Cogeneration: Where Will it Fit in the Deregulated Market?

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Several states in the United States are opening their electric power markets to competition. Among them California and Massachusetts on Jan. 1, 1998 (currently California experiences a problem with the trading computer's communication, so the implementation has been delayed beyond Jan. 1, 1998), Rhode Island on July 1, 1998, Pennsylvania on Jan. 1, 1999, and Michigan will phase in competition through 2002.

Cogeneration due to potentially high efficiency can be very competitive in a deregulated market. Cogeneration can achieve extremely high levels of thermal efficiency, much higher than the most advanced and sophisticated combined cycle power plants generating only electric power.

And thermal efficiency is one of the key factors in determining the power plant economics and feasibility. High efficiency means a lesser amount of fuel is used to generate the same amount of energy. In turn, burning a lesser amount of fuel means that fewer pollutants will be emitted.

PURPA 210 (Public Utility Regulatory Policy Act, enacted in 1978) legal definition of cogeneration reads: "Cogeneration means the sequential use of energy for the production of electrical and useful thermal energy... subject to the following standards:

a) At least 5% of the cogeneration project's total annual output shall be in the form of useful thermal energy.
b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5% of any natural gas and oil energy input."

In 1981 an amendment was issued that reads: "Cogeneration technology means the use for the generation of electricity of exhaust steam, heat, or resultant energy from an industrial, commercial, or manufacturing plant or process, or the use of exhaust steam, waste steam, or heat from a thermal power plant for an industrial, commercial, or manufacturing plant or process."

The legal definition of cogeneration does not lend much understanding of its nature to a person who is not familiar with cogeneration principles. Besides, the legal definition is misleading and lacks clarity. The right definition should be: **cogeneration is the simultaneous generation of electric power and useful thermal energy from any source of fossil or nuclear fuel.**

The thermal efficiency of conventional power plants is low due to significant energy losses that cannot be avoided unless you design a sophisticated and more expensive cycle. At a steam turbine plant the loss occurs during the steam condensation where the energy, equivalent to the latent heat, is rejected to the atmosphere via cooling towers. In a combustion turbine open cycle or a reciprocating engine application, again, a major energy loss occurs with the exhaust gas discharged to the atmosphere at high temperatures.

A typical utility steam turbine power plant has a 32% to 38% net efficiency (net efficiency is the ratio of net power generated to the fuel input. In turn, net power is the power at the generator terminals minus auxiliary load, sometimes called parasitic load). Table 1 shows the net efficiency of some steam turbine utility plants included in the top 25 U.S. plants for 1995. As can be seen, the best efficiency was within 36% to 38%. Combustion turbine open cycle efficiency is below 30%, and a reciprocating engine may have about 40% efficiency.

Let us now take a look at a conventional system for steam and electric power supply. Figure 1 shows a low-pressure boiler that supplies steam to process. This boiler is usually located at the same site where the user of steam is. The electric power is supplied from a plant (Figure 2) that can be located hundreds of miles away and the power is transferred via transmission lines.

In a combined cycle plant the gas turbine drives an electric generator. The exhaust gas is directed to a heat recovery boiler (a common term HRSG) and then exhausted through a stack. The HRSG generates high-pressure steam that is introduced to a steam turbine coupled with another electric generator. Sometimes, medium-

Rank	Plant Operator (Plant)	Heat Rate (Btu/kWh)	Efficiency (%) ★
1	Tennessee Valley Authority (Bull Run)	8,975	38.0
12	Pacific Gas & Electric Co (Moss Landing)	9,441	36.1
25	So. Carolina Generating Co. (Williams Station)	9,580	35.6

★ Efficiency = $\frac{3413 \text{ Btu/kWh}}{\text{Heat Rate (HR)}} \times 100\ \%$

Table 1. From the Top 25 Heat Rates (HR) at US Steam-Electric Plants List - 1995)

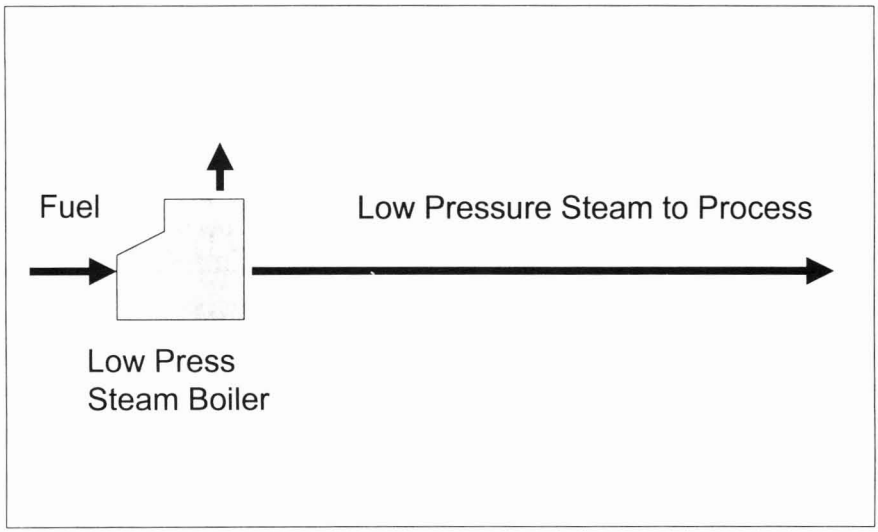


Figure 1. Conventional Process Steam System

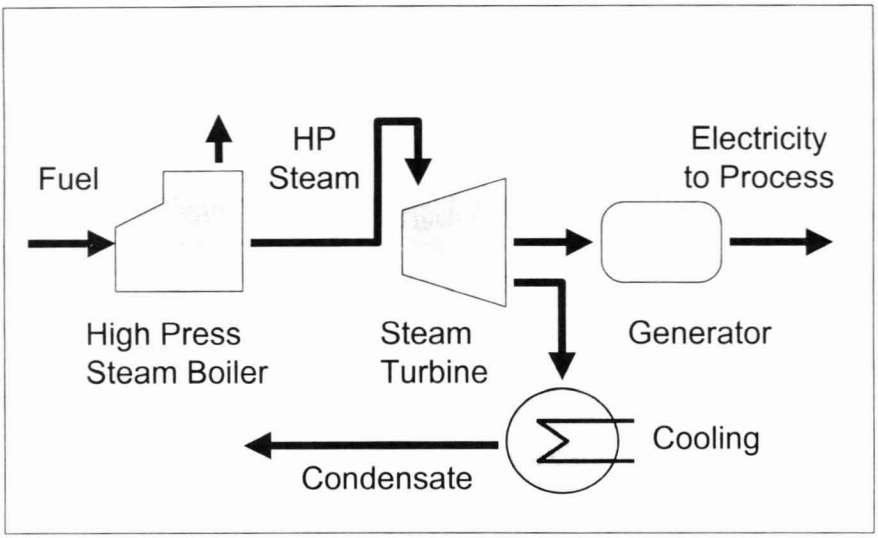


Figure 2. Conventional Electric Generating System

or low-pressure steam from the HRSG can be inducted into the steam turbine to boost its power output.

The reader can see why a combined cycle has a higher efficiency than an open cycle gas turbine or a steam turbine. The energy of the exhaust gas from the gas turbine is partially utilized in the HRSG, and the steam turbine exhausts less steam to the condenser. A combined cycle may achieve about 55% to 60% efficiency.

Usually, in a combined cycle the gas turbine generates approximately 2/3 and the steam turbine generates 1/3 of the total power. If a combined cycle is used in a cogeneration application, e.g. when some steam from the HRSG or from the steam turbine extraction (refer to Figure 3), or both is used for process or heating/cooling, the ratio of power generated by the gas turbine and steam turbine can be quite different.

Of course, the efficiency of a combined cycle cogeneration plant with the same initial parameters will be higher than 55% or 60%. In general, a good cogeneration plant can achieve an 85% efficiency and above.

All the cogeneration cycles with backpressure (non-condensing)

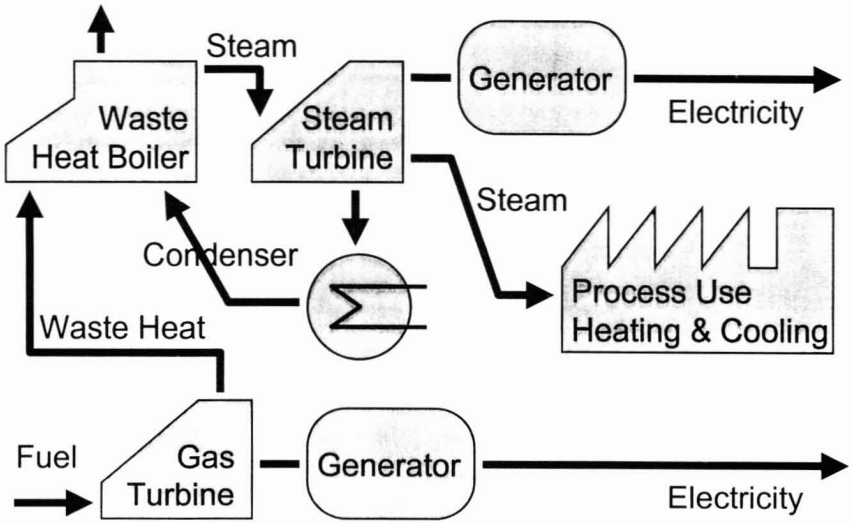


Figure 3. Cogeneration—Gas Turbine Combined Cycle

steam turbines, condensing turbines with extractions, combined cycles or heat utilized in a HRSG from a combustion turbine or from a reciprocating engine are called *topping cycles*. A topping cycle is the most common arrangement for cogeneration. When the fuel is first used for process and then the thermal energy of the exhaust gas is utilized for power generation, such cycle is called a bottoming cycle.

Another emerging technology for cogeneration application may be fuel cells. Their efficiency ranges from 40% to 57% depending on the type of fuel cell technology (phosphoric acid, molten carbonate or solid oxide). Again, in a cogeneration arrangement such efficiency can rise significantly.

Despite the variety of arrangements, **all the topping cycle cogeneration plants have certainly one thing in common: they supply useful thermal energy.** And when we show the steam extracted from a turbine or from a HRSG we have in mind either direct application of steam, or its use in a heat exchanger to produce hot water, or in an absorption chiller to produce chilled water. The aforesaid brings us closer to understanding the nature of the cogeneration plant's economics. And good economics are the key to survival: if a plant is highly economical it is competitive.

IMPORTANCE OF THERMAL LOAD AVAILABILITY

Depending on the type and size of the thermal load and the type and size of the electric demand, various types of prime movers and various sizes and turbine initial parameters can be selected. Each option is associated with a certain capital cost and has corresponding operating expenses. By comparing all annual costs versus revenues generated, the best option can be selected. Such a process is called cycle optimization.

Figure 4 shows the relationship between a steam turbine specific power (kW-hr generated per million Btu of thermal energy extracted) and initial steam parameters and extraction pressure. For example, if you use utility compatible 2400 psig/1000°F as inlet parameters, and the extraction pressure is 100 psig, you can generate approximately 95 kW-hr/MMBtu. However, if a cogeneration plant has inlet parameters 600 psig/750°F, it will generate only about 50 kW-hr/MMBtu. Of course, it will cost less to build the second plant, but it will generate lesser revenue.

Let's now take a look at the legal definitions of cogeneration and at the 5% and 42.5% minimum requirements referred to at the beginning of this article. The 5% requirement is called operating standard,

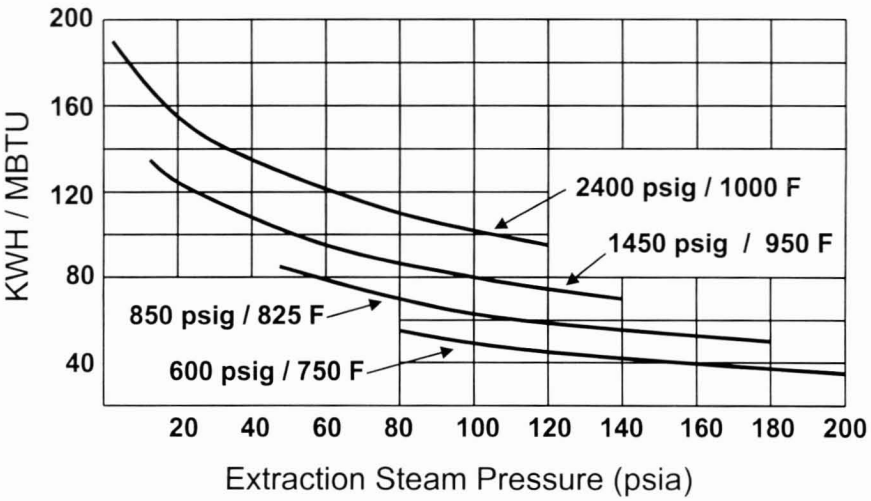


Figure 4. Steam Turbine Specific Power Output vs. Extraction Pressure

the 42.5% is called the efficiency standard. Using numbers from Figure 4 we can find that for a 600 psig/750°F plant and a backpressure turbine with 100 psig extraction pressure, the ratio of *thermal energy over the sum of electrical plus thermal energy* would be 85% instead of the 5% minimum required.

The 5% requirement means that approximately 10% only of the steam introduced to the turbine will be extracted, and 90% will go to the condenser with all the low efficiency implications. Which brings this cogeneration plant close to a conventional electric power plant, except, due to the cogeneration plant's low initial parameters its efficiency will be even lower than that of an average utility plant.

Of course, having a large condenser will add flexibility to the operation: it facilitates load switching and some peak load shaving. However, such performance should be limited only to a few hours a day, otherwise the cogeneration plant efficiency measured on an annual basis will drop substantially.

Therefore, to limit the condenser operation, a second requirement, the "efficiency standard," was formulated which requires that on an annual basis the ratio of the sum of electrical plus one-half of thermal energy over the fuel input shall be equal or more than 42.5%. In other words, for short periods of time you can use your cogeneration plant just for electricity generation, however, on an annual basis you need to generate more useful thermal energy.

Again, this requirement still leaves opportunities for extensive condensing operations. In our example the ratio will be higher than 50%. Should we use different initial parameters, this ratio may approach 70%. In other words, a lower annual ratio means you have generated much more electric power than is stipulated by your thermal load, and, probably sold the extra electricity to the utility.

Some states did develop more stringent QF (qualifying facility) requirements than FERC (Federal Energy Regulatory Commission), for example, in Connecticut a 20% minimum operating efficiency was required instead of 5%.

During the 80's many developers that met the above referenced minimum QF requirements, enjoyed the tax benefits and gaseous fuel use benefits (including special cogeneration low tariffs) and built independent power plants. Unfortunately, it was found later that some of these plants did not have one important key factor that makes cogeneration feasible and beneficial—**the proper thermal**

load profile.

Figure 5 shows a hypothetical daily thermal load profile (I am emphasizing the thermal load, but if the plant is put in a dispatch mode, the electric load profile may significantly affect the plant economics as well).

For simplicity let's assume that this is the plant's typical process load profile which means this plant operates round the clock and that approximately half of the time the load is close to 50% of the maximum. If you take a typical daily cooling load profile, its shape will look similar to Figure 5, except the peak and semi-peak area will be much narrower.

It would be a mistake to size the power equipment (high pressure boiler and turbine) for the maximum hourly load, because the larger size equipment will cost much more, and will be operating at full load only for a few hours a day. It is much more economical to size the equipment for the base load only, and shave the peak load with a low pressure boiler for process steam, or with a TES (Thermal Energy System) in a cooling application.

The next simplified graph (Figure 6) shows how much thermal energy can be used by one-shift, two-shift, and three-shift operations that have the same hourly maximum load. It is clear that a three-shift round the clock operation facility will require much more thermal energy annually as compared to a one-shift, although their hourly maximum load is the same.

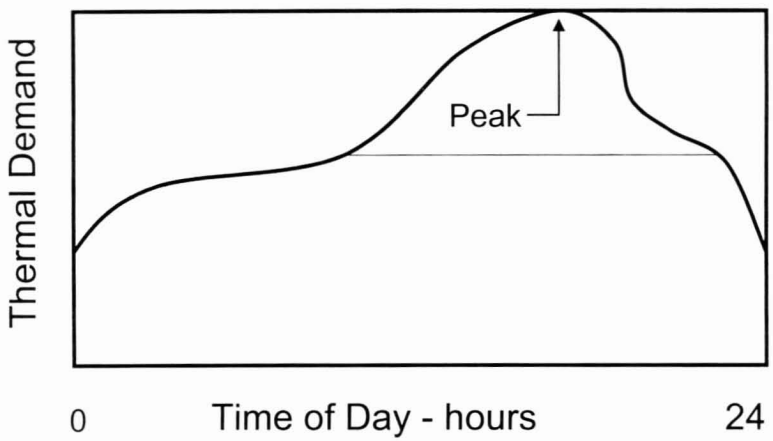


Figure 5. Process Load Profile—24 hr

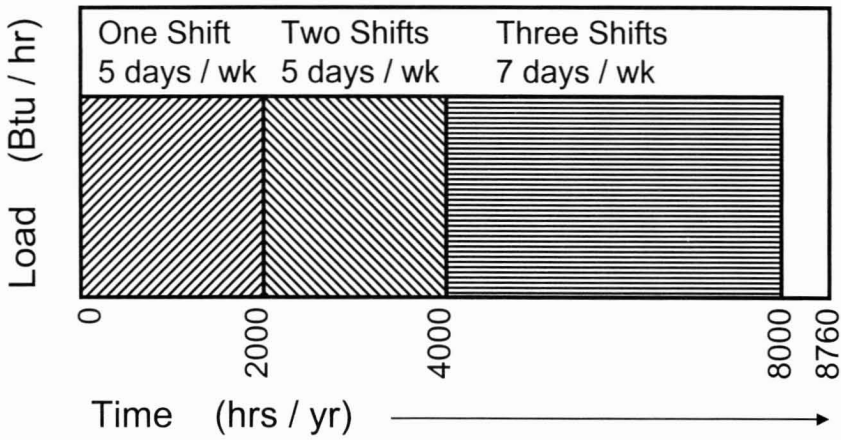


Figure 6. Annual Process Load Profile (simplified)

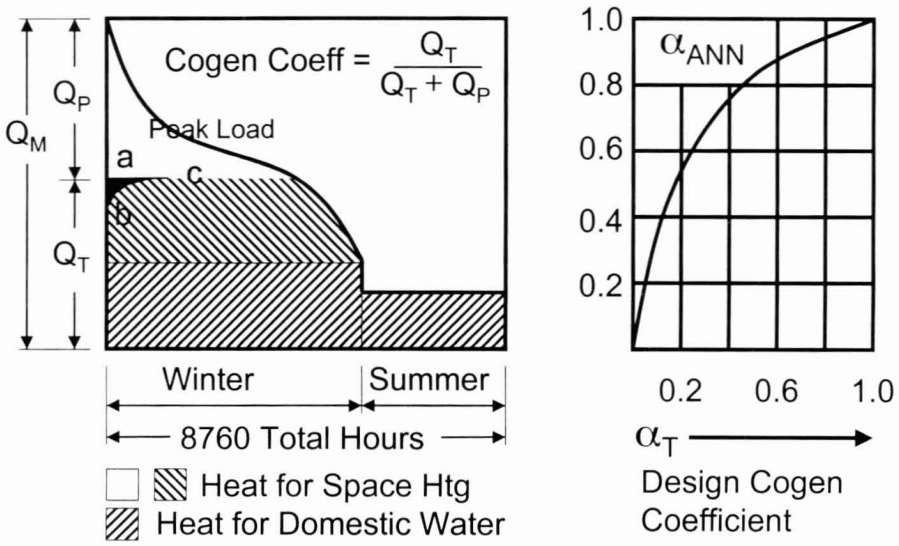
Therefore, it is much easier to justify a cogeneration plant that will supply thermal energy to a three-shift operation. If a facility operates only 1 shift, 5 days a week, in most cases the cogeneration plant will not be economical.

The next graph (Figure 7) shows an annual heating and domestic water load profile typical for a Midwestern city. The cooling load annual profile for a southern area (for example South California) may look alike, except there is no flat segment, and the word "winter" is replaced with "summer."

Again, the power equipment shall be sized for the base load only. The ratio of the optimal thermal load, for which the power equipment is sized, to the hourly maximum thermal load is termed "cogeneration design coefficient" (CDC). It is a very important factor for equipment selection and determination of the feasibility of a cogeneration plant.

As can be seen from Figure 7B if we select a CDC of approximately 0.5 for a heating or cooling load, this will assure that the cogeneration plant will be able to use over 80% of the annual thermal energy demand for simultaneous generation of electric power. The remaining peak load should be shaved off by less expensive low-pressure boilers or cooling sources.

I hope the above examples illustrate the importance of understanding the thermal load profile the cogeneration plant developer



7A 7B

Figure 7. Cogeneration Coefficient (Heating)

and/or a potential plant owner should consider. If you do not have valid actual thermal loads (not "maybe, in the future") you are wasting your money for cogeneration. But if the loads are "in store" on an annual basis, your project can be a winner.

I know a cogeneration plant in California that was designed to meet cooling loads of a famous hotel using absorption chillers. However, after the cogeneration plant was built, the owners of the hotel decided that they did not want absorption chillers due to their poor past experience with these types of chillers. Therefore, the cogeneration plant currently does not have thermal energy demand, and is mothballed. If the hotel owners were familiar with the cogeneration principles, this plant would either never have been built or would have been equipped with modern reliable absorption chillers that operate successfully.

COGENERATION AND DISTRIBUTED GENERATION

All of us have heard about distributed generation (DG) that is supposed to hit the market due to the deregulation. During recent years there have been a host of articles about DG, therefore, I will

not elaborate on this any further. In the majority of cases the ideal DG plant size will range from small to 25 MW—50 MW.

An often-asked question is what size cogeneration is feasible. In this article only a general answer can be given, because the economics of a cogeneration plant are very site specific. The majority of the readers probably know how an effect of scale works. The larger the plant is, the lesser is the capital cost per kW installed within the same technology, say steam turbine or gas turbine plant.

At smaller plant sizes the technology may need to change, for example, the application of reciprocating engines or fuel cells instead of steam or gas turbines, or application of a recently emerging new breed of very small gas turbines in the microcogen range.

One problem for microcogen gas turbines, though, may be the fuel supply. The microcogen gas turbines may require a high compression ratio, which means a need of natural gas pressure in the range of 350 to 500 psi. This may add a significant cost to the cogeneration plant and in some instances make it hard to justify.

By the way, the term "microcogen" needs to be defined. According to many authors and publications, microcogen units are below 500 kW. However, California Assembly Bill AB 1890 page 90, paragraph 331f labels "microcogen" everything below 1 MW.

In general, the size of reciprocating engines can range from 20 kW to 10 MW and higher, fuel cells could range from 200 kW to 2 MW, micro gas turbines range from 50 kW to 500 kW, small gas and steam turbines are in the 1 MW to 5 MW range. Common medium size turbines and combined cycle cogeneration plants are in the 10 MW to 50 MW. Large units can range in several hundreds of MW.

Recent examples of moderate size cogeneration plants that were found feasible: San Diego, California, 2.4 MW hospital cogeneration upgrade to increase the capacity to 4.7 MW and add absorption chillers; Mojave Soledad Mountain Mine (California) 10 MW cogeneration development; Chicago, Illinois, McCormick Place 4.5 million sq. ft. three-building central heating/cooling cogeneration plant with three 1.17 MW gas turbines.

As can be seen, the cogeneration plant is an ideal source for distributed generation. Cogeneration and the DG go hand-by-hand. So, being highly efficient and ideal for DG, will the cogeneration technology be competitive in a deregulated market? The answer is yes, of course.

OTHER ISSUES AFFECTING COGENERATION

Where stable thermal loads are available, proper selection of the major plant equipment will assure high efficiency. In turn, high efficiency of a cogeneration plant means lesser fuel used for generating the same amount of thermal and electric energy than can be obtained from a conventional scheme (thermal energy from a separate boiler and electric power from a utility plant).

And burning a lesser amount of fuel means lesser amounts of pollutants being emitted to the environment. In other words, a cogeneration arrangement is beneficial to the environment, and contributes to reduction in global warming.

I think the EPA should label cogeneration plants as "green" or "semi-green" technology and come up with an emission credit system that will serve as a bonus for generating a certain minimum of energy using lesser amount of fuel.

In December 1997 the United States Vice President Gore went to Kyoto (Japan) for an environmental summit on global warming. The United States was pressured to tighten emission limits further. This could have a devastating impact on energy prices and promote further the plants with the highest efficiency, among them, of course, cogeneration plants.

One extremely important question that may be asked by owners of existing cogeneration plants or by facilities that can be potential host sites for cogeneration: what if we do not have qualified manpower resources to operate our own cogeneration plant? There are several solutions. Companies like Steward & Stevenson, Kraft etc. and many local operators can sign a long-term operating agreement with such facility.

Another example of companies that are ready to take advantage of deregulation, is a recent agreement between DuPont Co.'s Conoco oil unit and a utility company (American Electric Power Co.) to set up a joint venture aimed at meeting the needs of heavy industrial users. This new company will buy the power plants of various manufacturing companies (steel, refined-oil, petrochemical and paper producers), upgrade them and then lease them back for a 17-year period. If asked, this company will also operate these plants.

One more example of this trend is the recent Tractebel's Power Inc. acquisition of two cogeneration plants from Simpson Paper—a

40 MW plant in Pomona, and a 42 MW plant in Ripon, both in California. These plants will continue to supply steam to Simpson Paper.

We keep hearing horror stories about the CTC (competitive transition charge) penalties imposed by some states to recover the utilities' stranded costs and to facilitate the deregulation. However, these charges are temporary. For example, in California the CTC charge will end by June 30, 2000. For a well-selected cogeneration plant a 2-year surcharge of about 2 to 3 c/kW-hr is not fatal. Such plant can generate revenues that will easily offset the CTC losses.

The bottom line is: if proper thermal loads are in place, and if the cogeneration unit is configured and sized to fit the available loads, and the proper technology is selected that will best meet the electric-to-thermal load ratio, such cogeneration plant will be a viable and competitive plant in a deregulated market. Such plant will save a significant amount of fuel and ultimately contribute to reduction of global emissions.

At the beginning of this article I have mentioned pros and cons of using a condensing steam turbine arrangement. This feature may be an advantage for a cogeneration plant in a deregulated market, adding operating flexibility, that allows load switching. Cogeneration plants that are equipped with condensing steam turbines or combination gas and steam turbines may have load-switching capabilities.

During the Electric Peak hours it may become beneficial to generate more thermal power from low-pressure boilers, TES, etc. and to divert more steam to the condenser instead of the extraction, in order to increase the electric output and sell extra peak power at an instant high rate.

Such thermal-to-electric load switching can be partially achieved within the existing PURPA limits or, if PURPA is repealed, as some experts suggest, under modified rules. Of course, a condensing arrangement requires higher initial capital cost and some additional operating expenses, however, deregulated market economics may justify less efficient condensing mode part time operation.

Another important issue is the type of fuel to be used for cogeneration plants. There are large industrial cogeneration plants that are burning coal, and there are medium size cogeneration plants burning wood or biomass, or other exotic fuels. However, the majority of cogeneration plants are using natural gas.

Natural gas is a clean fuel, it requires lesser pollution control equipment. And since gas market deregulation there were no shortages in gas supply, and the prices keep falling. Natural gas pipelines are usually available in the vicinity of dense thermal loads, although modifications and/or pipe size increase may sometimes be required.

How do states view cogeneration? It partially depends on the state population density, and prevailing industries and utilities' attitudes. Many states encourage cogeneration. For example, the state of California AB 1890, Section 372a states the following:

"It is the policy of the state to encourage and support the development of cogeneration as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth."

So, where does cogeneration fit in the deregulated market? It's like our local store. We do not need to drive on a freeway or take a bus, shopping for lower prices. It is near us, and in many cases may be the most economical source of both thermal and electric power.

ABOUT THE AUTHOR

Dr. Moisey Fridman is the manager of engineering of the west coast branch of Armstrong Service located in Cerritos, California. Armstrong Service is a leading company in steam and thermal energy supply. He is one of the experts in cogeneration and power plants, industrial energy supply, District Heating and Central Cooling systems. Previously he was with LG&E Power as a lead engineer and consultant, and with Sargent & Lundy's (Chicago, IL) analytical division as a senior engineering specialist on cogeneration and combined cycle power plant.

Dr. Fridman was involved in the development, engineering and design of numerous power plants in the United States, Europe and Asia, serving as a group leader, project manager and advisor to special task groups. He has worked in the U.S. since 1977. He received his MS degree in mechanical engineering from Kiev Polytechnic Institute (USSR) and his Ph.D. degree in cogeneration from Moscow Energy Institute. Having worked for major engineering and research companies, he has over 30 years experience in energy source development around the world. He is also a registered professional engineer in the states of Illinois and California.