Simplified Operator's Guidance for a Cogeneration Plant*

Russell P. Muschick, P.E.
G. Loren Toole

This article describes a simplified PC-based method which can be used to guide daily loading decisions typically required of cogeneration plant operators. This method has been successfully tested at an operating plant, with excellent results. Its main benefit accrues from avoiding lengthy data preparation and awkward calculations.

Instead it relies upon a small set of readily-available aggregate statistics such as the previous week's generation and standby energy cost which are typically logged in a plant control room. After initialization, the operator's program was used to set a monthly generation "target" for steam and electricity based on historic seasonal demands.

The overriding objective was to satisfy monthly targets; adjustments were made weekly to attempt to meet this goal. The method was designed to schedule least-cost operation for steam and electric production within the constraints of plant capacity, cost of standby electricity and related costs such as boiler rampup/rampdown. It can be easily modified to account for different load and cost patterns.

BACKGROUND

This method was developed for use at a Department of Energy complex located in the Southeast US. This facility, which covers an area of 300 square miles, serves as a nuclear weapons material processor. All electricity is currently purchased off-site although a significant portion

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was previously obtained from an on-site coal-fired cogeneration plant with process steam extracted as a by-product. The plant is rated at 58.2 MW electric and 350 Kpph output; it utilizes four boilers and six back-pressure turbines in the configuration shown in Figure 1.

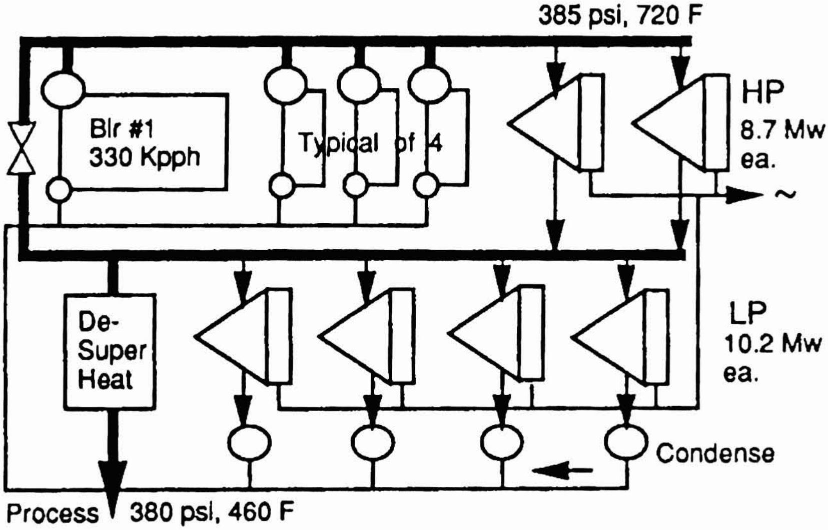

Figure 1. Boiler and Turbine Configuration

In order to explain the issues and basic terminology involved, we first review the following topics:

- Problem to solve
- Cost of plant operation
- Targeting

Problem to Solve

Our plant operator was confronted each day with a complex decision i.e. Minimize (Ce + Cs + Cp) subject to demands for steam and electricity, limits of plant capacity and contract capacity established by the local utility (the terms are Ce= electric generation cost, Cs= steam generation cost and Cp= purchased power cost).

This problem had been previously analyzed for monthly budgeting purposes, but daily plant loading was more complex. Our cost model was already unwieldy. Therefore we agreed that a new approach was clearly required.

First, a simple interpolation of the plant cost function was not useful. Many underlying factors especially demand for steam and electricity were constantly changing and it was not practicable for an operator to re-execute the cost model frequency. The model needed to be tightly integrated into our short-term load forecasting process.

Finally, we did not want to lose the credibility of our established costing methods by creating a new model. We ultimately decided to combine results from the existing plant cost and load forecast models into a system which could be used by virtually anyone with little training. This approach proved to be an excellent solution to the problem.

Cost of plant operation

Our method assumed that product costs from the cogeneration plant cycle were quantified for various levels of demand. This topic is generally beyond the scope of this article since the method chosen is specific to each plant and usually reflects the availability of different types of data.

For example, our records did not allow plant electric heat rate (a measure of efficiency) to be easily calculated, but our cost method required it. We were forced to conduct a series of controlled tests over a range of load levels to estimate this parameter. Other costing methods are designed to use different parameters (Ref. 1,2).

The actual cost model consisted of multiple regression equations which were numerically coupled through Ce and Cs. The cost analysis utilized estimates of site demand (load factor, peak) for both steam and electricity as well as fuel cost, purchased power cost, and boiler availability.

Then, an iterative series of calculations were performed at different plant electric output levels to determine the optimum generation for given conditions. At our site, process steam demand was considered to be a "must-run" quantity due to nuclear safety concerns. We often generated a minimum electric output of 18 MW while exporting 100-200 Kpph of steam. During periods of higher electric demand, it was often advantageous to increase electric output above the minimum.

Targeting

Here the term "target" refers to the quantity of electric needed to minimize costs over a fixed period of time, usually a week; units are

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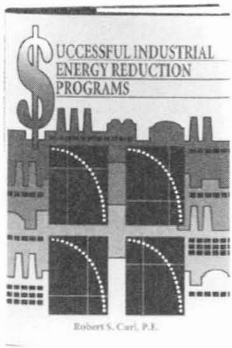

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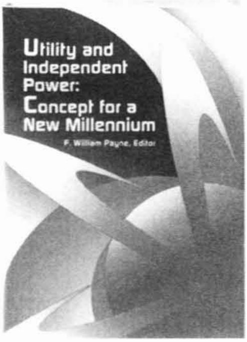

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megawatt-hours. Our plant operators' overriding concern prior to implementing the new method was to insure flexibility in setting targets. One alternative considered but rejected was to simply set a monthly target. This approach did not allow for interim adjustments made necessary by forced outages, unforeseen changes in demand or standby electricity costs.

We agreed that a daily targeting method was also probably too much refinement due to costly boiler ramping. The method was ultimately designed to use weekly targets set on Monday, with the option of a midweek correction.

METHOD OF ANALYSIS

The most important feature of the operator's program was ease-of-use, particularly in regards to gathering prior week's data for input to the model. Only six data items were needed. Two results were displayed as output: weekly (total) megawatt-hours generated and average turbine loading. Each re-calculation was automatically archived for later review. The user was prompted for inputs through click-on selections and numeric box entries while entering the following information:

Year? Month? Week of Month?

Select the time period for analysis. These inputs established the internal calendar, allowing the program to select a one of three load patterns, depending on season.

Previous week's standby power cost?

Enter the highest standby power cost quoted by utility dispatchers during the previous week, dollars per megawatt-hour ($/MWH). These data were taken from a plant report issued daily.

Previous week's site generation?

Enter the sum of megawatt-hours generated on-site during the previous week. These data were taken from a plant report issued weekly.

Previous week's total energy use?

Enter the sum of megawatt-hours consumed on-site during the previous week. Data were taken from a plant report issued weekly.

Other data not supplied by the operator were required to drive our program, notably a cost versus load matrix. The cost model was executed for "expected" conditions and then "incremental" conditions to quantify the impact on optimal plant loading. These results were entered in matrix format as shown in Figure 2.

		$/MWH		
		25	50	75
Δ	–20	27,670	29,352	31,035
MW	0	26,370	28,052	29,735
	20	25,070	26,752	28,435

Figure 2. Optimal Generation

There are several important features shown. First, the table entries represent electric generation needed to minimize costs for a full month; units are megawatt-hours. We previously referred to this quantity as the "target." The left column lists deviations from our monthly peak forecast i.e. –20, 0 and 20 MW. The top row lists deviations in the cost of purchased standby power i.e. 25,50 and $75 per MWH.

For example, if no deviation in peak demand occurs and standby power costs are $50/MWH, the target is shown to be 28,052 MWH. The cost of purchased electric demand is not considered. Instead, we assumed that the plant would always be operated over short intervals of time to avoid creating a sudden increase in purchase demand, and therefore to avoid utility ratchet charges.

The information contained in Figure 2 was embedded in the operator's model and became an integral part of the overall targeting process. Figure 3 shows the overall program flow. Steps 2, 3, and 4 yield key intermediate results which are discussed next. Entries from the cost versus load matrix are selected in Item 2 on the basis of calendar data. The operator program also establishes a "synthetic" prior week in Item 3 by proportioning weekly site energy over a unitized demand curve. The estimated weekly peak and load factor are compared to forecast quantities.

If there is a deviation from expected conditions, then a residual error (Δ peak, Δ load factor) is calculated. This error factor is utilized in the target interpolation. In practice, this situation always occurs although the errors are often quite small.

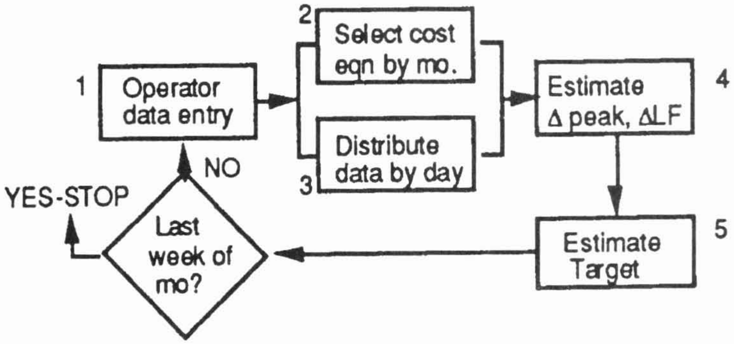

Figure 3. Program Flowchart

SAMPLE RESULTS

To illustrate results from our program, refer to Figure 4. Daily site demands for June, 1996 are shown in the upper plotline, while cogenerated power is arbitrarily assumed to be constant, roughly 840 megawatt-hours per day (an average of 35 MW). Also plotted are the weekly series of targets needed to optimize plant output. The "target" plotline shows small week-to-week adjustments are being made in response to changes in site demand.

However, by the last week, accumulated generation exceeds the desired sum of weekly targets. The program signals for a rampdown. Since this did not occur overall operation would not achieve least-cost levels. This case is somewhat unrealistic since plant output diverged from all weekly targets, but it illustrates the flexibility needed to reach a monthly cost goal.

Finally, it was necessary to track savings actually achieved with this method. Figure 4 illustrated a simple example in which generation was assumed to operate at constant output for the entire month. By comparing this profile at various loading levels to the target profile, a series of savings can be estimated. Figure 5 tabulates these results. The zero savings case assumes a must-run electric output of 18 MW and adequate steam extraction to meet site demand. Using a "flat" profile across all hours, savings relative to must-run operation are shown. At 35 MW output (approximating the target in Figure 4) over $40,000 per month is achievable. This savings includes both reduced purchased power costs as well as reduced fuel burn per unit production of both steam and electricity.

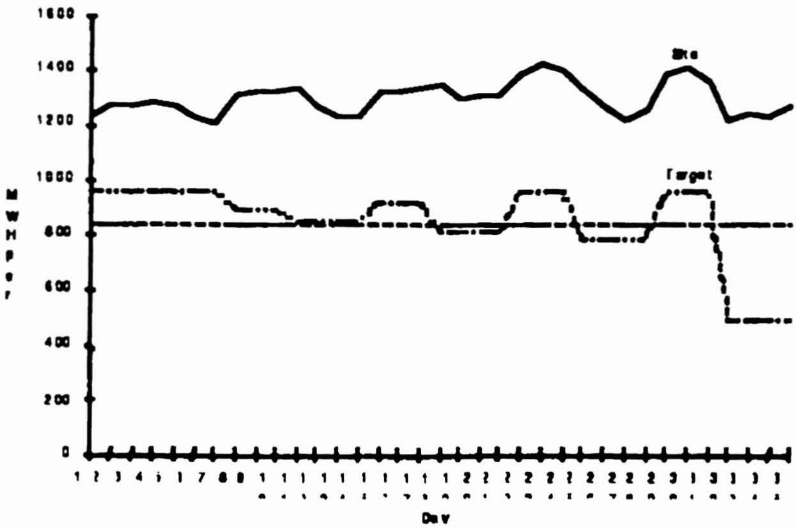

Figure 4. Generation Target Versus Site Demand

MW	Cost/Mo. 000's	Savings 000's	Δ Target MWH
18	1199	0	-18,600
26	1189	-10	-11,500
35	1159	-41	-1,300

Figure 5. Estimated Savings

SUMMARY AND CONCLUSIONS

While the primary goal of this method is to improve cogeneration plant economy, it offers significant operational benefits by avoiding lengthy data preparation and awkward calculations.

Section 1 outlined the process of characterizing production costs based on a pre-existing plant model. Section 2 described the operator program's features. It was designed to be simple to use in routine plant conditions, and it has proven to be operator-friendly. Finally, the estimated savings stream shown in Figure 5 suggested that costs associated with maintaining the software (primarily data entry and re-calibration) can be easily offset by "targeting" more efficient plant operation. The authors believe this method can be readily adapted to other plants, if product costs can be accurately estimated.

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ABOUT THE AUTHORS

Russell P. Muschick, P.E., serves as a principal engineer, Site Utility Department for Westinghouse Savannah River Company, Aiken, South Carolina. Mr. Muschick holds a BSME degree from Clemson University and has completed graduate studies in nuclear engineering at North Carolina State. He was employed for 20 years by Duke Power Company in both the fossil and the nuclear production departments. Currently, Mr. Muschick serves as chair of SRS Engineering Standards Board, Mechanical Equipment Committee. He is a Registered Professional Engineer in S.C. and N.C.

G. Loren Toole is currently assigned to Los Alamos National Laboratory, assisting in the development of high-power microwave systems. Mr. Toole received his B.S. and M.S. (power systems) degrees in electrical engineering from Georgia Tech. His industrial experience includes over 20 years in the promotion of energy-related projects such as cogeneration and load management. Mr. Toole serves as a principal, Kalmia Consultants, Aiken, SC.

Russell Muschick, P.E., WSRC, Site Utility Department, Building 777-20A, Aiken, SC 29808; russell.muschick@srs.gov

G. Loren Toole, Principal Engineer, Los Alamos National Laboratory, TA53 Building 31, RM 282, MS H827, Los Alamos, NM 87544; ph 505-665-0562; fax 505-665-2818; loren.toole@aotmail2.atdiv.lanl.gov