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Clean Power Supply Through Cogeneration

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Abstract

The objective of this paper is to summarize the engineering, economic and environmental implications of cogeneration (the simultaneous production of electricity and process thermal energy), and to explain how cogeneration can contribute to improving environmental quality by using fuels more efficiently than standard methods of production. The ability to evaluate alternative energy/environmental policies resides in understanding the fundamental thermal cycle dynamics of energy production and emissions abatement technologies. The cogeneration technologies presented are the Rankine cycle, Brayton cycle, and combined cycle. The emissions control technologies evaluated include the Wellman Lord, Chyoda Thoroughbred, Magnesium Oxide, conventional wet scrubbing, atmospheric fluidized bed combustion, and integrated gasification combined cycle. Electrical interconnection requirements and issues affecting of non-utility generation are also evaluated.

Chapter 1
Introduction

1.1 Objective

The primary objective of this report is to examine and explore the most "cost effective" and practical solution to reduce emissions from electric and thermal energy generation, in particular emissions of nitric oxide and sulfur dioxide, and to minimize negative externalities associated with satisfying New York state's electric and thermal demands. A secondary objective is to illustrate the interdependency between consumption of fuel for thermal heating, cooling, and electricity.[1]

1.2 Current Situation

Fifteen years ago nuclear energy was touted as a source of electricity "too cheap to meter." This phrase and the nuclear industry's claim that it was safe and reliable have been disproved through the course of time. The electric utility industry is now in a perplexed state. Some members cling to the past glories of nuclear power and hope it will return to the prominence and full glory they

[1] Environmental and economic externalities associated with thermal and, electric power production will be assessed from an individual rate payer's perspective and from a societal perspective. Examination of emissions abatement will focus on the technologies used to reduce nitric oxide and sulfur dioxide.

originally dreamed while facing the grim reality of high cost for nuclear plants and increased competition from independent power producers. Cogeneration by Non-Utility Generators (NUGS) is a rapidly growing factor that is changing the role of utilities and the way future energy needs will be met.

Recently, the droughts in the Midwest during the summers of 1987 and 1988 have raised concern over the effects of greenhouse gases. Nuclear power has begun to resurface as a "clean" means of generating electricity. The additional cost associated with nuclear power generation compared to fossil fuel generation could achieve greater reduction in emissions through more efficient fuel utilization. Cogeneration is an effective means of mitigating the three critical effects of industrial pollution: greenhouse effects, acid rain, and ozone depletion. Nuclear generation does not achieve the same thermodynamic efficiencies as cogeneration. Furthermore, the threat of nuclear accidents and the associated risks of nuclear waste disposal could lead to more serious environmental problems than fossil fuel power generation.

1.3 Legislative Enactments

Legislation currently defines cogeneration systems as providing electricity and a useful thermal output such as steam, hot air, fluid heating, or absorption refrigeration. Cogeneration is the sequential use of thermal energy from one fuel source to generate electricity and to provide process heat. The reject heat of one process becomes an energy input to a subsequent process so that the same fuel is used twice. The paper and wood pulp industries, in particular, have taken advantage of the efficiencies of cogeneration since the turn of the century.

Utilities have centered their construction efforts on building large power generation facilities where the exhaust heat is dumped in estuaries and aquatic bodies. The intrinsic inefficiency in this type of generation means that only 35% of the thermal input is converted to electric power. This situation has become more than a thermodynamically inefficient use of energy and has led to several legislative enactments.

In 1978, Congress enacted three bills under the National Energy Act: Public Utility Regulatory Policy Act (PURPA) , Power Plant and Industrial Fuel Use Act (FUA), Natural Gas Policy ACT (NGPA). Section 210 of PURPA describes the requirements that a cogeneration system must satisfy in order to qualify as either a small power producer or a cogenerator. A small power producer is defined as a facility operating with a maximum electric power production of 50MW. A complying cogeneration facility is first distinguished from a central generation facility because it is granted the right to use fossil fuel as a primary fuel as long as it meets certain minimum efficiency standards. The Energy Compliance Factor (ECF) is defined as follows [U.S. Congress 78a]:

$$ECF = \frac{\text{Power Output} + \frac{\text{Usable Heat}}{2}}{\text{Fuel Input}}$$

1) If the usable thermal energy output of the facility is greater than 15 percent of the total energy output of the facility, then the ECF must be at least 42.5 percent.

2) If the usable thermal energy output is greater than 5 percent but less than 15 percent of the total energy output, then the ECF must be at least 45 percent.

3) If the usable thermal energy output is less than 5 percent of the total energy output, then the facility does not qualify.

The definition of usable thermal energy output is restricted to only those uses where fuel would not otherwise be consumed for a certain purpose. For example, it is highly unlikely that fuel would be burned to heat driveways for snow removal or to heat aquatic bodies for increased fish production, and consequently, these activities would not qualify as legitimate uses of thermal energy. The EFC recognizes electrical energy as a higher form of energy by discounting the thermal energy by a factor of two.

A cogeneration facility qualifying for PURPA is often referred to as a non utility power producer (NUPP) because no more than 50 percent of a qualifying cogeneration facility can be owned by an electric utility. This situation tends to limit the role utilities can play in the development of cogeneration. Partly as a consequence of this law, utilities view NUGS as "PURPA sharks" who erode the utilities' rate base.

Another type of facility that is becoming a competitor of utilities is self generating cogenerators (SGC). These are usually large institutions or factories that generate some of their base load electric requirements and all their thermal demands, and use the utility to supplement their electrical demand. The underlying rationale for SGC is that it is cheaper to generate electric power at the site than to purchase power from a utility.

Concern about self generation and cogeneration eroding the utility's financial position is reflected in the "Annual Goals and Concerns" of William B. Ellis, Chairman and Chief Executive Officer (CEO) of Northeast Utilities Service Company [Electric World 88]:

> We have one very significant issue facing us this year and it's associated with competition. We want our rates to compete with alternative sources--- in particular with self generation.

Robert K. Campbell, President and CEO of Pennsylvania Power & Light Company is more blunt about his opposition to cogenerators in his statement of annual concerns and goals [Electric World 88]:

> This year, we have to make certain we do not lose markets to cogeneration facilities using natural gas or oil... These days any major industrial user of electricity routinely investigates the economics of cogeneration or self generation.

Congress was aware of utilities' opposition to cogeneration, and consequently granted the following benefits to SGCs and NUPPs under section 210 of PURPA [US Congress 78a]:

1) Electric utilities must purchase capacity and/or power from qualifying facilities desiring to sell it.

2) Electric utilities must sell power to qualifying facilities.

3) Electrical utility rates for sale of electricity to a qualified facility must be nondiscriminatory.

4) Rates for standby power shall not be based on the assumption that outages of all qualified facilities on a given electrical utility system will occur simultaneously or during peak periods.

Although these provisions do establish a viable market for cogenerators, cogenerators do not have a guaranteed market for any volume of product irrespective of demand and regardless of whether or not a willing buyer can be found. For example, a cogenerator may be subject to curtailment during off-peak hours depending on the minimum load factor of the servicing utility.

Utilities are constrained to operate with minimum loading limits. Pulverized coal fired boilers require fairly stable combustion conditions requiring a high minimum load. Nuclear and hydro facilities operate at low variable costs and have high minimum loads as well. The minimum load constraint of a utility may deem it impractical to accommodate cogeneration purchases when utility loads are low.

The Federal Powers Act preserves the operation of utilities' base load plants by stating that the Federal Energy Regulatory Commission cannot issue an interconnection order unless [FERC 80b]:

1) it is in the public interest and
2) would (a) encourage the overall conservation of energy or capital, or (b) optimize the efficiency of use of facilities or resources, or (c) improve the reliability of any electric agency to which the order applies, and
3) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility or qualifying cogenerator affected by the order.

Under the Fuel Use Act (FUA), both new and old cogeneration facilities are allowed to consume oil and natural gas as a primary process fuel. The Natural Gas Policy Act (NGPA) exempts qualifying cogeneration facilities from the interstate gas surcharge. Partly as a result of these two Acts as well as the complications of transportation, storage and other negative environmental externalities associated with burning coal, most new cogeneration facilities burn natural gas.

1.4 Consumer Shortfall

As currently designed, PURPA provides an incentive for energy savings through cogeneration, but under the full avoided cost standard no additional savings are passed on to the consumer.[2] The Federal Energy Regulatory Commission (FERC) defended the full avoided cost pricing in 1980, stating[3]:

1. That "any rate reductions will be insignificant for any individual customer."
2. That "ratepayers and the nation as a whole will benefit from decreased reliance of scarce fuels, such as oil and gas, and the more efficient use of energy."

The state of Mississippi felt the FERC rules were not "just and reasonable" to consumers. The Supreme Court upheld the FERC's avoided cost rule and concluded that "Consumers under the avoided cost rule should remain unaffected." Despite PURPA not directly passing the savings of cogeneration on to the consumer, it has resulted in reduced power production costs.

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[2] An exception to this is when cogeneration replaces nuclear power. Although there have been no new nuclear reactors proposed since 1978, the completion and start-up of reactors could produce power far in excess of the avoided costs.

[3] The quoted material can be found in FERC [80A] page 12222.

Chapter 2
Cogeneration Power Cycles

2.1 Cogeneration Cycles Considered

Cogeneration facilities are generally configured as topping-cycle systems. In a topping system, electricity is generated in the first stage of the power cycle and the exhaust heat is utilized in the second stage of the power cycle. Cogeneration is most attractive when there is a high thermal load to match the discharged heat from electric power generation. There are three cycles suitable for industrial, commercial, and utility cogeneration. The Otto cycle uses an internal combustion engine with natural gas as the fuel while the Rankine and the open Brayton cycle use turbines operating on steam and burnt natural gas as the central process fluids, respectively.

2.2 Cycle Analysis

Cogeneration systems are often compared on the basis of first law efficiency, power to heat ratio, and fuel consumed to power (FCP). The first law efficiency reflects the percentage of the input fuel energy that is actually used in producing useful thermal and electric energy. The power to heat ratio evaluates the electric power to the fuel input. The net plant heat rate is the inverse of the power to heat ratio and has units of MMBtu/kWh.

The FCP is the most encompassing parameter used to assess the thermal performance of a cogeneration cycle. The FCP is the incremental increase in fuel consumption for the cogeneration system relative to a decoupled energy system. The FCP is defined as follows:

$$FCP = \frac{F_{cog} - F_{ind}}{E_{cog} + (E_{ind} - E_{supp})} \qquad (2\text{–}1)$$

where the total fuel burned in the cogeneration cycle minus the fuel which would have otherwise been consumed to fulfill thermal requirements is divided by the cogenerator's power output plus the difference between the auxiliary power supplied with and without cogeneration.[4] (E_{cog} is the electric energy produced by the cogenerator, E_{supp} is the supplemental electric power consumed by the cogenerator, E_{ind} is the electricity consumed by the industrial customer without cogeneration, F_{cog} is the energy required by the cogeneration cycle, and F_{ind} is the energy consumed to meet the thermal load, without cogeneration.)

The FCP is superior to the other cycle analysis parameters because it accounts for the simultaneous production of electricity and thermal energy. For plants generating electric power only, the net plant heat rate equals the FCP and thus can be easily substituted

[4]Fuel chargeable to power often credits thermal power with an 84% efficient boiler. This is an industry standard adopted by General Electric.

as an input for the net heat rate in most cycle and power system models.[5] The power to heat ratio and net plant heat rate are the "critical" input parameters in decoupled electric power production but are of little importance in analyses of cogeneration cycles because they do not credit the thermal energy produced.

A high first law efficiency does not necessarily dictate that one cycle is a more productive or efficient means of utilizing the input fuel. For example, modular cogeneration units have first law efficiencies of 80 percent compared to the 66 percent of a coal fired system, but the coal fired unit produces a high pressure dry steam while the modular cogenerator produces only low pressure steam and hot water. Combined cycle gas turbines have the worst first law efficiency while steam generators have the best. This statistic is misleading because electricity is a higher form of energy, and in accordance with the second law of thermodynamics, should receive credit. Comparisons of the three cycles are summarized in Table 2-1 [OTA 83].

[5] Warning; direct substitution of FCP for the net plant heat rate implies that all the captured exhaust heat is allocated to supplement or offset a process that can use the exhaust heat. In an area where electric rates are relatively high, a cogenerator may be able to waste some of the exhaust and still maintain an economic advantage over decoupled generation. This is taken to be an unnecessarily inefficient process and thus is not considered.

Table 2-1: Brayton/Rankine/Otto Cycles

Technology	Unit Size	Fuels Used	Average Annual Availability (percent)	Full-load Electric Efficiency (percent)	Total heat rate (BTU/kWh)	Fuel Consumed to Power (Btu/kWh)	Electricity to Steam Ratio (kWh/MMBtu)	Cogeneration Application
Steam turbine topping	800 kW-100 MW	Natural gas, distillate, residual, coal, wood, solid waste and liquids.	90-95	14-28	10,000-20,000	4,500-6,000	30-75	Used in industry and utility applications. Best suited for low electric/thermal ratio.
Open-cycle gas turbine topping	800 kW-100 MW	Natural gas, distillate, residual, coal, wood, solid waste and liquids.	90-95	24-35	9,200-14,200	5,500-6,500	140-225	Potential for use in commercial and industrial sector
Combined gas turbine, steam	800 kW-100 MW	Natural gas, distilate, coal or biomass derived gases	77-85	34-40	8,000-10,000	5,000-6,000	175-320	Most atractive where process heat requirements are low and large electric demand. Used in refining ind t
Internal combustion engine	10 kW-2 MW	Natural gas, distilate, or synthetically derived gases.	80-90	33-40	8,300-10,300	5,500-7,500	350-700	Wide spread use in hospitals, hotels, apartment complexes, ar light industry. Must burn natural gas to meet strict environmental emission standards

2.3 Brayton Cycle

Natural gas is usually consumed in a combustion turbine via the Brayton cycle. Figure 2-1 illustrates the energy flow stream through a typical combined cycle. First, the gas is isotropically compressed in a combustion turbine and then burned in a "turbulent jet" fuel-lean flame. Additional air may be added after the combustion process to reduce the temperature of the turbine inlet temperature for metallurgical and environmental reasons.[6] The hot gases are expanded in the turbine to a lower enthalpy with only a slight increase in entropy.[7] The heat recovery steam generator (HRSG) recovers 92 percent of the energy in the turbine exhaust gases for additional power generation and process steam consumption. This yields an FCP of 5500, nearly twice the value achieved by utility combustors [OTA 1983]. The systems power output is a function of the turbine inlet temperature and compression ratio. A higher turbine inlet temperature provides a greater percentage of recoverable heat, increasing the thermal efficiency of the cycle. Thus it is desirable to keep the quantity of dilution air at a minimum.

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[6]Higher turbine inlet temperatures can cause increased turbine blade corrosion, greater turbine blade creep and increased NO_x emissions. Turbine blade corrosion results in reduced turbine life through the increased production and propagation of micro-cracks which eventually lead to t turbine blade failure. The temperature dependence of creep causes elongation of the blade and eventual contact with the shroud which results in sudden failure.

[7]Entropy is a measure of the irreversible energy losses in a system, and enthalpy is the internal energy of a system plus the the system's product pressure and volume.

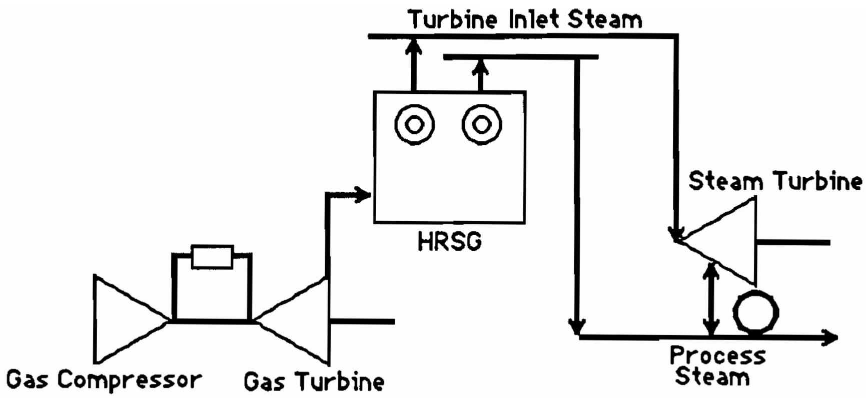

Figure 2-1: Brayton Cycle

Another configuration that burns natural gas is the combined cycle combustion turbine (CCCT). The energy flow is similar to the simple combustion turbine except the steam from the heat recovery regenerator is expanded through a second set of turbines before it is used as process heat. The additional set of turbine blades can raise the electric generation efficiency up to 42 percent. The large power to heat ratio makes the CCCT system attractive to a PURPA generator trying to maximize electric power production or to commercial customers trying to meet a large electric base load.

Most SGC systems are designed to satisfy the base thermal and electric loads. A daily or seasonably variable thermal load can be met by supplemental firing of the air rich exhaust gas to stoichiometric proportions.[8] This system is particularly attractive

[8]Stoichiometric combustion refers to the complete combustion of the fuel, resulting in a balanced combustion equation. For example, the combustion of methane (CH_4) results in the following reaction

$$CH_4 + 2O_2 + 2(3.76)N_2 \longrightarrow CO_2 + 2H_2O + 7.52N_2$$

with no excess air in the product gases.

in new applications where the avoided cost of the boiler can be saved. The additional input heat produced nearly doubles the exhaust steam output which can be used to either increase power production or to meet a greater thermal load.

2.4 Otto Cycle

The gas turbine is restricted to moderate and large scale power production greater than 800 kW. Smaller electric and thermal loads ranging from 10 to 600 kW can be met with modular cogeneration systems. Modular cogeneration units operate on the Otto cycle, using a large internal combustion engine that consumes natural gas or distillate oil as the primary input fuel.

Modular cogeneration units' small size and ease of installation make them attractive investments for the commercial and residential sectors. The exhaust gases and oil jacket provide hot water or low pressure steam for heating, cooling, or other thermal demands. The units are usually installed to satisfy a base electric and thermal load and are rarely classified as PURPA producers [Didellas 88].

Producing electricity at an average efficiency of 30 percent with 88 percent of the exhaust heat convertible to useful thermal energy explains the attractiveness of modular cogeneration. The engines typically are high speed spark ignited automotive engines. The small size and convenience of modular units have aroused the interest of many hotel and restaurant chains. Dual speed modular units can operate at 900 rpm to supply the base electric load and 1800 rpm many hotel and restaurant chains. Dual speed modular units can operate at 900 rpm to supply the base electric load and 1800 rpm during peak demand hours [Didellas 88]. The dual speed option reduces or eliminates reliance on utility power during peak demand hours.

At first, the proposal to rely on continuous power generation using an internal combustion engine caused great skepticism among potential customers. However, actual performance has been good, and a strong servicing network has limited criticism [Sobchak 88]. The per kilowatt capital costs and maintenance costs are usually greater for modular units than for turbine generators. Nevertheless, the low installation costs, small size and ease of retrofitting make modular units attractive for many installations, even in urban areas.

2.5 Rankine Cycle

Large thermal cogeneration loads can be met easily and efficiently using the Rankine cycle and coal combustors. An open coal combustor cogenerator operating under the Rankine cycle, illustrated in Figure 2-2, typically cycles with an FCP of 5000 MMBtu/kWh and a net heat rate of 9800 MMBtu/kWh.

In the Rankine cycle, pulverized coal is mixed with air preheated by the flue gas and is then blown into the combustion chamber and burned. The tubes lining the boiler turn the process water into high pressure steam. Heat is further transferred from the flue gas in primary and secondary superheat stages. The super heated steam is expanded in the turbine to a temperature and pressure slightly above

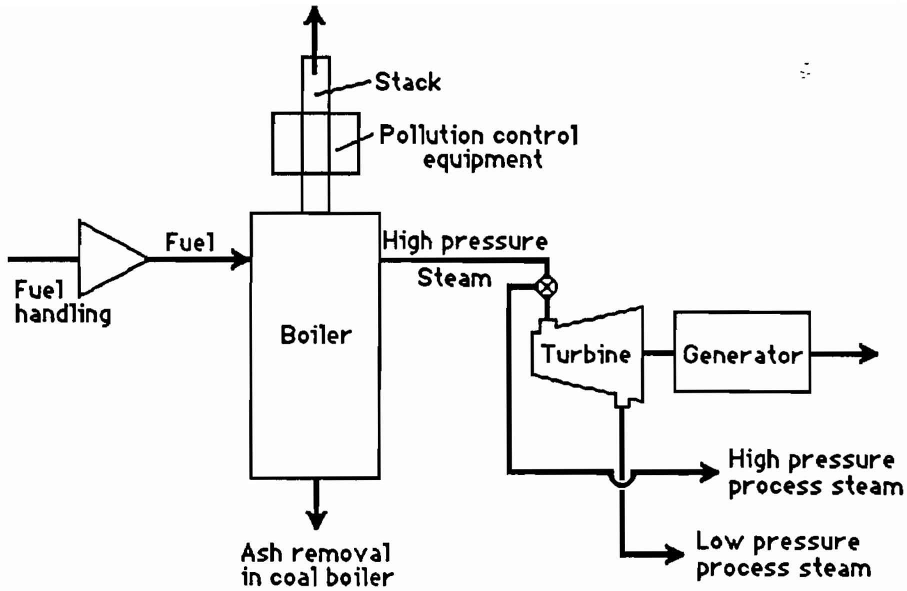

Figure 2-2: Typical Rankine cycle configuration

the enthalpy where condensation begins. Increased thermal loads can be met by routing the steam around the steam turbine or by extracting steam during the expansion process.

2.6 Coal as a Primary Fuel

Although natural gas is presently the primary source of cogeneration, the reliability and long history of coal combustors as a source of power makes their presence in large cogeneration systems inevitable. The US has large deposits of coal, and the generation of electricity is the primary use for coal. Natural gas, on the other hand, has many other uses, such as space heating in residential and commercial structures. In the long run, cogenerators will have to compete with central coal-fired capacity. Coal can be efficiently utilized with minimum environmental impacts using three methods:

- Open combustion coupled with flue gas desulfurization (FGD) of the exhaust
- Fluidized bed combustion using a mixture of coal and limestone (FBC)
- Integrated Gasification Combined-Cycle (IGCC).

Open coal combustors are the oldest and most common means of generating electric power. FBC and IGCC combustion have recently risen into the forefront as clean coal technologies and are both viewed as technological advances over open coal combustion (the traditional method used for base load plants). A more detailed description of FBC combustion and IGCC technology is given at the end of the next chapter.

Chapter 3
Emissions and Control Technology

3.1 Critical Pollutants

Burning coal is a relatively inexpensive and potentially environmentally sound method of generating electricity. Commonly practiced combustion technologies require treatment to the products of combustion to minimize environmentally hazardous levels of nitric oxides (NO_x), sulfur dioxides (SO_2), and particulates. Coal fired power plants account for 55 percent of all the man-made sulfur dioxide emissions in the United States, and industrial processes account for an additional 20 percent of sulfur emissions [Strehlow 84].

3.2 Sulfur Dioxide Formation and Acid Rain

Sulfur dioxide formation is a function of the sulfur content in the fuel; almost all of the sulfur in the input fuel is converted to SO_2 upon combustion. A small fraction of the SO_2 is deposited as fly ash. Sulfur dioxides have a half-life of six to ten days, during this time they are partially oxidized to form sulfuric acid which precipitates as acid rain.

Acid rain is a particularly severe problem in the Northeastern United States and Canada. In 1977, the Clean Air Act Amendment required 90 percent SO_2 removal for new coal fired power plants.[9] Impending legislation may require existing facilities in the Mid West and East to continue using regional high sulfur bituminous coal and scrub flue gases to meet more stringent sulfur emission standards [Simbeck 87].

The focus of the acid rain debate has centered on high sulfur coal burning boilers. Flue gas desulfurization (FGD) has been promoted by high sulfur coal producing states as an effective means of meeting impending SO_2 legislation. Over 90,000 MW of coal fired utility generating capacity in the U.S. uses limestone wet scrubbers [EPRI 87b].

3.3 Wet Scrubbing Processes

Wet scrubbing is accomplished by spraying an alkaline reagent, usually lime or limestone, into the flue gas. The limestone solution absorbs the SO_2 to form a calcium sulfite/sulfate sludge. The overall chemical reaction is [EPRI 83a].

$$CaCO_3(s) + SO_2(g) + 2H_2O + 1/2O_2 \longrightarrow CaSO_4 2H_2O(s) + CO_2(g) \qquad (4)$$

The makeup water lost to the treated flue gas, hydration, and dewatering result in an addition of over 1 gallon per minute (GPM) of makeup water per Megawatt generated. Typically, wet scrubbing is

[9]The standards required for Eastern coals are at least 90 percent reduction of potential emissions and a maximum limit of 1.2 lb/MMBtu on emissions. Coal from Western states can be burned with only 70 percent sulfur removal and a maximum limit of 0.6 lb/MMBtu.

more economical than dry scrubbing for high removal rates from high sulfur (Eastern) coal.

The high variable cost of conventional wet scrubbing shown in Table 3-1 has lead to the development of the Chiyoda Thoroughbred process. In this process, a calcium sulfate sludge is formed in a jet bubbling reactor that mixes with a limestone slurry to remove the SO_2. The advantages of this process over conventional limestone scrubbing are the better settling, filtering, and structural properties of the waste and more efficient use of the limestone [EPRI 83a]. Slurry pumps are not required, thus reducing capital and maintenance costs; most importantly, down time of the scrubber is reduced. In addition, the waste can be made into wallboard (Gypsum).

Although coal combustion is viewed as the most economical long-run technology to produce power, its use in large scale power plants will soon be limited to those localities where land filling is possible. Lately, siting and acquiring construction permits have become extremely sensitive issues throughout most of the country. The negative externalities or "hidden" costs associated with the FGD processes are the problems associated with disposal of the by-product sludge.

The Resource and Conservation Recovery Act (RCRA) of 1976 and the amendments to the act under the Hazardous and Solid Waste Amendments (HSWA) of 1984 identify coal ash and lime sludge as a low level hazardous waste. Currently, power generators are exempt from these disposal regulations, and the EPA has no plans to revoke this exemption. Proper disposal of utility wastes would be

Table 3-1: SO_2 Removal Costs

	lb SO2/ Ton	MMBTU/ton	lb SO2/BTU	KWH/YR	BTU/kWH	lb SO2 Emitted/YR	lb SO2/YR Removed	Mills/KWH env. control
Base Case @ 2% Sulf Coal with ESP	75	27.2	2.76E+06	2850000	9565	7.52E+16	0.0	1.5
Low Sulfur Case with ESP	19	24.2	7.85E+05	2850000	9992	2.24E+16	0.0	1.5
Conv. Lime Scrubber 90% remov. 2% Coal	75	27.2	2.76E+06	2850000	10520	8.27E+15	7.44E+16	14
Low Sulfur Scrubbing 70% rem. 2% Coal	19	24.2	7.85E+05	2850000	10480	7.04E+15	1.64E+16	7.4
Chyoda Thoroughbred 90% rem. 2% Coal	75	27.2	2.76E+06	2850000	10520	8.27E+15	7.44E+16	10.82
Wellman-Lord 90% remov. 2% Sulfur Coal	75	27.2	2.76E+06	2850000	10520	8.27E+15	7.44E+16	16.00
MGO 90% removal 2% Sulfur Coal	75	27.2	2.76E+06	2850000	10520	8.27E+15	7.44E+16	14.75
IGCC 99.9% removal	75	27.2	2.76E+06	2850000	10200	8.02E+13	8.01E+16	8.20
Cogen Base Case @ 2% Sulf Coal with ESP	75	27.2	2.76E+06	2850000	4670	3.67E+16	0.0	0.73
Cogen Conv. Lime Scrubber 90% remov.	75	27.2	2.76E+06	2850000	4920	3.87E+15	3.86E+16	6.44
Cogen IGCC 99.9% Removal	75	27.2	2.76E+06	2850000	5500	4.32E+13	4.32E+16	4.35

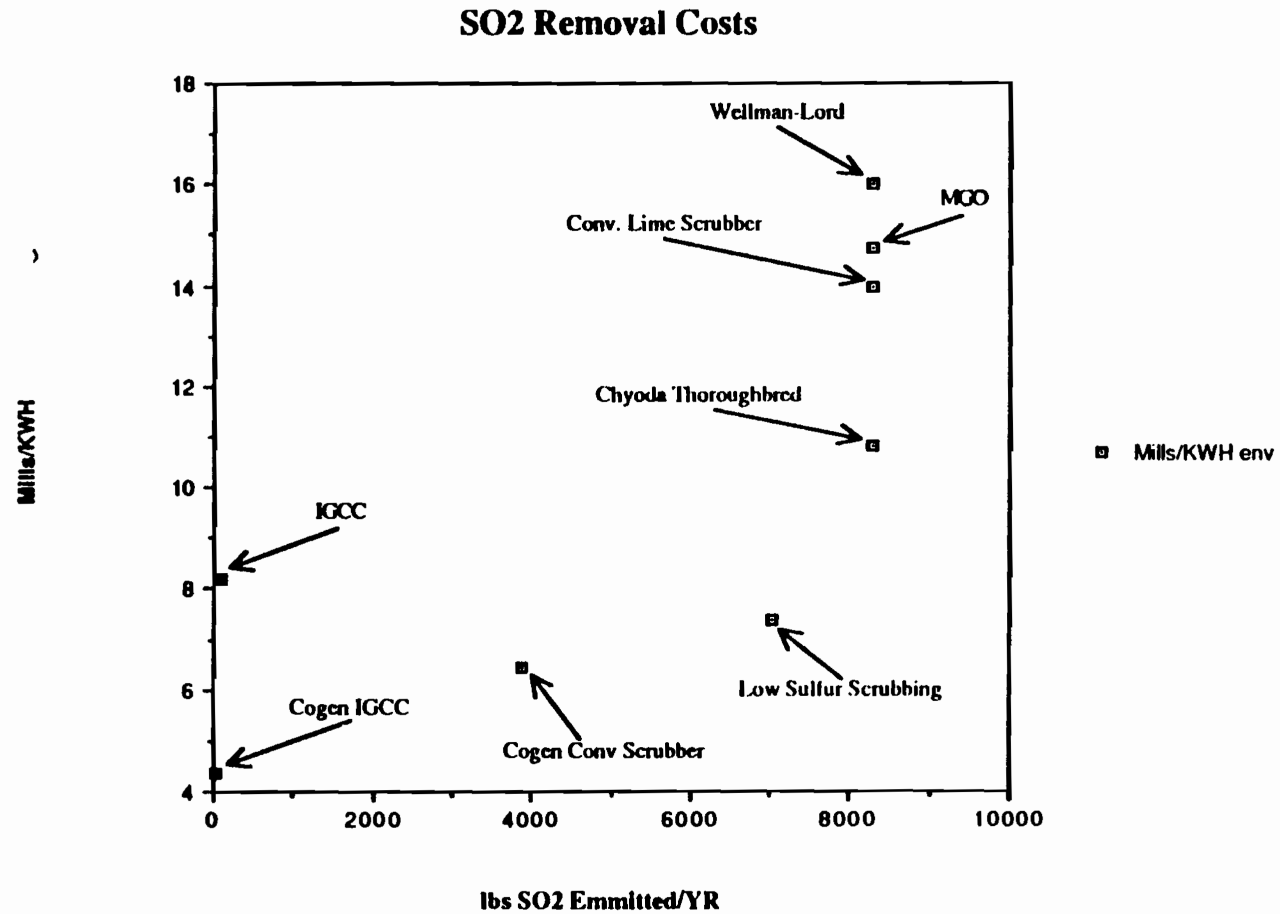

Figure 3-1: SO_2 Removal Costs

extremely costly and is vigorously opposed by utilities. It is important to remember that the utility industry underestimated the disposal problems associated with nuclear waste in the 1960's and 70's [Dorris 82]. Currently, the utility industry considers that the by-products of coal burning do not impose a serious waste disposal problem.

New York State recently enacted a hazardous waste bill that requires new facilities to dispose of the by-products of coal combustion as low level hazardous wastes [Mhyre 88]. At a minimum, the owners of generators are required to contain the wastes with a double lining to prevent ground water contamination. It is interesting to note that two of New York State's planned coal burning cogeneration facilities are currently considering disposing of the by-product wastes in Pennsylvania [Mhyre 88].

3.4 Regenerable Scrubbing Processes

Regenerable desulfurization processes are economical when disposal space is at a premium or when the disposal requirements are restrictive. The Wellman-Lord process is one approach to regenerable desulfurization. A concentrated sodium sulfite is used in a tray tower (versus a conventional lime scrubbers spray tower) to produce a sodium bisulfite-rich solution which is regenerated to sodium sulfite in a steam evaporator. The Wellman-Lord process produces a salable by-product but requires large quantities of methane and steam. A prescrubber is required prior to the absorber to remove HCL and SO_3 species [EPRI 83b].

The magnesium oxide (MGO) process is the least costly alternative regenerable process. It uses a grid-packed spray tower to remove SO_2 and to form magnesium sulfite/sulfate. The solids are calcined to form an SO_2 gas and a reusable magnesium oxide. [EPRI 83b] The MGO's reduced operating costs occur in the calcinator where process steam is produced versus the Wellman-Lord which consumes large quantities of steam. The strong potential for electro-chemical corrosion and the $1800^{\circ}F$ temperature of the calcinator may explain the limited development of the MGO process. Regenerable systems' higher operating and capital costs have hindered their development to date.

3.5 Fluidized Bed Boilers

Coal burning independent power producers have viewed FGD systems as costly and impractical and have turned toward fluidized bed combustion (FBC). In New York State, several large cogeneration projects are planning to use fluidized bed combustors. FBC is similar to the open coal combustors except the pulverized coal is mixed with a limestone powder before the combustion process begins.

The boiler design for a fluidized bed combustor is extremely expensive and remains to be tested successfully oyer a long period of time at sizes greater than 100MW. Corrosion and scaling on the walls of the boiler and the tubes of the superheater section have required more frequent boiler tube replacement than in conventional boilers [Stoiaken 87]. Scaling on the superheater tubes also reduces the coefficient of heat transfer between the flue gas and the superheated steam resulting in a slightly less efficient system. However, mixing powdered limestone does not impair the combustion efficiency of the system or drain ten percent of the energy produced as occurs with a lime scrubber. Disposal of FBC ash presents the same challenges as with open coal combustors. Although disposing of coal waste presents a serious environmental concern, it is typically not accounted for in planning models that analyze alternative solutions for controlling power plant emissions.

3.6 Nitric Oxide Formation

The focus of the acid rain debate has been on sulfur dioxide emissions, however, nitrogen oxides still pose a serious environmental threat. NO_x precipitates from the atmosphere as nitric acid and contribute to acid rain. Sufficient concentrations of NO_x and reactive hydrocarbons (HC) in the atmosphere form photo chemical smog in the presence of strong sunlight.[10] In unhealthy atmospheric concentrations, NO_x can cause permanent damage to the alveoli (air sacks) in the human respiratory system.

The formation of thermal NO_x has most successfully been modelled by the Zeldavitch mechanism.[11]

$$N_2 + O \longrightarrow NO + N,$$

$$N + O_2 \longrightarrow NO + O.$$

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[10]Photo chemical smog is scientifically referred to as tropospheric ozone.
[11]See Strehlow [84] for more information.

Nitric oxide formation is a slow but exponentially thermal sensitive reaction that only begins producing significant amounts of NO_x above 2700ºF. Unlike sulfur dioxide, NO_x can be controlled by changing the combustion process to minimize the flame temperature and the residence time of the combustion products. Dry controls of NO_x have achieved excellent results in reducing emissions. New utility coal boilers are said to achieve NO_x emissions of 0.30 lb/MMBtu[12] [Glover 88]. Emissions from combustion turbines can be reduced by altering the shape of the combustion chamber. Gases entering the initial combustion zone are compressed to a point where additional air is needed to complete combustion achieving levels of 0.20 lb/MMBtu.

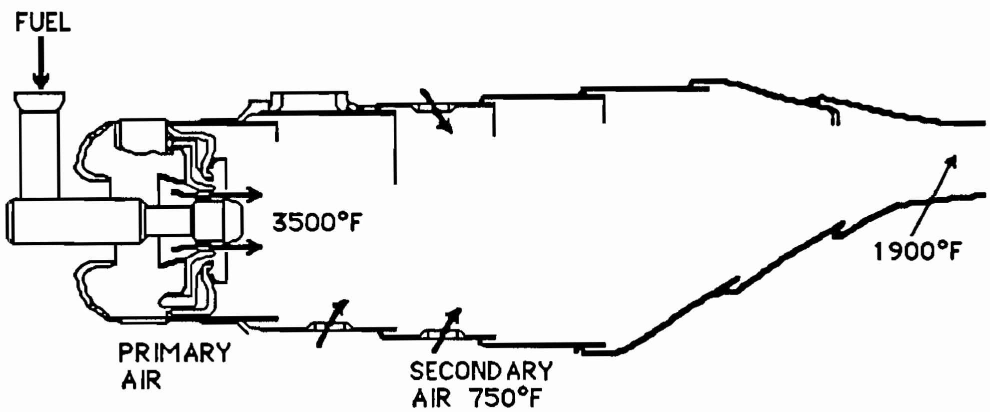

Figure 3-2: Dry NO_x Control Mechanism for Combustion Turbine

Most industrial gas turbines meet the NSPS of 0.2 lb/MMBtu without any special control provisions [Solt 84]. Further NO_x

[12]NSPS for NO_x are 0.5lb/MMBtu for sub-bituminous coal and 0.6 lb/MMBtu for bituminous coal. Predicted more stringent regulation may require between 0.1 and 0.2 lb/MMBtu. Attainment of lower values can be achieved with selective catalytic reduction EPRI [86a].

reductions may be required to meet the amount of emissions that can be produced in a single location, regardless of size and type of equipment installed.

Site limitations on the amount of pollution produced by a single source fall under the New Source Review (NSR) rules and Prevention of Significant Deterioration (PSD) regulations. If the locality under consideration falls into the class of a non-attainment area such as metropolitan New York, then the NSR rules apply. Otherwise, the siting falls under the less stringent PSD regulations. For a facility to be subject to PSD, the facility must have the potential to emit in excess of 100 ton/yr of a regulated pollutant identified under the Clean Air Act and have heat input equal to or greater than 250 MMBtu/hr. [Atkins ASE 88]. The NSR regulation is enforced by the local pollution control district. Often NSR regulations will require either Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) and emission offsets for large projects [Solt 84]. BACT requires that new equipment be as good as, or better than, anything that has already been demonstrated in another similar application. LAER requires new equipment to use technologies which are achievable even if they have not been demonstrated.

Strict NO_x control of BACT may sometimes be achieved by water or steam injection. Water or steam injection into the primary combustion zone of a gas turbine can result in a 30 to 70 percent reduction in NO_x. The extent of the NO_x formation is limited because of the sharp decrease in temperature caused by the dilution of the entering fluid. In other cases or when LAER is required, selective catalytic reduction (SCR) must be used to meet the strict standards. The Northeastern States for Coordinated Air Use Management (NESCAUM) has indicated the need to coordinate more stringent NO_x emission controls in the Northeastern states and is recommending the further adoption of catalytic technology as the best available control technology [Atkins 88].

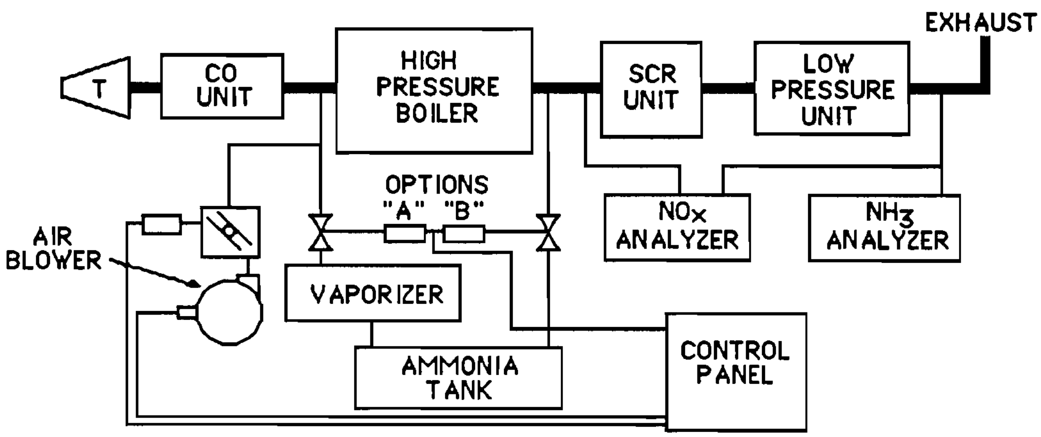

Figure 3-3: Selective Catalytic Reduction

Selective catalytic reduction (SCR) for modular cogeneration units has been used for several years to remove NO_x from the exhaust gases. (Modular cogeneration units using natural gas emit twice the NO_x per Btu of intake fuel compared to a gasoline engine.) SCR for air rich combustion turbines is a far more costly and complicated process compared to removing NO_x from internal combustion engines. SCR for combustion turbines is accomplished by spraying ammonia as far upstream of the catalyst as possible to provide good mixing before the catalyst. The exhaust gases pass through a catalytic bed and the ammonia reacts with the NO_x to form water and free nitrogen. The cost of SCR is very high and can make the economics of small scale gas turbine cogeneration unfavorable. SCR for large utility coal fired boilers also results in very high NO_x reduction but at a high operating and capital retrofit cost. The prohibitive cost of SCR may force a utility to generate power in a pollution control district that does not require SCR. For example, a large portion of Southern California's electric power is produced in Arizona as a result of their strict emission standards [Solt 88].

3.7 Integrated Coal Gasification

Integrated Coal Gasification Combined Cycle (IGCC) power production has long been ignored as a means of eliminating the negative externalities of power plant waste and controlling both NO_x and SO_2 emissions. IGCC is largely ignored as an effective control strategy because it is not suitable for retrofitting existing boilers, and new capacity has not been required in many regions until recently.

The success of the Cool Water IGCC Pilot Plant and the recent start-up of Dow Chemical's Plaquemine Louisiana gasification plant have shown that coal gasification is a reliable and affordable option for acid rain control. [EPRI 87a] Coal gasification has many advantages over traditional acid rain control technologies:[13]

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[13] The information in the following three paragraphs below is a combination of material from EPRI [87a], Spencer [87], Spencer [86], OTA [83] and EPRI [86a].

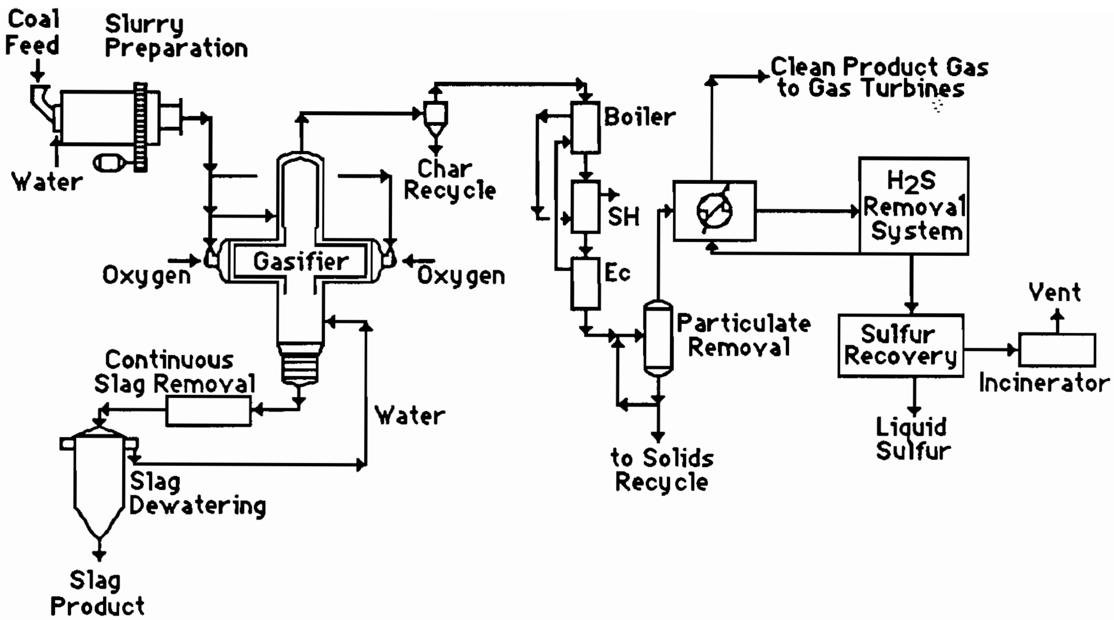

Figure 3-4: Coal Gasification Process

- Power is produced at a cost 10 percent less than that of a direct coal fired plant with scrubbers or a fluidized bed combustor (EPRI AP-3486).

- NO_x and SO_2 emissions are 10 percent of the NSPS and produce almost no particulates.

- The thermal efficiency of the combined cycle is significantly better than a steam cycle

- The rapid response of gas turbines to changes in load demand minimizes losses to daily load swing.

- The staged construction of IGCC allows accurate development of future power supply without the uncertainties of large capital projects.

- A clean hard crystalline slag is a by-product of the gasification process versus a low level hazardous waste from open coal combustors. Slag can be used as a base aggregate in road construction and maintenance as has been done in California.

- A solid sulfur is produced that can be sold commercially.

A disadvantage of coal gasification is an effluent waste. The gasification process results in several waste water streams containing ammonia, chloride, formate, fluoride, sulfide and a very low organic content with format composing essentially all of the organic content of the waste water stream. The waste water remains well within the regulatory standards and is not considered a serious environmental concern. The waste water is usually contained in a closed loop system with two evaporation ponds.

The economics of IGCC usually dictate phased construction [EPRI 83b]. Currently, coal combustion technology cannot economically compete with natural gas combustion turbines for new electric generation capacity [EPRI 87a]. This is due to the significantly lower capital cost of combustion turbines and temporary low price of natural gas. In the long run, natural gas prices are expected to rise, making the transition to coal gasification economical. Potomac Electric has announced plans to build a phased construction 360 MW IGCC plant. This decision was based on an in-house study concluding that a phased construction of IGCC has a $100 million (1983 dollar) present worth benefit over a 300-MW pulverized coal-fired unit with flue gas treatment [EPRI 87a].

Replacing existing coal burning facilities with coal gasification is economically less favorable than adding a FGD system, but increasing the generating capacity can make IGCC a favorable alternative. (Additional capacity can be added for 500 to 600 $/kWh.) Replacing a portion of an existing facility in an air district may result in compliance of impending regulatory standards on emissions without requiring emission controls on other facilities.

Chapter 4
Interconnection Requirements and Ambiguities

4.1 Cogenerators' Concerns

The link between independent power producers and the central power distribution system (grid) remains a central stumbling block for cogenerators. PURPA leaves the interconnection requirements to be decided by each utility. The stringency of interconnection requirement generally has been known to coincide with the local electric utility's view of NUG's. Excessive interconnection equipment and the long time delay over the local utilities' approval of the interconnection system can result in the cancellation of a viable project. In some instances, a utility's (such as Consolidated Edison) reluctance to respond promptly has resulted in legislation dictating that a utility must respond expediently to a cogeneration proposal.

4.2 Utility Concerns

Local utilities raise valid concerns that must be addressed in the interconnection of cogeneration system components. Most cogeneration systems operate in parallel with an electric utility. This interface poses great concern to the utilities for safe and reliable service of the feeder. Special measures are required by cogenerators to prevent the degradation of the quality of utility power and to ensure the safety of line workers. The variation in equipment and plant distribution systems makes each application unique. This in part explains the lack of uniform regulations and the differences in requirements among different utilities.

Cogenerators are classified into three different groups by size. The power from a large cogenerator (5MW or larger) is transmitted into the distribution substation, the power from a medium sized cogenerator (1 to 5MW) is distributed through feeders, and the power from a small cogenerator (1MW or less) is transmitted through the cogenerators' own lines.

4.3 Utility Protection

Electricity generated for the grid must remain within certain tolerances to maintain quality. Utilities want to ensure against cogeneration adversely affecting the utility's own equipment or degradation of power quality. The principal concerns to the utility are (1) fault detection and interruption, (2) protection, (3) stability, (4) transients, (5) voltage and current synchronization, (6) power factor, (7) power system balance, (8) quality of control equipment, (9) metering, and (10) harmonics. Depending on the size of the cogenerator and the type of generation technology employed, several of the ten issues may apply.

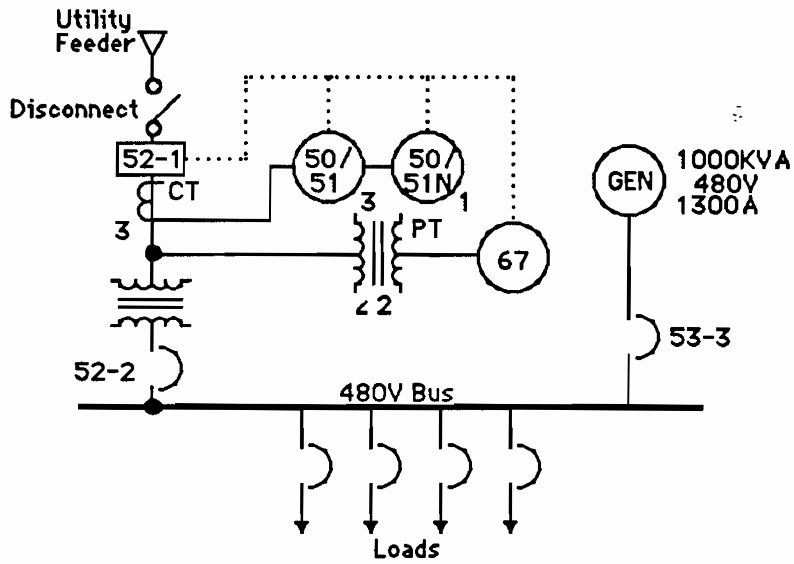

Figure 4-1: Protective Relays for NUG

Fault detection and interruption are necessary to maintain the safety of utility line workers, to prevent damage to the electric utility's equipment, and to limit the number of customers affected by cogenerator induced blackouts. A cogenerator's protective relays, similar to the ones shown in Figure 4-1, should automatically be disconnected from the line during a system blackout. An auxiliary disconnect breaker that can easily be accessed by a line worker is a necessary safety precaution to protect workers against a faulty disconnect switch.

A cogenerator operating with faulty or inadequate safety protection equipment can cause power outages to all customers along the cogenerator's feeder line in a radial distribution system and can cause a widespread and very costly blackout in a networking system [Nichols 88]. A radial system, modelled in Figure 4-2b, acts as a simple linear circuit. If the utility substation detects a fault in the line, then the flow of electricity is stopped over the line, resulting in a power outage to all electric customers along the same line.

The flow of electricity in a networking system (see Figure 4-2a) is far more intricate than in a radial system. Although networking systems are more complicated and more costly to operate than radial systems, the former provide a more reliable source of electricity.

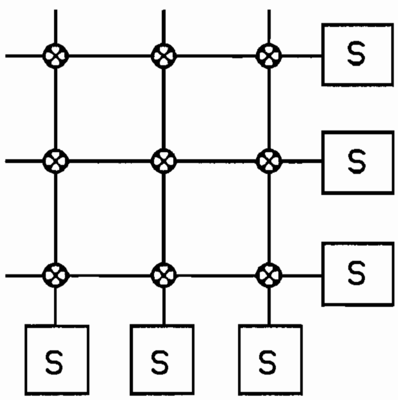

Figure 4-2a: Networking System

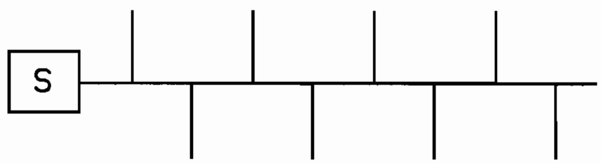

Figure 4-2b: Radial System

The grid patterns formed by the overlapping lines result in customers receiving electricity from several independent generation stations simultaneously. A cogenerator producing potentially damaging electricity and having faulty detection equipment would result in the substations servicing the dense grid detecting the fault. The supply of electricity would be interrupted resulting in a city wide blackout. The cost and dangers associated with city wide blackouts are too large to permit cogenerators to feed directly into the system. A cogenerator can interconnect at a substation, but this may be too far away to be considered a viable option. Thus, cogenerators in many metropolitan areas can only purchase power and are unable to sell power.

4.4 Power Quality

Maintaining power quality is another major concern of electric utilities. A cogenerator's voltage must remain within an acceptable range. A level voltage prevents electric motors from overheating and rapidly wearing out. Overcurrent and undervoltage relays are the standard form of protection used to disconnect the generator if the voltage falls outside a certain range. Overcurrent protection can be accomplished by either directional relays or impedance relay devices. Directional relay devices detect overcurrents on the utility hot side to trip the generator from faults that occur far from the utility system. Impedance relay devices provide the same protection as directional relays and offer the advantage of instantaneous overcurrent protection.

Transients are caused by sudden changes in electric loads, such as a large motor starting, circuit breakers interrupting large currents, fuses blowing, or disturbances from lightning. Transients are subdued by station arrestors, surge arrestors, surge capacitors, or lightening arrestors. Operating as a generator out of phase with utility power also results in large transients, thus, synchronization of the generator is important.[14]

Maintaining the NUG voltage and current in phase is essential to preserving the "quality" of the power. When voltage is in phase with the current, a power factor of one is achieved. If the inductive properties of a circuit are greater than the capacative, then the current can fall out of phase with the voltage resulting in a power factor less than one. The power factor is the cosine of the phase shift between the voltage and the current. Synchronous generators have a power factor of one whereas inductive generators operate with a power factor slightly less than one. If the voltage factor falls below 0.85 lagging, then a utility may ask the customer to install and pay for the necessary corrective capacitors [Ellis 86].

Voltage synchronization is essential to connecting any two parallel networks. Synchronization is accomplished through a synchro-check relay or voltage detector that activates reclosing of the relay. Every time the generator is disconnected from the grid, voltage synchronization must be checked. The ability of cogenerators to remain synchronized with the distribution network determines the stability of the system. A disturbance to the system may cause a loss of synchronization which could possibly result in a system wide blackout.

Utilities fear that a large number of small dispersed cogenerators could seriously endanger the system's stability. Robert K. Campbell, president and CEO of Pennsylvania Power & Light

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[14]Sources referenced in the above paragraph were Ellis [86] and OTA [83].

Company expresses his concern over cogenerators and transmission access: [Electric World 88]:

> ... I feel that open transmission access is high risk tinkering and one of the other major difficulties facing the industry. The idea of access to transmission in this country is very dangerous.

Different analysts cite widespread results on particular levels of cogeneration that would render the system unstable. The conservative estimate of 5 to 10 percent penetration of a service area is the standard proposed by several utilities. This standard has been exceeded by three fold in parts of Europe without any significant impact on the system's stability.

Utilities also express concern over the malfunctioning of protective relays causing damage to the utility's equipment or other customers' appliances. This concern has resulted in the New York Public Service commission ruling that the utility cannot require a cogenerator to assume responsibility beyond the proper installation and operation of the cogenerator's own equipment. This relinquishes the cogenerator from having to purchase liability insurance to insure against damage to other system users' equipment.

To ensure against faulty relays, the utility requires installation of "utility quality" equipment. Utility quality is defined by each utility's engineering staff and is generally more reliable and responsive, but it also costs more than industrial grade [Solar 86]. Interconnection costs per kilowatt rapidly decrease as the size of the cogenerator increases.

Chapter 5
Conclusions

This report has examined the technical, and institutional issues facing cogeneration as a viable solution to clean power development. Cogeneration has matured over the last ten years from a state of infancy to a widely used and accepted configuration of energy production. The original catalyst for cogeneration was PURPA. The incentive provided by PURPA to assist alternative energy development is slowly being superseded by the deregulation of the utility industry. This will produce a more open and competitive energy market enabling the higher efficiencies of cogeneration to be realized over traditional sources of generation.

The types of fuels and pollutant emissions which are saved through cogeneration are determined by the amount of electric and thermal energy produced via cogeneration and the characteristics of the energy being displaced in a region. Reduction of emissions in SO_2 and NO_x can economically and easily be achieved through control technologies. Each emission control technology was found to have different operating characteristics that made the applicability of a technology dependent on site specific parameters. The analysis concluded that the only technology with both low NO_x and SO_2 emissions and an environmentally neutral waste product was IGCC.

Cost estimates of pollutant reductions gained through cogeneration were found to be sensitive to regional fuel use characteristics and local environmental conditions. Potential savings in emissions that can be achieved via cogeneration are determined by the net electric and thermal demands of a region. It was found that the effectiveness of a control technology requires broader analysis than the examination of emission rates. The characteristics of the cogeneration cycle were found to be best represented by a parameter called fuel consumed to power, FCP. A complete analysis of the total benefits produced by cogeneration require the examination of energy production from a societal perspective.

Future policies intended to motivate cogeneration development should consider insuring non-utility generators equal and equitable transmission access. The link between cogenerators and the central distribution system was found to lack a uniform policy between regional utilities and left too much control in the local utilities domain. Interconnection policy should focus on the utility's concerns of protection and on the cogenerators need for expedient interconnection processing.

The FERC jurisdiction over transmission rates charged to independent cogenerators and their ability to obtain equal access to transmission lines still leaves too much control with a local utility. A consensus should be reached to determine the effects of cogenerators on system stability and the indirect costs associated with their interconnection. A specific incentive policy or the opening of the power generation market to competition will be handicapped unless independent cogenerators receive equal rights and access to bulk power lines at reasonable rates under reasonable operating terms.

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No. 91-19	Preparing the Data for Analysis	Tom Randolph