ABSTRACT

The practice of installing and operating electric generating equipment at or near the point of use is known as 'distributed generation' (DG). In contrast, the traditional model of electricity generation in the U.S., is usually called 'central station' generation. It consists of building and operating large power plants, transmitting the power at high voltage over long distances and then delivering it to the end user through local utility distribution systems.

What are the advantages of distributed power, and what are the weaknesses? This paper provides an overview of the technology and it's potential.

Distributed Power is Not New

Many industrial companies have installed and operated their own power plants instead of buying all of their power from the grid, especially in remote locations. Orphan industrial plants, like pulp and paper mills installed far from central stations, frequently produce their own process steam and electricity. Other users with critical loads have maintained on-site back-up power generation resources. These backup generation units typically are reciprocating engine generators, run on diesel fuel that is stored on site. DG plants can be large, generating dozens or even hundreds of megawatts for an industrial facility, or be as small as what is needed to cover the average electric needs of a house. In the U.S. market today, most DG plants fall into the 5-15 MW range for industrial facilities.

What is New

Power generation technologies have evolved significantly in the past decade, making DG much more efficient, clean and economically viable. The attractiveness of DG is enhanced by the recent surge in energy prices.

The prices of coal and natural gas, the chief fuels for central power generation, have risen sharply in the last few years and the price of petroleum is at historic highs. While it is not necessarily logical, the markets for the chief fuels of power generation move upwardly when the price of petroleum is high. Contributing factors to the current spike in fuel prices is the rise of industrial giants China and India, which rely heavily on traditional fuels and, importantly for the price of coal internationally, use tremendous amounts of shipping capacity for their trade. Since this phenomenon is not likely to reverse itself, we can now expect that the price of fuel will remain high for many years to come.

A new development is the fallout from deregulation initiatives on the federal and state level over the past few years. In response to these deregulation initiatives, many utilities have transformed themselves from integrated enterprises, generating, transmitting and distributing power, to essentially distribution companies and traders, buying power from independent producers or through regional markets and selling it to customers, making power more expensive as the price of fuel rises.

Another result of deregulation is that utilities no longer necessarily consider on-site power generators as competitors. Up until recently, many utilities were openly hostile to DG, seeing each distributed generator as a lost customer. Given their new status as distributors and traders, some utilities, and their state regulators, are seeing DG as a part of their capacity planning, a resource that can be called upon when supply is tight, or which allows them to avoid financing the installation of new capacity.

Technological improvements have enhanced the feasibility of DG. Technology for connecting distributed generators to the grid has improved steadily (synchronization and power quality control). The traditional transmission and distribution systems were originally designed by utility engineers implementing solutions for their own needs. With the advent of software controls, different utilities implemented different software solutions. Today, there is a considerable disparity between the technical characteristics of some electric distribution systems. This has tended to make connecting DG to the grid a costly exercise because individualized engineering has to be done for this interconnection of each distributed generator. However, there is now a new industry technical standard known as IEEE 1547-Standard for Interconnecting Distributed Resources with Electric Power Systems, that gives both engineers and utilities a point of reference that is helpful in planning on-site systems.

Finally, there has been great improvement in metering technology, with 'smart' or 'real-time' metering allowing users to see much more precisely how much power they are using at a given point in time and adjusting their usage accordingly. 'Net' metering allows a DG to measure how much power it puts back on the grid if it is generating more than its needs at any given time.

A New Focus on Energy Issues and Changes in Corporate Attitude

The realization that fuel prices are not likely to go down soon, and a growing awareness that deregulation has consequences for both cost and reliability, are engendering a shift in attitude on the part of corporate decision-makers. Before, energy was seen as being provided in a quasi-monopolistic way, but available when needed at a fairly predictable cost. Today, the cost of energy is becoming a major and unpredictable component of the price of goods and services, and decision-makers are focusing attention on how to control energy prices in order to remain competitive. They are also thinking that they cannot afford to lose production and critical functions if the grid is not available and are looking for ways to obtain back-up power.

All of these market and technological developments are adding up in such a way that corporate development planners and executive should be asking themselves whether it makes sense for their companies and facilities to be generating some or all of their own power. Further, for facilities that consume large volumes of natural gas for industrial heating applications and have large power demands, the economic model for the application of combined heat and power DG plants has proven ROI hurdle rates can readily achieve, if not far exceede, most corporate decision-makers expectations.

What follows is a discussion of some of the considerations involved and how obstacles can be navigated to result in a successful DG project.

Combined Heat & Power (CHP)

A combined heat and power (CHP) system produces multiple products, including electricity, steam and chilled water. In contrast, a traditional DG power plant, or a utility power plant, focuses on the production of electricity. Although CHP is usually a fossil fuel-based process, it can incorporate biomass, other biofuels, or industrial process waste gasses. But regardless of the fuel source, CHP is “greener” than a traditional power plant by virtue of its higher efficiencies. CHP systems typically achieve total system efficiencies of 60 to 80% for producing electricity and thermal energy. CHP is a proven, implemented process with more than 80,000 megawatts (MW) of CHP capacity in the United States[1].

The prime mover in a CHP system is most commonly a boiler or a combustion turbine burning coal, natural gas, biomass, biofuels, or waste industrial gas. Mechanical energy is most often used to drive a generator to produce electricity, while thermal energy produces steam or chilled water. The steam generated from a heat recovery boiler can be used to produce additional electricity in a steam generator, or in institutional or industrial settings, the low pressure steam can be used for process heating or to heat or cool buildings (using an adsorption chiller).

With advances in technology and the high efficiencies, a CHP plant is very efficient. For every MMBtu of energy that goes into the cogeneration plant, between 60% and 80% can be converted to electricity or heat (overall energy efficiency). The loss in energy comes from inefficiencies in the gas turbine, gearbox and generator.

A 5.0 MW gas-fired combustion turbine requires, on average, 75MMBtu’s per hour and provides 50MMBtu’s per hour of industrial heat. The gas turbine exhaust is typically around 600^{o}C (1100 ^{o}F). This heat is used as process heat or to produce steam in a heat recovery steam generator (HRSG) which is then used in a steam turbine for additional

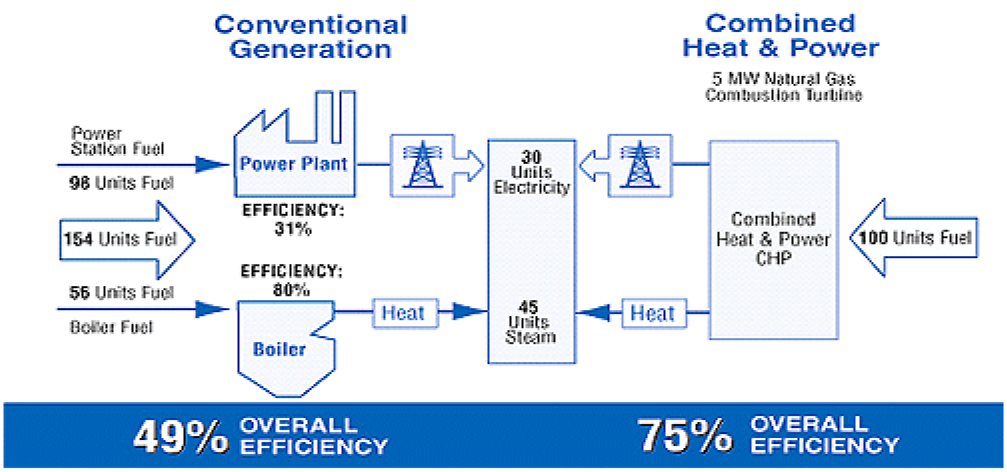
[1] http://www.epa.gov/chp/index.html

electricity production. This is often also referred to as cogeneration. Alternately, the steam can be used in an adsorption chiller to supply chilled water for cooling.

In order to maximize combustion turbine electric output, the inlet air must be cooled or chilled to approximately 55°F. The cogeneration plant heat output increases as the inlet air temperature is lowered. While the inlet air chiller consumes additional electricity, it also boosts generator output, often creating a net increase in power generation capacity.

In contrast, the average efficiency of fossil-fueled central power plants in the United States is 33 percent and has remained virtually unchanged for four decades. This means that two-thirds of the energy in the fuel is lost—vented as heat—at most power plants in the United States.

The illustration below demonstrates the efficiency gains of a 5 megawatt (MW) natural gas-fired combustion turbine CHP system compared to separate heat and power.



Although, CHP systems typically achieve system efficiencies of 60 to 80 percent, higher efficiencies can be achieved. For example, ExxonMobil's Beaumont Refinery in Beaumont, Texas, operates a 470 MW CHP system that achieves an operating efficiency of **88%**, requiring approximately 37 percent less fuel than typical onsite thermal generation and purchased electricity.

Based on this performance, the CHP system reduces carbon dioxide (CO_2) emissions by an estimated 2.4 million tons per year, which is equivalent to removing the emissions of approximately 397,000 cars or planting approximately 595,000 acres of forest.

Permitting & Siting Requirements for CHP

Even though CHP plants are more efficient than traditional power plants, they are still subject to the same permitting requirements under the Clean Air Act

For all CHP projects, pre-construction, construction and operating approvals must be obtained from local jurisdictions. The more involved approval procedures are those required by the local planning and building departments and the air district. Local planning and building departments must ensure that a CHP project complies with:

- Local ordinances (e.g., noise, aesthetics, set-backs, general plan and zoning, land use), and
- Standards and codes (e.g., fire safety, piping, electrical, structural, etc.).

Approvals may be in the form of a permit or license issued after an agency has verified conformance with requirements, or may be in the form of a program (e.g., landscaping, noise monitoring) that must be developed to ensure the environmental impacts are mitigated. Approval processes such as siting and zoning are not onerous tasks for most CHP projects, and even less of one for a large district energy system. However, three obstacles can sometimes slow down siting and zoning:

- *Codes often don't yet address many newer CHP technologies*
- Zoning issues such as noise and esthetics may arise
- Local code officials are sometimes unfamiliar with new technologies.

Environmental regulatory and local government agency approval costs, for which project planning has not been mapped out, may approach 15-30% of project costs and need to be considered as part of any CHP project economic feasibility study. The general approval process includes fee payment; paper work concurrent with fee payment, agency review and approval. These costs may include:

- Air pollution control equipment
- Noise abatement equipment or structures
- Landscape-related mitigation, and
- Agency review and approval fees.

The number of permits and approvals will vary depending on project characteristics such as the size and complexity of a project, the geographic location, the extent of other infrastructure modifications (e.g., gas pipeline, distribution), and the potential environmental impacts of construction and operations.

Site selection will determine the agencies (and local community) involvement. This includes such entities as the city or county planning agency, the fire marshal at the respective fire department/authority, the city or county building department, the environmental health department, and the air district.

The following is a general guide to the primary approvals that CHP sources must obtain:

1. **Local jurisdiction pre-construction** (*see below for New Source Review*) **and construction approvals**
   - **Planning** department land use, zoning and environmental assessment/review. A conditional use permit may be issued that identifies additional mitigation such as landscaping plans, air pollution control, architectural treatments and noise abatement. Project impacts evaluated for conformance and environmental impacts—which could include esthetics, agriculture resources, cultural resources, geology / soils, hazards and hazardous materials, mineral resources, noise, recreation, transportation / traffic. Noise impacts evaluated by this agency. Jurisdiction defined by city or county limit. Contributing factors to the differences in agencies' reviews include: nearby affected communities, local ordinances, nearby affected plant and wildlife species, understanding of CHP technology environmental impacts, and inter-agency coordination efforts.
   - **Building** department review and approval of project design and engineering. Approvals issued for projects in conformance with building code requirements. The local building department will expect a CHP project's design and operation will conform to building codes, e.g., local and national building codes; in addition, conformance with fire codes is required. Project design must consider industrial and worker safety, as defined by the authority having jurisdiction. Jurisdiction is typically defined by city or county limit.
   - **Air district** approval for construction. For both small and large generation sources, the air regulatory and permit requirements continue to evolve throughout the nation, with particular emphasis on state-of-the-art technologies, precedent setting permit actions, and Best Available Controls Technology (BACT) guidance documents/policies. Compliance demonstration is required for meeting and record keeping of emissions, fuel usage, operating times, and emissions source testing. Primary area is the control of air pollution to protect public health. Issues that an air agency considers include: exemption thresholds (e.g., capacity, emission levels), controlled emission levels, type of fuel(s) fired, proximity to sensitive receptors (e.g., schools, day cares, hospitals), siting at a new location or an existing site (e.g., commercial building, industrial facility),

health risk exposure of combustion by-products, and a demonstration that projected emission levels are met via source testing.

- Each air district has its own set of regulations. BACT requirements is the most notable difference for air agency approval of a CHP project, particularly for NO_x emissions. The NO_x level is based on some controlled level of emissions and therefore may require add-on control technology. Jurisdiction defined by county limit or a group of counties comprising an air district.

- There are explicit air permit exemption thresholds and thresholds stipulating the need for an air permit. For CHP projects, fossil fuel-fired technologies such as reciprocating engines and steam powered turbines must obtain an air permit. All districts require the same type of information, however, differences from agency to agency include:

    - Application forms and fees

    - Title V permit program implementation

    - Details of support information required

    - Emission factors to estimate air toxics

    - BACT requirements and pollutant-specific cost-effectiveness benchmarks

    - Degree of air modeling required

- Application forms and fees differ in terms of level of detail and cost for review. For all CHP projects, emissions must be estimated, exhaust gas parameters must be defined (for air toxics evaluation), and a demonstration of compliance with rule requirements must be made. US EPA has developed an Emissions Calculator to provide an estimation of the expected emissions from a CHP facility for various operating scenarios.

- The Midwest CHP Application Center's Volume B - Permitting Issues, nearly half of all facilities in the Midwest had to obtain a Clean Air Act Title V permit and had to use an outside consultant for permitting purposes. If a facility has an existing Title V operating permit, the CHP project must be included in this permit. Therefore, a modification of the operating permit is necessary. For many agencies, separate Title V application forms and fees apply. Additionally, there are separate review and processing times. Both local and federal regulatory requirements must be identified. Depending on the emission levels, a public comment period may be necessary. For permit exempt CHP sources, a minor modification may be obtained, thus avoiding a more rigorous review and public comment.

- Criteria pollutant emission factors may differ from agency to agency. For most CHP technologies, factors provided by the vendor and/or source test results of similar technologies are relied upon as the most representative, while default emission factors are used in absence of vendor information. If this is the case, it would be necessary for a developer to determine whether he/she is in agreement with the air agency's default factor.

- Air and water permitting, especially for facilities classified as a major emissions source or a facility in need of a National Pollutant Discharge Elimination System (NPDES) water discharge permit, may constitute the critical elements of the timeline during the development of a CHP project.

2. **Local natural gas distribution company approval**
    - Interconnection study
    - Natural gas pipeline connection/supply

3. **Other potential approvals**
    - Environmental/health department. Approvals issued for projects in conformance with federal and state hazardous materials and waste management requirements. Jurisdiction defined by city or county limit.
    - Public works
    - Regional water quality control board
    - Fire department. Approvals issued for projects in conformance with fire code requirements. May also be organization responsible for portions of environmental health-related requirements. Jurisdiction typically defined by city or county limit.
    - Water/wastewater district. Water supply and discharge. Water permits, while not required for many CHP prime movers, are usually required for heat recovery and energy utilization equipment. Approvals issued for allowable discharge to sewer system; evaluates waste streams that may enter various bodies of water (e.g., lakes, streams, bays, estuaries, coastal waters, etc.). Ensures compliance with stormwater requirements. Project conformance with federal Clean Water Act and local water and wastewater quality

4. **Local jurisdiction post-construction and operation approvals**
    - Planning department and building department confirmation and inspection of installed CHP source.
    - Air district confirmation that CHP emissions meet emissions requirements

All CHP projects are subject to the Federal US EPA New Source Review (NSR) (some just may be small enough to be classified as minor source permits under the NSR program).

The New Source Review (NSR) is a preconstruction review and permitting program that considers emissions such as nitrogen dioxide, carbon monoxide, particulate matter, ozone, and other emissions as legislated by Congress in Title I of the Clean Air Act (Act) to preserve or restore air quality.

The 1977 Amendments to the Act required implementation of a Prevention of Significant Deterioration (PSD) program. Requirements were then promulgated into those States, as State Implementation Plans (SIPs), where there was no approvable plan in place. The purpose of the PSD program is to ensure that the permitting of proposed new industrial facilities and the associated economic growth will occur in a manner consistent with the preservation of clean air resources.

There are three types of NSR permitting requirements. A source may have to meet one or more of these permitting requirements. The three types of NSR requirements are:

1. Prevention of Significant Deterioration (PSD) permits which are required for new major sources or a major source making a major modification in an attainment area;
2. Nonattainment NSR permits (NNSR) which are required for new major sources or major sources making a major modification in a nonattainment area; and
3. Minor source permits.

These permits are legal documents that the source must follow. They specify what construction is allowed, what emission limits must be met, and often how the source must be operated. They may contain conditions to make sure that the source is built to match parameters in the application that the permit agency relied on in their analysis. For example, the permit may specify stack heights that the permit agency used in their analysis of the source. Some limits in the permit may be there at the request of the source to keep them out of other requirements. For example, the source may take limits in a minor NSR permit to keep the source out of PSD. To assure that sources follow the permit requirements, permits also contain monitoring, recordkeeping, and reporting requirements.

Areas of the country with poor air quality are subject to the more stringent requirements of nonattainment NSR permitting. Areas of the country with sufficient existing air quality are subject to PSD permitting.

In a nonattainment area, any stationary pollutant source with potential to emit more than 100 tons per year is considered a major stationary source. In PSD areas the cutoff level may be either 100 or 250 tons, depending upon the source.

The benefits of CHP are not recognized at the federal level when permitting new projects; however, some states have adopted specific regulations to encourage CHP projects.

To minimize pitfalls, Venture recommends the following steps:

Step 1. Define Source

- Is CHP its own source or part of another source?
- Is CHP a new source or a modification to an existing source?

Step 2. Calculate Emissions

- For a new source, estimate potential to emit (PTE) based on design operational capability but can account for operational limits, fuels, emissions controls.
- For modifications to existing source, determine net emissions increase (if any); and source-wide creditable contemporaneous increases - source-wide creditable contemporaneous decreases + modification increases.

Step 3. Determine NSR Applicability

A CHP project will trigger Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) if it is a new major source or a major modification of an existing major source.

Step 4. Explore Options to BACT/LAER Analysis

- Exemptions in rule (e.g. some fuel switching is exempt)
- Reduce emissions below threshold level
    - Install pollution controls
    - Take operating limits
- Emission netting

- Trade cost vs. emissions

Step 5. Meet with Permitting Officials

- Meet early in the process
- Present your proposal
    - Ensure that source definition, emissions factors, calculations are approved by the authority (*Permitting authorities have interpretative latitude for NSR)*
    - Ensure both agree if BACT/Lowest Achievable Emissions Rate (LAER) is triggered
- Ask about other applicable requirements (water regulations, NSPS, HAPs)
- Negotiate permit terms and conditions
    - Fuels, controls, hours, monitoring & reporting

Step 6. Permits

- For both Major and Minor Sources
    - Submit permit application
    - Obtain permit to construct
    - Obtain permit to operate

Summary

The energy landscape has changed dramatically over the last decade; from regulatory, cost, technology, and environmental perspectives. Owners should evaluate their options for energy, and look carefully at on-site generation as a viable alternative to purchasing power from the grid.

Furthermore, with a national growing concern over greenhouse gas emissions, CHP is an excellent alternative to a traditional power plant. CHP has higher overall efficiencies and produces more useful power for fewer emissions. Although some states have recognized the benefits of CHP and adopted rules to encourage CHP projects, federal regulations have yet to follow suit. Large CHP projects which are subject to NSR permitting requirements are not able to take full advantage of state CHP permit benefits.

Venture Engineering & Construction has considerable experience in the traditional, distributed generation and CHP power markets. To learn more about our capabilities, or to assist you with your distributed generation project (from permitting through construction), please contact our Senior Power Engineer, Mr. Robert Gambon, PE at 412-231-5890, ext. 311.

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