiency for the gas motors and the STG and calculates constraints used by the on-line optimization program. Therefore the power efficiency equations for those pieces of equipment are contained inside the plant model.

Conclusion

The word optimization is composed of two pieces that of options or choice and of minimizing or maximizing. Whenever a situation exists where there are multiple pieces of equipment making a common commodity optimization is possible. In this example there were three plants acting as one large plant. Each plant had multiple pieces of equipment making the water, steam and power clearly lending itself to the need for an optimization system. The system was installed in the spring of 2007 and has been running. The customer E.ON is using the system. The gas forecast is very useful and the unit commitment is aiding them. The system has not been in use long enough to tabulate total amount of savings.

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