OAK RIDGE NATIONAL LABORATORY

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ORNL CHP Capacity Optimizer User's Manual

C. Randy Hudson

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Engineering Science and Technology Division

ORNL CHP CAPACITY OPTIMIZER USER'S MANUAL

C. Randy Hudson

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Prepared by
OAK RIDGE NATIONAL LABORATORY
P.O. Box 2008
Oak Ridge, Tennessee 37831-6283
managed by
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ABSTRACT

Evaluation of potential cooling, heating and power (CHP) applications requires an assessment of the operations and economics of a particular system in meeting the electric and thermal demands of a specific end-use facility. Given the electrical and thermal load behavior of a facility, the tariff structure for grid-supplied electricity, the price of primary fuel (e.g., natural gas), the operating strategy and characteristics of the CHP system, and an assumed set of installed CHP system capacities (e.g., installed capacity of prime mover and absorption chiller), one can determine the cost of such a system as compared to reliance solely on traditional, grid-supplied electricity and on-site boilers.

Research sponsored by the DOE Distributed Energy Program has lead to the development of a methodology to determine the optimal capacities for CHP prime movers and absorption chillers using nonlinear optimization algorithms and hourly operation simulation of CHP systems. The methodology has been coded into a stand-alone Microsoft Excel spreadsheet tool that performs the capacity optimization and operation simulation. This document provides a guide to the use of the automated spreadsheet tool that can be used by end-users and system developers to determine the most appropriate capacities for prime mover and chiller that will maximize the life-cycle, net present value savings produced by CHP systems.

INTRODUCTION

Selecting the proper installed capacity for cooling, heating, and power (CHP) equipment is critical to the economic viability of distributed energy/CHP projects. Poorly matched installed capacities can cause an otherwise profitable project to incur a life-cycle economic loss. To enhance the likelihood of a positive economic outcome, the CHP Capacity Optimizer has been developed to provide guidance on the proper installed capacities for distributed energy (DE) prime movers and absorption chillers in commercial applications.

Generally, CHP systems are not the sole source of electricity and thermal resource for a facility. In most cases, these systems are merely alternatives to utility grid-supplied electricity, electric chillers, and electric or gas-fired on-site water heating. As a result, CHP systems are characteristic of the classic "make-or-buy" decision, and economic viability is relative to grid-based electricity and on-site boiler heating. This tool simulates both a CHP system and a traditional non-CHP approach (i.e., electricity solely from the grid, heating from on-site boilers) to form a relative economic savings resulting from installing a CHP system. Through the use of a nonlinear optimization algorithm, the installed equipment capacities that maximize the relative economic savings are determined.

GENERAL INFORMATION

The general structure of the tool consists of two nested sections: an outer, controlling optimization algorithm and an inner operation simulation routine. The optimization algorithm seeks to maximize the net present value (NPV) savings produced from using the CHP system relative to a non-CHP scenario (where electricity is obtained solely from the grid and heating loads are met by an on-site boiler). The overall flow of the optimization algorithm is shown in Fig. 1. Starting with an initial "guess" for the installed electrical generator and absorption chiller capacities, an hour-by-hour operation simulation is performed to develop a value of the NPV savings objective function for the given generator and chiller capacities. Within the optimization algorithm, a stopping criterion based on change in the objective function is used to control the updating of the optimization routine and subsequent iterative looping back to the operation simulation with a new set of candidate installed capacities.

For the operation simulation, the general flow of calculations is shown in Fig. 2. Once the electrical and thermal loads and general equipment/economic parameters are defined, for each iteration of the optimization routine, a trial set of distributed generator and absorption chiller capacities are provided to the operations simulator. Two separate simulations must be performed. First, the hour-by-hour costs for satisfying the thermal and electric loads solely by a traditional utility grid/on-site boiler arrangement must be calculated. This is referred to as the non-CHP or grid-only scenario. A second, separate calculation develops the hour-by-hour costs of meeting at least some part of the specified loads with a CHP system. Two sets of annual operating costs are then determined by summing the relevant hourly costs of meeting thermal and electric demands from either the grid and on-site boiler solely (i.e., the non-CHP scenario) or from CHP operations. A differential annual operating cost (or net annual savings, if the CHP scenario is less costly than the non-CHP scenario) is determined based on the annual cost difference between the non-CHP scenario and the CHP-available scenario. A net present value is then determined by calculating the present worth of the net annual savings over the number of years defined by the planning horizon at the defined discount rate and adding the installed capital costs of the CHP system, adjusted for income tax effects (e.g., depreciation). Additional detail on the operation simulation methodology is provided in Appendix A.

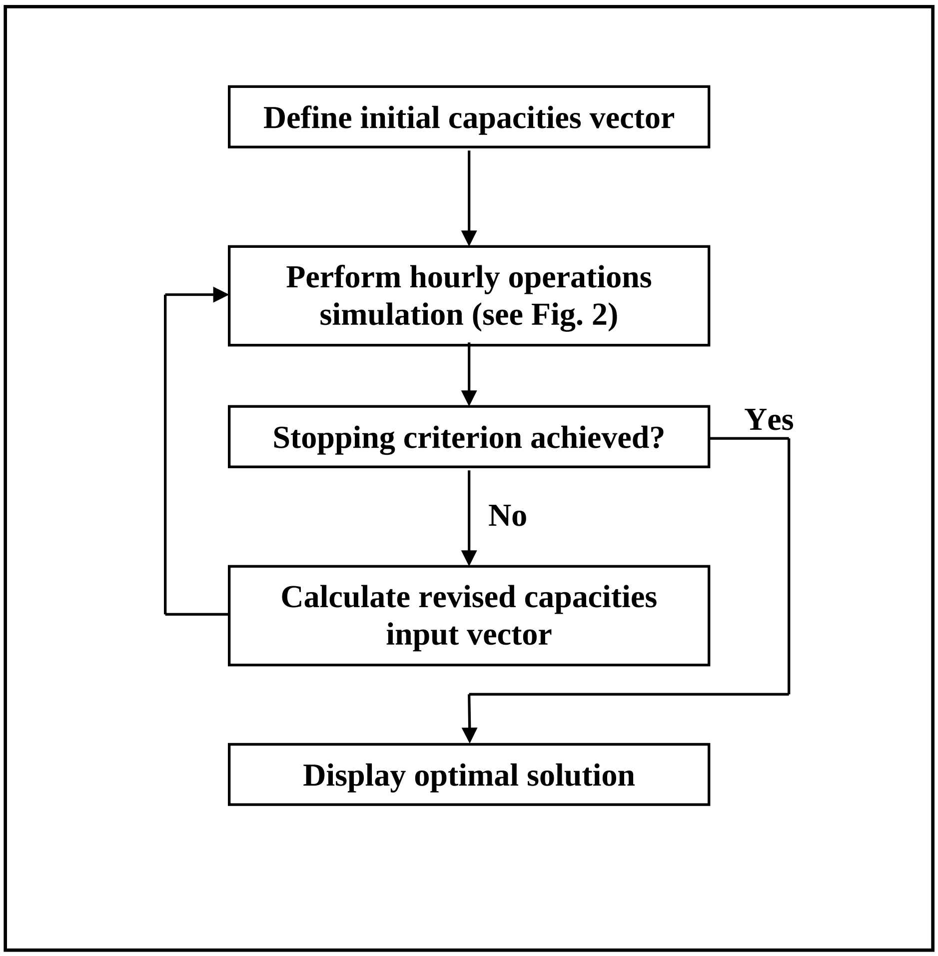

Fig. 1. Overview flow chart for optimization model.

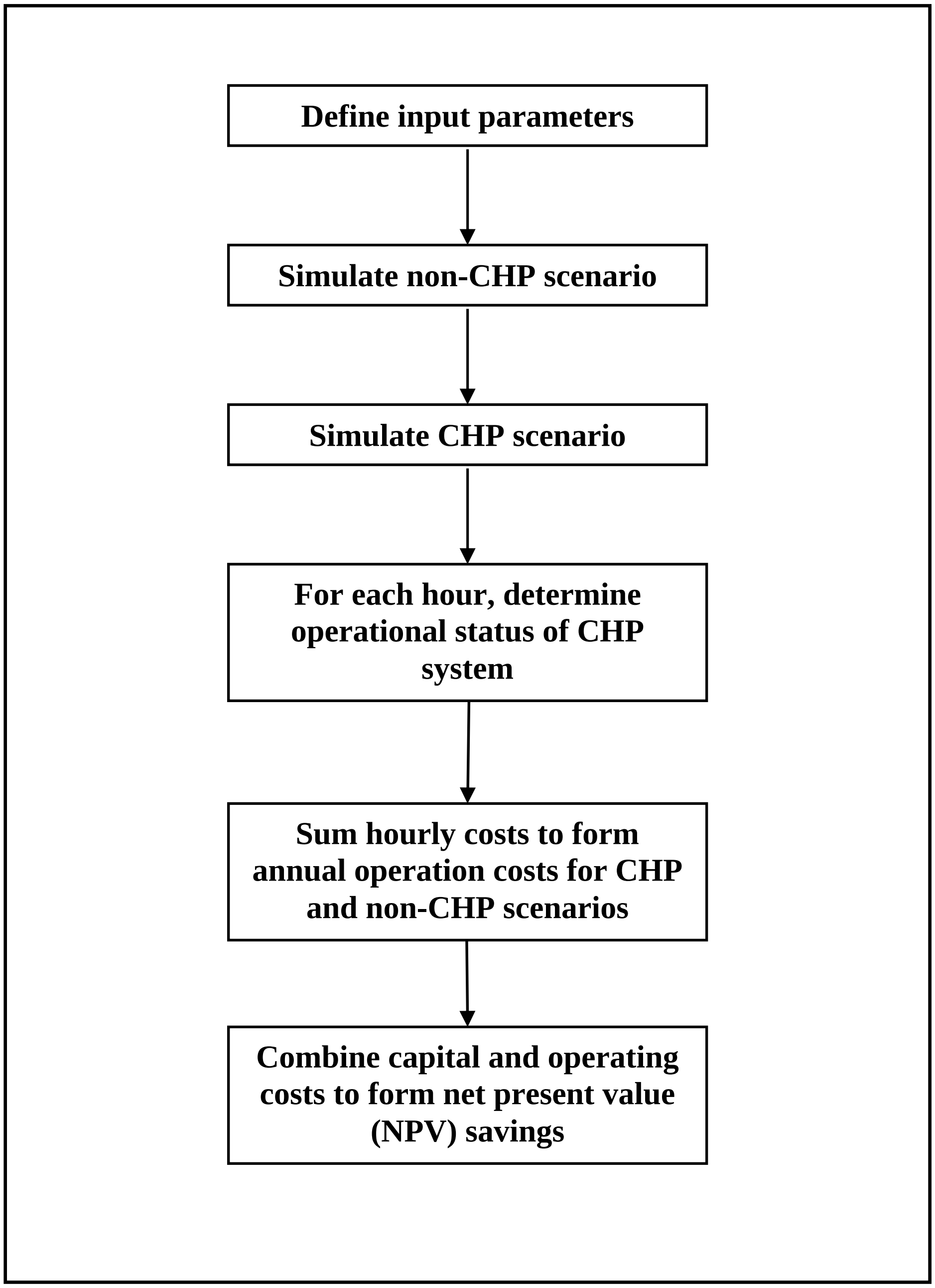

Fig. 2. Operations simulation flow chart.

DATA NEEDS

The data needed to run the CHP Capacity Optimizer are shown in Table 1. In recognition of the problems identified in the literature regarding the use of average or aggregated demand data [Orlando (1996); Gamou, Yokoyama and Ito (2002); Hudson and Badiru (2004); Hudson (2005)], this approach utilizes demand (load) data expressed on an hourly basis, spanning a one year period. Use of hourly data has the advantage of explicitly capturing the seasonal and diurnal variations, as well as non-coincident behaviors, of electrical and thermal loads for a given application. In many cases, actual hourly demand data for an entire year may not be available for

Table 1. Input variables used in CHP capacity optimizer

Variable	Typical units
Facility loads	
Hourly electrical demand (non-cooling related)	kW
Hourly heating demand	Btu/hour
Hourly cooling demand	Btu/hour
Electric utility prices	
Demand charge	$/kW-month
Energy charge	$/kWh
Standby charge	$/kW-month
On-site fuel price (LHV basis)	$/MMBtu
Equipment parameters	
Boiler efficiency (LHV)	Percent
Conventional chiller COP	Without units
Absorption chiller (AC) COP	Without units
Absorption chiller (AC) capacity	RT
AC minimum output level	Percent
AC system parasitic electrical load	kW/RT
Distributed generation (DG) capacity, net	kW
DG electric efficiency (LHV) at full output	Percent
DG minimum output level	Percent
DG power/heat ratio	Without units
Operating and maintenance (O&M) cost	$/kWh
Number of DG units	Units
DG capital cost	$/kW installed
AC capital cost	$/RT installed
General economic parameters	
Planning horizon	Years
Discount rate	Percent/year
Effective income tax rate	Percent

a specific site. In these situations, building energy simulation programs are available that can develop projected hourly loads for electricity, heating, and cooling on the basis of building application, size, location, and building design attributes (e.g., dimensions, insulation amounts, glazing treatments) [InterEnergy/GTI (2005); Oak Ridge National Laboratory (2005)].

Electric utility pricing will be discussed in a following section on data input to the model. The fuel assumed for on-site distributed generation and on-site water/steam heating in this report is natural gas, expressed on a $/MMBtu lower heating value (LHV) basis. The heating value of natural gas refers to the thermal energy content in the fuel, which can be expressed on a higher heating value (HHV) or lower heating value basis. The difference in the two heating values relates to the water formed as a product of combustion. The higher heating or gross value includes the latent heat of vaporization of the water vapor. The lower heating or net value excludes the heat that would be released if the water vapor in the combustion products was condensed to a liquid. As DG/CHP systems try to limit exhaust vapor condensation due to corrosion effects, the usable heat from natural gas is typically the LHV. In the United States, natural gas is typically priced on a HHV basis, so care should be used in entering the proper value. The conversion between HHV and LHV is heat $content_{HHV}$ = heat $content_{LHV} \times 1.11$ for natural gas.

The definitions for the other parameters listed in Table 1 are as follows:

Boiler efficiency—The thermal efficiency of the assumed on-site source of thermal hot water/steam (e.g., boiler) for the baseline (non-CHP) scenario, expressed on a lower heating value (LHV) basis.

Conventional chiller COP—The coefficient of performance for a conventional electricity-driven chiller. It is determined by dividing the useful cooling output by the electrical energy required to produce the cooling, adjusted to consistent units.

Absorption chiller COP—The coefficient of performance for the CHP system absorption chiller (AC). It is determined by dividing the useful cooling output by the thermal energy required to produce the cooling, adjusted to consistent units. Parasitic electrical support loads (e.g., pump and fan loads) are addressed separately.

Absorption chiller capacity—The installed capacity of the absorption chiller in refrigeration tons (RT). This is an independent variable in the optimization process.

AC minimum output level—The minimum percent operating level, relative to full output, for the absorption chiller. This is also known as the minimum turndown value.

AC system parasitic electrical load—The electrical load required to support the absorption chiller. The chiller load should include the chiller solution pump, the AC cooling water pump, and any cooling tower or induced draft fan loads related to the AC.

Distributed generation (DG) capacity—The installed capacity of the distributed electrical generator (i.e., prime mover), expressed in net kilowatts. This is an independent variable in the optimization process.

DG electric efficiency (LHV) at full output—The electricity production efficiency of the DG prime mover at full output. This efficiency can be determined by dividing the electricity produced at full output by the fuel used on a LHV basis, adjusted to consistent units.

DG minimum output level—The minimum percent operating level, relative to full output, for the DG unit. Also known as the minimum economic turndown value.

DG power/heat ratio—The ratio of net electrical power produced to useful thermal energy available from waste heat, adjusted to consistent units.

O&M cost—The operating and maintenance cost of the total cooling, heating and power system, expressed on a $/kWh of electricity generated basis.

Number of DG units—The number of prime mover units comprising the system. Currently, the model is limited to no more than two units, each identical in size and performance. The optimum capacity determined by the model is the total capacity of the CHP system, and for a two-unit system, that capacity is split equally between the units.

DG capital cost—The fully installed capital cost of the distributed generation system, expressed on a $/net kW basis.

AC capital cost—The fully installed capital cost of the absorption chiller system, expressed on a $/RT basis.

Planning horizon—The assumed economic operating life of the CHP system. The default value is 16 years to be consistent with U.S. tax depreciation schedules for 15 year property. Currently, 16 years is the maximum allowed planning horizon in the model.

Discount rate—The rate used to discount cash flows with respect to the time-value of money.

Effective income tax rate—The income tax rate used in income tax-related calculations such as depreciation and expense deductions. The effective rate reflects any relevant state income tax and its deductibility from federal taxes.

STARTING THE CHP CAPACITY OPTIMIZER

The file is distributed with an initial file name of CHPOptimum.xls. It is designed to run on the Microsoft Excel platform. As it is a rather large file (25 MB in uncompressed format or 7 MB zipped format), it is typically distributed on CD. Once in an uncompressed format, the file can be opened using Microsoft Excel.

In order for the tool to work properly, Excel macros must be allowed to run. Depending upon your computer security settings, you may be prompted to enable macros, which you should do for this program. The tool will not have functionality if Excel macros are disabled.

The opening screen for the tool is shown in Fig. 3. Input to the tool is made on the upper left section of the main screen, an enlarged view of which is shown in Fig. 4.

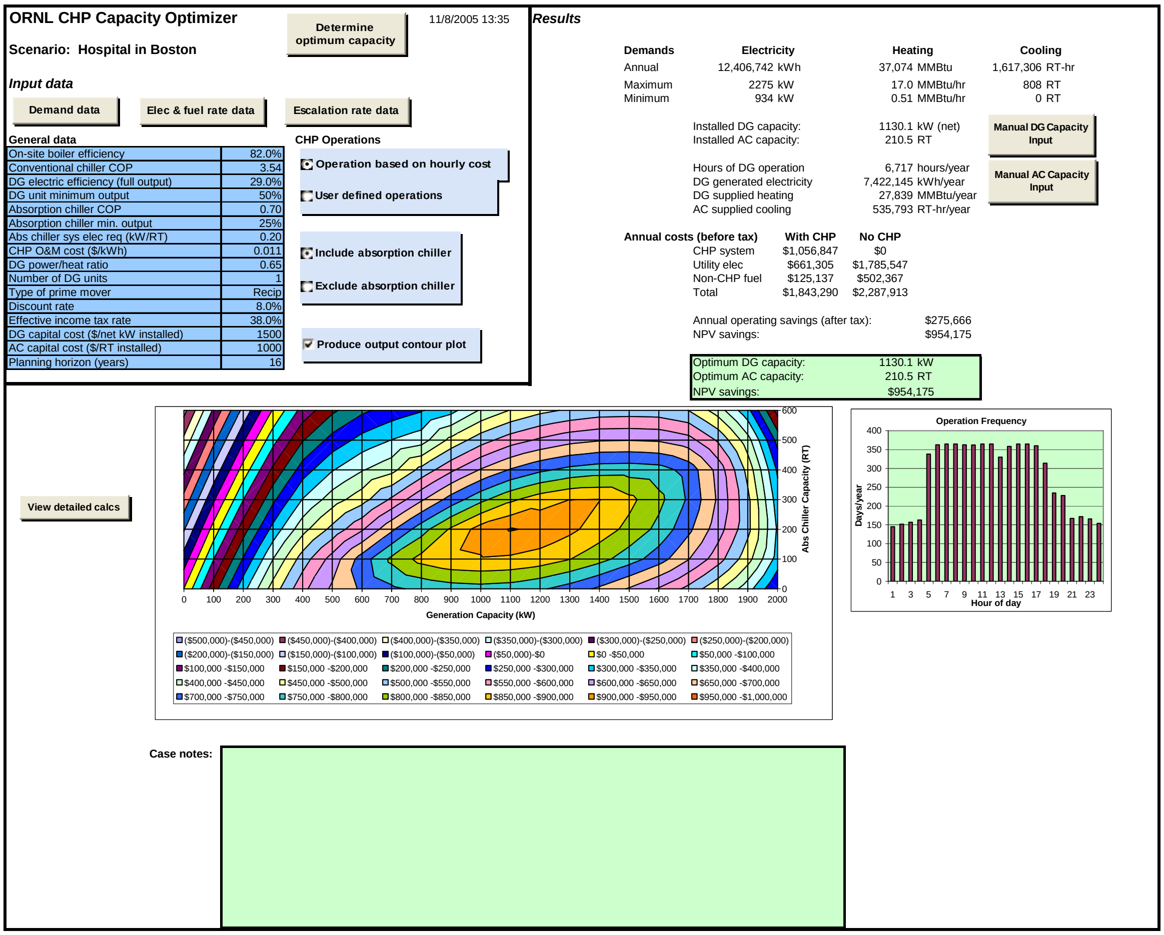

Fig. 3. Main screen of ORNL CHP capacity optimizer.

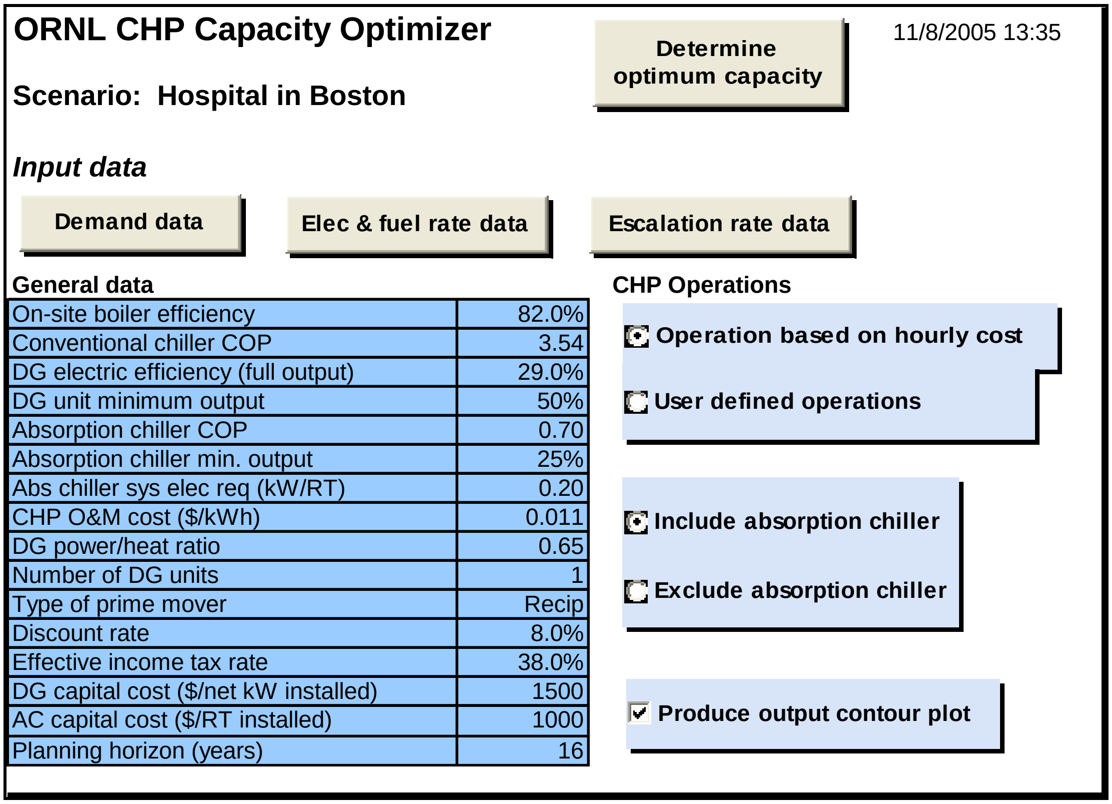

Fig. 4. Input section of the main screen.

DEMAND DATA

The hourly thermal and electric load data are accessed through the "Demand data" button shown in Fig. 4. By clicking on the button, the hourly loads data sheet is shown. On that sheet hourly heating, cooling, and electric loads for the base year (i.e., the first year of operation) of the facility under consideration are stored. Although the complete demand data sheet consists of 8,760 hourly entries, Fig. 5 provides a sample listing of the layout for the first 24 hours of the base year. It should be noted that the heating and cooling loads are expressed on an end-use, as-delivered basis. The "reported cooling electric kW" load is the corresponding electricity consumed to satisfy the cooling load if the cooling is provided by electric chillers. It is not a required input, but does serve to determine an average, default COP for conventional chillers. The final column of data, the "non-cooling electric load" is a required input describing the electrical load of the facility, *exclusive* of any cooling load. As cooling may be provided by an absorption chiller under CHP operation, electrical demand related to cooling is calculated explicitly within the simulation model. The day-of-week (DoW) field can be defined by the user as needed to match a specific year. The convention that must be used is Monday = 1, Sunday = 7. Holidays are defined by assigning the DoW to be 7.

The source of hourly load data can be actual hourly metering for existing facilities, if available, or the output of a building simulation program. There are at least three existing building simulation tools available that can develop the hourly loads needed for input. One tool is EnergyPlus, developed and available at no charge under the DOE Building Technologies Program [EnergyPlus (2006)]. Another is BCHP Screening Tool, available at no charge from Oak Ridge National Laboratory. The other known tool is Building Energy Analyzer offered by InterEnergy Software [InterEnergy/GTI (2005)]. All the building simulation tools can save hourly

Return to Main					Input data from raw datafile			
				Annual max:	6991660	4525781	316	634
				Annual min:	378187	0	11	387
					BTU		Rpt. Cooling	Non-cooling
Month	Day	Hour	DoW		Heating load	Cooling load	Electric kW	Electric load
1	1	1	7		1867479.5	136125.7	32.1	392.1
1	1	2	7		2397348.6	126168.3	31.2	392.1
1	1	3	7		2056502.7	124676.7	31.0	392.1
1	1	4	7		2627097.7	121184.1	30.7	392.1
1	1	5	7		2939225.3	110788.4	29.7	392.1
1	1	6	7		4422894.8	274938.1	45.8	412.6
1	1	7	7		5195368.7	282405.8	46.6	434.9
1	1	8	7		4641695.2	300239.9	48.3	528.8
1	1	9	7		4411973.3	345155.0	51.6	539.8
1	1	10	7		3246873.0	373695.9	51.6	501.4
1	1	11	7		3574033.2	485477.4	54.6	501.4
1	1	12	7		2982991.3	867395.4	72.5	501.4
1	1	13	7		2809368.9	934564.3	76.0	501.4
1	1	14	7		2419090.2	993841.7	79.1	501.4
1	1	15	7		2964515.2	1043938.2	81.7	501.4
1	1	16	7		3284243.9	1049130.6	82.0	501.4
1	1	17	7		2950980.5	979270.0	78.3	471.4
1	1	18	7		2436668.1	978383.4	78.7	471.3
1	1	19	7		1835157.9	951811.7	77.4	518.3
1	1	20	7		2021437.6	806352.0	70.1	507.6
1	1	21	7		1721414.7	569310.9	58.9	486.8
1	1	22	7		1901758.0	504166.3	55.9	410.4
1	1	23	7		2111762.9	367518.9	51.6	392.0
1	1	24	7		1724036.9	319376.9	50.3	392.0

Fig. 5. Sample demand data.

loads to a data file. The process to save the raw hourly load data from these programs and prepare it for use with the CHP Capacity Optimizer is described in Appendix B.

ELECTRIC AND FUEL RATE DATA

Electric utility rates are defined in a separate sheet, accessed by clicking the "Elec & fuel rate data" button on the main sheet. Utility tariffs can be very complex and vary widely from utility to utility. The current input structure, shown in Fig. 6, tries to accommodate the most common forms of tariffs, which can have different prices by time-of-day and by season. The current model is limited to two seasonal patterns. As is common in most utility tariffs, the cost of electricity consists of an energy component and a demand component. The energy cost component is the number of kilowatt-hours consumed in a given hour times the unit price charged per kilowatt-hour. As shown, the unit price can change by time-of-day. Similarly, demand charges can be divided into blocks by time-of-day. Up to three demand blocks (i.e., peak, shoulder, and off-peak) can be modeled. For each demand block, the monthly demand charge is based on the highest weekday kilowatt demand level in each month for that block multiplied by the unit demand price. Currently, the model internally assumes that all weekends and holidays are charged at off-peak rates. The preparation of electric rate data from a sample utility tariff is described in Appendix C.

As some utilities require customers who self-generate to be assigned to a tariff different from those who purchase all their electricity from the utility, a second complete set of tariffs data is used for the CHP scenario. In addition, a separate capacity standby charge should be entered, if applicable. If there is no separate tariff for self-generating customers, the tariff data should simply be copied from the non-CHP section. Both tariffs must have data entries.

Unit fuel prices are also entered on this sheet. Similar to electricity, there can be different prices offered to facilities having a CHP system, so two prices (one for each scenario) must be

Return to Main

NOTE: All data to be expressed in year 1 rates

Electric rates		Pattern 1		Pattern 2	
Non-CHP Energy		Energy	$/kWh	Energy	$/kWh
month	pattern #	hour	rate	hour	rate
1	1	1	0.07781	1	0.078
2	1	2	0.07781	2	0.078
3	1	3	0.07781	3	0.078
4	1	4	0.07781	4	0.078
5	2	5	0.07781	5	0.078
6	2	6	0.07781	6	0.078
7	2	7	0.07781	7	0.078
8	2	8	0.09653	8	0.09114
9	2	9	0.09653	9	0.09114
10	2	10	0.09653	10	0.09114
11	1	11	0.09653	11	0.09114
12	1	12	0.09653	12	0.14913
		13	0.09653	13	0.14913
		14	0.09653	14	0.14913
		15	0.09653	15	0.14913
		16	0.09653	16	0.14913
		17	0.09653	17	0.14913
		18	0.09653	18	0.09114
		19	0.09653	19	0.09114
		20	0.09653	20	0.09114
		21	0.07781	21	0.078
		22	0.07781	22	0.078
		23	0.07781	23	0.078
		24	0.07781	24	0.078

Non-CHP		Pattern 1				Pattern 2			
Demand		Demand	$/kw-mo			Demand	$/kw-mo		
month	pattern #	hour	peak	shoulder	off-peak	hour	peak	shoulder	off-peak
1	1	1				1			
2	1	2				2			
3	1	3				3			
4	1	4				4			
5	2	5				5			
6	2	6				6			
7	2	7				7			
8	2	8		6.58		8		3.64	
9	2	9		6.58		9		3.64	
10	2	10		6.58		10		3.64	
11	1	11		6.58		11		3.64	
12	1	12		6.58		12	16.12		
		13		6.58		13	16.12		
		14		6.58		14	16.12		
		15		6.58		15	16.12		
		16		6.58		16	16.12		
		17		6.58		17	16.12		
		18		6.58		18		3.64	
		19		6.58		19		3.64	
		20		6.58		20		3.64	
		21				21			
		22				22			
		23				23			
		24				24			

Non-CHP Fuel Price	
Fuel price on LHV basis	
$9.00	$/MMBtu

Electric rates		Pattern 1		Pattern 2	
CHP Energy		Energy	$/kWh	Energy	$/kWh
month	pattern #	hour	rate	hour	rate
1	1	1	0.07781	1	0.078
2	1	2	0.07781	2	0.078
3	1	3	0.07781	3	0.078
4	1	4	0.07781	4	0.078
5	2	5	0.07781	5	0.078
6	2	6	0.07781	6	0.078
7	2	7	0.07781	7	0.078
8	2	8	0.09653	8	0.09114
9	2	9	0.09653	9	0.09114
10	2	10	0.09653	10	0.09114
11	1	11	0.09653	11	0.09114
12	1	12	0.09653	12	0.14913
		13	0.09653	13	0.14913
		14	0.09653	14	0.14913
		15	0.09653	15	0.14913
		16	0.09653	16	0.14913
		17	0.09653	17	0.14913
		18	0.09653	18	0.09114
		19	0.09653	19	0.09114
		20	0.09653	20	0.09114
		21	0.07781	21	0.078
		22	0.07781	22	0.078
		23	0.07781	23	0.078
		24	0.07781	24	0.078

CHP		Pattern 1				Pattern 2			
Demand		Demand	$/kw-mo			Demand	$/kw-mo		
month	pattern #	hour	peak	shoulder	off-peak	hour	peak	shoulder	off-peak
1	1	1				1			
2	1	2				2			
3	1	3				3			
4	1	4				4			
5	2	5				5			
6	2	6				6			
7	2	7				7			
8	2	8		6.58		8		3.64	
9	2	9		6.58		9		3.64	
10	2	10		6.58		10		3.64	
11	1	11		6.58		11		3.64	
12	1	12		6.58		12	16.12		
		13		6.58		13	16.12		
		14		6.58		14	16.12		
		15		6.58		15	16.12		
		16		6.58		16	16.12		
		17		6.58		17	16.12		
		18		6.58		18		3.64	
		19		6.58		19		3.64	
		20		6.58		20		3.64	
		21				21			
		22				22			
		23				23			
		24				24			

CHP Fuel Price	
Fuel price on LHV basis	
$9.00	$/MMBtu

CHP Standby Charge

0	$/kw-mo

Fig. 6. Electric and fuel rate data.

entered. The price of natural gas is typically quoted on a HHV basis. However, it is typical that fuel usage calculations are performed on a LHV basis. For consistency, the prices entered must be on a LHV basis. The conversion between HHV and LHV is heat $content_{HHV}$ = heat $content_{LHV} \times 1.11$ for natural gas.

Finally, all unit prices should be current to the first year of operation. Escalation of prices through time will be discussed in the following section.

ESCALATION RATE DATA

As it is unlikely that prices will remain steady over the economic study period, unit prices for electricity, fuel, and operating and maintenance (O&M) can be escalated through time. In addition, heating, cooling, and electrical loads can be escalated as well to reflect changes in loads as a function of time. Escalation input is accessed via the “Escalation rate data” button on the main sheet. For each cost or load category, the annual percent change from the previous year for up to a maximum of 16 years can be entered. As shown in Fig. 7, the escalation rate does not have to be constant during the study period, but rather can vary from year to year. Values can be positive for escalation or negative for de-escalation. The model levelizes the various escalation components to produce a multiplier to the base-year values. When escalation is present, the values used in the hour-by-hour calculation are levelized values, which produce equivalent results to an explicit year-by-year price/load adjustment.

Escalation data			Expressed in percent change from previous year			
Year	**Fuel price**	**Elec price**	**O&M cost**	**Heat load**	**Cool load**	**Elec load**
2	-0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
3	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
4	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
5	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
6	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
7	0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
8	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
9	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
10	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
11	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
12	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
13	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
14	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
15	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
16	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
Levelized	1.010125	1.047144	1.042355	1.000000	1.000000	1.000000

Fig. 7. Sample escalation input data.

GENERAL DATA

The remaining input data and simulation options are entered from the main sheet. As shown in Fig. 8, data related to the existing and proposed systems must be entered. The individual items needed were defined earlier in this report. In addition, there are three input switches available on the main sheet to allow the user to explicitly define when the CHP system operates, whether the system should include an absorption chiller, and whether a contour plot should be produced.

General data	
On-site boiler efficiency	80.0%
Conventional chiller COP	4.00
DG electric efficiency (full output)	30.0%
DG unit minimum output	40%
Absorption chiller COP	0.70
Absorption chiller min. output	25%
Abs chiller sys elec req (kW/RT)	0.20
CHP O&M cost ($/kWh)	0.011
DG power/heat ratio	0.65
Number of DG units	1
Type of prime mover	Recip
Discount rate	8.0%
Effective income tax rate	38.0%
DG capital cost ($/net kW installed)	1500
AC capital cost ($/RT installed)	1000
Planning horizon (years)	16

CHP Operations

- (•) Operation based on hourly cost
- ( ) User defined operations

- (•) Include absorption chiller
- ( ) Exclude absorption chiller

- [x] Produce output contour plot

Fig. 8. General data and simulation controls.

Although typical analyses will use hourly cost as a determinate for running the CHP system, if it is desired to explicitly define the hours of CHP system operation (e.g., weekdays between 9 a.m. and 6 p.m.), then upon selecting "User defined operations," a new button, "Define op schedule," will appear, which takes the user to an hour-by-hour table, shown in Fig. 9. Hours indicated with a binary value of 1 specify that the CHP system must run, irrespective of cost.

With respect to the absorption chiller option, if the user wishes to explicitly exclude consideration of an absorption chiller, for example, when the benefit of having an absorption chiller in the system is economically marginal, the user can simply click the "Exclude absorption chiller" button to force chiller exclusion.

Finally, the production of the contour plot consumes slightly more than half of the computational time required for an optimization analysis. For parametric studies that evaluate various input values, it may be desirable to exclude the production of the contour plot for each scenario. A check box option is available on the main sheet to limit the production of the contour plot.

Hour	Weekends	Weekdays
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	0
7	0	0
8	0	0
9	0	1
10	0	1
11	0	1
12	0	1
13	0	1
14	0	1
15	0	1
16	0	1
17	0	1
18	0	1
19	0	0
20	0	0
21	0	0
22	0	0
23	0	0
24	0	0

Fig. 9. User defined operating schedule.

DETERMINING OPTIMUM CAPACITY

After all input has been made, the economic optimum capacity is determined by pressing the "Determine optimum capacity" button. The optimization routine is computationally intensive. Depending upon the clock speed of the PC, the optimization may take from 3 to 7 minutes.

RESULTS AREA

Summary results are provided in the upper right portion of the main sheet. As shown in Fig. 10, this area restates the electrical and thermal loads, identifies the optimum installed capacities, summarizes CHP system operation, and provides cost data related to both the non-CHP and CHP systems. As mentioned earlier, the cost and/or load escalation is computationally handled by a levelization method, and therefore, the annual performance and cost data represent levelized values over the period of time defined by the planning horizon.

Within the summary results area, the optimum capacities are further highlighted in a green box. While this may seem redundant, it allows the user to explore other capacity values while keeping the calculated optimum in view. Specific capacity values can be entered manually using the two manual input buttons shown in Fig. 10. All operation and cost parameters are recalculated with any manually entered capacity inputs. The results can then be compared to the calculated optimum values shown in the green inset.

Two graphs are also part of the main screen. On the lower right of the main screen, a summary of the operation of the CHP system is provided by showing the number of days per year that the system operates for each hour of the day. (See Fig. 11.) As mentioned above, these values are levelized across the planning horizon if escalation is present.

Results

Demands	**Electricity**		**Heating**		**Cooling**	
Annual	5,466,118	kWh	16,919	MMBtu	1,250,204	RT-hr
Maximum	958	kW	7.0	MMBtu/hr	377	RT
Minimum	387	kW	0.38	MMBtu/hr	0	RT

Installed DG capacity:	413.4	kW (net)	**Manual DG Capacity Input**
Installed AC capacity:	37.7	RT	
Hours of DG operation	6,951	hours/year	**Manual AC Capacity Input**
DG generated electricity	2,871,510	kWh/year	
DG supplied heating	13,630	MMBtu/year	
AC supplied cooling	114,451	RT-hr/year	

Annual costs (before tax)	**With CHP**	**No CHP**
CHP system	$354,301	$0
Utility elec	$322,945	$676,192
Non-CHP gas	$40,493	$208,294
Total	$717,739	$884,486

Annual operating savings (after tax):	$103,383
NPV savings:	$416,943

Optimum DG capacity:	413.4	kW
Optimum AC capacity:	37.7	RT
NPV savings:	$416,943	

Fig. 10. Summary results area of model.

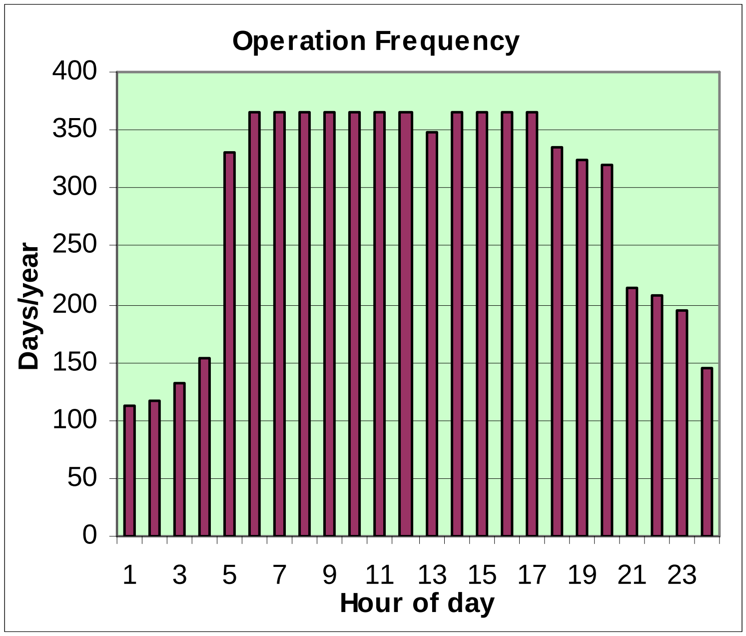

Fig. 11. Hourly operating frequency.

In the lower left of the main sheet, a contour plot of the entire solution space is provided in order to give the user a better insight into the economic impact of alternative (i.e., less than optimal) capacity decisions. As shown in Fig. 12, it provides a color-coded, topographic representation of the NPV savings from the CHP system for various combinations of installed prime mover and absorption chiller capacities.

Under certain input conditions, the model may conclude the optimization process at a local optimum that is not the global (overall) optimum. If that appears to be the case (e.g., from

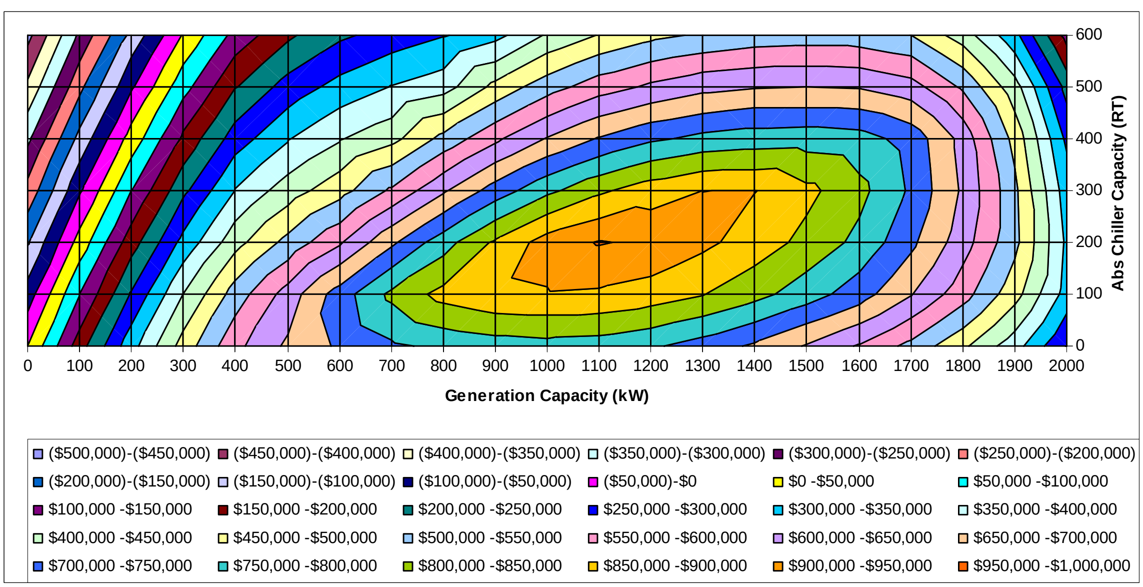

Fig. 12. Contour plot of objective function.

inspection of the contour plot), there is an "Optimization Settings" button beneath the Case notes area on the main screen which allows a different optimization starting point* to be tried. In rare instances, several different starting point values and subsequent optimization runs may need to be tried in order to find the global optimum set of capacities. In addition, the optimization stopping criterion of $50.00 change in NPV savings per iteration can be modified in this area also.

DETAILED RESULTS

Detailed, hour-by-hour results can be reviewed by clicking on the "View detailed calcs" button, located to the left of the contour plot. The hourly computation sheet is the heart of the operation simulation. There is a row of calculations for each hour of the year. The calculations described in Appendix A are performed in this detailed sheet. The return to the main sheet can be found at the top of column AQ.

MISCELLANEOUS TIPS

Each case/scenario must be saved as a separate Excel file. To create unique filenames, the Excel File, Save As method should be used. Spreadsheet tabs typically located at the bottom of each sheet have been hidden. If preferred, the tabs can be displayed by selecting on the Excel menu bar, Tools, Options, View, Sheet tabs. If desired, additional worksheets for user notes/summaries etc. can be added by selecting from the menu bar, Insert, Worksheet. In order to navigate from the user-added sheet(s), tabs, as discussed above, must be displayed and utilized.

PROBLEMS AND SUGGESTIONS

It is hoped that this tool will provide useful guidance in the selection of CHP equipment capacities. If you would like to be notified of any updates, or to report problems or suggestions for improvement, please send an email to Dr. Randy Hudson at hudsoncrii@ornl.gov.

*The optimization starting point is defined by a value between 0 and 1, corresponding to a range of electrical load from 0 to annual maximum. Thus, a starting point value of 0.5 sets the first iteration capacities at 50% of the annual maximum demands for electricity and cooling.

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Appendix A
OPERATION SIMULATION METHODOLOGY

Appendix A
OPERATION SIMULATION METHODOLOGY

SYMBOLS

C_{CHPi}	Cost of CHP system operation in hour *i*
C_{DGi}	Cost of operation for distributed generator in hour *i*
C_{esi}	Cost of supplemental grid-based electricity in hour *i*
C_{gb}	Annual cost of fuel for on-site boiler
C_{gbi}	Cost of fuel for on-site boiler for hour *i*
C_{gsi}	Cost of fuel for supplemental heating in hour *i*
C_{OM}	Unit operating and maintenance cost of the CHP system
C_S	Annual cost savings of CHP system relative to non-CHP system
C_U	Annual cost of non-CHP system
C_{Ui}	Cost of non-CHP system in hour *i*
d_{ci}	Cooling demand for hour *i*
d_{ei}	Electrical demand for hour *i*
$d_{e^\circ i}$	Non-cooling related electrical demand for hour *i*
d_{hi}	Heating demand for hour *i*
D_n	Depreciation tax benefit in year *n*
d_{pAC}	Parasitic electrical load of absorption chiller for pumps and fans
D_{Uj}	Monthly utility charge for electrical demand
E_U	Annual cost of utility-supplied electricity
f_{AC}	Minimum operating fraction for absorption chiller
f_{DG}	Minimum operating fraction for distributed generator
G_{AC}	Installed cooling capacity of absorption chiller
g_{ci}	Absorption chiller cooling produced in hour *i*
G_{DG}	Net installed electric capacity of distributed generator
g_{ei}	CHP electrical generation in hour *i*
g_{Ti}	CHP thermal energy generated in hour *i*
I_{AC}	Installed unit capital cost for absorption chiller
I_{CHP}	Total investment (capital) cost for CHP system
I_{DG}	Installed unit capital cost for distributed generator
k_{AC}	Binary absorption chiller preference indicator
M_{ei}	Maximum CHP electrical demand for hour *i*
M_{Ti}	Maximum CHP thermal demand for hour *i*
NPV_{CHP}	Net present value of the CHP system
r_{djk}	Grid-based utility unit demand charge for month *j* and block period *k*
r_{ei}	Grid-based utility unit price for electric energy for hour *i*
r_g	Unit price for on-site fuel (e.g., natural gas)
s_{ci}	Supplemental cooling-related electricity required in hour *i*
s_{gi}	Supplemental gas for on-site boiler required in hour *i*
s_{ei}	Total supplemental grid-based electricity required in hour *i*
s_{hi}	Supplemental heating required in hour *i*
ε_{Ui}	Hourly charge for electricity by utility

η_{AC}	Efficiency (COP) for absorption chiller
η_b	Thermal efficiency of on-site boiler
η_{DG}	Electrical efficiency of distributed generator
η_{EC}	Efficiency (COP) for electric chiller
θ	Power to heat ratio of distributed generator

NON-CHP SYSTEM

As mentioned above, the non-CHP scenario assumes that there is no distributed generation system, that all electrical loads are met by the grid-based utility, and that all heating loads are met by an on-site boiler. Costs related to the non-CHP system scenario for a given hour are determined on the basis of satisfying the specified non-cooling electrical demand, $d_{e^o i}$, the heating demand, d_{hi}, and the cooling demand, d_{ci}. It is important to note that each of these demands is expressed as an end-use consumption value. As cooling in the non-CHP scenario is assumed to be provided by electricity-based chillers, the electrical consumption related to this cooling demand must be determined and added to the non-cooling electrical demand. This is done by recognizing the COP of the electric chiller, such that total non-CHP electrical demand for hour *i* can be expressed as

$$d_{ei} = d_{e^o i} + d_{ci} / \eta_{EC} \quad .$$

In the typical utility tariff, the pricing of electricity provided by a utility to an industrial or commercial customer consists of an energy charge, related to the actual amount of electrical energy consumed, and a demand charge, related to the *rate* of energy consumption (i.e., power level). The actual terms and structure of pricing tariffs vary widely from utility to utility. For some tariffs, the energy unit price, r_{ei}, may vary by hour of the day (known as a time-of-use tariff) and also by season. The demand charge rate, expressed on a \$/kW-month basis, may also vary by season and hour of the day. If there are multiple demand charge rates, varying by time of day, it is considered a block pricing arrangement. Typically, utilities will have a two- or three-block structure related to the peak and off-peak times, or the peak, shoulder, and off-peak times of day, respectively. The demand charge, assessed at the rate r_{djk} applicable for month *j* and block *k* of time, is then based on the highest power demand placed on the utility within that block interval during the course of a month. The total demand-related charge is then the sum of the demand charges incurred across all the time blocks.

Mathematically, the hourly energy charge for hour *i* can be expressed as

$$\varepsilon_{U\,i} = r_{ei} \cdot d_{ei} \quad .$$

The demand charge for a given month *j* with *n* distinct demand blocks can be expressed as

$$D_{Uj} = \sum_{k=1}^{n} \max\left[d_{ei}\right]_{jk} \cdot r_{djk} \quad ,$$

where $\max\left[d_{ei}\right]_{jk}$ is the maximum hourly electrical demand in the daily time period defined by block *k* experienced during month *j*. Over the period of a year, the total annual cost of utility-supplied electricity is

$$E_U = \sum_{i=1}^{8760} \varepsilon_{Ui} + \sum_{j=1}^{12} D_{Uj} \quad .$$

In the non-CHP scenario, it is assumed that heating demands will be met by a natural-gas fired boiler. The cost of the natural gas consumed in a given hour i with a unit price for natural gas of r_g and a boiler efficiency of η_b is

$$C_{gbi} = r_g \cdot d_{hi} / \eta_b \quad .$$

The cost of natural gas over a one year period is the sum over all i hours,

$$C_{gb} = \sum_{i=1}^{8760} C_{gbi} \quad .$$

Finally, the total annual operating cost for the non-CHP system is

$$C_U = E_U + C_{gb} \quad .$$

CHP SYSTEM

Relative to the non-CHP scenario, developing the annual cost for a CHP-based system is substantially more complicated. There can be utility surcharges (e.g., standby fees) which are imposed as a result of operating self-generation equipment. In addition, the unit pricing for electricity, r_{ei} and r_{djk}, may be different for customers using a CHP system than for those buying all their supply solely from the utility. The operational considerations related to the CHP system are of considerable influence as well. As an example, the fuel efficiency of electrical generation equipment is directly proportional to relative output level. Typically, the highest efficiency (i.e., most electricity produced for the least fuel consumed) is at or near full rated output. Depending upon the type of prime mover, electrical efficiencies at low part-load can be 65 to 75% of full-load efficiency. As a result, there is a general lower limit on part-load operations. A typical minimum operating value is 50% of rated unit capacity. The limit becomes influential when the electrical demand is less than 50% of the rated unit capacity, requiring that electricity be purchased from the grid. Thus, there is an economic trade-off related to the size of the CHP generation capacity. A CHP system sized to meet peak electrical or thermal loads will incur higher utility standby charges and will have less ability to operate during periods of low demand. Conversely, a smaller sized system may be able to operate a larger fraction of time, but may result in a higher fraction of unmet load for the facility (resulting in higher utility purchases, typically at peak pricing). The economics are further influenced by the direct relationship of CHP electrical generation capacity and useful thermal energy available. Smaller electrical capacity means less useful thermal byproduct, which might then require additional gas-boiler or electric chiller operation.

In the detailed modeling of operations in the CHP scenario, an initial consideration is the determination of the best use of the available thermal energy. Depending on the relative prices of grid-based electricity and natural gas and the efficiencies of the various equipment items, it may be more economical to preferentially satisfy heating demands rather than cooling demands (via an absorption chiller) with the available thermal energy from the CHP prime mover. A binary variable, k_{AC}, is set to a value of 1 to indicate a preference of using the thermal energy for meeting cooling demand if (1) an absorption chiller is present in the system, (2) the cooling demand is greater than or equal to the minimum operating level for the absorption chiller, that is,

$$d_{ci} \geq f_{AC} \cdot G_{AC} \quad ,$$

and (3) if the substitution cost of one unit of thermal energy displacing electric cooling is greater than the substitution cost of that unit of thermal energy displacing on-site boiler heating,

$$\eta_{AC} \cdot r_{ei} / \eta_{EC} > r_g / \eta_b \quad .$$

If the variable k_{AC} is set to 1, then available thermal energy from the prime mover is first used to drive the absorption chiller. Any excess thermal energy available from the prime mover is used to satisfy heating demands. Conversely, if $k_{AC} = 0$, then available thermal energy from the prime mover is first used to satisfy heating demands, with any excess going to drive the absorption chiller, as long as the potential output of the chiller is greater than its minimum operating level.

Another consideration for the absorption chiller is its minimum operating duration. Absorption chillers take some time to start-up and reach equilibrium temperatures and are not designed to cycle on and off quickly. Based on discussions with technical experts on absorption chiller operations, a 4 hour minimum continuous operating duration is imposed on any absorption chiller operation [Zaltash (2005)]. For any given hour, this is accomplished in the model by evaluating the chiller operation in the previous three hours and the potential operation in the following three hours. If the current hour could accommodate chiller operation based on the minimum operating level of the chiller, and if any contiguous combination of operation during this ±3 hour window, including the hour under consideration, yields 4 or more hours of continuous operations, operation of the chiller is allowed in the current hour. Otherwise, the absorption chiller does not operate in the current hour.

In order to determine the generation output of the DG system for a given hour, the maximum *potential* electrical demand for that hour must be determined. First, if there is no absorption chiller or if the cooling demand for the current hour is below the absorption chiller minimum operating level, the maximum electrical demand, M_{ei}, is the same as the electrical demand in the non-CHP scenario, since all cooling for that hour must come from electric chillers. Thus, from the prior section,

$$M_{ei} = d_{ei} = d_{e^o i} + d_{ci} / \eta_{EC} \quad .$$

If an absorption chiller is available to run in a given hour and if the DG electricity production in meeting the non-cooling demand, $d_{e^\circ i}$,, plus the parasitic electrical load of the absorption chiller, d_{pAC}, produces sufficient thermal energy to satisfy *both* heating and cooling demands, then

$$M_{ei} = d_{e^\circ i} + d_{pAC} \quad .$$

Otherwise, M_{ei} depends on the thermal preference, k_{AC}. If $k_{AC} = 1$, indicating a preference to use the thermal energy for absorption cooling, then if

$$\left[\left(d_{e^\circ i} + d_{pAC}\right)/\theta - d_{ci} / \eta_{AC}\right] \geq 0 \quad \text{and} \quad G_{AC} \geq d_{ci} \quad ,$$

$$\text{then } M_{ei} = d_{e^\circ i} + d_{pAC} \quad .$$

Otherwise, when there is insufficient thermal energy to satisfy all the cooling demand via the absorption chiller, additional CHP system electrical demand is added to the non-cooling demand base value to supply electric chillers, such that

$$\mathrm{M_{ei}} = d_{e^\circ i} + d_{pAC} + \frac{\left[d_{ci} - \left(d_{e^\circ i} + d_{pAC}\right)/\theta \cdot \eta_{AC}\right]}{\eta_{EC}} \cdot \frac{1}{\left[1 + \eta_{AC}/(\theta \cdot \eta_{EC})\right]} \quad .$$

The latter term is included in order to recognize that as more electricity is produced to meet the shortfall, more thermal energy is available for cooling via the absorption chiller.

If the thermal preference is to satisfy heating demand first, $k_{AC} = 0$, then if

$$\left(d_{ei}/\theta - d_{hi}\right) \leq G_{AC} \cdot f_{AC}/\eta_{AC} \quad ,$$

such that there is insufficient thermal energy available for cooling purposes, then $\mathrm{M_{ei}} = d_{ei}$, which includes the additional electrical load for electric chillers to satisfy cooling demands.

However, should there be sufficient thermal energy remaining after meeting the heating demand,

$$\mathrm{M_{ei}} = d_{e^\circ i} + d_{pAC} + \frac{\left\{d_{ci} - \left[\left(d_{e^\circ i} + d_{pAC}\right)/\theta - d_{hi}\right] \cdot \eta_{AC}\right\}}{\eta_{EC}} \cdot \frac{1}{\left[1 + \eta_{AC}/(\theta \cdot \eta_{EC})\right]} \quad .$$

With respect to determining the maximum potential thermal demand, for any hour *i,* the maximum thermal demand of the CHP system, M_{Ti}, is d_{hi} if $d_{ci} < G_{AC} \cdot f_{AC}$ or $d_{hi} + \min\left(d_{ci}, G_{AC}\right)/\eta_{AC}$ otherwise.

Once the maximum potential thermal and electric demands are calculated for each hour, the operation of the CHP system for each hour can be determined. It should be noted that calculations for CHP operations are performed for each hour of the year, irrespective of whether the CHP system will actually run in that hour. The determination of whether the CHP system runs in a given hour is dependent on the operating strategy chosen. In some cases, the operation of a CHP system may be specified explicitly by the owner/operator, irrespective of hourly costs (e.g., to coincide with daily shift schedules). In other cases, the decision to operate the CHP system may be based solely on an energy cost make-or-buy decision for a given hour (i.e., in an economic dispatch mode). Thus, the costs of potentially operating the CHP system must be known to allow for cost comparisons.

For any hour *i*, the potential electric generation is based on the maximum CHP electric demand, $\mathrm{M_{ei}}$. If $\mathrm{M_{ei}}$ is less than the minimum operating level of the distributed generator, $G_{DG} \cdot f_{DG}$, then the electric generation, g_{ei}, is zero. Otherwise, g_{ei} = minimum($\mathrm{M_{ei}}$, G_{DG}), where G_{DG} is the net electrical generating capacity of the distributed generation CHP system. The corresponding potential thermal energy available, g_{Ti} = minimum(M_{Ti}, g_{ei}/θ).

To provide that all thermal and electrical demand is satisfied, any electrical, heating, or cooling demand not provided by the CHP system must be supplemented by the utility grid/on-site boiler. To determine the amount of supplemental heating needed, the heating demand, d_{hi}, is compared to the thermal energy generated, g_{Ti}, taking into account any thermal energy utilized by the absorption chiller. Mathematically,

$$s_{hi} = d_{hi} - (g_{Ti} - g_{ci}/\eta_{AC}) \quad .$$

The corresponding gas required for the on-site boiler will be $s_{gi} = s_{hi} / \eta_b$. Similarly, the amount of grid-supplied electricity needed to provide supplemental cooling (i.e., cooling beyond that provided by the CHP system) can be expressed as

$$s_{ci} = (d_{ci} - g_{ci}) / \eta_{EC} - (g_{ei} - d_{e^o i} - d_{pAC}) \text{ if } g_{ei} > d_{e^o i} \quad .$$

Otherwise,

$$s_{ci} = (d_{ci} - g_{ci}) / \eta_{EC} + d_{pAC} \quad .$$

In addition to grid electricity used for any supplemental cooling, if $G_{DG} < d_{e^o i}$, the difference will also be obtained from the grid, such that

$$s_{ei} = s_{ci} + (d_{e^o i} - g_{ei}) \quad .$$

Forced outages of the CHP system have not been included in this analysis. This is due to the stochastic nature of forced outages and the impact a random outage would have on the capacity optimization (e.g., do outages occur at a peak time or at an off-peak time?). It can be argued that random forced outages should not influence the determination of the appropriate capacity (i.e., the system should be sized under the assumption that the equipment will run when requested), but rather such outages should be considered in determining the project economic viability only after equipment sizes have been selected. Including random outages requires a separate, stochastic analysis of the reliability of the CHP system (e.g., Monte Carlo analysis) in order to determine the project NPV savings including forced outage effects. Initial investigation in including forced outages indicates that the absolute NPV savings will decrease due to the unavailability of the CHP system, but that the optimum capacities remain the same.

Costs for the CHP system for each hour are determined as the sum of the operating costs of the distributed generation system, the cost of any fuel used in boiler firing for supplemental heating, and any grid-supplied electricity purchased to cover supplemental electrical loads. The operating costs of the DG system include natural gas fuel and system O&M costs. The hourly cost for the DG system is calculated as

$$C_{DGi} = g_{ei} / \eta_{DG} \cdot r_g + g_{ei} \cdot C_{OM} \quad .$$

Costs for supplemental gas and electricity are $C_{gsi} = s_{gi} \cdot r_g$ and $C_{esi} = s_{ei} \cdot r_{ei}$, respectively. The total hourly cost for the CHP system can be expressed as

$$C_{CHP\,i} = C_{DGi} + C_{gsi} + C_{esi} \quad .$$

It should be noted that the electrical efficiency of the distributed generator is not a constant value, but, as mentioned at the beginning of this section, is a function of the output level of the generator. Part-load efficiencies also differ by type of prime mover (e.g., gas turbine, reciprocating engine). The efficiency relationships used in the model are based on an assessment of part-load efficiency data from Fischer (2005), Goldstein et al. (2001), Orlando (1996), and Petchers (2003). This study uses polynomial functions of the electric output fraction (i.e., part-load fraction) to generate DG part-load efficiency values. The polynomial equations and resulting part-load efficiency curves are shown in Fig. A.1 for fuel cells, reciprocating engines, and gas turbines.

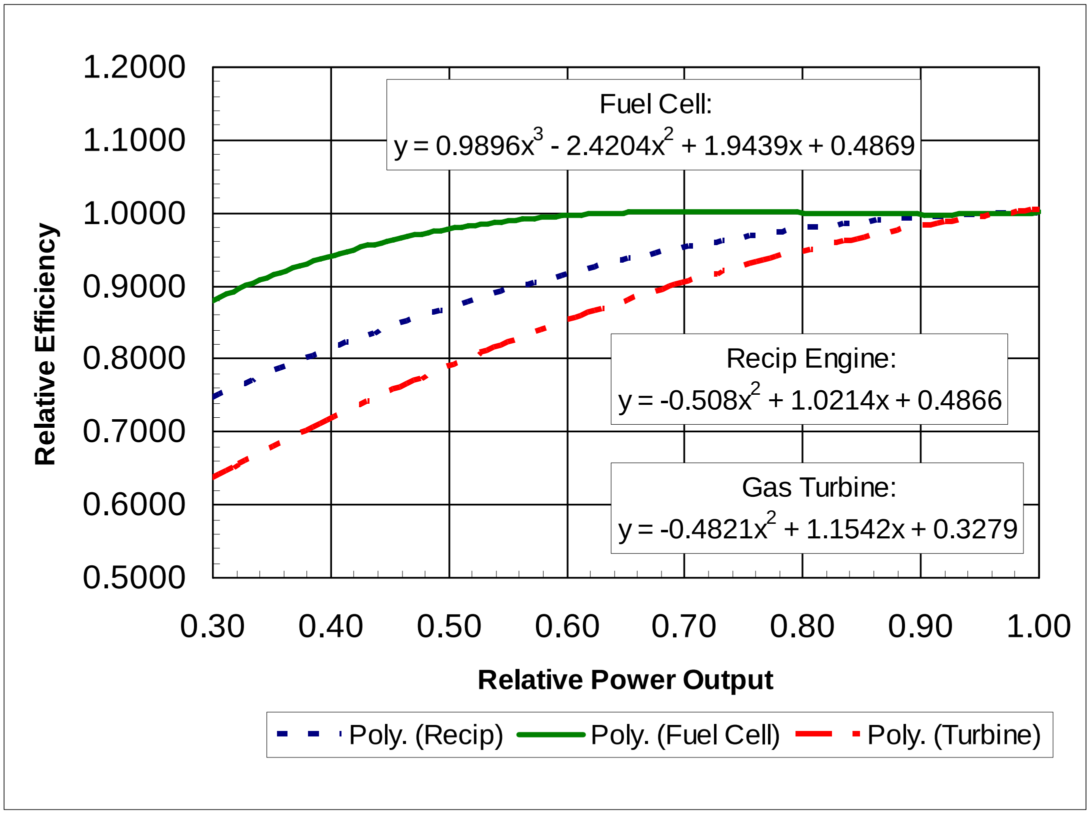

Fig. A.1. Part-load DG electrical efficiency factors.

As mentioned above, the determination of whether the CHP system operates in a given hour is based on the operational strategy selected. If an explicit, a priori operations schedule is not defined, hourly CHP system operation is determined on the basis of least cost when compared to the cost of the non-CHP scenario. If, for a given hour, the operation of the CHP system satisfies the electrical and thermal demands for less cost (on an energy-cost basis) than the non-CHP scenario, then the CHP system operates in that hour. Otherwise, consideration must be given to running the CHP system anyway at an energy-cost loss, so as to avoid being the hour that sets the demand charge for the month. Recall that the demand charge for a given demand block in a month is determined by the highest power demand occurring during that block of time for the entire month. Typically, the amount of economic loss related to a given hourly energy cost differential is very small compared to setting the demand charge for the month by not running the CHP system in that hour. Therefore, if $(d_{ei} - s_{ei}) \cdot r_{djk} > C_{CHPi} - C_{Ui}$, then the CHP system will be scheduled to operate in that hour. Otherwise, the CHP system will not run in that hour, and all energy will be provided by the electric grid and on-site boiler.

Once the operating decision is made, hourly costs can be summed over the entire annual period to obtain the annual operating cost for providing electricity, heating, and cooling to the facility. Recalling that two separate scenarios are determined simultaneously, the amount of annual cost savings (if any) from operating a CHP system, relative to relying on grid-based electricity and on-site boiler heating, can be defined as

$$C_S = C_U - \sum_{i=1}^{8760} C_{CHPi} \quad ,$$

where C_U is the annual cost of the non-CHP scenario, as defined in the previous section. If C_S is positive, then the CHP system has a lower annual operating cost, and the value represents a savings relative to the non-CHP scenario.

Operating costs such as electricity and gas are considered expense items and are tax-deductible with respect to determination of income tax. Therefore, total annual operating savings C_S is multiplied by $(1-t)$, where t is the effective income tax rate applicable to the facility under study, to determine an after-tax annual cost. If state income tax is a relevant consideration, the effective income tax rate can be determined as

$$t = \text{state rate} + \text{federal rate} * (1 - \text{state rate}) \quad ,$$

to reflect the deductibility of state taxes on federal taxes.

In order to equitably determine the economic viability of a CHP system, the capital or investment costs of the CHP system, and related income tax effects, must be included. The total capital investment cost of the CHP system is

$$I_{CHP} = G_{DG} \cdot I_{DG} + G_{AC} \cdot I_{AC}$$

and includes all equipment, labor, and materials to fully install the CHP system. As capital assets may be depreciated for income tax purposes, the income tax benefits of CHP asset depreciation are determined using a 15-year recovery period as defined by the Internal Revenue Service MACRS depreciation schedules [Internal Revenue Service (2004)].

Finally, the capital and operating cost elements are combined to create the net present value (NPV) of the cost savings of the CHP system. The cost savings NPV, which serves as the objective function for optimization, is expressed as

$$NPV_{CHP} = PW\left[C_S \cdot (1-t)\right] - I_{CHP} + PW(D_n) \quad ,$$

where PW is the present worth of a series of cash flows and D_n are the annual tax benefits resulting from depreciation of the CHP system capital investment.

Appendix B
HOURLY LOAD DATA DEVELOPMENT AND PREPARATION

Appendix B
HOURLY LOAD DATA DEVELOPMENT AND PREPARATION

As mentioned in the body of this report, there are at least three existing building simulation tools available to develop the hourly loads needed for input to the CHP Capacity Optimizer. One such tool is the BCHP Screening Tool available at no charge from Oak Ridge National Laboratory (email: fischersk@ornl.gov). Another tool is Building Energy Analyzer (PRO version) offered by InterEnergy Software (http://www.interenergysoftware.com/BEA/BEA.htm). A third tool is EnergyPlus available at no charge from the DOE Building Technologies Program. The steps needed to obtain hourly load data from each software and to prepare the data for input to the CHP Capacity Optimizer are described in this appendix. This appendix does not, however, provide user instructions for running these simulation programs, as such instruction is provided by each of the software providers.

UTILIZING DATA FROM BCHP SCREENING TOOL

When preparing a simulation using the BCHP Screening Tool, there is a switch that must be set in order to produce hourly load files. The switch must be set *before* running the simulation. As shown in Fig. B.1, the switch is located on the software menu bar under the File heading. Once set, when a simulation is performed, two .csv (comma separated value) files will be produced, one for case “A” (i.e., typically baseline case) and another for case “B” (i.e., CHP scenario). The CHP Capacity Optimizer needs to have input from the case “A,” traditional utility scenario (i.e., a non-CHP scenario). The baseline .csv file (initially named “untitled-A.csv”) can be opened directly by Microsoft Excel. The file contains heating, cooling, and total electrical load data by hour for an entire year in units of Btu for heating and cooling and kW for electrical load.

Because a portion of the total electrical load included in the baseline, non-CHP case is for electricity-supplied cooling, of which CHP systems will reduce, the electrical load values produced by the BCHP Screening Tool must be split into two categories: electrical load related to cooling and all other electrical loads (i.e., non-cooling related electrical loads). The cooling-related electrical load can be approximated by dividing each of the hourly cooling loads provided by the BCHP Screening Tool by 3412.8 to convert from Btu units to kWh units and then by dividing by an assumed coefficient of performance (COP) for the electrical chiller. Typically, electrical chillers have a COP within the range of 4 to 6. This hourly cooling-related electrical

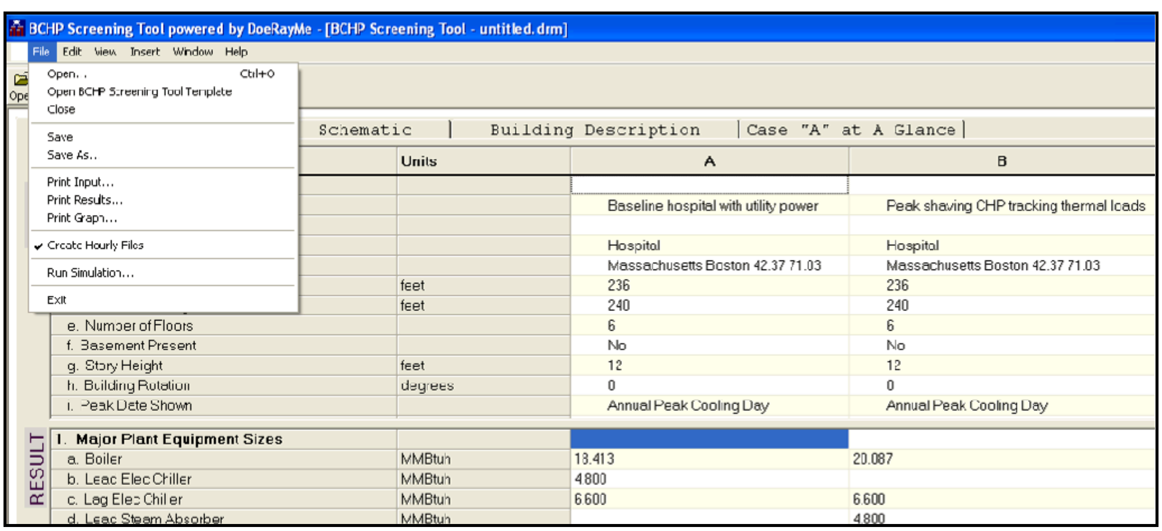

Fig. B.1. BCHP screening tool hourly load data switch.

load must then be subtracted from the hourly total electrical load reported by the BCHP Screening Tool to calculate the non-cooling electrical load. In order to facilitate moving the hourly data into the CHP Capacity Optimizer, it is suggested that the column containing the total electric load in the untitled-A.csv spreadsheet be moved to the right by two columns, such that the calculated electric cooling load and non-electric cooling load columns, as described above, are adjacent to the cooling thermal column. In this manner, the data order will be consistent with the format of the CHP Capacity Optimizer, as shown in Fig. 5.

UTILIZING DATA FROM THE BUILDING ENERGY ANALYZER

The option to save hourly data within Building Energy Analyzer PRO (BEA) is provided *after* the simulation has been performed. After the simulation, a "Save Hourly Data" button will be available as shown in Fig. B.2 to save the hourly data in an .mdb (Microsoft Access) formatted file. This file must be converted to an Excel file by using the File, Export, Save As type command within Microsoft Access. Once in Excel format, the data must be combined, as discussed below, to the level needed by the CHP Capacity Optimizer. Also, only the baseline data (for the non-CHP system) is needed, so the load data provided for the alternative case can be deleted from the loads spreadsheet file (rows 8762–17521).

The Building Energy Analyzer segregates energy loads into heating load, cooling load, domestic hot water (DHW) load, and five different electric meter loads. As the CHP Capacity Optimizer needs only a heating load, cooling load, cooling-related electrical load, and non-cooling related electrical load, some of the raw outputs from BEA must be combined. In

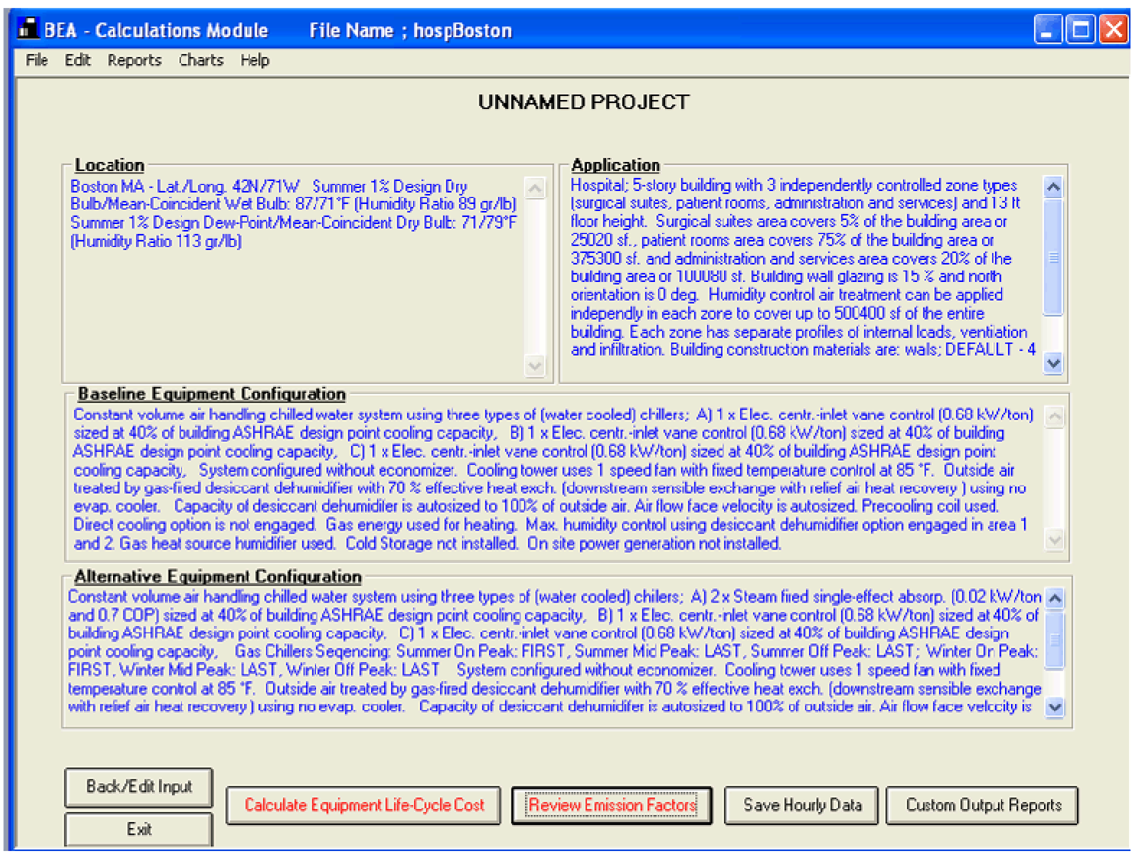

Fig. B.2. BEA save hourly data option screen. (Used with permission.)

particular, the heating and DHW loads are combined to form a single heating load, expressed in Btu units. The cooling-related electrical load is given in the BEA output as Electric Meter 5. The non-cooling loads are formed as the sum of Electric Meters 1 through 4 in the BEA output. All electric loads are expressed in kWh units. As with the BCHP Screening Tool, manipulation of the columns of raw data in the spreadsheet created by Microsoft Access into a format consistent with Fig. 5 will allow a simple cut and paste operation to import the loads data into the CHP Capacity Optimizer. To avoid file linkages between the CHP Capacity Optimizer and the raw data spreadsheet, the transfer of the load data should be done using the Paste Special, Values option within Excel.

The following macro can be helpful in automating the data manipulations of the raw data Excel spreadsheet created in MS Access when using BEA Pro.

```
Sub Datapreparation()
‘
‘ Datapreparation Macro for creating input needed for CHP optimization
‘ from a raw Excel sheet created using BEA Pro
‘ Apply this macro to the raw data spreadsheet created by MS Access, Export operation
‘
 Rows(“8762:8769”).Select
 Range(Selection, Selection.End(xlDown)).Select
 Selection.ClearContents
 Range(“A8761”).Select
 Selection.End(xlUp).Select
 Range(“I1”).Select
 Selection.EntireColumn.Insert
 Selection.EntireColumn.Insert
 Selection.EntireColumn.Insert
 Range(“I1”).Select
 Selection.NumberFormat = “General”
 ActiveCell.FormulaR1C1 = “Heat Load”
 Range(“J1”).Select
 Selection.NumberFormat = “General”
 ActiveCell.FormulaR1C1 = “Cool load”
 Range(“K1”).Select
 Selection.NumberFormat = “General”
 ActiveCell.FormulaR1C1 = “Cool elec”
 Range(“L1”).Select
 ActiveCell.FormulaR1C1 = “Noncool elec”
 Columns(“I:L”).Select
 Selection.Columns.AutoFit
 Range(“I2”).Select
 ActiveCell.FormulaR1C1 = “=RC[-3]+RC[-1]”
 Range(“J2”).Select
 ActiveCell.FormulaR1C1 = “=RC[-3]”
 Range(“K2”).Select
 ActiveCell.FormulaR1C1 = “=RC[6]”
 Range(“L2”).Select
 ActiveCell.FormulaR1C1 = “=SUM(RC[1]:RC[4])”
 Range(“I2:L2”).Select
 Selection.NumberFormat = “0”
 Selection.NumberFormat = “0.0”
```

```
 Selection.Copy
 Range("I3:I8761").Select
 ActiveSheet.Paste
 Application.CutCopyMode = False
 'ActiveWorkbook.Save
End Sub
```

UTILIZING DATA FROM ENERGY PLUS

Building energy demand data can be generated in EnergyPlus by using the Report Meter output, expressed on an hourly basis, while running a simulation over a one year run period. The simulation should be for the building of interest with no on-site generation operating. The relevant meters are Electricity:Facility, Cooling:Electricity, PlantLoopHeatingDemand:Facility, PlantLoopCoolingDemand:Facility. After the EnergyPlus simulation has completed, the meter file with 8,760 hourly data points will need to be post-processed to convert the EnergyPlus data to units expected by the CHP Capacity Optimizer. The easiest approach is to create four new columns that are consistent with the demand data screen in the CHP Capacity Optimizer (see Figure 5 in the Demand Data section of this report). The plant loop heating demand and plant loop cooling demand must be converted to BTUs, the cooling electricity must be expressed in kilowatts, and the non-cooling electrical load must be the difference between the total facility electricity and the cooling electricity, expressed in kilowatts.

In determining the non-cooling related electrical load, an alternative to the post-processing subtraction is to create a Meter:Decrement in EnergyPlus that subtracts the Cooling:Electricity from Electricity:Facility. The decrement meter can then be part of the Report Meter output with the conversion to kilowatts being the remaining post-processing step.

In either approach, the data in the four new columns can be copied and pasted into the demand data area in the CHP Capacity Optimizer. To avoid file linkages between the CHP Capacity Optimizer and the raw data spreadsheet, the transfer of the load data should be done using the Paste Special, Values option within Excel. If desired, the optimized equipment capacities determined by the CHP Capacity Optimizer can serve as guidance for setting capacities in subsequent on-site generation simulations of EnergyPlus.

Appendix C
SAMPLE UTILITY TARIFF

(Used with permission.)

Appendix C
SAMPLE UTILITY TARIFF

(Used with permission.)

The electricity utility price data shown in Fig. 6 are generally obtained from utility tariffs or other schedules that define how end-user electricity consumption will be charged. Tariffs are a ready source of utility electricity price information, as most utilities publish them on their Internet web sites. Tariffs are prepared by the utility and submitted for approval to the relevant state office with utility oversight (e.g., a public utilities commission). Unfortunately, tariffs are not necessarily easy to interpret and extract the appropriate data. There are generally several tariffs offered by a utility company. The appropriate tariff is typically determined by the type of service (e.g., residential, commercial, industrial) and by the magnitude of power consumption. Tariffs can also be voluminous and legalistic. In order to understand how to extract the relevant data from a utility tariff, the tariff for Pacific Gas and Electric medium commercial time-of-use service, Schedule E-19, will be used as an example [Pacific Gas and Electric Company (2005)]. The complete E-19 tariff is currently 29 pages in length, but not all pages are necessary to provide the input needed for CHP evaluations. Therefore, this appendix will address only the sections of the E-19 tariff that are needed to model the unit electricity pricing in the optimization model. Sections of the tariff that are highly relevant to this study are indicated with highlighting.

The first section of the tariff, as shown in Fig. C.1, defines the applicability of the tariff to the particular customer. Generally, this applicability relates to a minimum or maximum power consumption (i.e., billing demand) during a period of time. Various subdivisions of rates or treatments are also defined in the initial section, as shown in Fig. C.2. An important element in Fig. C.2 is the definition of maximum demand. Some utilities have a demand charge that is set by the highest level of demand during a month, irrespective of what day or time the demand occurs. As the CHP Capacity Optimizer uses a demand charge avoidance strategy in deciding whether to operate the CHP system, discussed in Appendix A, the maximum demand charge rate should be included with (i.e., added to) the demand charge block with the highest time-of-use demand charge (e.g., added to the peak block demand charge). While the absolute monthly peak load could occur at an off-peak time of day, the discrepancy introduced is considered minimal.

Further categorization of the applicable rate is shown in Fig. C.3, where pre-existing conditions define a rate structure. Once the applicable rate structure is identified using information on the previous figures, the appropriate quantitative unit prices can be found. As shown in Fig. C.4, the rates used in this study are the demand and energy rates under the assumption of delivery at secondary voltage. As customer/meter charges are flat rates which will be incurred with or without a CHP system, they are not needed as input to the CHP Capacity Optimizer. The section below the total rate table, unbundling of total rates, is merely a restatement of the above rate, subdivided by each contributing cost element. It is interesting information, but not needed for the model. Fig. C.5 provides the definitions of the demand charge and the energy charge. The treatment of time-of-use rates is clarified in this section. The actual times that constitute the time-of-use periods are defined in Fig. C.6. It is noted that the time boundaries for partial-peak and off-peak are defined on the half hour. As the minimum time division for the optimizer model is hourly, the rates in the model are applied to the beginning of the hour with equivalent total duration. It should also be noted that, as is typical of most utilities, weekends and holidays are considered off-peak times.

PG&E **Pacific Gas and Electric Company**
San Francisco, California

	Revised	*Cal. P.U.C. Sheet No.*	22759-E
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	21358-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE

CONTENTS: This rate schedule is divided into the following sections:

1.	Applicability	14.	Common-Area Accounts	(T)
2.	Territory	15.	Contracts	|
3.	Firm Service Rates	16.	Voluntary Service Provisions	|
4.	Metering Requirements	17.	Billing	|
5.	Definition Of Service Voltage			|
6.	Definition Of Time Periods	18.	Fixed Transition Amount	|
7.	Power Factor Adjustments	19.	CARE Discount for Nonprofit Group-Living Facilities	|
8.	Charges For Transformer and Line Losses	20.	Optional Optimal Billing Period Service	|
9.	Standard Service Facilities			|
10.	Special Facilities	21.	Electric Emergency Plan Rotating Block Outages	|
11.	Arrangements For Visual-Display Metering	22.	Standby Applicability	|
12.	Non-Firm Service Program	23.	Department of Water Resources Bond Charge	|
13.	Non-Firm Service Rates			(T)

1. APPLICABILITY: **Initial Assignment:** A customer must take service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period (referred to as Schedule E-19). If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule. Schedule E-19 is not applicable to customers for whom residential service would apply, (see except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

(D)

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-19 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Voluntary E-19 Service: This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 16. (T)

(Continued)

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	Vice President	*Resolution No.*	
53911	*Regulatory Relations*		

Fig. C.1. Schedule E-19 initial page.

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. APPLICABILITY: (Cont'd.) Depending upon whether or not an Installation or Processing Charge applies, the customer will be served under one of these rates under Schedule E-19:

Rate V: (N) Applies to customers who qualify for the voluntary provisions of this tariff and at least one of the following: (1) to customers who are served under Schedule E-19 Voluntary prior to January 1, 1996, and have not changed rate schedules since that time; or (2) to customers whose service has an existing and appropriate time-of-use meter installed and initiated service on this schedule during 1996; or (3) to customers who signed an "Incentive Program Prescriptive Performance Off-Peak Cooling Application" with PG&E prior to January 1, 1996, in order to install a thermal energy storage system and now are about to operate that system. (N)

Rate W: Applies to customers whose maximum demand is less than 200 kW and whose account does not have an appropriate time-of-use meter. The customer must pay a **"Time-Of-Use Installation Charge"** prior to taking service under this schedule. (T)

Rate X: Applies to customers whose account has an appropriate time-of-use meter, but is not currently being served under this schedule. (D) The customer will be required to pay a **"Time-Of-Use Processing Charge"** (N) prior to taking service under this schedule. The Time-Of-Use Processing Charge will be waived for those customers who are initially required to be placed on a time-of-use schedule when their maximum demand is 200 kW or greater for three consecutive months and selects this schedule. (N)

Transfers Off of Schedule E-19: If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary E-19 service or to a different applicable rate schedule. (N) After being placed on this schedule due to the 200 kW or greater provisions of this schedule, customers who fail to exceed 199 kilowatts for 12 consecutive months may elect to stay on the time-of-use provisions of this schedule or elect an applicable non-time-of-use rate schedule. (N)

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be 500 through 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-19.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 6 for a definition of "Peak-Period.") See Section 16 for the definition of maximum demand for customers voluntarily selecting E-19.

(Continued)

Fig. C.2. Maximum demand definition.

Pacific Gas and Electric Company
San Francisco, California

	Revised	Cal. P.U.C. Sheet No.	22946-E
Cancelling	Original	Cal. P.U.C. Sheet No.	21359-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. APPLICABILITY: (Cont'd.)

Standby Demand: For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).

2. TERRITORY: This rate schedule applies everywhere PG&E provides electricity service.

3. FIRM SERVICE RATES:

Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing. (T)

Customers that received the benefit of the 10 percent rate reduction prior to January 1, 2004, and who pay the Fixed Transition Amount (FTA), shall be subject to the rates set forth in Table A, which include the FTA charge and the Rate Reduction Bond Memorandum Account (RRBMA) credit. All other firm service customers taking service under this rate schedule shall be subject to the rates set forth in Table B.

(Continued)

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	Vice President	*Resolution No.*	
54019	*Regulatory Relations*		

Fig. C.3. Further rate category distinctions.

Pacific Gas and Electric Company
San Francisco, California

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Cancelling	Revised	Cal. P.U.C. Sheet No.	23144-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

Table B (Non-FTA Rates)

TOTAL RATES

Total Customer/Meter Charge Rates	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 ($ per meter per day)	$5.74949	$4.59959	$20.04107
Customer Charge Rate V ($ per meter per day)	$2.66119	$2.66119	$2.66119
Customer Charge Rate W ($ per meter per day)	$2.50349	$2.50349	$2.50349
Customer Charge Rate X ($ per meter per day)	$2.66119	$2.66119	$2.66119
One-time TOU Installation Charge ($ per meter)	$443.00	$443.00	$443.00
One-time TOU Processing Charge ($ per meter)	$87.00	$87.00	$87.00
Optional Optimal Billing Period Service ($ per meter per month)	$130.00	$130.00	–
Optional Meter Data Access Charge ($ per meter per day)	$0.98563	$0.98563	$0.98563
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$13.12 (R)	$11.28 (R)	$6.85 (R)
Maximum Part-Peak Demand Summer	$3.64 |	$2.54 |	$0.55 |
Maximum Demand Summer	$3.00 |	$3.01 |	$0.67 |
Maximum Part-Peak Demand Winter	$3.58 |	$2.54 |	$0.69 |
Maximum Demand Winter	$3.00 (R)	$3.01 (R)	$0.67 (R)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.14913 (R)	$0.12418 (R)	$0.13585 (R)
Part-Peak Summer	$0.09114 |	$0.08099 |	$0.09315 |
Off-Peak Summer	$0.07800 |	$0.07331 |	$0.08452 |
Part-Peak Winter	$0.09653 |	$0.08861 |	$0.10742 |
Off-Peak Winter	$0.07781 (R)	$0.07422 (R)	$0.08916 (R)
Average Rate Limiter ($/kWh in summer months)	$0.14043	$0.14043	–
Peak Period Rate Limiter ($/kWh in summer months)	$0.97773	$0.84937	$0.58676

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Demand Rates by Component ($ per kW)	Secondary Voltage	Primary Voltage	Transmission Voltage
Generation:			
Maximum Peak Demand Summer	$6.33 (R)	$7.39 (R)	$6.85 (R)
Maximum Part-Peak Demand Summer	$1.75 |	$1.67 |	$0.55 |
Maximum Demand Summer	($3.28) |	($2.47) |	($3.75) |
Maximum Part-Peak Demand Winter	$1.73 |	$1.67 |	$0.69 |
Maximum Demand Winter	($3.28) (R)	($2.47) (R)	($3.75) (R)
Distribution:			
Maximum Peak Demand Summer	$6.79	$3.89	$0.00
Maximum Part-Peak Demand Summer	$1.89	$0.87	$0.00
Maximum Demand Summer	$1.94	$1.14	$0.08
Maximum Part-Peak Demand Winter	$1.85	$0.87	$0.00
Maximum Demand Winter	$1.94	$1.14	$0.08
Transmission Maximum Demand*	$2.32	$2.32	$2.32
Reliability Services Maximum Demand*	$2.02	$2.02	$2.02

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

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100509		Regulatory Relations		

Fig. C.4. Time-of-use demand and energy rates.

Pacific Gas and Electric Company
San Francisco, California

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Cancelling	Revised	Cal. P.U.C. Sheet No.	21364-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-19 is the sum of a customer charge, demand charges, and energy charges:

– The **customer charge** is a flat monthly fee.

– This schedule has three **demand charges,** a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 6.) (T)

– The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

– If applicable, all **TOU Installation** or **TOU Processing Charges** must be paid in one lump sum before the customer can take service under this rate schedule. Payments for these charges are not transferable to another service or refundable, in whole or part. PG&E will place the account on this schedule within four weeks of receiving payment from the customer. The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer. (T)

– The monthly charges may be increased or decreased based upon the power factor. (See Section 7.) (T)

– As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the level of the customers maximum demand and the voltage at which service is taken. Service voltages are defined in Section 5 below. (T)

– Please note that the rates in the table above apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule. (T)

(Continued)

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	Vice President	*Resolution No.*	
54090	*Regulatory Relations*		

Fig. C.5. Definition of demand and energy charges.

COMMERCIAL/INDUSTRIAL/GENERAL

SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE

(Continued)

6. DEFINITION OF TIME PERIODS: Times of the year and times of the day are defined as follows: (T) (L)

SUMMER	Period A (Service from May 1 through October 31):	
Peak:	12:00 noon. to 6:00 p.m.	Monday through Friday (except holidays).
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays).	
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays (L)
WINTER	Period B (service from November 1 through April 30):	
Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays).
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays). Saturday, Sunday, and holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

7. POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent. (T)

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by 0.06 percent of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA will be increased by 0.06 percent for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes.

8. CHARGES FOR TRANSFORMER AND LINE LOSSES: The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2. (T)

(Continued)

Fig. C.6. Definition of time periods.

An important exemption for distributed energy resources is shown in Fig. C.7. Electric utilities can charge a fee for having power *available* if the CHP system can not operate. In this particular tariff, the utility waives the standby fee, subject to the requirement of participating in real-time pricing, when it is offered by the utility in the future.

The resulting combination of all these elements into the data necessary for the CHP Capacity Optimizer is shown in Fig. C.8.

PG&E ***Pacific Gas and Electric Company***
San Francisco, California

	Revised	*Cal. P.U.C. Sheet No.*	22782-E
Cancelling	Revised	*Cal. P.U.C. Sheet No.*	22669, 21371,21383-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

22. STANDBY APPLICABILITY: SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E's power grid and who have not elected service under Schedule E-NEM, will be exempt from paying the otherwise applicable standby reservation charges. (T)

DISTRIBUTED ENERGY RESOURCES EXEMPTION: Any customer under a time-of-use rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a time-of-use (TOU) schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to time-of-use (TOU) and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - *Competition Transition Charge Responsibility for All Customers and CTC Procurement*, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.

23. DWR BOND CHARGE: The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (T)

Advice Letter No. 2623-E
Decision No. 05-01-056
53933

Issued by
Karen A. Tomcala
Vice President
Regulatory Relations

Date Filed February 7, 2005
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Resolution No.

Fig. C.7. Standby charge exemption.

Electric rates Non-CHP Energy		Pattern 1 Energy	$/kWh	Pattern 2 Energy	$/kWh
month	pattern #	hour	rate	hour	rate
1	1	1	0.07781	1	0.078
2	1	2	0.07781	2	0.078
3	1	3	0.07781	3	0.078
4	1	4	0.07781	4	0.078
5	2	5	0.07781	5	0.078
6	2	6	0.07781	6	0.078
7	2	7	0.07781	7	0.078
8	2	8	0.09653	8	0.09114
9	2	9	0.09653	9	0.09114
10	2	10	0.09653	10	0.09114
11	1	11	0.09653	11	0.09114
12	1	12	0.09653	12	0.14913
		13	0.09653	13	0.14913
		14	0.09653	14	0.14913
		15	0.09653	15	0.14913
		16	0.09653	16	0.14913
		17	0.09653	17	0.14913
		18	0.09653	18	0.09114
		19	0.09653	19	0.09114
		20	0.09653	20	0.09114
		21	0.07781	21	0.078
		22	0.07781	22	0.078
		23	0.07781	23	0.078
		24	0.07781	24	0.078

Non-CHP Demand		Pattern 1 Demand	$/kw-mo			Pattern 2 Demand	$/kw-mo		
month	pattern #	hour	peak	shoulder	off-peak	hour	peak	shoulder	off-peak
1	1	1				1			
2	1	2				2			
3	1	3				3			
4	1	4				4			
5	2	5				5			
6	2	6				6			
7	2	7				7			
8	2	8		6.58		8		3.64	
9	2	9		6.58		9		3.64	
10	2	10		6.58		10		3.64	
11	1	11		6.58		11		3.64	
12	1	12		6.58		12	16.12		
		13		6.58		13	16.12		
		14		6.58		14	16.12		
		15		6.58		15	16.12		
		16		6.58		16	16.12		
		17		6.58		17	16.12		
		18		6.58		18		3.64	
		19		6.58		19		3.64	
		20		6.58		20		3.64	
		21				21			
		22				22			
		23				23			
		24				24			

Electric rates CHP Energy		Pattern 1 Energy	$/kWh	Pattern 2 Energy	$/kWh
month	pattern #	hour	rate	hour	rate
1	1	1	0.07781	1	0.078
2	1	2	0.07781	2	0.078
3	1	3	0.07781	3	0.078
4	1	4	0.07781	4	0.078
5	2	5	0.07781	5	0.078
6	2	6	0.07781	6	0.078
7	2	7	0.07781	7	0.078
8	2	8	0.09653	8	0.09114
9	2	9	0.09653	9	0.09114
10	2	10	0.09653	10	0.09114
11	1	11	0.09653	11	0.09114
12	1	12	0.09653	12	0.14913
		13	0.09653	13	0.14913
		14	0.09653	14	0.14913
		15	0.09653	15	0.14913
		16	0.09653	16	0.14913
		17	0.09653	17	0.14913
		18	0.09653	18	0.09114
		19	0.09653	19	0.09114
		20	0.09653	20	0.09114
		21	0.07781	21	0.078
		22	0.07781	22	0.078
		23	0.07781	23	0.078
		24	0.07781	24	0.078

CHP Demand		Pattern 1 Demand	$/kw-mo			Pattern 2 Demand	$/kw-mo		
month	pattern #	hour	peak	shoulder	off-peak	hour	peak	shoulder	off-peak
1	1	1				1			
2	1	2				2			
3	1	3				3			
4	1	4				4			
5	2	5				5			
6	2	6				6			
7	2	7				7			
8	2	8		6.58		8		3.64	
9	2	9		6.58		9		3.64	
10	2	10		6.58		10		3.64	
11	1	11		6.58		11		3.64	
12	1	12		6.58		12	16.12		
		13		6.58		13	16.12		
		14		6.58		14	16.12		
		15		6.58		15	16.12		
		16		6.58		16	16.12		
		17		6.58		17	16.12		
		18		6.58		18		3.64	
		19		6.58		19		3.64	
		20		6.58		20		3.64	
		21				21			
		22				22			
		23				23			
		24				24			

CHP Standby Charge

0 $/kw-mo

Fig. C.8. Electricity rate input data sheet.