Real Cost for Energy Sufficiency

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ABSTRACT

Managing energy costs in mid-size industrial and commercial firms is a complex problem that often focuses on the direct costs of energy resources (electrical energy, gas and oil), to exclusion of other components of the total life cycle-cost of owning and running a business operation. Such a system life-cycle cost is affected over time by commodity and energy costs, energy availability and reliability, operation and maintenance costs/investments and the costs of emissions. More recent publications focus real cost models of energy management and take into account cost control, risk reduction and efficiency improvement. Costs and investments associated with reliability and demand pricing are often oversimplified or not included in the costing models. This article explores methods for extending the real options and cost models to include costs of reliability, demand pricing, emissions pricing and commodity pricing to allow the real cost models to be used as comprehensive methods for energy efficiency management. Note ownership or financial costs are typically included in the demand cost—which is often considered a capital recovery factor. Costs of reliability of different microgrid configurations are discussed and numerical examples for microturbine and cogeneration scenarios are presented.

Key Words: cogeneration, consumption pricing, cost options, demand pricing, distributed generation, emission pricing, energy sufficiency, life-cycle cost, real options, reliability cost, zero cost, zero variance.

INTRODUCTION

The emergence of distributed generation presents a challenge to established energy management methods. The private control over a microgrid provides lower energy costs, but increases the management burden. Energy sufficiency, the degree to which one controls one's own energy supply, necessitates a forward-looking energy management process that follows zero cost and zero variance principles, under an overall system life-cycle-cost approach.

The energy management process described in the paper "Energy Sufficiency Kaizen" (Overturf et al. [1]) relies on cost model for different sources of energy. This article provides a more detail description of cost structures relevant to decisions involved in investment and operation of distributed generation assets and its impact in the life-cycle cost/profit of running a business. To illustrate the case, just imagine the cost-effectiveness of powering an airport, hospital or resort using poorly maintained diesel generators alone, fired with locally supplied fuel.

ENERGY SOURCES AS PORTFOLIO OF ASSETS

Energy sources considered as portfolio of assets, each associated with certain market contract for supply of energy, are described in detail in the energy sufficiency paper and also depicted in Figure 1.

In different time steps various energy contracts are realized based on availability and price of different energy sources. The objective of the planning phase of on-site generation systems is to ascertain the economic value of different energy investments under uncertainty using the real options methods. For a detail review of capital investment decisions based on real options refer to Dixit et. al [3] and Siddiqui et. al [4][5]. This article proposed inclusion of commodity, reliability and emissions pricing into the real options methods.

Once on-site generation resources exist there is the on-going decision making process of dispatching the available resources based on actual prices associated with the contracts. It is part of normal operation and maintenance of the energy resources. The concepts of continuous energy productivity improvement and Energy Kaizen are described in Overturf et. al [1][2]. The remainder of this article further develops the methods for accounting for energy costs as well as accounting of the impact of reliability of different energy sources on the economic value production of a business. The purpose of including the additional cost components of the energy resources is to provide a real energy costs bases of production, as opposed to averaged energy costs. Averaged

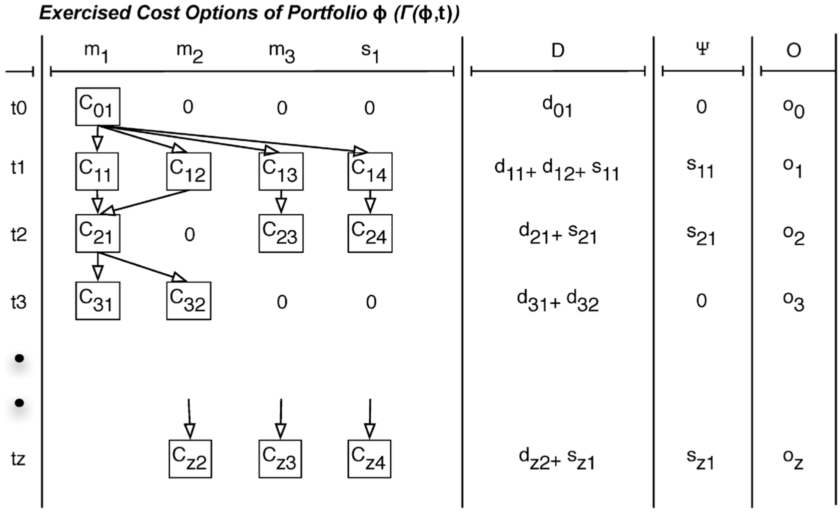

Figure 1. Exercised Cost of Options of Portfolio ϕ (Γ(ϕ,t))

costs may not reflect the proper relationships between the economic output of the enterprise and the energy costs.

The real cost function will be described by the following equation. Each component of the cost will be subsequently treated in more detail.

$$\Gamma_r(\Phi,x) = \Lambda + \sum_{j=1}^{n+k} \left[c_{xj}\bullet d_{xj} + \gamma_{xj}^{d} + e_{xj}\bullet U\left(d_{xj} - d_{tj}\right) + o_{xj}\right] \qquad (1)$$

Where

$\Gamma_r(\Phi,x)$ = Real cost for of the resource portfolio Φ at time step x.

Λ = Economic loss function

n = Number of energy resources (off-site).

k = Number of energy resources (sufficiency on-site resources).

c_{xj} = Commodity price of energy per volume for resource j at time step x.

d_{xj} = Volume of energy provided by resource j at time step x.

γ_{xj}^{d} = Demand charge associated with resource j at time step x.

e_{xj} = Emission price per volume of energy for resources j at time step x.

U(z) = Threshold function, explained below in emissions pricing section.

d_{tj} = Threshold of energy volume above which emissions pricing applies for resource j.

0_{xj} = Operations and maintenance costs associated with resource j at time step x.

Portfolio Real Cost Model

The basic energy cost equality is c * d, or unit cost times volume. This cost accounting takes into consideration average cost of energy. Using average energy costs may be adequate in simple scenarios, but as other components of the energy costs increase, using averages will tend to distort the economic decisions reached through the analysis. Additional cost factors considered in the article will include emissions pricing, demand charges and costs associated with reliability and its impact on loss of production.

EMISSIONS PRICING

Sustainability accounting requires that no further cost is incurred to anyone after process use, i.e., an indefinitely intact resource balance sheet.

Consider that today most western city dwellers pay for their water supply twice: once for the water, and once for subsequent waste treatment. This cost burden was inconceivable 50 years ago. Some localities even have 2 meters that measure the flow of incoming fresh water and outgoing waste water. This allows for a more precise cost allocation of fresh water supply and waste water treatment.

Analogous to water pricing, the offset environmental costs of energy purchases can be modeled as a simple multiplier sensitive to volume, called ex. However, unless this value is reflected consistently in the balance of payments, its inclusion is voluntary. Further, if offset market receipts are to have any meaning in portfolio considerations, the corresponding expense must be captured at this level.

For example, Table 1 shows actual contracts traded in June 2011 for Landfill Gas emissions offsets on Intercontinental Exchange (ICE) market. The contracts were valued at $1.25 per metric ton of avoided methane gas emissions. ICE offers some of the contracts previously traded on Chicago Climate Exchange CCX [8].

If the facility had access to locally produced methane (e.g. digester) that could be converted into thermal and electrical energy, the additional

Table 1.
ICE Landfill Gas Emissions Offsets: Actual Contracts Traded in June 2011

Trade Date	Vintage	QTY (CFI's)	QTY (MT)	Price $/MT	Type of Transaction	CFI Delivered
06/14/11	2009	11	1,100	$1.25	OTC	Landfill Methane Offset
06/14/11	2008	2	200	$1.25	OTC	Landfill Methane Offset
06/14/11	2007	20	2,000	$1.25	OTC	Landfill Methane Offset
06/14/11	2007	150	15,000	$1.25	OTC	Landfill Methane Offset
06/14/11	2006	10	1,000	$1.25	OTC	Landfill Methane Offset
06/14/11	2005	10	1,000	$1.25	OTC	Landfill Methane Offset

CFI: Carbon Financial Instrument
MT: Metric Ton
Source: CCX Daily Transaction report 2011.

source of revenue could be realized from the offset market. In such case the offsets could be treated as negative price, reducing the cost base of the energy.

The emission pricing can be expressed in the following formula:

$$E = \sum_{j=1}^{n+k} \left[e_j \cdot U\left(d_j - d_{tj}\right)\right] \tag{2}$$

Where,

e^j = Emissions pricing rate in $/volume of energy for resource j.
d_j = Volume of energy consumed from resource j.
d_{tj} = Threshold volume of energy consumption from resource j, beyond which emission pricing applies.

$$U(x) = \begin{cases} x, & x \geq 0 \\ 0, & x < 0 \end{cases} \text{ – Threshold function.}$$

DEMAND CHARGES

Market supplied energy, in gaseous, electrical, or any other form, does not follow a linear cost curve. For example, in the electrical industry, concerns for capacity of the transmission and distribution network require peak load considerations. Similar rules apply to natural gas or oil storage and distribution. The energy supply is not infinitely elastic; therefore, utility companies transfer their capacity ownership and financial and maintenance costs through so-called demand charges, which can be modeled as:

$$\gamma^d = c^d \cdot \left(\max_{\tau=0\rightarrow(T-\Delta t)} \frac{1}{\Delta t} \int_{\tau}^{\tau+\Delta t} L(\tau) d\tau \right) \tag{3}$$

Where,

γ^d = Demand charges [\$]
c^d = Demand rate [\$/kW]
τ = Time variable [hours]
T = Billing period, typically a month [days * 24 hours]
Δt = Sampling period, typically 15 minutes [0.25 hours]
L(t) = Instantaneous load in [kW]

Note that in Equation (3) the expression between parentheses is the *Billing Demand, D(t).*

Demand charges must be included for most large electrical grid contracts. Therefore, the actual price for grid contract *m* must use anticipated load profile data. Some utilities may apply so called "ratchet demand charges" where the demand charge in a given billing period cannot be less than a certain percentage of a past peak demand charge. Demand rate may vary with time of day, further complicating the pricing formula.

Following is an example of the demand charge calculation.

Example 1: Billing Demand

In Figure 2, the period Δt contains the highest rate of energy drawn during the billing period T ($\Delta t \, \varepsilon \, T$). The instantaneous load during the period Δt is:

$$L(t) = \left\{ \begin{array}{l} 200\ [\mathrm{kW}],\ 0 \le t < \frac{\Delta t}{2} \\ 100\ [\mathrm{kW}],\ \frac{\Delta t}{2} \le t < \Delta t \end{array} \right\} \tag{4}$$

The billing demand rate is c^d = \$10.00 per kW of the load averaged over a sampling period Δt = 15 minutes [0.25 hours].

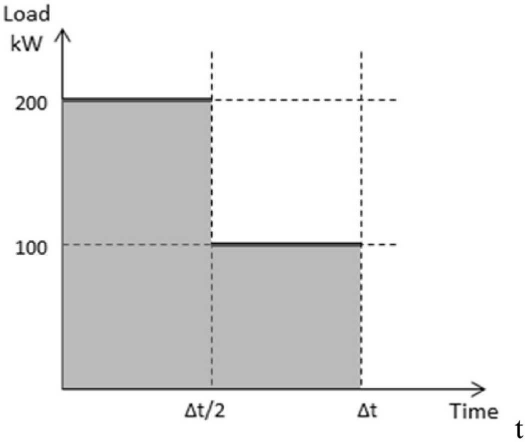

Figure 2. Demand is the highest instantaneous load over time.

So the billing demand *D(t)* is:

$$\frac{1}{\Delta t}\int_{\tau}^{\tau+\Delta t} L(\tau)d\tau = \frac{1}{\Delta t}\left[\int_{0}^{\frac{\Delta t}{2}} L(\tau)d\tau + \int_{\frac{\Delta t}{2}}^{\Delta t} L(\tau)d\tau\right]$$

$$\frac{1}{\Delta t}\int_{\tau}^{\tau+\Delta t} L(\tau)d\tau = \frac{1}{0.25}\left[\int_{0}^{0.125} 200d\tau + \int_{0.125}^{0.25} 100d\tau\right]$$

$$\frac{1}{\Delta t}\int_{\tau}^{\tau+\Delta t} L(\tau)d\tau = \frac{1}{0.25}\left[(200\tau)\,\Big|_{0}^{0.125} + (100\tau)\,\Big|_{0.125}^{0.25}\right] = \frac{1}{0.25}[25 + 25$$
$$- 12.5] = 150\text{ kW} \tag{5}$$

The demand charge for at billing period (usually a month) would be:

γ^{d} = 150 kW • \$10/kW = \$1,500

If such a peak occurs only once during a billing period the demand charges are applied for that month. An extreme example would be if the facility turned on its equipment for the 15-minute period and then did not turn on any equipment for the rest of the month. The total charges for energy and demand charges would be:

$$c_{x1} = \$0.15/\text{kWh}$$

$$d_{x1} = 200\ \text{kW} \bullet 0.125\ \text{hours} + 100\ \text{kW} \bullet 0.125\ \text{hours} = 37.5\ \text{kWh}$$

$$c_{x1} \bullet d_{x1} = 0.15 \frac{\$}{\text{kWh}} \bullet 37.5\ \text{kWh} = \$5.625$$

The total cost for the billing period not counting basic service charges and other charges would be $1,505.63.

THE COST OF UN-RELIABILITY, OR THE VALUE OF RELIABILITY

In cases where the downtime of energy resources results in significant loss of economic output, it is important to include their availability into the cost equation. We propose to remedy this with a reliability cost factor in the real cost equation, in terms of the energy system's availability.

Generally speaking, availability of an energy resource, market or sufficiency, is the percent of the time such a resource is available when it is needed. It can be expressed as

$$\text{Availability} = \frac{\text{MMTTF}}{\text{MTTF} + \text{MTTR} + \text{MTTM}} \tag{6}$$

Where, MTTF is Mean Time To Failure, MTTR is Mean Time To Repair, and MTTM is Mean Time To Maintain. All variables have the same units of time [e.g. hours] per some standard period such as a year, expressed as *H* hours of operation per year (between 1 to 8760 hours). Refer to Brown et al. [7] for reliability of electric power distribution networks.

The downtime in hours per year can then be calculated as follows:

$$\text{Downtime} = (1 - \text{Availability}) \bullet \text{H} \tag{7}$$

If the loss of the economic output due to 1 hour of downtime is established to be γ, then the expected annual loss of economic output is:

$$\Lambda = \gamma \bullet (\text{Downtime}) \tag{8}$$

The annual loss of economic output Λ, as considered in this article is the result of disruption in supply of energy needed for a business process. Disruption of energy supply could be a result of many different factors. Each of the energy resources will have a certain characteristic reliability performance that will be further considered in this article.

There are at least two ways to accomplish the integration of the loss function with energy costs.

(a) The most intuitive way is to include the loss function as an additive component of the overall portfolio cost:

$$\Gamma_r(\Phi,x)= \wedge + \sum_{j=1}^{n+k} \left[c_{xj} \cdot d_{xj} + \gamma_{xj}^{d} + e_{xj} \cdot U\,(d_{xj} - d_{tj}) + o_{xj}\right] \tag{9}$$

(b) Another way of factoring reliability could use multiplicative cost factor. (See Overturf et al. [2] p.45.)

Computation of Λ is demonstrated in the following example.

Example 2: Value of Reliability of a DG System

For an example of the cost of un-reliability in terms of loss of economic output, consider a simple distributed generation (DG) scenario of an industrial plant that is supplied with electrical energy from three resources: the grid and two turbines. In addition, in this example we will estimate the value of reliability of DG. All the possible states of this DG system are listed in Table 3. The plant shown on Figure 3 can produce at full capacity when supplied either by the grid or two turbines. When there is no electricity from the grid and only one turbine is running, only half of the capacity can be produced. (See states 6 and 7 in Table 2.)

The system states can also be visualized with the Venn diagram shown in Figure 4.

The plant output in relation to the different states of the electrical energy resources is summarized in Figure 3. For example, state 2 (s2) in the Venn diagram indicates that turbine #2 is off, however the plant can continue to generate 100% of output since the grid and turbine #1 are ON.

Assuming that the plant operates for 16 hours per day (two 8-hour

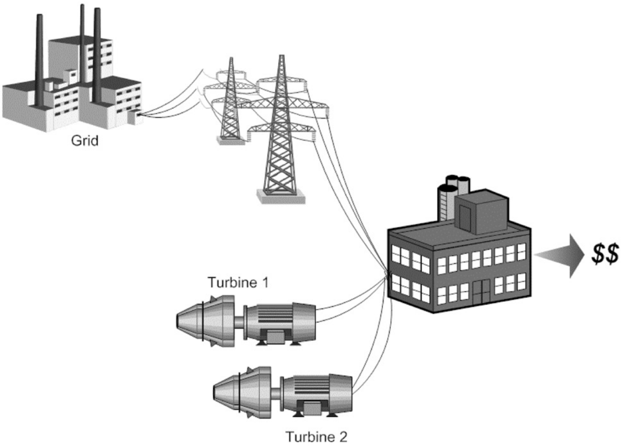

Figure 3. A DG System: A plant with three energy sources.

Table 2. Possible States for DG System Example 2

State	Grid	Turbine #1	Turbine #2	Plant output
1	ON	ON	ON	100%
2	ON	ON	OFF	100%
3	ON	OFF	ON	100%
4	ON	OFF	OFF	100%
5	OFF	ON	ON	100%
6	OFF	ON	OFF	50%
7	OFF	OFF	ON	50%
8	OFF	OFF	OFF	0%

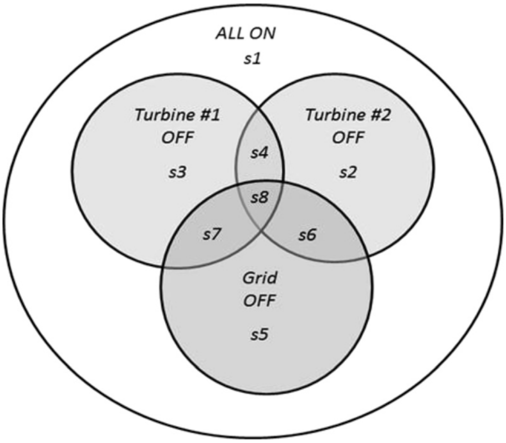

Figure 4. Venn diagram showing eight (8) possible DG system states

shifts—maintenance time not counted as generating revenue), 358 days per year (assuming 1 week shut down) for a total of 5,728 hours of operation, it produces product or revenue at a rate of λ = \$10,000 per hour. Hence, the ideal situation when fully operational for the year would generate O = \$52.8 million of revenue.

But utility power supply is not perfect, and the electrical supply from the grid is down on average for 16 hours. (During the plant operating hours, one day per year downtime means 99.697% grid availability.)[1] During a typical year, the economic value lost will equal Λ_1 = \$160,000 per year.

However, consider that we install 2 on-site turbines with average downtime of 24 hours each. (During production time, 2 days per year downtime means 99.545% turbine availability.)[2] The economic loss due to power interruption is reduced to under Λ_2 = \$728 per year. The actual probabilities of the different system states and the associated values of production are summarized in Table 3.

Therefore, the savings, or the value of reliability resulting from the DG system is the difference $\Lambda_1 - \Lambda_2$ = \$159,272 per year.

By installing 2 turbines (that individually are not as reliable as the grid) we have effectively eliminated the probability of a total interruption of production from the plant. There is a probability of 0.003% that the plant production will be reduced to only half of the full capacity, but the total average loss is now only \$728 per year. That is a significant reduction from \$160,000 expected loss with grid only. Thus the reliability

Table 3. DG System States Probabilities and Associated Production Values

State	Grid	Turbine #1	Turbine #2	Plant output	Probability of the state	Expected production value
1	ON	ON	ON	100%	98.79224%	$52,142,543
2	ON	ON	OFF	100%	0.45128%	$238,184
3	ON	OFF	ON	100%	0.45128%	$238,184
4	ON	OFF	OFF	100%	0.00206%	$1,088
5	OFF	ON	ON	100%	0.30039%	$158,548
6	OFF	ON	OFF	50%	0.00137%	$362
7	OFF	OFF	ON	50%	0.00137%	$362
8	OFF	OFF	OFF	0%	0.00001%	$0
			Actual Expected Production Value [$]			$52,779,272
			Full Capacity Production Value [$]			$52,780,000
			Annual loss of production [$]			**$ (728)**

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1. Grid Availability = (11 – 16 hours/5728 hours) * 100% = 99.697%
2. Turbine Availability = (1 – 24 hours/5728) * 100% - 99.545%

value of the DG system is $159,272 per year.

The amount of investment required for the turbines depends on energy intensity of the plant's process. In this simple example, an investment of $160,000 would purchase about 60kW-70kW worth of micro-turbines and have a simple payback of one year (assuming light manufacturing process). However, one would not justify investment in an on-site generation turbine only for backup purposes. In a more complicated scenario where the plant uses both electrical and thermal energy installing cogeneration, or combined heat and power (CHP), turbines will supply energy at a potentially lower cost than separately purchasing electricity and thermal energy from natural gas, etc. A biomass or natural gas-fired cogeneration system would supply all of the thermal needs of the plant and generate the electricity from the 2 turbines. In such a system the preferred operating state would be state S5 when both turbines are operating, and the grid is essentially there for backup only. Now, in addition to reduction in loss of production, the plant can realize additional savings by utilizing fewer energy sources, savings that can be computed using the real cost model.

Reliability Considerations of Renewable Resources

It should be noted that inclusion of non-dispatchable resources such as PV solar and wind may or may not change the reliability of the system. Due to safety requirements imposed on grid-interactive PV and wind systems, such intermittent systems have to shut down in case of grid failure; hence, they are typically not suitable as backup resources. In such cases on-site PV and wind systems can be treated as a purely stochastic energy source with a predetermined (amortized investment plus operating costs per kWh) cost. If the systems were sized properly the goal would be to utilize these sources whenever the solar and wind energy supply is adequate.

Uninterrupted plant production cannot rely solely on these intermittent resources and the grid—thus making DG turbines the essential dispatchable resources. If the DG microgrid (grid and turbines supplying a plant) is designed properly, the economic loss of output should be affected only by the reliability of dispatchable resources or turbines. Stating it differently, the non-dispatchable resources affect only the energy cost portion of the equation. Coupling of energy storage resources such as compressed air or fly wheel based technologies can be used with PV and wind resources to create a dispatchable energy resource.

For extensive treatment of renewable electric power systems refer to Masters [6].

Generalized Formula for n Energy Conversion Systems

We now derive formulas for a more complex energy source scenario with *n* different sources. The example of 2 turbines and the grid supplying the plant can be generalized to n different resources using the following formulas:

$$P_k = \prod_{i=1}^{n} \left[\delta_i p_i^u + \left(1 - \delta_i\right) p_i^d\right] \tag{10}$$

Where,

P_k = Probability of system state k

n = Number of resources

p_i^u = Probability of resource i being up.

p_i^d = Probability of resource i being down.

δ_i^k = State of resource i (0 when down and 1 when up) during system state k.

The resource is considered up when it is ready to supply energy, not necessarily when it actually supplies the energy.

Next, the expected production is

$$E_k = \left\{ \begin{array}{ll} 1, & \sum_{i=1}^{n} \delta_i^k \bullet p_i^k \geq 1 \\ \sum_{i=1}^{n} \delta_i^k \bullet p_i^k, & \text{Otherwise} \end{array} \right\} \tag{11}$$

Where,

E_k = Expected production output during system state k (decimal proportion of production between 0 and 1)

n = Number of resources

p_i^k = Production percent enabled by resource i (decimal proportion of production between 0 and 1) during system state k. (Explained in the following example.)

δ_i^k = State of resource i (0 when down and 1 when up) during system state k.

The expected system production output for an operating period such as a year, expressed as hours per period. (For a period of one year the hours would be between 1 and 8760).

$$E = \sum_{k=1}^{2^n} \left(E_k \bullet P_k \bullet \lambda \bullet H\right) \tag{12}$$

Where,

E_k = Expected production output during system state k (decimal proportion of production between 0 and 1)
P_k = Probability of system state k
n = Number of resources
γ = Value of production [$] per 1 hour of operation.
H = Number of operating hours per year.

The reliability loss function Λ can then be defined as a difference between ideal operating hours (e.g. full 8760) and the expected production E.

$$\Lambda = \gamma \bullet H - E \tag{13}$$

Example 3: The Value of Reliability with Cogeneration Resources

Consider a similar plant as in Example 2, but now the plant requires both electrical and thermal energy sources. The 2 turbines are used in cogeneration mode, and each can supply 50% of electrical and thermal demand of the production process. The turbines could be fired by biomass, making them independent from the supply of natural gas and grid electricity. Two additional resources are 2 natural gas-fired boilers that can supply 50% of thermal demand each. The boilers together with the grid can supply 100% of thermal and electrical demand. If Turbine 1 or 2 is down, then boiler 1 or 2 can pick up the thermal demand respectively and the grid can pick up the electrical demand. Configuration of the cogeneration system is shown in Figure 5.

Table 4 lists all of the possible system states and their respective probabilities and expected production value. Some states (e.g. state 32) have several possibilities for satisfying energy requirement. The plant operator could use the grid and boilers or the turbines to fulfill the energy demand. The operational choice would be done based on cost analysis. However, all of the possible system states are considered for the probability analysis.

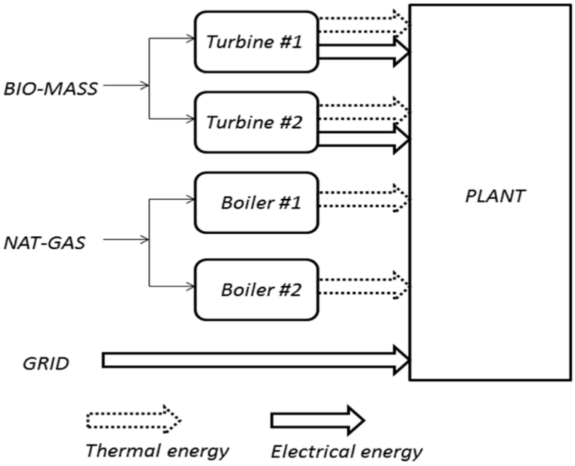

Figure 5. Cogeneration System

Computation of the proportion of production enabled by resource j in state k is directly dependent on the system configuration of the different energy conversion resources and their contribution to the production process. In cases where number of system states is small, such as in this example, the proportion of production for each state k can be pre-computed as shown in Table 4, column "Plant Output."

A more general method is to use a vector description for each state k of the form:

$$\rho^k = \left\{\rho_0^k, \rho_1^k, \ldots, \rho_n^k\right\}$$

For example in states 1 through 16 the following vector describes the relationship of the turbines and production.

$$\rho^{1,,16} = \{0, 0.5, 0.5, 0, 0\}$$

This represents the situation where the turbines contribute 50% of the production. In states 1 through 16 the grid is down, therefore the status of the boilers is irrelevant since without electrical energy the production cannot continue anyway.

For states 17 through 20 the vector would be:

$$\rho^{17,,20} = \{0, 0, 0, 0.5, 0.5\}$$

State	Grid	Turbine #1	Turbine #2	Boiler #1	Boiler #2	Plant Output	Probability of the State	Expected Production Value
1	0	0	0	0	0	0	0.00000%	$0
2	0	0	0	0	1	0	0.00000%	$0
3	0	0	0	1	0	0	0.00000%	$0
4	0	0	0	1	1	0	0.00001%	$0
5	0	0	1	0	0	50%	0.00000%	$0
6	0	0	1	0	1	50%	0.00001%	$2
7	0	0	1	1	0	0	0.00001%	$0
8	0	0	1	1	1	50%	0.00095%	$273
9	0	1	0	0	0	50%	0.00000%	$0
10	0	1	0	0	1	50%	0.00001%	$4
11	0	1	0	1	0	50%	0.00001%	$4
12	0	1	0	1	1	50%	0.00143%	$410
13	0	1	1	0	0	100%	0.00002%	$12
14	0	1	1	0	1	100%	0.00240%	$1,372
15	0	1	1	1	0	100%	0.00240%	$1,372
16	0	1	1	1	1	100%	0.27208%	$155,849
17	1	0	0	0	0	0%	0.00000%	$0
18	1	0	0	0	1	50%	0.00002%	$5
19	1	0	0	1	0	50%	0.00002%	$5
20	1	0	0	1	1	100%	0.00179%	$1,026
21	1	0	1	0	0	50%	0.00003%	$8
22	1	0	1	0	1	50%	0.00300%	$858
23	1	0	1	1	0	100%	0.00300%	$1,717
24	1	0	1	1	1	100%	0.34034%	$194,948
25	1	1	0	0	0	50%	0.00004%	$11
26	1	1	0	0	1	100%	0.00450%	$2,580
27	1	1	0	1	0	50%	0.00450%	$1,290
28	1	1	0	1	1	100%	0.51141%	$292,936
29	1	1	1	0	0	100%	0.00753%	$4,314
30	1	1	1	0	1	100%	0.85535%	$489,946
31	1	1	1	1	0	100%	0.85535%	$489,946
32	1	1	1	1	1	100%	97.13379%	$55,638,235
					Actual Expected Production [$]			$57,277,123
					Full Capacity [$]			$57,280,000
					Annual loss [$]			$ (2,877)

Table 4. Possible States for Cogeneration System of Example 3

In these states production can be satisfied only through a combination of boilers and grid. The entry 0 for the grid indicates that it cannot satisfy the production by itself; thermal energy is needed.

For states 21 through 24 the vector would be:

$$\rho^{21,24} = \{0, 0, 0.5, 0.5, 0\}$$

For states 25 through 28 the vector would be:

$\rho^{25,,28} = \{0, 0.5, 0, 0, 0.5\}$

For states 29 through 32 the vector would be:

$\rho^{29,,32} = \{0, 0.5, 0.5, 0.5, 0.5\}$

The system parameters assumed for the example are:

- Factory operating hours 5,728 per year (16 hours per day—358 days).
- Grid downtime is 16 hours/year.
- Turbine #1 downtime is 20 hours/year.
- Turbine #2 is 30 hours/year.
- Boiler #1 and #2 downtime is 50 hours/year each.

In the base case, when the grid can supply all the power and the boilers the heat without need for the turbines (states 17 through 32) the expected production output Σ E 17,32 = \$57,117,825/year.

When the grid is down, heat and power are solely supplied by the cogeneration turbines and the boilers (states 1 through 16), and the expected production output Σ E 1,16 = \$159,298 per year. This is the value of cogeneration reliability. Note the value of the total expected production for all sates is Σ E 1,32 = \$57,117,825 + \$159,298 = \$57,277,123 per year.

Of course, in addition to reliability savings, we need to factor in the fact that cogeneration can be twice as energy efficient (as high as 80% overall system efficiency) than heat and power supplied independently from boilers and the grid (30 to 50% cycle efficiency, depending on actual fuel sources and performance).

CONCLUSION

This article has demonstrated how to extend the real cost models over the life cycle of energy systems to include all relevant demand charges, emission charges, operating and maintenance costs and reliability impact on economic output. Note that we don't specifically account for separate ownership or leasing, nor financial costs, in this article since we consider them part of the demand charges. By considering the different energy cost components, rather than average energy costs, the real cost model can become a better tool in optimizing enterprise energy efficiency. Trade-offs between investments in various on-site energy conversion technologies can be more precisely assessed when taking into account their inherent reliability and operating costs. Investments in on-site energy conversion systems such as micro-grids was demonstrated to have a significant impact on reducing potential economic losses due to exposure to a single energy resource such as grid or natural gas.

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