POLITECNICO DI MILANO
Polo Regionale di Lecco
Faculty of Engineering
M.Sc. in Mechanical Engineering

STATE OF THE ART ANALYSIS OF SMALL SCALE COGENERATION UNITS BASED ON RECIPROCATING ENGINE AND GAS TURBINE

(A thesis submitted in the partial fulfillment of the requirements for degree of Master of Science in Mechanical Engineering)

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Preface

This thesis has been carried out during the year 2009-2010 as a M.Sc. Student for the Faculty of Engineering at Politecnico di Milano, Italy. I would like to take the opportunity to thank my supervisor Professor Stefano Campanari for doing an excellent job and helping me throughout the year.

Md. Nazim Uddin Ahammed

05/07/2010

Abstract:

The main objective of this study has been to investigate the state of the art in the area of small scale based combined heat and power generation. Where the world status on the small-scale cogeneration system such as overview ,best commercial units ,current research & development and some interesting demonstration have been studied and discussed. Also the efficiency of the cogeneration unit has been studied with different types of fuel. Other aims have been to identify proper natural gas and biomass based CHP Technology and also to go through some case studies where the optimization of the plant was made by considering different technology by proper optimization method. The technology investigated the reciprocating engine and gas turbine (both internally and externally fired) , where both the natural gas and biomass are taken in to account.

Key words: Small scale cogeneration, CHP, Heat and Power, Energy balance, Sizing of CHP, EFGT, IFGT, IC engine.

Content

Chapter 1: Introduction

1.1 Background

The demand of cogeneration is going on with a high rate in the world. Previously manufactures were giving more concern on the commercial view point. There were little concern on the emission and global warming. Now-a day's many researches is going on emission. The global warming and the climate change is one of the most discussed topics in the scientific community. Major evidence shows that the global warming is caused by an increased concentration level of green house (GHG) in the atmosphere. This increase is almost entirely caused by human activities and partly due to electricity and heat generation. Resulting the effects of increasing intense of tropical cyclones ,sea level rise, melting of the arctic cap etc. have consolidate government and nation to take joint measures to reduce the emission of anthropogenic GHG to the atmosphere in order to mitigate the climate change.

In September 2007 the Swedish Scientific council on climate Issues released a report with scientific recommendation for future Swedish climate policy target at national, EU and International levels. The council conclude that the EU's target of limiting the increase of the global mean temperature to 2°C above pre-industrial values is a reasonable basis for emission reduction measures. This target is likely to be achieved if GHG concentration in the atmosphere is stabilized at 400ppmv CO_2 equivalents in 2050.To achieve this global GHG concentration, the emission by the year 2050 needs to be at least halved compared to the 1990 level and by the end of the century global emission need to have been reduced to almost zero.

One issue is to decide which measure to prioritize .According to the council a combination of increasing energy efficiency with use of present and future technologies along with a fundamental reform of consumption patterns is crucial to achieve this target.

Combined heat and power generation

Combined heat and power or cogeneration is defined as the simultaneous production of both useful heat and electricity power in the same plant. The biggest advantage of cogeneration is the high total efficiency this gives resources effective operation which is crucial if the emission targets are fulfilled but also for achieving economic viability. Efficiency up to 90% have been achieved with cogeneration, compared with the conventional way of generating electricity and heat in separate plants which achieves efficiencies up to about 60%. Figure 1.1 below shows the difference between cogeneration and separate generation. It can clearly be seen why this technology is interesting for the future .Especially on the small scale market where CHP could replace the more common heat plants.

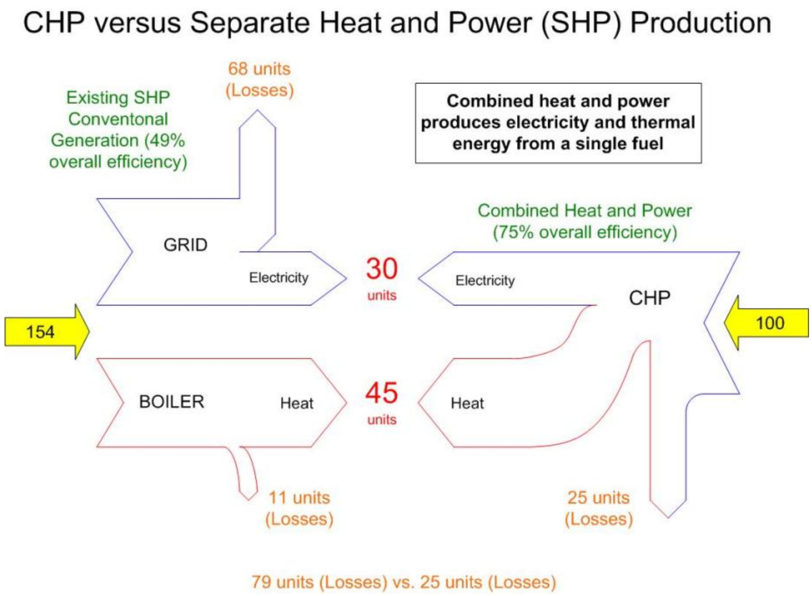

Fig: 1.1: CHP vs. Separate Power and heat generation

At present there are numerous methods of cogeneration. The most common and promising technologies along with their respective state of development are listed in table 1.1.

Table 1.1: Different types of CHP based Technologies

Technology	**Present state of Development**
Steam turbines	Established
Steam Engines	Under development (Demonstration unit)
Gas Engines	Established
Gas turbine/Combined cycle	Under development(demonstration unit)
Externally fired gas turbines(EFGT)	Under development (Pilot units)
Organic ranking cycle(ORC)	Established
Stirling engine	Under development

1.2. Objective

As mentioned there are numerous different technology for small scale biomass based combined heat and power generation. The main objective of this study is to perform an impartial investigation of the state of the art in the area both from technological and economic perspective. The investigation should point out possible technical obstacle for commercialization of the considered technologies and in addition determine where future R & D should be directed. In more detail the study will focus on

- ✓ World current status of cogeneration.
- ✓ Most interesting demonstration in the world wide.
- ✓ Worldwide policies on cogeneration.
- ✓ Summarize national and international R&D and collection information of economic and operational experience of biomass and natural gas based CHP technology in the electrical output range up to $1MW_e$.
- ✓ Identify future technological improvements and pin point where future research should be focused.

Chapter 2: Performance and emission of small scale Cogeneration (Gas Turbine and Reciprocating Engine) Technology

Gas turbine and reciprocating engine's cogeneration systems are dominating the world's small scale cogeneration sector. Here in this section the efficiency, technology and performance of both reciprocating engine and gas turbine based cogeneration will be described. Finally the advantages and disadvantages of gas turbine and reciprocating engine will be discussed.

2.1: Gas Turbines:

There are two types of gas turbine cogeneration systems are available. Internally fired and externally fired .Both are economically and technically viable. For the small scale the internally fired is preferable because of its compactness.

2.1.1: Technology

Gas turbines are currently the favored prime mover in larger-scale cogeneration wherever natural gas is available at costs less than 3 to 4 times the equivalent energy cost of solid fuels. For operation, intake air passes through a compressor before being heated by the combustion of the fuel. The expanding air is then used to drive a turbine before exiting through the exhaust and heat processes (see figure 2.1). Compressors require a large amount of energy, making the choice of compressor crucial to the overall efficiency of the turbine.

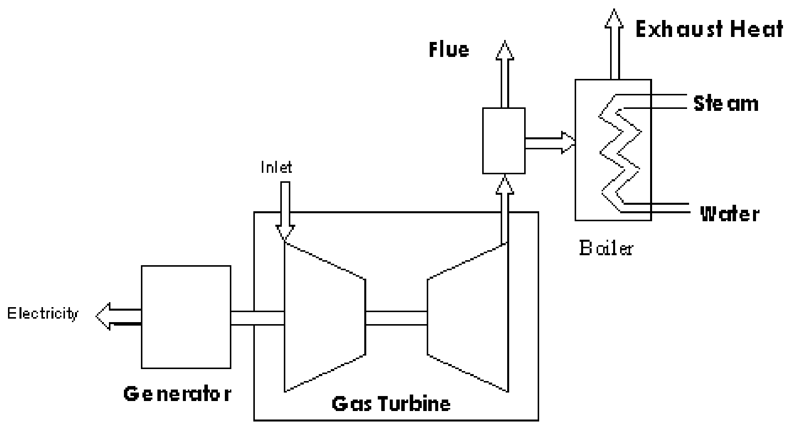

Fig: 2.1 Gas Turbine Schematic [1]

Due to the high oxygen content in the exhaust gas, the combustion of further fuel can be supported without the addition of extra air to raise the quality of heat. This process is known as supplementary firing, and can efficiently raise the exhaust gas temperature from around 500°C to 1000°C or more, raising the overall heat: power ratio of the cycle. This can be useful for industrial processes, which require high-temperature steam, such as some chemical processes.

2.1.2: Performance and Efficiency

The electrical efficiencies of modern gas turbines range from 28% to 42% simple cycle efficiency, with typical efficiencies of 32%. For systems larger than 3MW, the gas turbine exhaust, typically around 540°C, can be used to produce high-pressure steam, which then powers a second generator. Such combined-cycle gas turbines (CCGT) have electric efficiencies of 35%-55%. The pass-out steam from the steam turbine can be used to meet on-site heat requirements increasing overall efficiencies to 75% to 90%. This lowers electricity production, but improves overall economics. To improve electrical generating efficiency and reduce NOx it is possible to inject steam into the combustion chamber. Current production gas turbines have NOx emissions from 2 to 25 ppm, before external controls. Additional NOx reduction methods have been successfully developed for gas turbines, so where very low emission levels are specified, it is possible to attach end of pipe solutions such as Selective Catalytic Reduction (SCR).

2.1.3: Fuel Types

Since the combusted fuel passes through the turbine, clean gases must be used to avoid blade erosion. Natural gas is the main fuel source, but other fuels can be used. Distillate oils and gas oils are often used in combination with cheaper interruptible gas supplies. Waste fuels such as biogas, coke-oven gas and landfill gas can be used provided that their composition is consistent and their calorific values relatively constant.

2.1.4: Applications:

Industrial, Commercial

- ✓ Simple cycle gas turbines are generally used to provide peaking power or back up power without any provision of heat.
- ✓ Recuperated cycle gas turbines utilize the exhaust gas to preheat the compressed air before it enters the combustion chamber.
- ✓ Cogeneration cycle gas turbines are suitable for industrial and commercial applications. In industrial applications the exhaust gases can be used to produce process steam or chilling, or directly for drying processes if direct contact with exhaust gases is permissible.
- ✓ CCGT systems are best suited to public utility companies (without heat recovery) and industrial plants where there is an abundant supply of natural gas or other gaseous fuel.

2.1.5: Advantages and Disadvantages

Advantages

- ✓ Easier to install than steam turbines and high pressure boilers, while being less area intensive and having lower capital costs;
- ✓ Large systems have high efficiencies with relatively low capital cost;
- ✓ High temperature steam production.

Disadvantages

- ✓ Require premium fuels, often natural gas, that have high price volatility;
- ✓ The high temperatures involved require heat-resistant materials, raising production costs;
- ✓ Reduced efficiencies at part load;
- ✓ Turbine performance is significantly reduced at high altitudes or high ambient temperatures;
- ✓ Small system costs are relatively high and efficiencies are lower than with some other generation systems.

2.1.6: Economic Performances

Table.2.1: Cost Range for Open Cycle Gas Turbines and CCGT/CHP [1]

Parameter	CCGT	CHP
Installed Capital Cost ($/kW)	800 - 1,800	800 – 1,300
Operating and Maintenance ($c/kWh)	0.3 - 1.0	0.3 – 1.0
Levelized Cost ($c/kWh)		
8000hrs/year	4.0 - 5.5	4.0 – 4.5
4000hrs/year	5.5 - 8.5	5.5 – 6.5

Gas turbines are a mature and economically efficient technology with broad acceptance in the electricity market place. The installed capital cost of a gas turbine cogeneration system varies between $800-$1,800/kWh. This is due to large variations in turbine size from a few kW to many hundred of MW. The O&M costs range from $0.3c-$1.0 c/kWh.

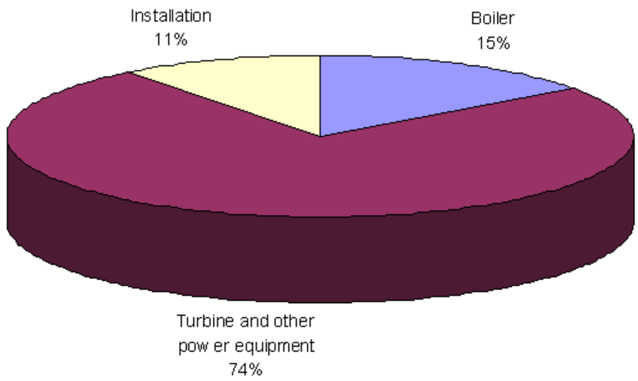

Fig 2.2: Installed cost for Gas turbine [1]

Inspections and blade washing must be carried out, around every 4,000 hours or so, to ensure the turbine is free of excessive vibration due to worn bearings, rotors and damaged blade tips. Entire hot section replacement is often required at roughly five-year intervals, and usually involves a complete inspection and rebuild of components. Therefore, O&M costs vary significantly depending on the quality of regular servicing

2.2: Reciprocating Engines:

As like gas turbine here also the performance, technology, efficiency and economics of reciprocating engine has been described.

2.2.1: Technology

Reciprocating engines operate on the same principles as petrol and diesel automotive engines. They enjoy high volume mass production and are often the lowest capital cost per kW of capacity. Reciprocating engines currently account for the majority of DE units for continuous use under 5 MW_e and for back-up power. Like automotive engines, reciprocating engines can be split into two categories; compression ignition (diesel cycle) engines and spark ignition (Otto cycle) engines.

Compression Ignition Engines	**Spark Ignition Engines**
Compression engines are usually four-stroke direct ignition machines, often equipped with turbochargers and intercoolers. The distillate and heavy oil fuelled reciprocating engines often use the diesel cycle, which relies on the heat of compression to ignite the fuel. The piston’s compression stroke raises the pressure and temperature of the combustion air above the self-ignition temperature of oil, and then very high-pressure injectors spray a mist of atomized fuel into the hot air, causing immediate ignition, expansion and power stroke.	Spark ignition engines are a derivative of compression ignition engines, the difference being that a high intensity spark as well as compression is used to instigate the combustion. To obtain lower NOx emissions, modern spark engines use a pre-chamber to create a near stoichiometric mixture (an exact ratio with no excess of reactants) of the fuel with air. Spark ignition engines give less heat to the exhaust gas and more heat to the cooling system than compression engines.

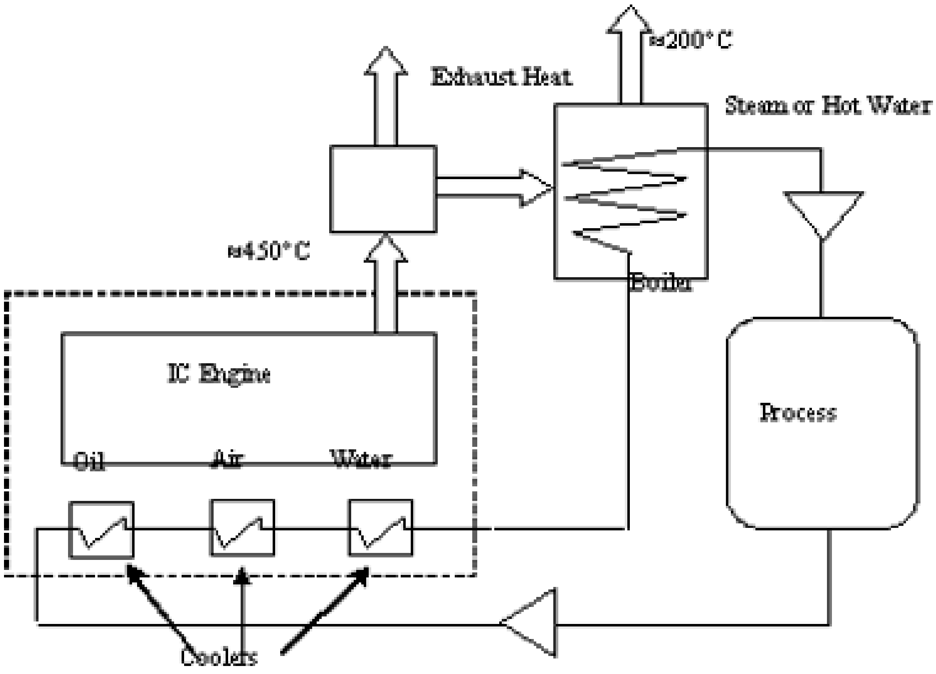

Fig 2.3: Reciprocating Engine Schematic (Including Boiler)[1]

To optimize the air-intake, modern engines use a turbocharger / compressor package that raises the pressure of the air in the intake manifold to over twice atmospheric pressure. To further increase air into the cylinder, the compressed air, which has been heated by the compression, is after cooled. This removal of some of the heat of compression allows more molecules of oxygen to enter the pistons on the intake stroke, further increasing the fuel that can be burned on each cycle and thus almost doubling the power output compared to naturally aspirated engines. This has significantly lowered the capital cost of reciprocating engine based cogeneration systems.

2.2.1: Performance and Efficiency

Compression engines achieve electrical efficiencies in the range of 35-55% and size range of 75 kW-20 MW. Spark ignition engines have lower efficiencies (30% to 50%), due to the possibility of knocking - caused by over rapid combustion of fuel in the cylinder. They are also smaller in size, ranging from 15 kW to 10 MW. Up to a third of the fuel energy is available in the exhaust at temperatures from 370-540°C, but the other rejected heat is low temperature, often too low for most processes. (Jacket cooling water at 80 to 95°C, lube oil cooling at 70°C and intercooler heat rejection at 60°C, all difficult to use in CHP). Reciprocating engines operate with significantly less excess air than gas turbines, so that combustion temperatures are higher, with detrimental effects on NOx production, which does not occur below about 1300°C. Thus, although excess air reduces engine fuel efficiency, it is usually essential to control NOx emissions. Modern engines have delayed ignition timing and increased compression ratios, which help reduce NOx without compromising power output and efficiency.

2.2.2: Fuel Types

Compression ignition engines generally use diesel fuel. Natural gas or evaporated gasoline is more difficult to ignite with a compression engine and depends on spark plugs to ignite the fuel and create the combustion that leads to the power stroke. Dual fuel engines can operate in the pure oil injection mode, but can burn up to 97% natural gas. Industrial applications of gas engines can use oil as fuel, though gas-engine applications would be very attractive where natural gas, LNG, or biogas is available. Spark ignition engines mostly use natural gas, though biogas and other gases can be used.

2.2.3: Applications

Small Industrial, Commercial, Residential

- ✓ Low maximum temperatures in the cooling system limit useful heat recovery. However, in some cases where technical difficulties have been overcome, supplementary firing can be used to increase the quality of heat.

- ✓ Depending on size, reciprocating engines can be used to produce up to 15 bar of steam from the exhaust gases with independent production of hot water at 85-90°C from the cooling system;
- ✓ If the heat from the exhaust gases and cooling systems are combined it is possible to produce water at 100°C and steam at higher temperatures;
- ✓ The exhaust gases can also be directly recuperated and used for drying or CO_2 production. All residual energy from the engine can be used to produce hot air.
- ✓ Reciprocating engine cogeneration is typically applied in buildings and institutional settings, and less frequently for industrial use.

2.2.4: Advantages and Disadvantages

Advantages

- ✓ Lowest first cost of all CHP systems;
- ✓ High efficiencies at part load operation give users a flexible power source allowing for a range of different applications;
- ✓ Short start-up times to full loads (10-15 seconds), make reciprocating engines suitable for backup power systems and peak shaving applications;
- ✓ High reliability.

Disadvantages

- ✓ Relatively high vibrations in reciprocating engines require support and special foundations with shielding to reduce noise;
- ✓ Relatively high maintenance, strongly offsetting the fuel efficiency advantages;
- ✓ Full utilization of the varied heat sources is difficult;
- ✓ Frequent maintenance intervals - every 600 to 1000 hours.

2.2.5: Economic Performance

Table 2.2: Cost Range for Reciprocating Engines [1]

Installed Capital Cost ($/kW)	900 – 1,300
Operating and Maintenance ($c/kWh)	0.5 – 1.5
Levelized Cost ($c/kWh)	
8000hrs/year	5.5 – 6.5
4000hrs/year	6.0 – 8.0

Through time reciprocating engines have achieved low initial capital costs, strong O&M support networks and high partial load efficiency. They achieve greatest economic benefits when used in small to medium size applications from 1 kW-5 MW. As the table above shows, the installed cost for reciprocating engines is between $900-1,300/kW. The figure below shows the breakdown. Reciprocating engines have a large number of moving parts, increasing all-in maintenance costs to over $10/MWh, compared to $4.5/MWh for gas turbines.

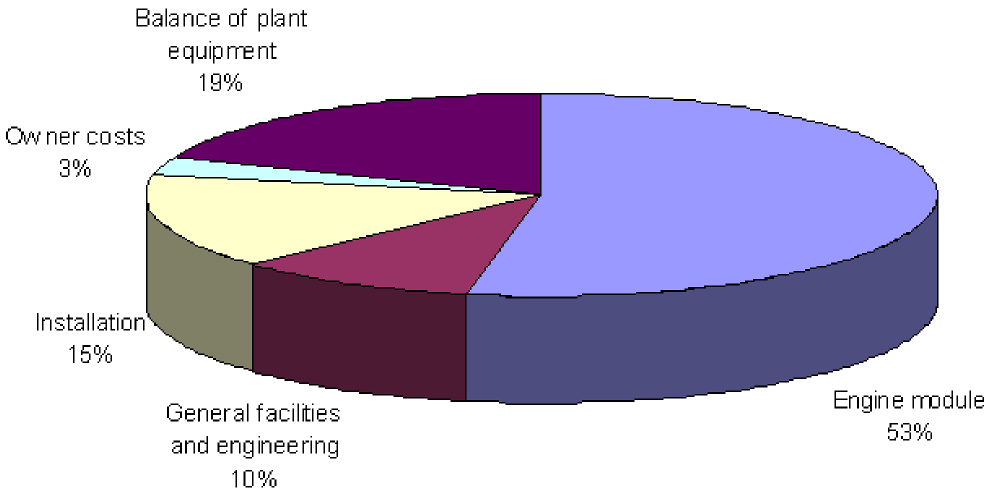

Fig: 2.4 Total Installed Cost for a 500kW Reciprocating Engine [1]

Chapter 3: Technical and commercial study of cogeneration unit

3.1: Technical comparison of a CHP using various blends of gasohol in an IC engine

Different kinds of fuels are used in cogeneration units. Here in this section a technical comparison is made for different kind of fuels .Finally the results are shown for all the cases.

3.1.1: Engine modeling

This model **[7]** is based on the first law of thermodynamics and a multi-zone model. Two zones are considered: the unburnt and burnt gases. Assumptions include a uniform pressure throughout the combustion chamber, uniform temperature for the burnt and unburnt gases, no heat transfer between the unburnt and burnt gases at the flame front, unburnt gases and burnt gases at chemical equilibrium. The model is divided into four major parts which include: intake and exhaust, compression, combustion, and expansion. The model is based on the first law of thermodynamics:

$$\mathrm{d}Q - \mathrm{d}W = \mathrm{d}E. \qquad \text{--}(1)$$

Heat transfer in the compression process is calculated from the following formula by Annand[41]

$$Q = \frac{A\left(\frac{0.6K_{\mathrm{m}}}{b}\right)Re^{0.7}(T_{\mathrm{g}} - T_{\mathrm{w}}) + 0.42428 \times 10^{-8}(T_{\mathrm{g}}^{4} - T_{\mathrm{w}}^{4})}{6N}. \qquad \text{---------------------}(2)$$

Internal energy of the mixture is a function of combustion chamber composition and temperature. Combustion chamber consists of fuel and air mixture. Assuming constant composition in compression one may write

$$E_{\mathrm{R}}(T) = w\left(e(T)_{\mathrm{C}_n\mathrm{H}_m\mathrm{O}_x} + \frac{1}{\phi}\left(n + \frac{m}{4} - \frac{x}{2}\right)e(T)_{\mathrm{O}_2} + \frac{3.76}{\phi}\left(n + \frac{m}{4} - \frac{x}{2}\right)e(T)_{\mathrm{N}_2}\right). \qquad \text{-------------------}\ (3)$$

Laminar flame speed of bio-ethanol–gasoline blend is calculated from the empirical correlation given by Gulder[42]

$$U_{\mathrm{L}}(\phi, T, P) = U_{\mathrm{LO}}(\phi)\left(\frac{T_{\mathrm{ub}}}{T_0}\right)^{\alpha}\left(\frac{P}{P_0}\right)^{\beta}, \qquad \text{--}(4)$$

where U_{LO} is the laminar flame speed at the reference conditions(T0 ¼ 300K and P0 ¼ 1 atm.) which is determined as follows:

$$U_{\mathrm{LO}} = ZW\phi^{\eta}\exp(-\xi(\phi - 1.075)^2). \qquad \text{--}(5)$$

Co-efficient for gasoline, ethanol, and ethanol–gasoline blends are given in Table 3.1. The estimation step is divided to four parts: calculation results of the volume change, calculation of adiabatic pressure and temperature, homogenizing of burned and unburned gases, and homogenizing pressure in the cylinder. In combustion and expansion step, heat transfer is calculated from the following formula[41]:

$$Q = \frac{-A\left(\frac{0.6K_m}{b}\right)Re^{0.7}\left[\left(\frac{T_{b,new}+T_b}{2} - T_w\right) + 0.42428 \times 10^{-8}\left(\left(\frac{T_{b,new}+T_b}{2}\right)^4 - T_w^4\right)\right]}{6N}. \quad \text{---------------------(6)}$$

Air flow ratio is calculated by using the following equation

$$\dot{m} = \frac{C_D A_R P_0}{\sqrt{RT_0}}\left(\frac{P_T}{P_0}\right)^{1/\gamma}\left\{\frac{2\gamma}{\gamma-1}\left[1-\left(\frac{P_T}{P_0}\right)^{((\gamma-1)/\gamma)}\right]\right\}^{1/2}. \quad \text{------------------------------(7)}$$

If $P_T/P_0 \leqslant (2/(\gamma+1))^{\gamma/(\gamma-1)}$, the flow is choked and the air flow ratio is calculated as follows[43]:

$$\dot{m} = \frac{C_D A_R P_0}{\sqrt{RT_0}}\gamma^{1/2}\left(\frac{2}{\gamma+1}\right)^{(\gamma+1)/2(\gamma-1)} \quad \text{---(8)}$$

Engine model outlet is the flue gas with distinct temperature and rate. Having flow properties, one can calculate the availability and compare the various flows at same conditions. The flow availability is estimated as follows [44]:

$$a_f = (h - h_0) - T_0(s - s_0). \quad \text{---(9)}$$

The enthalpy and entropy are functions of temperature and Cp:

$$\frac{C_{P,i}}{R} = a_{i1} + a_{i2}T + a_{i3}T^2 + a_{i4}T^3 + a_{i5}T^4, \quad \text{--(10)}$$

Table 3.1:Coefficient for laminer flow speed [7]

Fuel	Z	W(m/s)	ŋ	ξ	z	B	
						ϕ≤ 1	ϕ ≥1
C_8H_{18}	1	.4658	-0.326	4.48	1.56	-.22	
C_2H_5OH	1	.4650	-0.250	6.34	1.75	$-.17\varnothing^{-0.5}$	$-.17\varnothing^{0.5}$
C_8H_{18}+C_2H_5OH	$\chi_E^{-0.351}+.007$	.4658	-0.326	4.48	$1.56+.23\chi_E^{-0.46}$	$\chi_G\beta_G+\chi_E\beta_E$	

$$h=\int C_P\,dT \Rightarrow \frac{h}{RT}=a_{i1}+\frac{a_{i2}}{2}T+\frac{a_{i3}}{3}T^2+\frac{a_{i4}}{4}T^3+\frac{a_{i5}}{5}T^4+\frac{a_{i6}}{T}, \quad \text{---(11)}$$

$$s=\int\frac{C_P}{T}dT+R\ln(\frac{P}{P_\circ})\Rightarrow \frac{s}{R}=a_{i1}\ \ln\ T+a_{i2}T+\frac{a_{i3}}{2}T^2+\frac{a_{i4}}{3}T^3+\frac{a_{i5}}{4}T^4+a_{i7}. \quad \text{---(12)}$$

Consider a mixture of n ideal gases at temperature T and pressure p. The flow availability can be calculated as

$$a_f=\sum_{i=1}^{n}X_i\left[\int_{T_0}^{T}\left(1-\frac{T_0}{T}\right)C_{P,i}\,dT\right]+RT_0\ \ln\left(\frac{P}{P_0}\right). \quad \text{---(13)}$$

For comparison between various blends we need to estimate the availability which is calculated as follows:

$$A_f=\dot{m}_g a_f. \quad \text{---(14)}$$

Efficiency is one of the important properties for the evaluation and comparison of systems. Two cases are assumed. The first case is SHP in which only mechanical work is produced. The second case is CHP in which mechanical work and heat are produced. For the first case the efficiency is estimated as follows[45]:

$$\eta_0=\frac{W}{F}, \quad \text{---(15)}$$

where W is the mechanical work or output electricity and F the fuel energy consumption for producing W.

For the CHP case, i.e. the second case, an alternative performance criterion is sometimes used. It is an artificial thermal efficiency in which the energy in the fuel supply to the CHP plant is supposed to be reduced by the amount which would be required to produce the heat load in a separate heat generation boiler. The artificial efficiency of system is

$$\eta_a=\frac{\dot{W}}{\dot{F}-(\dot{Q}_U/\eta_B)}=\frac{\eta_0}{1-(\dot{Q}_U/\eta_B\dot{F})}, \quad \text{---(16)}$$

Where Q is the heat load and η_B the boiler efficiency.

3.1.2: Experimental setup

The engine that is used in the experimental setup[7] is a SI, four-cylinder, four-stroke, water-cooled, constant compression one. It has a swept volume of 331 cm^3. Dimensions of the engine are: the bore B ¼ 71mm and the stroke St ¼ 83.6 mm. Carbon monoxide (CO) emission was measured by means of an exhaust gas analyzer connected to exhaust pipe outlet. Spark advance was adjusted as 251 before top dead center and it was held constant. The engine performance parameters and CO emissions have been determined for gasoline at the compression ratios of 9.7. In order to load the engine and measure the output torque, an electric dynamometer is coupled to the engine. The dynamometer type is eddy current and it is manufactured by Schenck. Experimental work is done in the Mega Motors laboratory in Tehran, Iran.[7]

3.1.3: Results and discussion

In this investigation, engine tests are done for the speeds of 3500 and 4000 rpm. Since the assumed frequency is 60 Hz, the speed will be 3600 rpm for electricity generation. These tests were done for gasoline and the model was validated by using the test results. Using the model, results for various blends of ethanol–gasoline are calculated for 3600 rpm. The theoretical estimations have been performed with the blends containing 5, 10, 15, and 20 volume percentage of bio-ethanol. Figs. 3.1 and 3.2 show the experimental and theoretical pressure for 3500 and 4000 rpm and full load conditions with gasoline fuel. They reveal that the theoretical pressure curves in compression and expansion process are the same as experimental ones. In combustion process, especially, in the start point of combustion, theoretical results are higher than experimental ones. This is due the fact that the combustion balance equations are used instead of combustion kinetic equations in the theoretical modeling as the kinetic of bio ethanol combustion is not found yet. The theoretical and experimental results for carbon monoxide are shown in Fig. 3.3. It shows that the theoretical results are lower than the experimental results. However, these amounts are the same at 3500 rpm. This difference is due to the fact the idealizing conditions are assumed for the

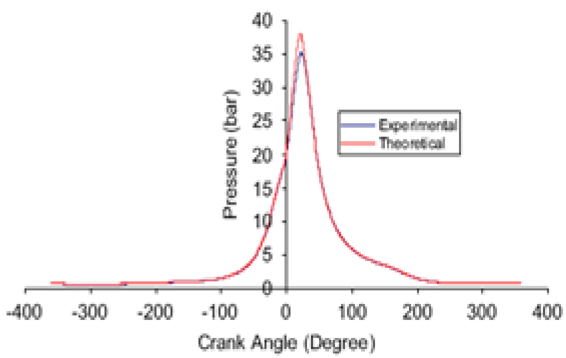

Fig 3.1:P-Theta diagram for gasoline for 3500 rpm and full load [7]

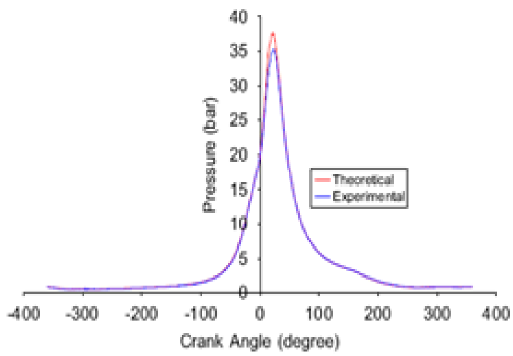

Fig 3.2:P-Theta diagram for gasoline for 4000 rpm and full load [7]

combustion process. In fact, the CO gas amount in the theory and experience are the same at 3500 rpm. Also, as the calculations are done at 3600 rpm, therefore one can assume the model results to be true. Using the model, the maximum pressure and temperature, outlet pressure and temperature, and outlet components of the flue gas are estimated. Figs. 3.4 and 3.5 show the maximum pressure and the maximum temperature estimated by model for various blends at full load, respectively. As is shown, on increasing bio-ethanol in the blend, the maximum cylinder pressure is increased. Also, the energy in the blend is increased which is the one of the reasons for the increasing of pressure and temperature. [7]

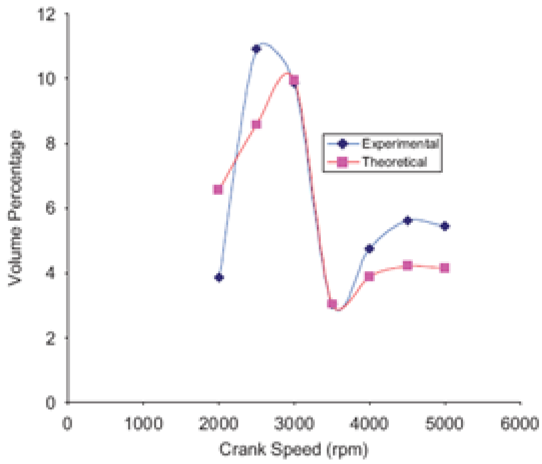

Fig 3.3: The volume percentage of co for gasoline at full load[7]

The existence of O and H in bio-ethanol composition is another reason for the increasing of temperature and pressure. As is demonstrated, increasing bio-ethanol in the blend also results in an increase in the temperature. It is due to the fact that the pressure and temperature are two dependent properties. Also, on increasing the C content in the blend with increasing bio-ethanol, the CO volume percentage is reduced. Fig. 3.6 shows the volume percentage of CO for various blends at full load. Flue gas composition is shown in Table 3.2. Using the results of engine model and the exergy modeling, the flow availability for the flue gas for the various blends at the full load and 3600 rpm are calculated and are shown in Table 3.3. As bio-ethanol in the blend is increased, the availability of the flue gas is increased. The flow availability has direct relation with temperature and pressure. Therefore, increasing the temperature and pressure with increasing bio-ethanol in blend, will cause the availability of the flue gas to increase.[7]

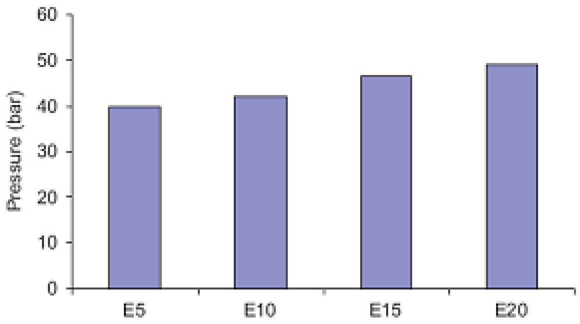

Fig 3.4: The maximum pressure for various blend at full load. [7]

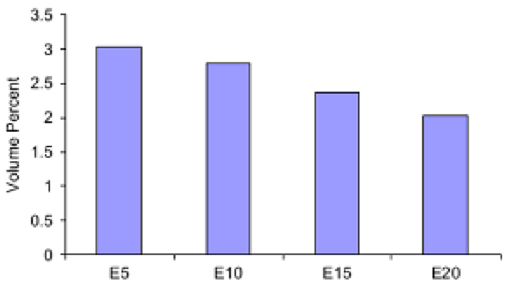

Fig 3.5:The volume percentage of co for various Full blend at full load[7]

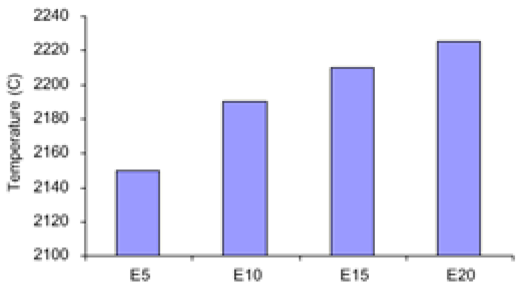

Fig 3.6: The maximum temperature for the various blends at full load. [7]

Table 3.2: The flue gas comparison for various blends[7]

Blend	NO	O_2	N_2	H_2	H_2O	CO_2	CO
E5	.0012	2.2	72	.0072	0.38	20.5	3.036
E10	.0013	2.06	71	.0072	0.6	21.5	2.8
E15	.016	1.98	70	.0072	0.9	22.6	2.37
E20	.0019	1.9	69	.0072	1.3	23.75	2.03

Table 3.3: The flow availability of the flue gas for various Blend[7]

Blend	Mass Ratio(g/h)	Flow availabilty(KJ/kg)
E5	110.250	310
E10	106.588	330
E15	104.216	365
E20	100.000	407

Increasing the other gas contents such as CO2, H2O, and NO which have higher heat capacity than other combustion products, is another reason for the increasing availability of flue gas with increasing bio-ethanol. As bio-ethanol in the blend increases, the quality of the flue gas for direct or indirect application increases It is assumed that the boiler efficiency is 90%. For calculation of the efficiency, the fuel heat value is necessary. Since the fuel composition is variable, the fuel heating value varies. The fuel heating values for the various blends are shown in Table 3.4. The efficiencies for two cases of CHP and SHP are shown in Table 3.5. The system efficiency for the CHP case is higher than that of the SHP[7]

Table 3.4: Lower heating value of the various blend

Fuel	LHV(KJ/kg)
Gasoline	44000
Bio-ethanol	27000
E5	40.656
E10	39.054
E15	37.650
E20	36.408

Table3.5: The system efficiency for the various blend

Blend	$Ŋ_{a(\%)}$	Ŋ(%)
E5	33.36	29.82
E10	35.2	31.23
E15	37.99	33.1
E20	40.48	34.6

case. As bio-ethanol in the blend is increased, the system efficiencies for the two cases are increased. Since the electricity production is constant, the fuel consumption varies. Moreover, as the fuel energy (i.e. the fuel consumption multiplied by the fuel heating value) reduces, therefore the efficiency increases. In fact, the increase in the exhaust temperature will cause the useful heat value to increase and the efficiency will increase. [7]

3.2: Review of some Commercial cogeneration units [7-16]

There are many kinds of commercial units are available from different manufacture. They are renowned for their performances, efficiency and power and thermal output. In this section we will discuss some of this kind of units. There many companies who are producing small scale cogeneration unit. Among this capstone, Alfagy, cogeneration America, Tedom, Kawasaki, Janbacher etc are renowned. In the next three pages I am illustrating some of these units. First two tables contains the reciprocating units both for natural gases and for biomass. Last one for gas turbine.

Table 3.6: Natural Gas (Reciprocating Engine)

			Performances at nominal ISO conditions						natural gas fuel, ISO conditions, ppmvd or		
Manufacturer	Model	Size	Weight	net electric efficiency	net electric power output	heat power output	net thermal efficiency	heating fluid / temperatures (e.g. water 70-90°C)	NOx	CO	manufacturer website
name	name	(LxWxH)	(kg)	%	(kW)	(kW)	%				
Co-Energy America	SDPM150EI6MS4	106" x 48" x 112"	10,600 lbs	34.7	150	164	50.01	176-195	0.15 g/bhp-hr	0.60 g/bhp-hr	www.coenergyamerica.com
Tedom	Cento T160	3950x1685x2650	5100	38.5	160	196	47.1	50-71	651 mg/m3	501 mg/m3	cogeneration.tedom.eu
Tedom	Cento T180	3950x1685x2650	5100	37.9	175	223	48.2	50-70	650 mg/m3	500 mg/m3	cogeneration.tedom.eu
SCHMITT ENERTEC	Alfagy B200	3.6 x 1.45 x 2.45m	4300	36	200	264	48.01	70-90	500 mg/Nm	650 mg/Nm³	www.alfagy.com
SCHMITT ENERTEC	Alfagy B233	3.6 x 1.45 x 2.45m	4300	36	233	264	48.01	70-90	500 mg/Nm	650 mg/Nm³	www.alfagy.com
Co-Energy America	SDPM150EI6MS4	122" x 66" x 112"	11,600 lbs	34.8	250	1,248 kbtu/h	51	176-195	<0.15 g/bhp-hr	<0.60 g/bhp-hr	www.coenergyamerica.com
Jenbacher	J208 GS	12,200 x 2,500 x 2,600	5600	38.07	330	420	42		>500 mg/m3	<0.60 g/bhp-hr	www.gepower.com
Jenbacher	J312GS	4,700 x 2,300 x 2,301	9400	38.07	418	500	46.02	50-70	350 mg/m3	<0.60 g/bhp-hr	www.gepower.com
Jenbacher	J312GS	4,700 x 2,300 x 2,300	9400	39.08	435	497	45.04		500 mg/m3	<0.60 g/bhp-hr	www.gepower.com
Jenbacher	J216 GS	5,300 x 2,300 x 2,300	9900	38.8	559	666	46.2	70/90	>350 mg/m3	650 mg/Nm³	www.gepower.com
Jenbacher	J316GS	5,300 x 2,300 x 2,300	9900	40.3	582	649	44.9	70/91	500 mg/m3	650 mg/Nm³	www.gepower.com
Tedom	Quanto D580	11500x4400x8200	24890	42	600	693	48.4	70/95	500 mg/Nm3	650 mg/Nm3	www.tedom.eu
Jenbacher	J320GS	5,700 x 1,900 x 2,300	1100	40.7	794	870	44.9	70/92	500 mg/m3	650 mg/Nm³	www.gepower.com
Jenbacher	J412GS	6,000 x 1,800 x 2,200	11500	41.5	844	828	42.9	70/93	500 mg/m3	650 mg/Nm³	www.gepower.com
Jenbacher	J416GS	6,700 x 1,800 x 2,200	13700	49.2	850	897	43.8	70/94	500 mg/m3	650 mg/Nm³	www.gepower.com

Table 3.7: Bio Gas (Reciprocating Engine)

Manufacturer	Model	Size	Weight	net electric efficiency	net electric power output	heat power output	net thermal efficiency	heating fluid / temperatures (e.g. water 70-90°C)	NOx	CO	manufacturer website
name	name	(LxWxH)	(kg)	%	(kW)	(kW)	%				
Tedom	Cento T160	3950x1685x2650mm	5100	38.2	160	197	47	80/70 °C	>500 mm/Nm3	650mm/m3	cogeneration.tedom.eu
Tedom	Cento T180	3950x1685x2650mm	5100	37.6	175	223	47.9	80/70 °C	>500 mm/Nm3	650mm/m3	cogeneration.tedom.eu
Jenbacher	J208GS	4900 x 1700 x 2000mm	5600	39.1	249	295	46.3	80/70 °C	>500 mm/Nm3	650mm/m3	www.gepower.com
sokratherm cogenera	E 2848 LE 322	3.000x1200x2.200mm	4400	38.4	252	174	50.2	80/70 °C	>500 mm/Nm3	<0.60 g/bhp-hr	www.sokratherm.com
Jenbacher	J208GS	4900 x 1700 x 2000mm	5600	38.7	330	400	47	80/70 °C	>500 mm/Nm3	650mm/m3	www.gepower.com
sokratherm cogenera	E 2842 LE 322	3300x1200x2200mm	5,390	38.7	366	245	49.7	80/70 °C	>500 mm/Nm3	<0.60 g/bhp-hr	www.sokratherm.com
Jenbacher	J312 GS	4,700 x 2,300 x 2,300	9400	40.4	526	558	42.9	70/90	>500mg/Nm3	1200mg/Nm3	www.gepower.com
Tedom	Quanto D580	11500*4400*8200	24890	42.5	600	646	45.7	70/94	>1000mg/Nm3	1300mg/Nm3	www.tedom.eu
Jenbacher	J316GS	5,300 x 2,300 x 2,300	9900	40.5	703	774	42.5	70/91	>500 mg/Nm3	1200mg/Nm3	www.gepower.com
Tedom	Quanto D770	14000*4600*8200	31430	42.6	800	863	45.8	70/95	>1000mg/Nm4	1300mg/Nm4	www.tedom.eu
Jenbacher	J316GS	5,700 x 1,900 x 2,300	1100	39.9	834	970	42.3	70/92	>500 mg/Nm3	1250mg/Nm3	www.gepower.com
Jenbacher	J412GS	6,000 x 1,800 x 2,200	11500	39.9	834	910	43.7	70/93	>500 mg/Nm3	1300mg/Nm3	www.gepower.com

Table 3.8: Gas Turbine

						Performances at nominal ISO conditions						Emissions, natural gas fuel, ISO conditions, ppmvd or mg/Nm3 (specify)	
Manufacturer	Model	Size	Weight	Fuel type	Net electrical EFFICIENCY	Total efficiency	net electric power output	Net thermal efficiency	Heat rate	heat power output	heating fluid / temperatures (e.g. water 70-	NOx	manufacturer website
name	name	(LxWxH)	(kg)				(kW)			(kW)			
Capstone	C65-ICHP	760x2200x2400	1000	Natural gas		82%	65		12.4 MJ/kWh	120	70/90	>18mg/m3	www.capstoneturbine.com
Capstone	C200	1700x3700x2500	2776	Natural gas	33%		582	44.9	10.9 MJ/kWh	649	70/91	500 mg/m3	www.capstoneturbine.com
Vericor	VPS1	4270 x 4290 x 8500		Natural gas			487	20.4	16754 Btu/kWh	870	70/92	500 mg/m3	www.vericor.com
Kawasaki(natural gas	GPB15	5300x1650x2350	11000	Natural gas			1490	24.2	14880 kJ/kW-hr		70/93	25ppm	www.kawasaki.com
Kawasaki(natural gas	GPBX	5.9x2.0x3.7	11000	Natural gas			1430	23.6	15260 kJ/kW-hr		70/90	2.5ppm	www.kawasaki.com
Kawasaki(natural gas)	GPB15D	5300x1650x2350	17200	Natural gas			1,490	24	15030 kJ/kW-hr			25ppm	www.kawasaki.com
Talbotts	BG100(Biomass)			Biomass	20%	80%	100			250	90	25ppm	www.talbotts.co.uk

Chapter 4: Overview of small scale cogeneration

Here I will be describing the present situation of small scale cogeneration status and potential and the future opportunities in different countries. This section includes the overview of the current global status of CHP development. Two challenges have confronted this task:

1) Not all countries systematically collect CHP data. However, while some countries have been able to achieve a high share of these technologies, most countries have been much less successful.
2) Policy makers and industry are investing in policies and measures that increase the use of CHP and DHC as part of a larger portfolio of energy technology solutions.

The most important driver in most markets is the relationship between electricity and fuel prices. It remains the case that in the great majority of countries the prices of both are still artificially determined by government or state agencies rather than by a market mechanism. Therefore a clear link between the electricity price and the profitability of investment in cogeneration. With reserve margins continuing to decline and fuel prices continuing to rise in most regions, this is tending to push up electricity prices. Policymakers and energy companies needed to introduce and strengthen strategies geared towards fuel and energy efficiency. DE(District Heating) is likely to be an important part of these solutions.

However, there is no international definition or standard to ensure that all data reported as CHP are truly comparable. World electricity demand continues to rise, and the installation of many more decentralized CHP systems would be an ideal way to meet at least some of the new generation capacity required. At first I illustrate here the recent status of total order received by the cogeneration companies in the whole world for small scale in comparison to other scale cogeneration. then I will focus mostly on the over view of small scale cogeneration different countries such as USA, Japan, India, whole Europe, Finland and so on.

4.1 Small scale power generation order in comparison to bigger scale

In figure 4.1 the comparison of order for different power ranges have been shown as percent wise. As the range increases we see that the order of power generation decreases. One important thing here can be noted that the small power ranges are more demandable than larger scales. From the figure it can be seen that the percentage of .5 to I MW is higher for these two specific annum which is almost 60% of the overall. The more demandable ranges are .5 to 1,I to 2 and 2 to 3.5 MW. Which means that small scale CHP units are dominating the large power generation.

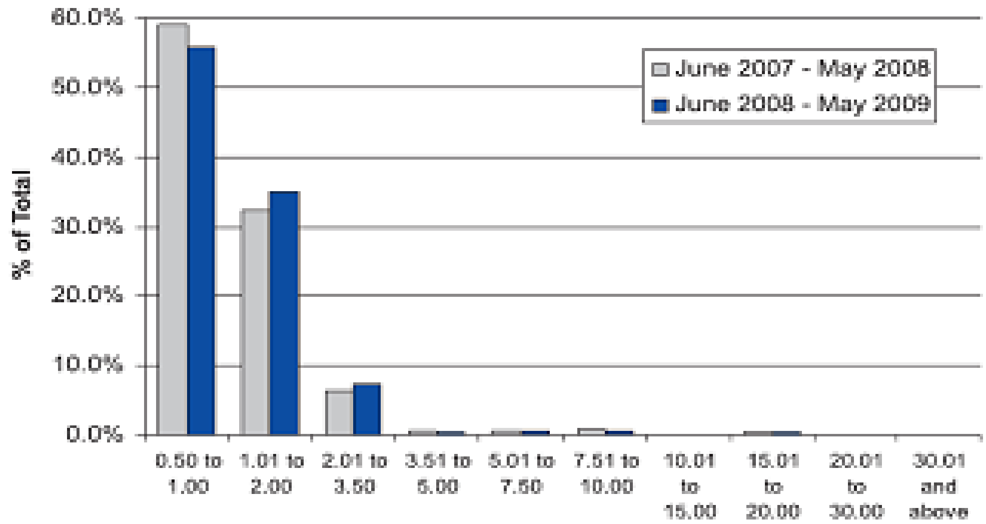

Fig 4.1: Comparison of order worldwide by power range [3]

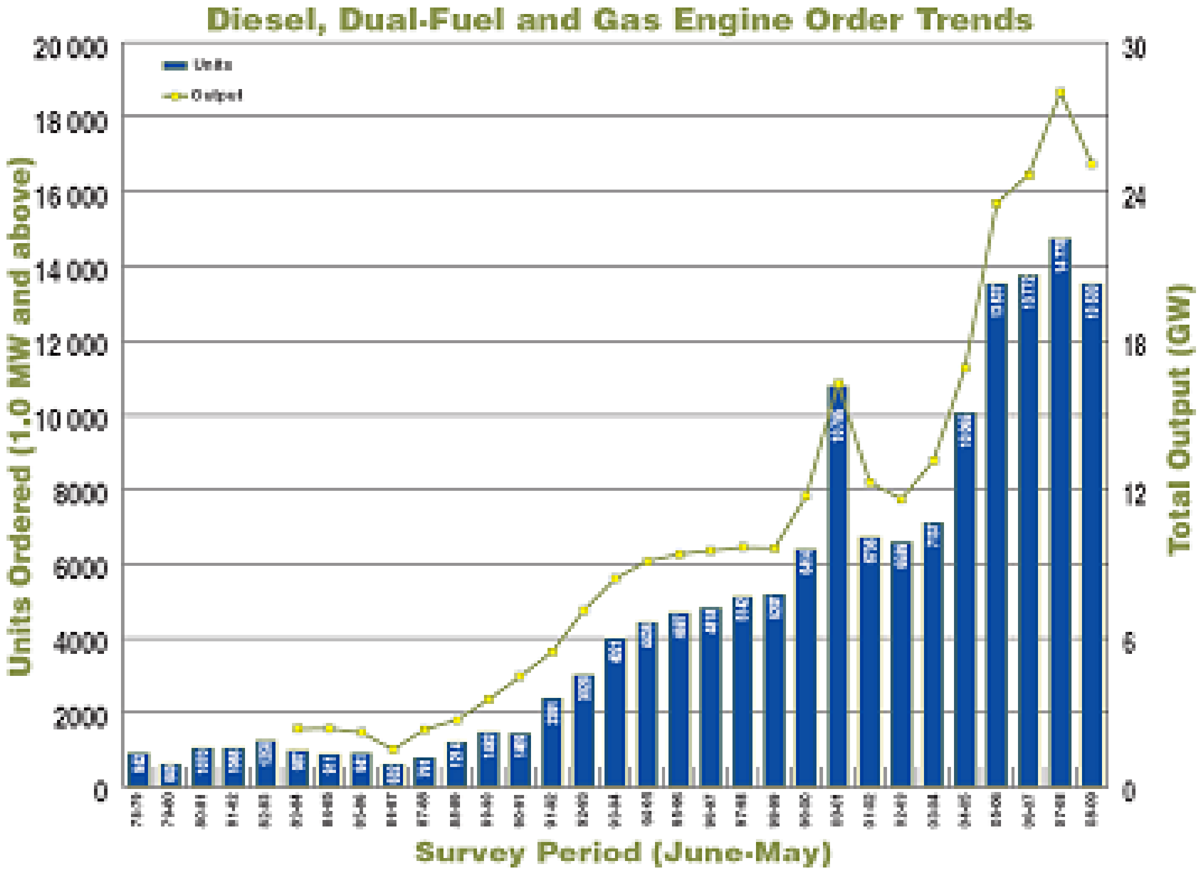

Fig 4.2: Power generation order survey [3]

The figure 4.2 has shown here is for orders in the 1.0 to 30.0+ MW power ranges only. A year ago, project activity, while perhaps not as robust as it had been in prior years, was still strong. The global gross domestic product (GDP) growth projection for 2009 was tagged at somewhere just over 4%. However, considering the events of the last year, a 15% decrease in diesel, dual-fuel and gas engine orders and a 30% decrease in gas turbine orders does not seem out of line nor should these decreases in order activity come as a great surprise. If this annual survey summary was instead an annual financial report, we would likely state: “the results are in line with expectations.”[3]

4.1.1:Diesel, Dual-Fuel and Gas Engine Orders

The number of units ordered during the survey period covering June 2008 through May 2009 totaled 30 688 compared to 36 154 in the prior-year period, representing an overall decrease of 15%. Looking at it from a power range split perspective, however, there was relatively little deviation in regard to the power ranges as a percentage of the total, (see figure 4.1). With a focus on the 0.5 to 2.00 MW power range, which makes up the majority of the orders, in 2008, 0.5 to 1.00 MW orders made up 59% of the total compared to 56% in 2009.

The 1.01 to 2.00 MW power range shows a slight increase, whereas in 2008, this segment

POWER GENERATION ORDER SURVEY

DIESEL, DUAL-FUEL & GAS ENGINE ORDERS, June 2008 – May 2009

Output Range (MW)	Units Ordered	Total Engine Output (MW)	Type of Generating Service: Stand-by	Peak-ing	Contin-uous	Fuel: Diesel Fuel	Heavy Fuel	Dual-Fuel	Liquid Biofuel	Nat. Gas	Western Europe	Eastern Europe & Russia	Middle East	Far East	Southeast Asia/ Australia	Central Asia	North Africa	Central, W., E., & S. Africa	North America	Central America & Caribbean	South America
0.50-1.0	17 155	13 013	8174	870	8111	16 429	3	1	0	722	2764	767	2717	1343	1109	2734	75	786	3447	343	1070
1.01-2.0	10 745	15 146	4540	789	5416	9776	27	0	0	942	2540	367	1130	1711	766	791	7	253	2625	152	403
2.01-3.5	2255	5429	1038	148	1069	1594	278	4	3	376	406	52	293	141	132	124	11	35	780	52	229
3.51-5.0	111	444	6	5	100	23	29	2	0	57	26	10	11	3	16	1	0	0	7	33	4
5.01-7.5	153	915	37	6	110	90	35	4	4	20	14	7	24	47	20	10	0	8	10	3	10
7.51-10	155	1342	49	24	82	4	95	0	2	54	5	0	30	4	10	2	0	11	9	0	84
10.01-15	31	359	0	1	30	1	28	2	0	0	2	0	7	0	2	0	0	4	0	2	14
15.01-20	82	1449	0	0	82	0	60	15	2	5	20	0	8	1	0	23	1	15	0	14	0
20.01-30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30.01 & above	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	30 687	38 097	13 844	1843	15 000	27 917	555	28	11	2176	5777	1203	4220	3250	2055	3685	94	1112	6878	599	1814

Revised data November 2009

DIESEL, DUAL-FUEL & GAS ENGINE ORDERS, June 2007 – May 2008

Output Range (MW)	Units Ordered	Total Engine Output (MW)	Type of Generating Service: Stand-by	Peak-ing	Contin-uous	Fuel: Diesel Fuel	Heavy Fuel	Dual-Fuel	Liquid Biofuel	Nat. Gas	Western Europe	Eastern Europe & Russia	Middle East	Far East	Southeast Asia/ Australia	Central Asia	North Africa	Central, W., E., & S. Africa	North America	Central America & Caribbean	South America
0.50-1.0	21 376	16 151	10 108	6465	4803	20 635	2	8	0	731	3751	1232	3102	3304	657	2297	3	607	4852	259	1312
1.01-2.0	11 727	16 828	5005	3694	3028	10 035	304	0	4	1384	2885	514	1214	1922	409	895	1	218	2851	298	520
2.01-3.5	2316	5681	1213	392	711	1663	79	0	3	571	553	121	100	167	84	110	0	21	969	58	133
3.51-5.0	180	720	8	11	161	72	43	1	2	62	18	19	22	35	16	29	6	23	4	8	0
5.01-7.5	150	881	10	62	78	72	25	2	4	47	52	7	19	8	28	6	0	4	9	5	12
7.51-10	284	2487	44	0	240	8	138	0	13	125	28	28	59	1	7	40	0	19	30	25	47
10.01-15	29	367	0	0	29	1	28	0	0	0	1	0	0	4	0	0	0	10	0	3	11
15.01-20	83	1490	0	0	83	0	63	11	5	4	5	0	2	0	0	43	7	5	10	4	7
20.01-30	8	168	8	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0	0	8
30.01 & above	1	41	0	0	1	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0
Totals	36 154	44 814	16 396	10 624	9134	32 486	691	22	31	2924	7293	1921	4518	5442	1201	3420	17	907	8725	660	2050

June 2007-May 2008 table shown above is a revised table. The table that appeared in the 2008 survey contained incomplete data.

Fig 4.3: different type's generator order's [3]

DIESEL, DUAL-FUEL & GAS ENGINE SPEEDS

Output Range (MW)	June 2007 - May 2008 Speed Range (r/min): under 300	300-600	720-1000	above 1000	June 2008 - May 2009 Speed Range (r/min): under 300	300-600	720-1000	above 1000
0.50-1.0	0	0	119	21 257	0	0	92	17 063
1.00-2.0	0	0	303	11 424	0	0	97	10 648
2.01-3.5	0	1	151	2164	0	0	310	1945
3.51-5.0	0	11	168	1	0	1	89	21
5.01-7.5	0	0	150	0	4	0	126	23
7.51-10	0	4	280	0	0	4	151	0
10.01-15	4	25	0	0	0	31	0	0
15.01-20	0	83	0	0	0	82	0	0
20.01-30	0	8	0	0	0	0	0	1
30.01 & above	1	0	0	0	0	0	0	0
Totals	5	132	1171	34 846	4	118	865	29 701

Fig 4.4: Diesel, Dual-fuel & Gas engine speeds [3]

represented 32% and in 2009, increased to 35% of the total orders. Type of generating service was the only category illustrating any fluctuation of totals on a percentage basis, although the 2009 data for this category does, in fact, align closely to the 2007 results. In 2009, 45% of the engines ordered were for standby, just 6% for peak applications and 49% for continuous duty. In 2008, 45% were standby, 29% were peaking and 25% continuous. The 2007 results indicated a greater number of orders for standby applications, which came in at 60%, but peaking orders represented 9% of the total, comparable to the 2009 data. In 2008, only 25% of all orders were identified as continuous duty and in 2007, this application represented 31% of the total orders. With nearly half of all 2009 orders received identified as continuous duty. The spike in peaking applications in 2008 appears to be a one-time anomaly and not an indication of a new trend. The engine operating speed data was consistent to prior years, with 97% of all engines operating above 1000 r/min. Diesel-fueled engine orders were also consistent with prior-year data, coming in at 91% compared to 90% and 89% in 2008 and 2007, respectively. Natural gas-fueled engines made up 7% of the total orders compared to 8% in 2008 and 10% in 2007. From a geographic perspective, there are no significant changes or new trends. There was a slight increase in the number of units ordered for the Middle East and for Central Asia — but only by two or three points. The Far East saw the largest percentage drop year over year, with only 11% of the total units ordered for this region compared to 15% the year prior.

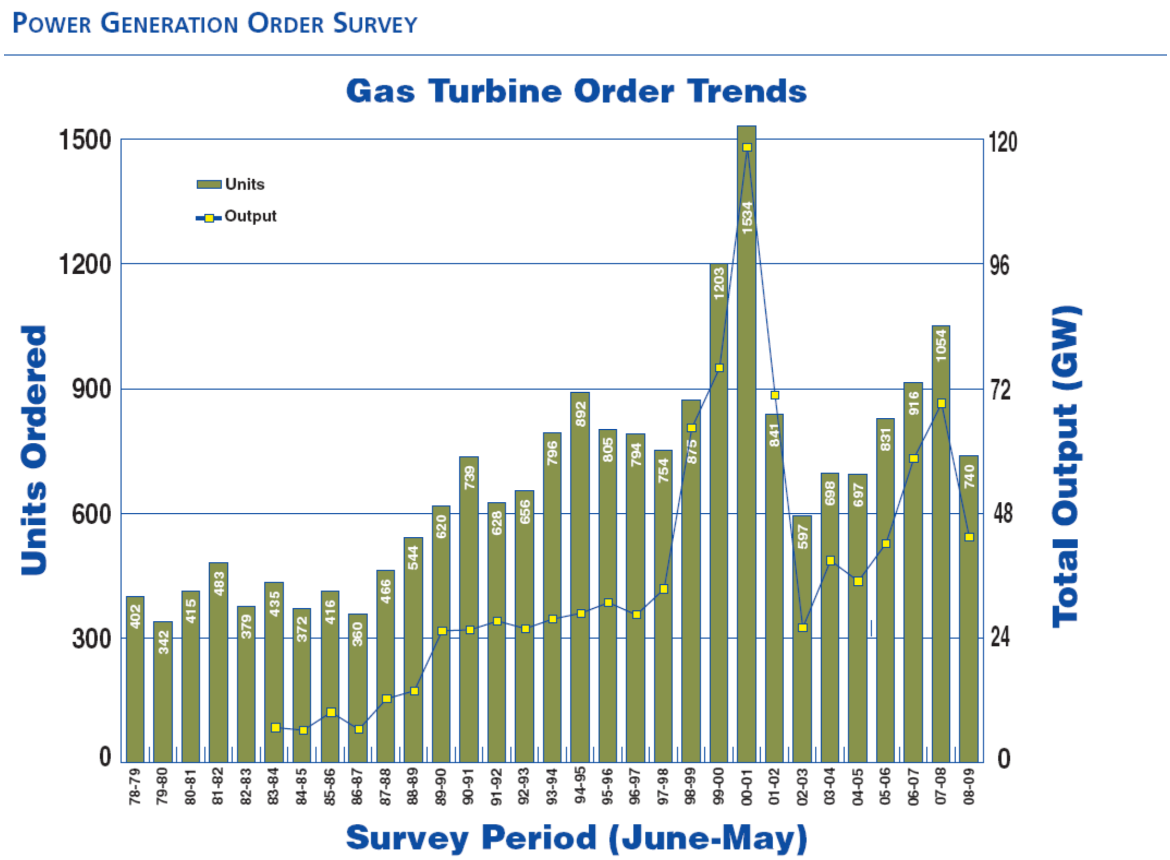

Fig 4.5: Power generation order survey [3]

4.1.2: Gas Turbine Orders

Overall orders decreased from 1054 in 2008 to 740 units for the same reporting period, 2009, representing a 30% decline. there were year-over-year fluctuations in the sub-categories, including a nearly equal offset in the type of generating service from continuous duty to standby as well as some moderate variations in the power ranges as a percent of total from the year prior (see figure 4.2). In 2009, the 1.0 to 2.0 range made up 15% of the total orders compared to approximately 12% in the prior-year reporting period. The 60.00 to 120.00 MW range also saw a relatively steep increase as percent of the total, increasing from 7% to nearly 15%. Conversely, the 120.01 to 180.00 MW range and the 20.01 to 30.00 MW range both decreased as a percentage of total orders, 3% and 5% respectively. With regard to fuel type, heavy fuel saw an increase from

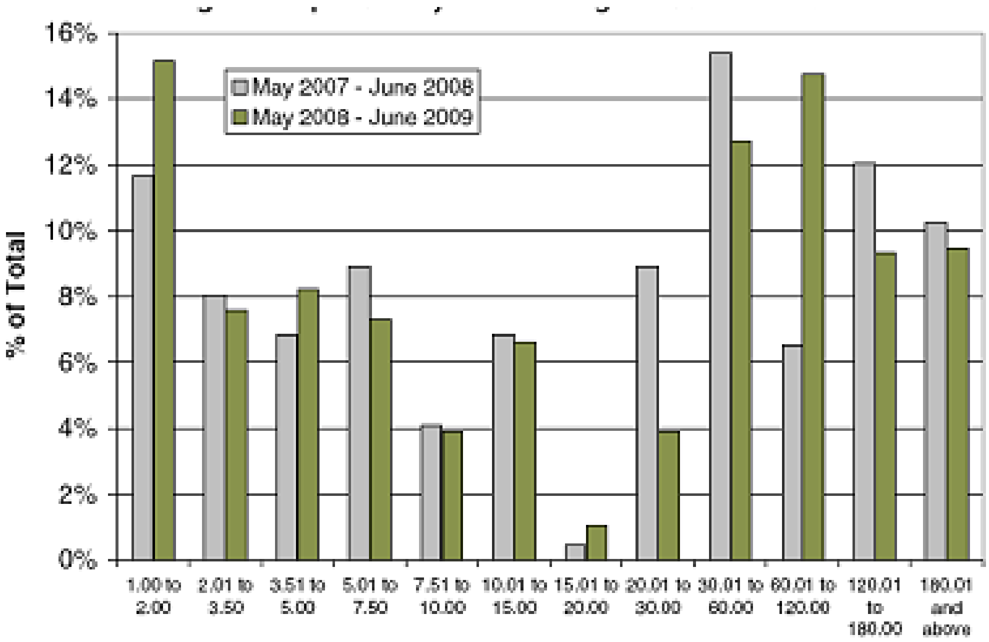

Fig 4.6: Comparison of power ranges [3]

Power Generation Order Survey

GAS TURBINE POWER GENERATION ORDERS, June 2008 – May 2009

Output Range (MW)	Units Ordered	Total Engine Output (MW)	Type of Generating Service			Fuel (Units)				Western Europe	Eastern Europe & Russia	Middle East	Far East	Southeast Asia/ Australia	Central Asia	North Africa	Central, W., E., & S. Africa	North America	Central America & Caribbean	South America
			Stand-by	Peak-ing	Contin-uous	Diesel Fuel	Heavy Fuel	Dual-Fuel	Nat. Gas											
1.00-2.0	112	154	94	0	18	46	49	10	7	1	8	6	95	2	0	0	0	0	0	0
2.01-3.5	56	144	48	0	8	19	24	6	7	2	0	5	47	0	0	1	0	1	0	0
3.51-5.0	61	272	20	0	41	7	13	6	35	6	1	2	23	4	3	0	0	21	0	1
5.01-7.5	54	314	0	0	54	0	0	19	35	5	10	11	10	6	3	0	3	6	0	0
7.51-10	29	219	0	0	29	0	0	10	19	1	8	4	2	6	0	0	0	6	0	2
10.01-15	49	642	1	0	48	2	0	17	30	2	13	8	6	5	2	1	2	10	0	0
15.01-20	8	133	0	0	8	0	0	5	3	1	7	0	0	0	0	0	0	0	0	0
20.01-30	29	761	0	5	24	6	0	0	23	0	5	8	0	5	0	3	0	3	0	5
30.01- 60	94	3880	0	44	50	2	0	33	59	16	9	18	4	7	1	4	5	26	0	4
60.01-120	109	9054	2	82	25	2	67	7	33	7	13	70	0	3	3	0	0	6	0	7
120.01-180	69	10207	0	35	34	2	7	13	47	1	15	27	1	1	10	2	2	10	0	0
180.01 & above	70	17405	0	14	56	2	6	21	41	9	9	17	7	5	2	3	8	10	0	0
Totals	740	43 185	165	180	395	88	166	147	339	51	98	176	195	44	24	14	20	99	0	19

GAS TURBINE POWER GENERATION ORDERS, June 2007 – May 2008

Output Range (MW)	Units Ordered	Total Engine Output (MW)	Type of Generating Service			Fuel (Units)				Western Europe	Eastern Europe & Russia	Middle East	Far East	Southeast Asia/ Australia	Central Asia	North Africa	Central, W., E., & S. Africa	North America	Central America & Caribbean	South America
			Stand-by	Peak-ing	Contin-uous	Diesel Fuel	Heavy Fuel	Dual-Fuel	Nat. Gas											
1.01-2.0	123	176	89	0	34	46	45	11	21	6	17	2	92	2	2	0	2	0	0	0
2.01-3.5	85	267	65	0	20	26	23	28	8	1	9	1	65	3	0	3	1	1	1	0
3.51-5.0	72	324	34	0	38	19	13	8	32	8	2	12	32	7	0	0	0	10	0	1
5.01-7.5	94	547	0	2	92	2	0	49	43	7	12	4	5	22	20	0	5	8	0	11
7.51-10	43	328	0	0	43	0	0	20	23	10	4	0	4	7	3	3	4	7	0	1
10.01-15	72	855	0	13	59	3	0	33	36	7	13	1	15	10	6	2	5	10	2	1
15.01-20	5	82	0	1	4	0	0	2	3	0	1	0	3	0	0	0	1	0	0	0
20.01-30	94	2549	1	45	48	5	0	50	39	6	16	17	1	5	2	6	8	14	0	19
30.01-60	162	9374	0	104	58	0	0	44	118	32	22	12	4	28	1	4	9	42	0	8
60.01-120	69	7633	0	35	34	0	0	33	36	9	17	12	4	3	4	0	2	14	0	4
120.01-180	127	19 167	0	58	69	3	2	65	57	6	18	36	9	17	6	8	8	11	0	8
180.01 & above	108	28 304	0	0	108	0	0	32	76	36	14	12	7	4	5	17	0	8	2	3
Totals	1054	69 606	189	258	607	104	83	375	492	128	145	109	241	108	49	43	45	125	5	56

June 2007-May 2008 table shown above is a revised table. The table that appeared in the 2008 survey contained a typographical error.

Fig 4.7: Gas turbine power generation order [3]

8% to 22% while dual-fuel orders decreased from 36% to 20% of the total. Both diesel fuel and natural gas remained comparable to the prior year with diesel fuel orders coming in at 12% compared to 10% in the prior year and natural gas coming in at 46% compared to 47%, prior year. Regionally, the Middle East saw the largest gain while both the Far East and North America saw slight increases in order activity. Western Europe, Southeast Asia and Australia, Central Asia, all regions of Africa and South America all saw decreased levels of activity.[3]

4.2: Cogeneration overview US

4.2.1: Overview

In the US, the level of installed CHP capacity continues to increase, now in excess of 82 GWe. A number of states, rather than the federal agencies, have been making the running by reducing barriers and introducing incentives for DE. Large generation and supply companies have dominated electricity markets in the US for decades, with contributions from municipal and cooperative utilities. The introduction of the Public Utility Regulatory Policy Act (PURPA) in 1978 encouraged specified non-utility owners to operate generating facilities meeting heat-recovery efficiency standards. With high power prices, and low gas costs, large units were built under this law. The 1992 National Energy Policy Act then allowed non-utility companies to compete in wholesale markets. Cogeneration / DE markets experienced resurgence from the late 1990s until 2002, when gas prices tripled. A number of states, notably California, New York and Texas have been reducing barriers for interconnection and backup charges, and the Federal Energy Regulatory Commission has adopted national standards for units under their jurisdiction. The Energy Policy Act of 2005, signed by President Bush in August, includes requirements that all states consider updating their interconnection standards, and includes other provisions favorable to distributed generation.

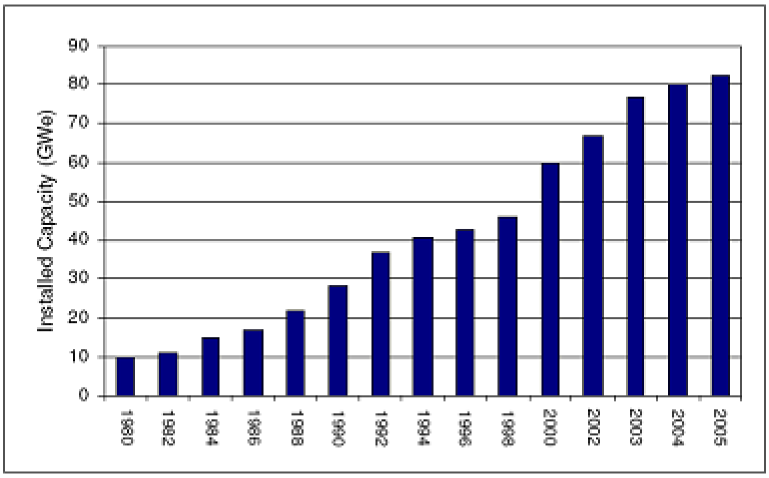

Fig: 4.8: cogeneration power growth in USA [1]

Key Drivers

- ✓ The US DOE and EPA have set aggressive cogeneration goals.
- ✓ State Regulatory Commissions are exploring more competition and removal of barriers.
- ✓ Outages, rising power prices and utility mergers and divestures are raising interest in local generation.
- ✓ National security concerns about system vulnerability.
- ✓ Long term coal contracts are delaying coal price increases by utilities.

Key barriers

- ✓ High gas prices and volatility discourage gas fired CHP in coal based power areas.
- ✓ Continued interconnection barriers and 15 state bans on third party generation.
- ✓ Continued bans on private wires crossing public streets in all 50 states.
- ✓ Emissions standards that do not reflect the efficiency of cogeneration and other DE.

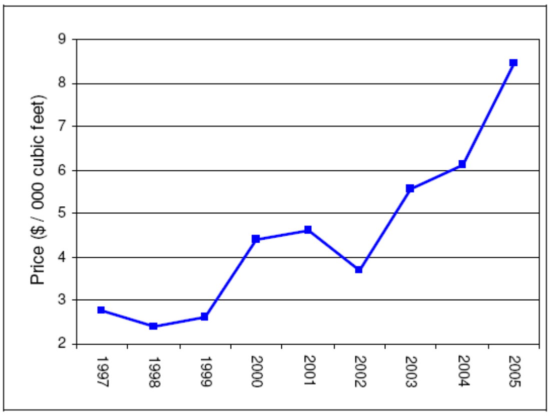

Fig: 4.9: US Natural gas prices for electricity [1]

Prospects

The US DOE has set targets to double cogeneration levels to 92 GWe by 2010; this is considered likely to be exceeded. A number of States, notably a coalition of North-Eastern states and California, have initiated programmes to reduce greenhouse gas emissions. The States of Nevada, North and South Dakota and Pennsylvania have added recycled energy to their mandated portfolio standards.

4.2.2: CHP or Cogeneration for Saving Energy and Carbon in Commercial Buildings in USA

Here in the table 4.1 the heat and electric efficiencies for separate heat and power technologies used in the analysis. Current and future small-scale CHP is more efficient on a system basis (80- 90% efficient) than even the best current and future separate heat and power (SHP) technologies. Here different kind of technology have been shown**.** None of the other recent studies that examine the potential of CHP to energy and reduce the carbon comprehensively examines available and soon to be available small scale CHP for building (summarized in DOE/EPA 1997). This is understandable in light of the current small installed capacity (< 5GW) of small-scale CHP, but it is believable that dramatic growth in this area is possible. Small-scale CHP will soon be a greatly updated and transformed technology. In the next two or three years, many new, more efficient, and lower-cost small CHP systems will become available (Kaarsberg & Elliott 1998). Although CHP is well established in industry, building energy experts still view it as an unproven technology. For small-scale CHP to achieve a significant penetration of the building sector there will have to be some effort devoted to demonstrating its reliability and cost savings to potential users. In addition, all CHP technologies must overcome the many barriers detailed in the references (DOE/EPA 1997; Kaarsberg et al. 1998; Munson & Kaarsberg 1998).

Table 4.1**:** Efficiencies of Conventional Separate Heat and Power (SHP) Technologies. [17]

Separate Heat and Power (SHP) Technologies	Heat	Electric	System
New, Utility-sized Combined Cycle Gas Turbine including T&D losses	N/A	51%	51%
Current U.S. grid including T&D losses	N/A	30%	30%
Typical New Gas Furnace	80%	N/A	80%
New Gas Water Heater	65%	N/A	65%

Efficiency for both engine and turbine for 100 kW units has been shown here. From the table it can be said that the overall efficiency for engine is better than the efficiency of turbine. Also the electrical efficiency is better than turbine. Commercial buildings that now use CHP tend to be large, high occupancy buildings with large thermal (especially hot water) loads such as hotels and hospitals. The thermal to electric (T/E) ratio of such facilities is typically greater than 1.4--well matched to available engine-based package CHP units. Recently, utility barriers such as high exit fees and backup charges have led to a decline in small-scale CHP in some states (Kaarsberg and Munson 1998). Small-scale CHP is expected to encounter increasing problems with environmental permitting because state and regional air authorities require expensive end-of-pipe control technologies that can add 25% to the CHP's cost. (Onsite 1998.) But new small-scale CHP technologies, on micro turbines, are generating great interest from the media and Wall Street. The small-scale market should also be helped by service innovations. Beyond maintenance contracts, companies have expanded CHP services to include financing and environmental permitting.

Table 4.2: Comparison of two different CHP Prime Movers [17]

100 kW unit	Electric %	Thermal %	Temperature Range	System %	T/E	SHP/CHP$\vert_{fuel}$
Engine (today's)	40 (35)	50 (55)	90--120°C hot water, low-grade steam	90	1.25 (1.57)	2.00 (1.65)
turbine	30	50	>500°C	80	1.66	1.67

Table 4.3: Comparison of Buildings' Demand for Heat and Supply of Heat from Electricity Generation (US commercial building)[17]

Type		A. Site Electricity (Quads)	B. Heat (Quads)
1	Residential	3.7	7.4
2	Commercial	3.4	11.6
3	Total Demand	7.1	19
4	Power Supply	7.1	16 (now unused)

In this section it is examined the inputs (Table 4.4) and the results (Tables 4.5&4.6) of a simple calculation of savings from CHP for high-occupancy, heat-intensive buildings on the electric and gas grids (e.g., hospitals or hotels). Because these buildings operate seven days/week, they will be early CHP clients. The only building energy characteristic that enters our calculations is the shape of the daily profiles for electricity and heat, both space heat and hot water (ADL 1995).

Table 4.4**:** Assumptions for Technology Comparisons in Tables 4.5 and 4.6

A. CHP Technology		B. Displaced SHP Site Electricity (Power)	C. Displaced SHP Thermal (Heat)
(1) Today's Engine		Today's Grid (182g/kWh)	Electric space & water heating in retrofits
(2) Today's Engine		Today's Grid (182g/kWh)	Gas space and water heating in new and retrofitted buildings
(3) 2010 Engine		CCGT (97g/kWh)	"
(5) 2010 turbine	Winter	CCGT (97g/kWh)	"
	Summer	CCGT (97g/kWh)	Electric (COP=3) space cooling in new buildings [replaced with waste-heat- powered Absorption Chiller (COP=1.6)]
(6) 2010 Engine		marginal coal (289g/kWh)	Gas space and water heating in new buildings
(8) 2010 turbine	Winter	marginal coal (289g/kWh)	"
	Summer	marginal coal (289g/kWh)	Electric (COP=3) space cooling in new buildings [replaced with waste-heat- powered Absorption Chiller (COP=1.6)]

Although Table 4.6 includes three technologies and two markets, for the purpose of describing the method and nature of the results, I discuss just one (engine) of the three technologies. Consider a 100 kW_e unit (and scale up the tables to macro units, i.e., 1 GW installed in the U.S.). This 100 kW_e engine supplies 140 kWh_{th} of heat. It can be assumed that one or more of these units will roughly match the winter heat demand profile, with backup boilers filling in on the coldest days, and that some electricity will be bought or sold as needed.

Over six months of "winter" (the heating season) it is assumed that the engine serves its load at a 75% duty factor. In "summer" (the six-month cooling season), engines' and fuel cells' outlet temperatures are too low to operate an absorption chiller, so duty factor is made halve (assuming only production of hot water) for 6 months. The yearly average duty factor is then three quarters of 75 percent of the year, this corresponds to 4,928 hours/year, and generation of 493 MWh_e. Table 4.4 summarizes the assumptions for all the cases.[17]

Small-scale CHP units already have a successful track record in a wide range of building applications. Because existing small-scale CHP technology has a relatively high T/E ratio (55/35=1.4), it has been most successful in situations with a large hot water demand, such as colleges, hotels, hospitals, and some restaurants. (See Major 1995 for an excellent set of case studies.) The purpose of this section is to show that CHP benefits are not solely, or even mainly, dependent, upon the success of new, yet- unproven technologies.

Table 4. 5: Energy and Carbon Use and Savings for Today's Small-scale CHP Technologies, for 1 GW_e of Installed Capacity. Cases (1) & (2) are Defined in Table 4.4.

CHP Technology	Primary Energy in TBtu, for 1 GW_e Running 4,928 Hours/year (A)				Energy Savings % (B)	Carbon Avoided % (B)	Carbon in MtC per Installed GW_e			
	CHP Fuel	SHP Electric (Table 4.4 Col. B)	SHP Heat (Table 4.4, Col. C)	Savings (SHP-CHP)			CHP Fuel	SHP Electric (Table 4.4 Col. B)	SHP Heat (Table 4.4 Col. C)	Savings (SHP-CHP)
(1) Today's Engine-I^2R retrofit	48	56	84	92	66%	69%	0.7	0.89	1.34	1.53
(2) Today's Engine-new Bldg.	48	56	20	28	37%	41%	0.7	0.89	0.29	0.48

New Technologies in 2010

Introduction of high-temperature ceramics and other advances in combustion technology will continue to increase electric efficiencies for both engines and turbines. Thus, in the 2010 scenarios, the estimated electric efficiency of the engine is raised to 40% and that of the turbine is raised 30% from today's figures. In summer, because the turbine can run an absorption chiller, thus displacing peak electricity used for cooling. It is assumed that it runs 6,570 hours/year. Also assumed that engines will not be routinely running chillers in 2010. In examining the range of possibilities and other studies, It is concluded [17] that the variation in the SHP technologies used for comparison could be greater than the variation in CHP technology. Thus, in Table 4.6**,** provided two extremes of SHP technology. In Table 4.7, contain the average of these two to estimate savings.

Table 4.6: Energy and Carbon Use and Savings for Three 2010 Small-scale CHP Technologies, for 1 GW_e of Installed Capacity. Cases (3)-(8) are defined in Table 4.4.

CHP Technology (in 2010)	Primary Energy in TBtu (a)				Energy Savings %	Carbon Savings %	Carbon in MtC per installed GW			
	CHP fuel	SHP fuel (Table 4.4, col. B)	SHP Heat (Table 4.4, col. C)	Savings (SHP-CHP)			CHP fuel	SHP fuel (Table 4.4, col. B)	SHP Heat (Table 4.4, col. C)	Savings (SHP-CHP)
BAU Scenario (vs. CCGT)										
(1) Engine	42	33	16	7	14	14	0.61	0.48	0.23	0.10
(2) turbine	75	44	33	3	4	4	1.09	0.64	0.49	0.04
High Efficiency/Low-Carbon Scenario (vs. marginal coal plants)										
(3) Engine	42	56	16	30	41	63	0.61	1.43	0.23	1.04
(4) turbine	75	75	47	47	39	63	1.09	1.90	1.05	1.86

2010 Market Estimates for Building CHP Technologies

Because of uncertainties in future policies, and in future technologies, It is reluctant to predict the exact mix of technologies that might deliver carbon savings by 2010. But as seen above, potential impacts could vary significantly depending on this mix. Thus, in this section, examining the energy and carbon results for a plausible set of market penetrations, recognizing the large uncertainty. Table 4.7 presents a possible set of market penetrations for 2010. These market estimate ranges are not a result of our analysis, but are extrapolations from other's estimates.

Table 4.7:shows that savings from small-scale building CHP can approach 10% of the total 2010 emissions for commercial buildings. This is nearly 6 percent of the total, or 37% of commercial buildings' proportionate share, of the reductions needed for the U.S. to reach the Kyoto Treaty emissions levels. (Kyoto 1997; EIAa 1997).

CHP Technology	Installed GW Estimates	<SHP> Energy Savings (Quads)	<SHP> Carbon Savings (MtC)
Engine	0 -- 5	0 -- 0.09	0 -- 2.8
turbine	10 -- 15	0.25 -- 0.37	9.5 -- 14.2
Total	15 -- 25	0.33 -- 0.63	12.3 -- 22.6
% 2010 Baseline	5 -- 11%	2 -- 4%	4 -- 8%

4.3: Cogeneration Overview of Japan

The industrial sector is Japan's biggest energy consumer (almost 50%) followed by the commercial/residential sector (27%) . Since the first oil shock of 1973, considerable energy conservation efforts have stabilized industrial demand growth, but this has almost doubled in the commercial / residential sectors with the widespread use of electrical appliances. Energy production has, over this time period, shifted from oil-dominated (80% to 50%) to a more balanced mix of natural gas, nuclear power and coal, but Japan still has low self-sufficiency. Most of Japan's electricity (83%) is generated by large-scale, utility-owned central power systems. The rest (17%) comes from independent power producers, using on-site technologies, including CHP, wind power and biomass power. Nuclear energy and natural gas are the main power sources, respectively supplying around 30% and 25% of the nation's electricity. Here the cogeneration capacity that has been found by the end of year 2009 is given separately for both commercial and Industrial Sector . [17]

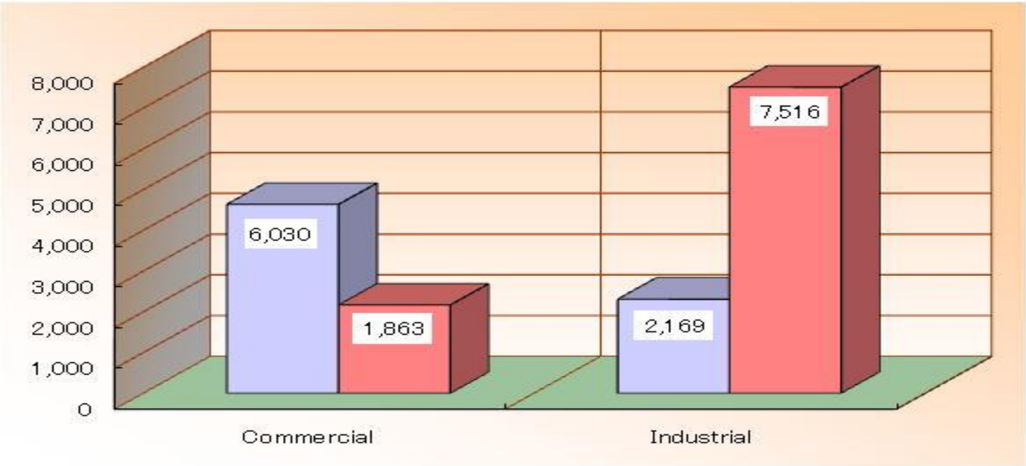

Fig 4.10: Cogeneration capacity for both industrial and commercial[3]

Table: 4.8: Installed capacity [1]

Net Installed Sites	Net Installed Capacity (MW)	Capacity per Site (kW/Site)
Total 8,199	Total 9,379	Total 1,144

4.3.1: CGS (CHP) Status by Type of Prime Mover

Here the total cogeneration installed separately for gas turbine, Gas engine and diesel engine for both commercial and Industrial use has been shown.

Table 4.9: Cogeneration capacity by prime mover [1]

Prime Mover		Net Installed Unites (Unit)	Net Installed Capacity (MW)	Capacity per Unit (kW/Unit)
Gas Turbine	Commercial	523	443.2	847
	Industrial	782	3,588.5	4,589
	Total	1,305	4,031.7	3,089
Gas Engine	Commercial	6,062	754.8	125
	Industrial	1,165	1,535.9	1,318
	Total	7,227	2,290.7	317
Diesel Engine	Commercial	1,985	665.0	335
	Industrial	2,279	2,391.2	1,049
	Total	4,264	3,056.1	717

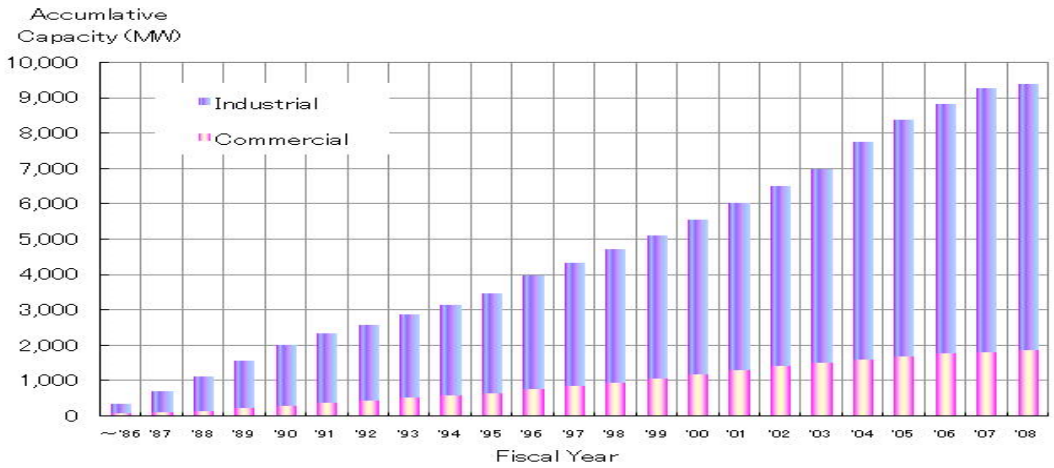

Fig 4.11: Year wise data for accumulate capacity up to 2008

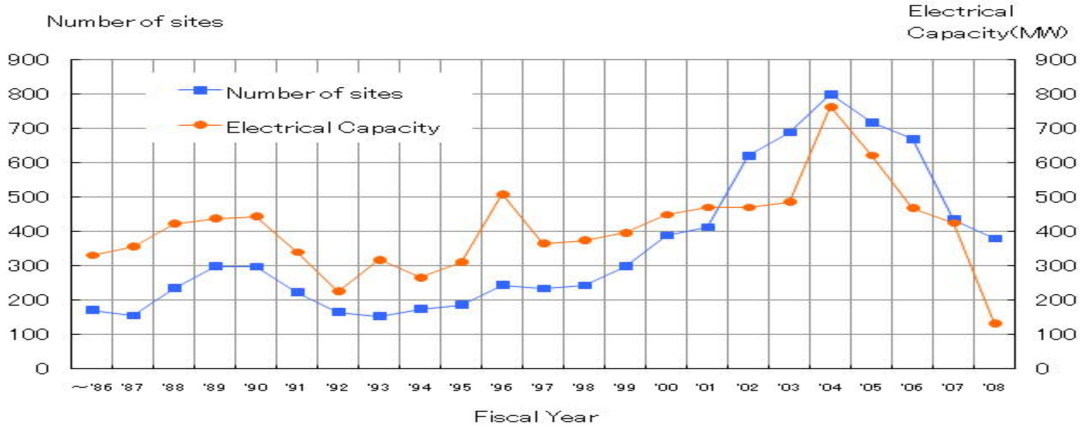

Fig 4.12: Year wise data for no. of site and electrical capacity

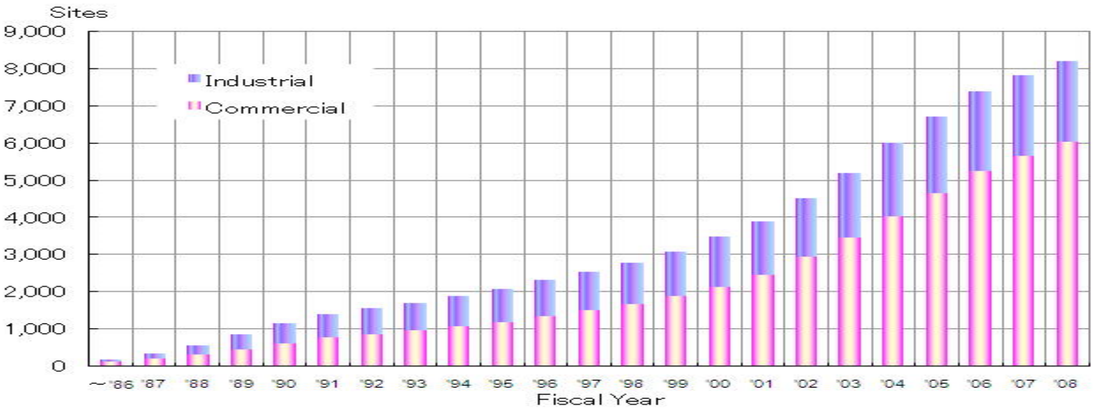

Fig 4.13: Sites related to industrial and Commercial [1]

4.3.2: CGS (CHP) Status by Commercial Sectors [1]

(as the end of March 2009)

In table 4.10 below shows the total no. of installation, electrical capacity and average capacity per site. From the capacity per site we see that almost all the data are less that 1 MW. Also it can be seen that the lots of installation of cogeneration in different commercial sector.

Table 4.10: cogeneration status by commercial sector [3]

Sector	Number of Installations (Site)	Electrical Capacity (MW)	Capacity per Site (kW/Site)
Store	1,681	370.7	221
Hospital	845	320.3	379
Hotel	643	225.2	350
Office	414	198.4	479
Sports Facility	419	105.8	252
Welfare Facility	667	24.0	36
Public Bath	368	30.3	82.3
Training Center and Sanatorium	144	46.9	326
Gas Station	77	4.9	63
School	132	61.5	466
District Heating and Cooling	35	138.2	3,949
Others	605	336.8	557
Total	5.652	1788	316

4.3.3: Share of Sites by Commercial Sectors

Total Number of Sites : 6,030 (as the end of March 2009)

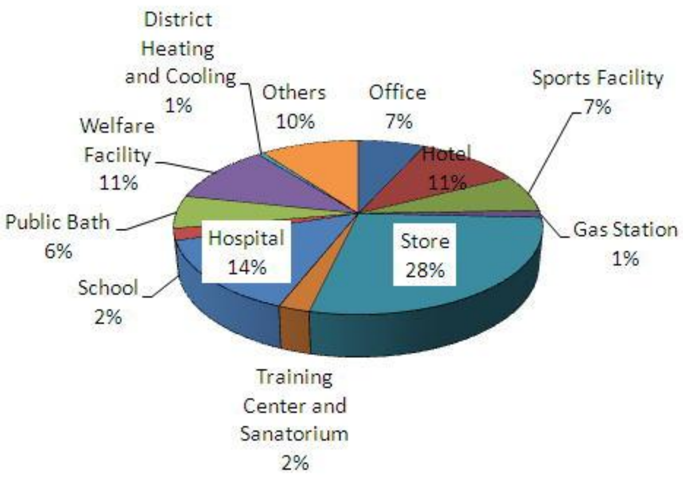

Fig:4.14:Shares of commercial sector[3]

4.3.4: CGS (CHP) Status by Industrial Sectors

(as the end of March 2009)

Here we see that capacity per site for industrial sector is mostly higher than 1MW.So it can be assumed that the small scale cogeneration plant is dominating in this sector.

Table: 4.11: CHP status by industrial sectors [3]

Sector	Number of Installations (Site)	Electrical Capacity (MW)	Capacity per Site (kW/Site)
Food	449	675.2	1,504
Chemical and Pharmaceutical	371	1,805.1	4,865
Machinery	306	1,187.5	3,881
Electric Equipment	187	705.0	3,770
Iron and Metal	221	801.9	3,629
Textile	99	402.7	4,068
Pulp and Paper	87	416.6	4,789
Gas, Oil and Other Energy	85	783.9	9,222
Glass, Soda and Ceramics	50	176.5	3,529
Others	314	561.3	1,788
Total	2,169	7,515.6	3,465

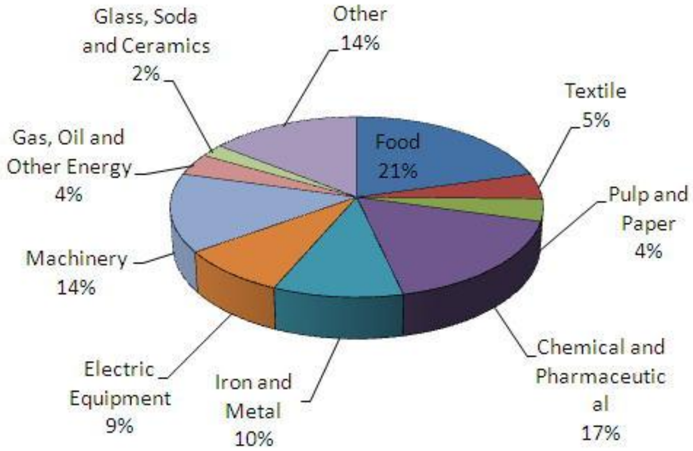

Fig 4.15: Share of Sites by Industrial Sectors [1]
Total Number of Sites : 2,169
(as the end of March 2009)

Key Drivers

- ✓ Technical guideline (1986) and feed-in tariffs (1992) for grid connected operation.
- ✓ An extensive incentive programme for micro- CHP.
- ✓ Ageing boiler steam turbine plants in industrial sector provide a large potential for cogeneration systems.
- ✓ Japan’s Energy Master Plan (2003) emphasizes the importance of the co-existence of DE systems with large-scale central power.
- ✓ Subsidies, accelerated capital allowances for corporation tax and long-term loans for DE.

Key Barriers

- ✓ High cost of protection devices for grid connected operation especially for small scale DE.
- ✓ Deregulation is not sufficient especially in terms of health/safety requirements for power generators.
- ✓ Electricity prices continue to fall with liberalization.
- ✓ Still high cost of cogeneration and/or renewable equipment.
- ✓ Low prices of excess electricity to be bought by electric utility companies.

4.4. Cogeneration overview of India

The Indian electricity system is notorious for high losses and much of the existing generation is also in need to make upgrade. Rapid increase in demand for power is exacerbating the problem. Power is under state jurisdiction and as a result many developments will be different from state to state. Potential for decentralized energy remains high in all states especially by using agricultural wastes as fuels. Indeed, in the 2005 saw an increased interest in generating power from local fuel sources. Cogen India, for example, worked with local distilleries to promote cogeneration. Availability of gas in States like Gujarat and to a lesser extent in Andhra Pradesh is substantial. The capacity data here includes stand-by diesel generators that do not really contribute to power generation or heat recovery.

Total electricity generation	495.9	TWh
Total electricity capacity	94	GWe
DE generation	68.2	TWh
DE capacity	18.7	GWe

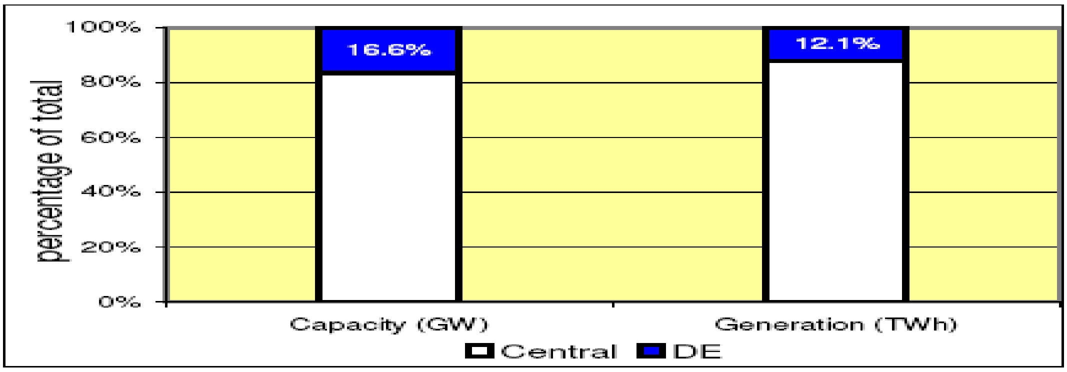

FiG 4.16 : Electricity generation[3]

Key Drivers

- ✓ Growing demand for power.
- ✓ High electricity prices.
- ✓ Poor quality of power, frequent power failures, fluctuations.
- ✓ Need for efficiency and resultant competitiveness in order for industry to overcome high power tariffs.
- ✓ Availability of natural gas and biomass.
- ✓ Availability of equipment for power generation in smaller capacities, heat recovery etc.
- ✓ National organization for the promotion of cogeneration (Cogen India).

Key Barriers

- ✓ Power purchase policy (discriminatory access, cost based interconnection fees, high standby charges, inconsistent policy with respect to purchase of excess power).
- ✓ Shortage of investment finance.
- ✓ Limited natural gas network.
- ✓ Delay in implementation of provisions of Electricity Bill 2003 by some individual States.

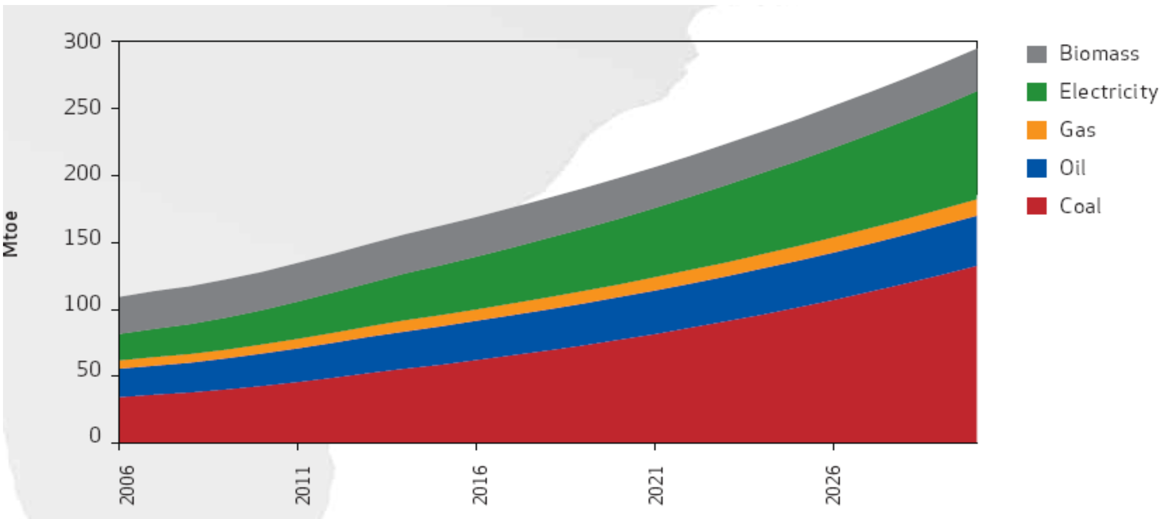

Fig 4.17: Generation by different fuel [3]

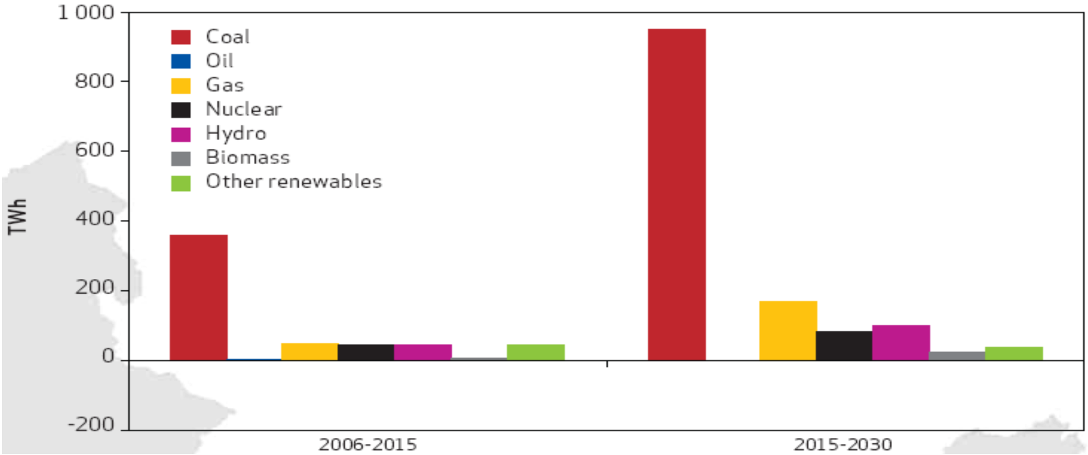

Fig 4.18: Generation potential [3]

Prospects

Captive power plants could increase substantially in the next few years in states like Gujarat where natural gas is increasingly available from off-shore and onshore reservoirs. Andhra Pradesh may have to wait longer for stable gas supplies. Increased gas supply will result in competition between central CCGT plants and more efficient cogeneration applications. Only policy could shift investment to the more efficient CHP. In the rest of the country, most of the increase in DE capacity would result from renewable sources.

4.5: Cogeneration overview of China

China has a strong potential in small scale cogeneration as its growth is remarkably high also lots of opportunity is available to for small scale CHP. Here in figure 4.19 we can see that total energy supply is increasing from 1980 to 2005. Among this it is found that the percentage of coal and natural gas is growing highly.

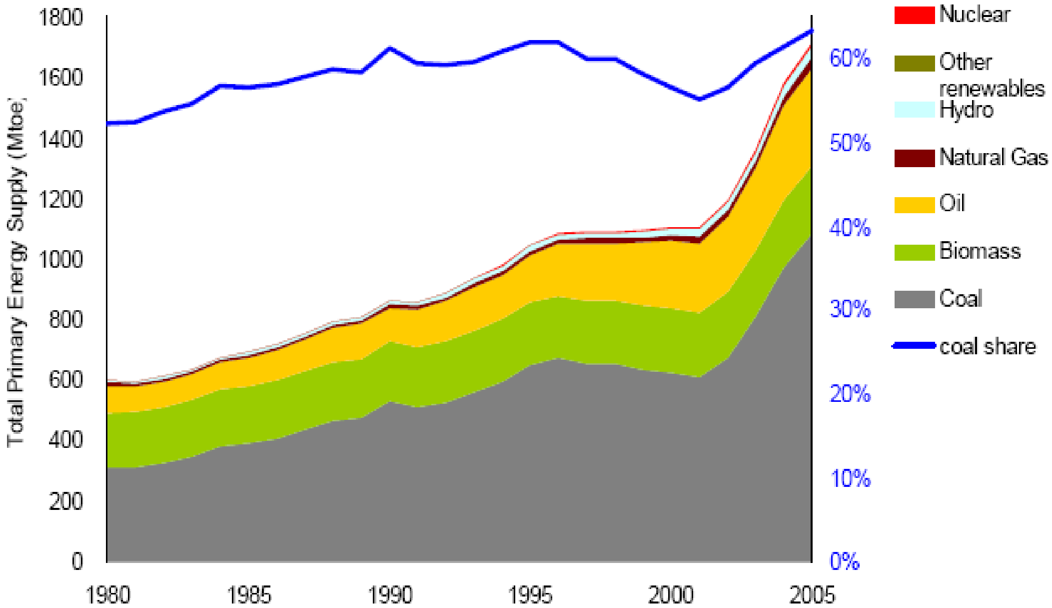

Fig 4.19: Total primary energy supply, China [40]

The feature of existing cogeneration in china:

- ✓ Historic interest in supporting coal-fired CHP.
- ✓ As of 2004, over 1500 units with 32 GWe capacity.
- ✓ CHP units provide 60% of central heating in urban locations.
- ✓ Mostly at industrial manufacturing sites and central heating in Northern cities.

- ✓ Potential to more than triple this capacity.

District Heating in China

- ✓ 50% of major cities have DH systems.
- ✓ Significant growth.
- ✓ Growth in power generation offers many opportunities for waste heat recovery.

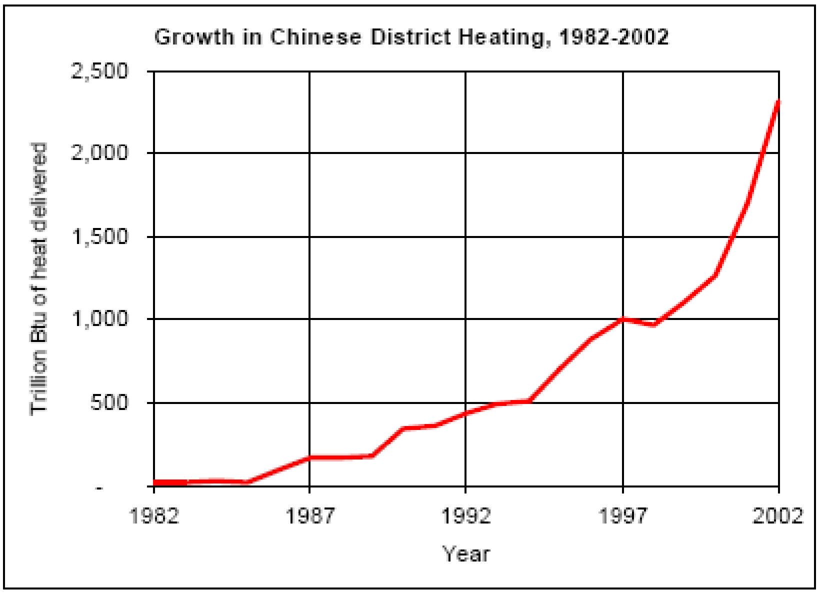

Fig 4.20: Growth in Chinese district heating [40]

- ✓ Rapid increase in demand for AC in cities.
- ✓ This demand causing electrical shortages.
- ✓ Most AC provided by inefficient units.
- ✓ Growing market share for central DC systems.

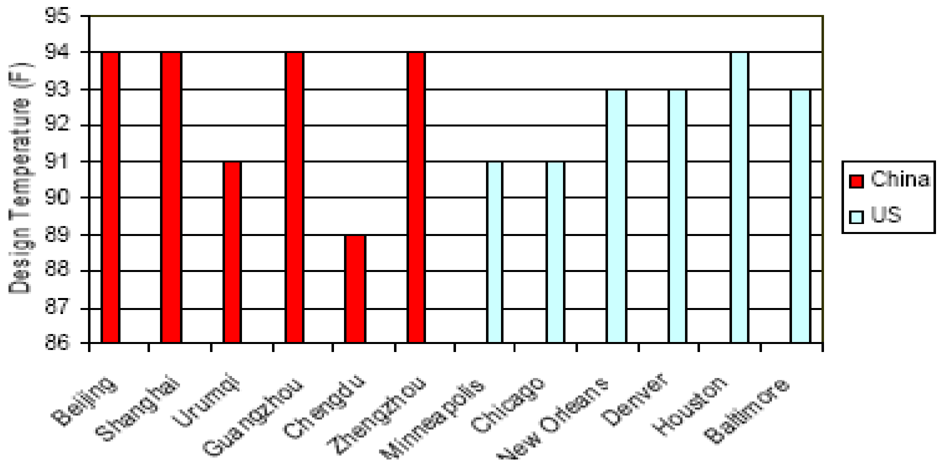

Fig 4.21: Air Conditioning Design Conditions in Major Chinese Cities Compared to Sample of US Cities with District Cooling(Source: International District Energy Association)[40]

Barriers to CHP/DHC Development in China

- ✓ Low level of government awareness.
- ✓ Incentives, financing insufficient.
- ✓ Need to promote clean, highly efficient systems.
- ✓ Competition with renewables, other technologies.
- ✓ Lack of technology/know-how among industry, local governments.
- ✓ Difficulties in connecting to grid.

- ✓ Natural gas supply.

Key Drivers

- ✓ Increasing electricity tariffs in 2004-05.
- ✓ Wider availability of natural gas.
- ✓ Occasional severe power shortages.
- ✓ Ongoing power market restructuring.
- ✓ Almost 50% of Chinese cities have centralized steam or hot water distribution systems that are ideal for cogeneration.
- ✓ A World Bank financed programme for rapid renewable energy development.
- ✓ Non cost-reflective energy pricing and price volatility.

Total electricity generation	2194.3	TWh
Total electricity capacity	442.4	GWe
DE generation	219.4	TWh
DE capacity	48.1	GWe

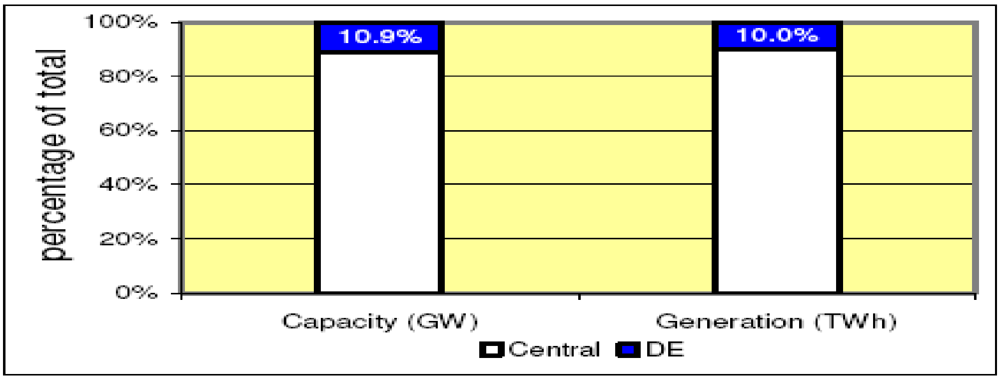

Fig 4.22: Electricity and DE Data[3]

In the 1970s and 1980s, China became concerned about energy-saving for the first time. The introduction of an energy-efficiency policy by the Chinese government sparked relatively rapid development of cogeneration systems in the late 1980s and 1990s. The predominant forms of DE in China are coal-fired steam turbine cogeneration systems – providing heat to municipal district heating systems and industrial sites – and small-scale hydro electric power. In 2004 the total CCHP capacity reached 56 GW$_e$, of which 30.1 GW$_e$ gas-fired. Chinese energy policy is slowly opening up to the opportunity of DE. In 2000 a regulation on the development of CHP was passed, and in September 2004 the National Development and Reformation Committee submitted a report on Issues of Decentralized Energy Systems.

Prospects

China's level of cogeneration and DE development is above the global average but could be greatly increased as power demand continues to surge. Even a small share of the overall market growth could result in significant development of the DE market. Thermal cogeneration capacity is projected to grow rapidly in coming years with estimated annual additions of at least 3 GW$_e$. The government's target for DE demonstration projects is 100 by 2010. With recent increases in coal prices, the massive demand for electricity exceeding supply and the shelving of projects representing 32 GW$_e$ of capacity due to environmental concerns, the financial and environmental benefits to be gained from DE could become better recognized. However, as most cogeneration in China is coal-fired, this has also suffered greatly from the fuel price increases.

4.6: Cogeneration over view of Europe

Countries throughout Europe are currently exploring the advantages offered by cogeneration technology as the EU gears up to promote its more widespread use. Cogeneration is already an established concept in the Nordic countries and, increasingly, in other parts of Europe. The EU as a whole is now examining the concept in detail with countries across the region passing new legislation that will radically change the structure of local power and heat markets. Cogeneration offers undisputed advantages. But it remains to be seen whether all EU member states grasp them fully. The concept, according to COGEN Europe, the European Association for promotion of cogeneration, is the most efficient way to deliver heating, cooling and electricity. Countries across Europe have enthusiastically adopted the concept. Finland, Denmark and the Netherlands, for example, today employ cogeneration extensively to provide electricity and district heat to local communities and industry, but the range of possible applications is limited only by the imagination.

4.6.1: European Cogeneration economic potential in 2020

Estimates of economic potential are derived directly from an explicit technical potential or are simply declared as "the potential" without clarification of the technical potential. It was difficult to extract the information on potential from different countries reports:

- ✓ Some results tended to be heavily qualified and not tabulated but included in text.
- ✓ Some countries have a wide range of potentials dependent on real or future variables rather than a single value, in this instance we chose the lower end of the range.
- ✓ Some countries reported in terms of TWh of electrical output rather than capacity, in this instance I made an estimate of capacity from the output figure.
- ✓ The absence of full language translation of some countries reports until late in the analysis period proved to be a challenge which leaves the risk that some nuances of the data have been missed.

Different approaches and assumptions have been used by different country when it comes to the economic potential. Several factors of economic and the perceived market effectiveness of cogeneration plants have been used with a given internal rate of return on investment (IRR) level being a popular hurdle. Required operating hours and assumed levels of policy support are also used as screening methods, as are assumptions on implementation feasibility in different country. In most cases the existing economic support mechanisms have been taken into account. Where both technical and economic potential are explicit, economic potential is significantly lower than the evaluated technical potential in the different country. Some countries have chosen not to give a single potential estimate but have rather modeled the potential under different scenarios, reflecting for example the effect of different carbon prices and support schemes.

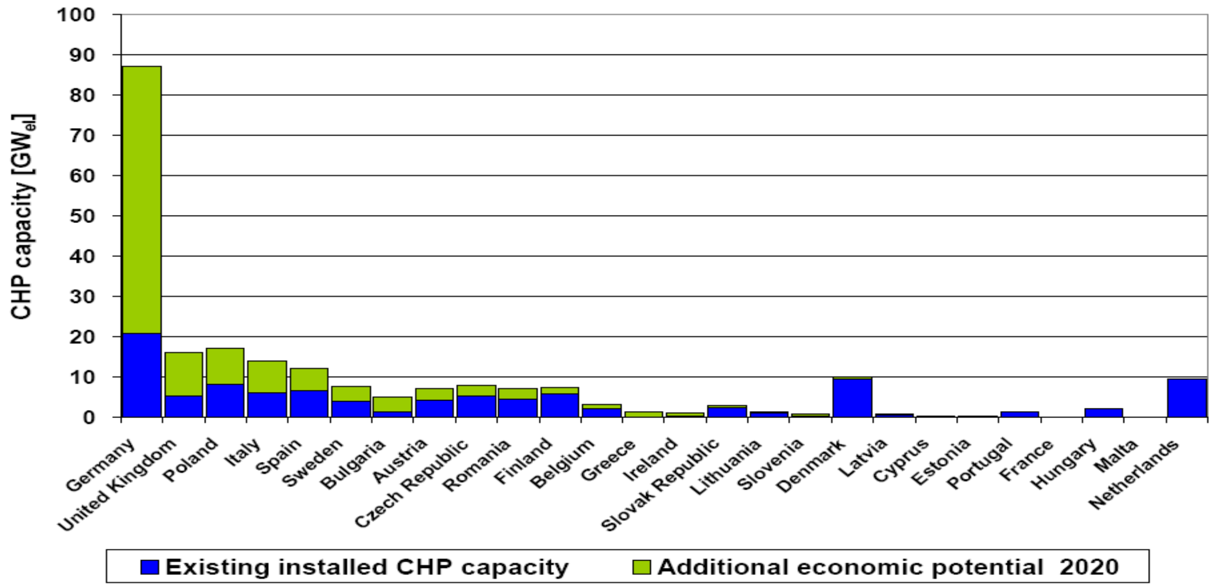

Figure 4.23: Existing installed cogeneration capacity and reported additional economic potential in the year 2020[1]

Its report on a feasibility analysis using an annual interest rate of 8% in the commercial sector and 5% for the public sector;

- ✓ The economic effectiveness of the cogeneration potential for small scale (and micro) units in the services and household sectors is still below wider market application (in some countries for example on average only 5% of evaluated technical potential is treated as economic potential in).

Regional observations [1]:

- ✓ There is significant unexploited industrial heat potential for cogeneration in Europe. In the larger economies this makes up around 50% of the potential.
- ✓ In southern parts of Europe, the industrial potential and tertiary sector heat potential have been stressed over the district heating potential. The cooling potential is also stressed.
- ✓ Significant potential exists in some countries particularly for refurbishment of district heating schemes and their upgrade to include modern cogeneration (where currently only heat is distributed). This is universally the case where a large district heating infrastructure already exists.
- ✓ In many countries the highest share of economic potential in the evaluated technical potential is linked to the modernization and upgrade of cogeneration units in district heating systems, with the replacement of existing steam turbines by combined cycle units running on natural gas.
- ✓ There is a definite trend to extrapolate the future opportunity from known past successes. Hence in countries which have a strong history of district heating and a lesser experience in industry, the potential is seen very much in expanding district heating, with less opportunity in moving more cogeneration into industry to be based on industrial heat. In countries such as the United Kingdom where there is a history of industrial cogeneration and virtually no district heating, the additional potential is all seen as being in industry and small commercial developments. In Germany which has a strong tradition in both segments, both segments are seen as potential for expansion.

4.6.2: European Cogeneration technical potential in 2020

Only 14 countries have reported a technical potential although every EU countries must have made this assessment as a first step to assessing economic potential. The reported figures, compared to current installed capacity are shown in figure 4.27 below.

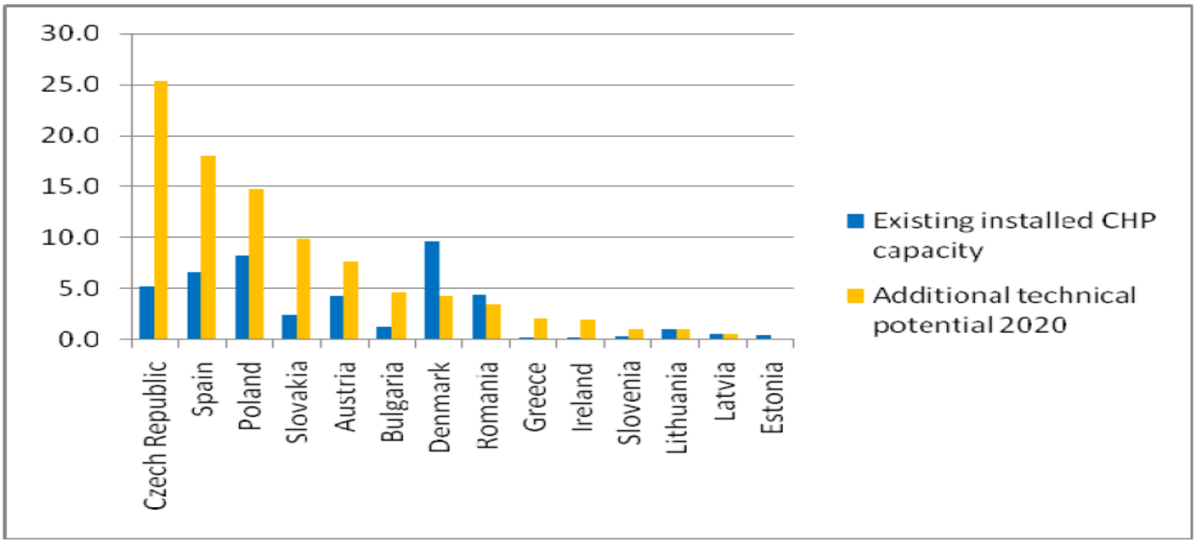

Figure 4.24: Comparison of the Member State identified technical potential (additional) compared with the existing installed capacity.[1]

There is no simple or direct relationship between the identified technical potential and the existing installed capacity. Eight countries of EU have identified the technical capacity as twice as large or more than the installed capacity. The technical potentials are based on the analysis of current cogeneration status with projections of future heat and electricity demand. The level of detail and approaches in considering sectors and sizes/technologies/energy sources of cogeneration units varies but the majority of analyses are based on a segmentation approach, i.e. bottom up. When the different EU States evaluated technical potential against their economic criteria, the economic potential emerged as in figure 4.25 below.

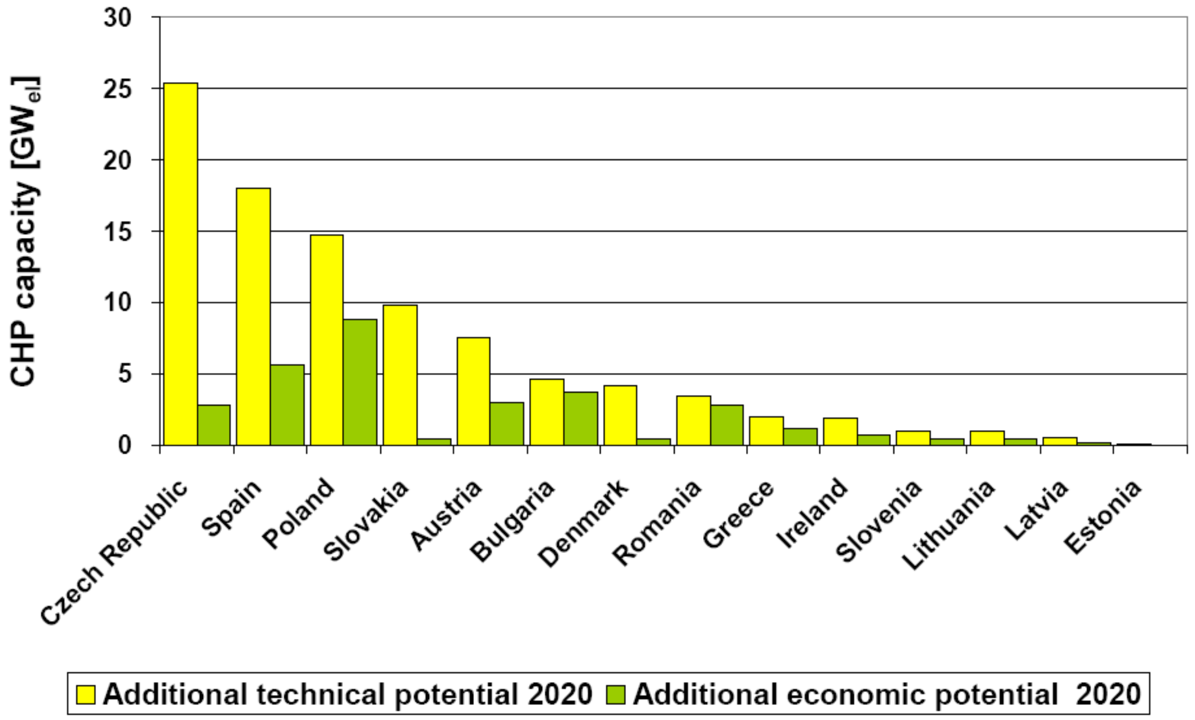

Figure 4.25: Reported additional technical and economical potential of cogeneration electrical capacity by 14 States in the year 2020

4.6.3: Barriers to growth of cogeneration[1]:

Many countries (Romania, Greece, Cyprus, Germany, Spain and Estonia) have highlighted administrative and procedural barriers to the further development of cogeneration. These relate to the difficulties of developing commissioning and running cogeneration plants. A sample of the types of problems still being faced is given below:

- ✓ Authorization procedures are bureaucratic and difficult to work with.
- ✓ There is an undue cost of information associated with the proposal and early development of a project.
- ✓ Procedures for connection to electrical grids are not standardized or codified.
- ✓ Placing of cogeneration electricity on the local energy market does not allow for the characteristics of operating cogeneration.
- ✓ Initial costs of connecting to the grid and thereafter operating the plant unduly burden the Cogeneration plant.
- ✓ Unfavorable provisions concerning back-up electricity supplies decrease the credit items of cogeneration producers from the avoided network charges.

4.7: Small-scale biomass CHP potential in Finland

Finland is renowned for their biomass fuel. For this reason here in this subpart I will be describing the existing CHP based on biomass as well as the potential of cogeneration in Finland.

CHP potential including all fuels

CHP (Combined Heat and Power production) has long traditions in Finland. First CHP plants were built in 1960s and big coal and peat fired CHP plants were built in 1970s.Building of CHP plants was based on large enough district heating activities in towns, in 2000 there were 48 places in Finland, which have CHP production connected to DH network. The total capacity was 4128 MW electricity and 5671 MW heat. Helsinki has the biggest CHP capacity 1017 MW in electricity and 1300 MW in heat. CHP plants produce about 76% of Finnish district heating energy. CHP extra potential in Finland has been evaluated to be 941 MW of electricity and 1670 MW of heat with 6000 hours annual peak load time based on district heat energy consumption in 2000. The CHP potential is evaluated to be 3685 MW electricity and 5020 MW heat with 2000 hours annual peak load time. The total amount of possible CHP units is 194 divided in seven categories. The distribution of CHP units is shown in Figure 4.29 categorized by the unit size. In evaluating the CHP potential CHP plants have to be able to drive 6000 h/a or 2000 h/a based on heat load in existing Finnish DH-systems in 2000. The same principle is used in those places, where CHP production already exists. The potential of the heat capacity is evaluated based on the rest of heat load after CHP production already existing. The share of existing CHP production cannot be more than 80% of total annual heat demand.

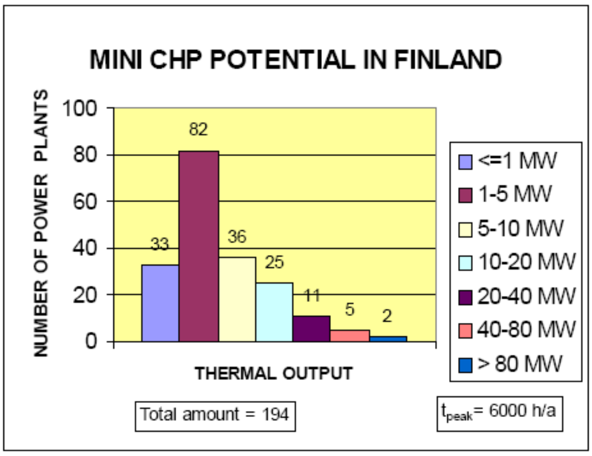

Fig 4.26: Mini CHP in Finland Thermal output [3]

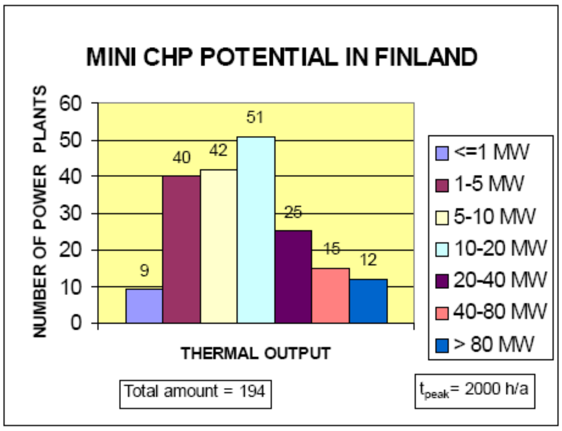

Fig 4.27: Mini CHP in Finland thermal output [3]

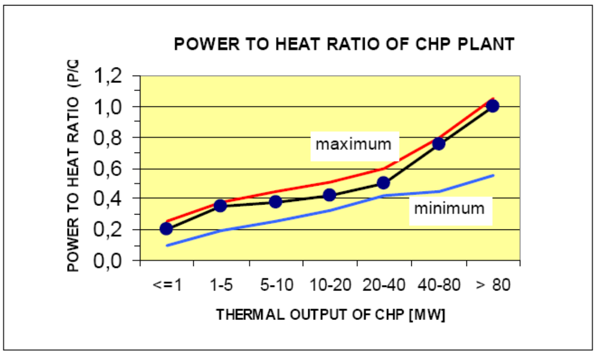

Fig 4.28: Power to heat ratio of CHP Plant [3]

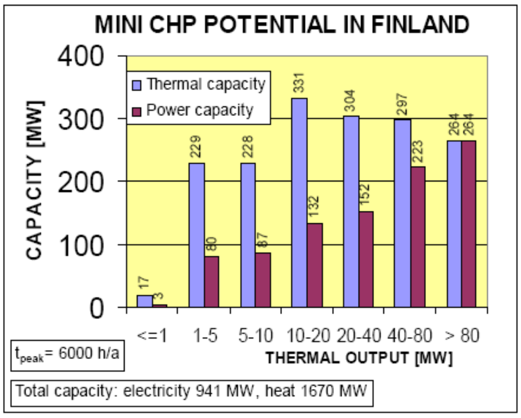

Fig 4.29: Mini CHP potential in Finland [3]

The potential capacity of CHP is calculated based on the power to heat ratio shown in Figure 4.33. The potential capacity of CHP plants is shown in Figure 4.34 divided in seven categories. The total demand of fuel is about 2 TWh, when peak load time is 6 000 or 2000 hours a year. As we can see in figure there are four main areas, where bio fuel installations are possible:

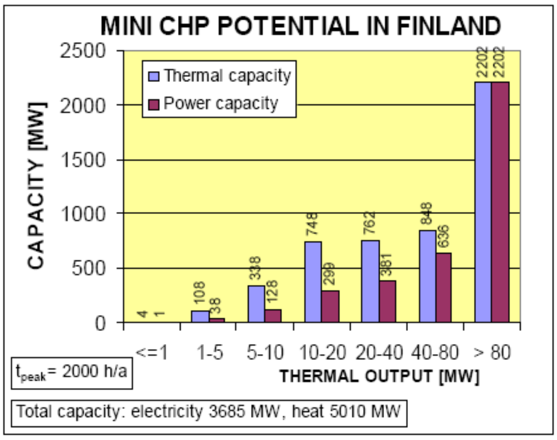

Fig 4.30: Mini CHP both for thermal and Power capacity [3]

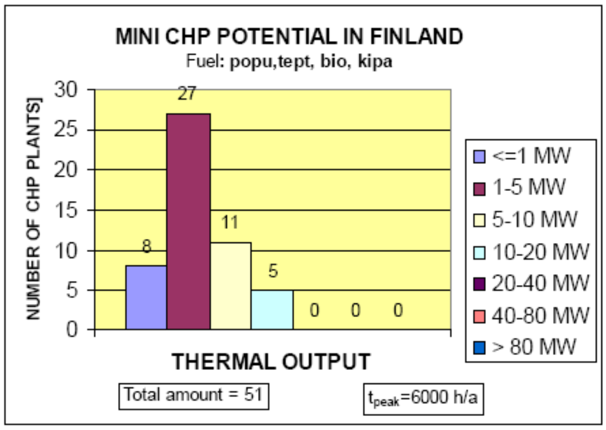

Fig 4.31: Mini CHP potential in Finland [3]

CHP potential has been evaluated to be 80 MW of electricity and 214 MW of heat with 6000 hours of annual peak load time based on district heat energy consumption produced on bio fuel in 2000. The CHP potential is evaluated to be 293 MW of electricity and 641 MW heat with 2000 hours of annual peak load time. The total amount of possible CHP units is 51. The distribution of CHP units is shown in Figure 4.35 categorized by the unit size. We see that 90% of potential CHP plants belong to the category less than 10 MW of thermal effect, if 6000 h/a of peak load demand is required. The range 1.5 MW covers the most part of the CHP amount having proportion of 53%. Correspondingly the proportion in the thermal size of 20 MW or less is 82%, if 2000 h/a peak load time is demanded including biggest proportion of 31% in the category of 10.20 MW

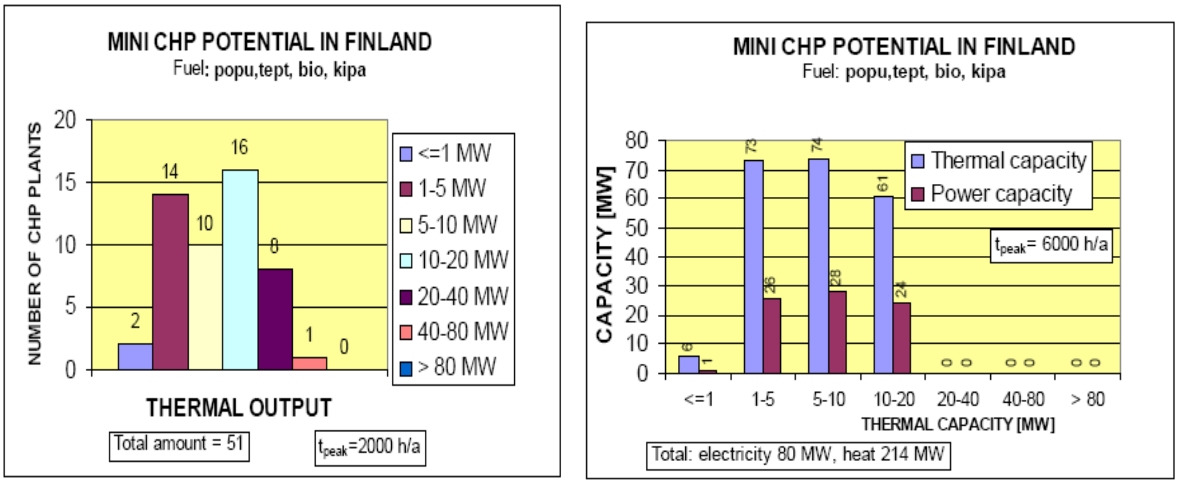

Fig 4.32: The potential capacity of CHP plants [3]

Chapter 5: Interesting demonstration activities

There are lots of interesting cogeneration power plant have been installed in the world wide. They are interesting because of their economical and technological purposes as well as for the high no. of cogeneration units for the same plant. In this section we will discuss some of these plants both for both gas turbine and gas engine.

5.1. Externally fired gas turbine

The EFGT is not a new concept, as several EFGT plants were built between the years 1930-1960. At that time they were used to fire like coal, mine gas and blast furnace gas and oil, which could be burnt in internally fired gas turbines lead to a diminish of interest in EFGT technology, At present a new grown interest in the EFGT technology has flourished, much thanks to increasing oil and gas prices but also due to increasing focus on environ friendly energy. The idea is to utilize an EFGT with renewable biomass .The technology is currently under development by several institutes and companies, for example University of Rostock, the Swedish Royal Institutes of technology, Talbotts biomass Energy and Compower AB. Yet Talbotts biomass Energy is the only company that could be identified with a commercial module currently available.

5.1.1: Talbotts Biomass Energy

Talbotts is the UK's largest manufacture of biomass heaters and boilers and has developed a commercial applicable EFGT-system, the 'BG100 biomass generator '.The BG100 is capable of operating on a wide range of biomass fuels ,including forest and agriculture residues, wood chips, wood pallets and various energy crops. The unit will produce 100 kW_{el} along with 200-250kW_{th}.This is below the minimum of 1MW_{th} which was the lower boundary limit for this study. However it was included ,since it was the only commercial EFGT technology that could be identified at present,[30] .The first installation of BG100 took place at Harper Adams University College in December 2005.It supplies 25% of Harper Adams electricity demand and could provide for a large part of heat needed by the student union and conference building. The objective of the project was to 'demonstrate a fully vertically integrated on farm CHP system which include the production. Harvesting and utilization of a range of biomass energy sources and the subsequent distribution of the thermal energy generated through an onsite heat network'[31].

Technology

The BG100 utilize an open cycle technology. Biomass enters the furnace from a fuel bunker. The furnace has a triple pass ceramic combustion zone which accept fuel with moisture content up to 40%, [30]. Flue gases exits the furnace and are fed through a gas/gas heat exchanger which heat up compressed air to about 800°C .The air is then expanded in a turbine which is direct coupled with a power generator. The turbine exhaust is further used as combustion air in the furnace and residual heat of the furnace flue gases are capture in a water/gas heat exchanger that produces district heat water at a temperature of 90°C,[31]. The process is shown figure 5.1.

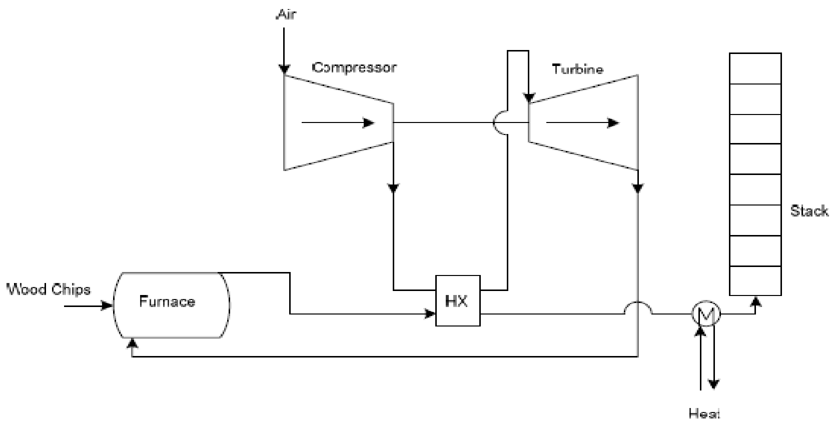

Fig 5.1: Process description of the BG100 Biomass Generator

System Performance

No experimental performance test have been identified. However, according to Tatt [30] the unit is able to achieve a total efficiency exceeding 80% and an electrical efficiency over 20%.The plant is also capable to run in fully automatic continuous operation 8000 hours annually.

Economic evaluation

Some changes had to be done to the economic calculation given in appendix [F1-F4] to make them valid for a plant of this size .As mentioned before, no system performance test has been identified therefore some of the values had to be assumed .The thermal output was chosen to 225 kW_{th} (Midway between 200 and 250 kW_{th}, which was the specified nominal thermal output).Furthermore the fuel input was assumed to 400 kW_{th}, resulting in a total efficiency of 81 % which fit the stated value of 'above 80' well. The initial investment of the module amounts to 600000€ along with an annual cost of 15000€ for service[30] .The specific investment for a theoretical heat part was taken from Kjellstorm [7] and amounts to 444 €/ kW_{th} . Because of the small plant size, the fuel assumed to be used was pallets. The price for briquettes and pallets is taken 23.4 € /MWh. The important values are summarized in table 5.1 below.

Table 5.1: Data for economic calculation

Parameter	Unit	Data
P_{el}	[kW]	100
P_{th}	[kW]	225
P_{fuel}	[kW]	400
η_{mano}	[%]	67
Total investment	[€]	600000
Interest rate	[%]	.06
Economic Life	[Years]	20
Technical Lifetime	[Years]	20
Annuity factor(a)	%	8.7
Service cost	€/a	15000
Fuel cost(C_{fuel})	[€/MWh]	23.4
Annual operation hours[h]	[Hours]	8000

Using the values in Appendix (F1-F4) the COE becomes 108€/MW_{el}, Details calculation are presented in appendix. Calculation also shows that with a fuel price of 15€/MWh the BG100 has low COE, especially considering the relatively small size of the plant. Hence, further up scaling could make this technology very competitive for the future small scale CHP market.

5.1.2:Vrije Universiteit, Brussels

The Vrije University in Brussels is currently developing an EFGT plant of the size 500 kW_{el} (See fig 5.2).The aim of the project is to demonstrate a CHP plant based on air blown fluidize bed gasifier working together with an EFGT. Thus biomass is first gasified before it is burned in the gas heat exchanger .The final goal is to develop a commercial plant in the range of 2 to 5 MW_{el},[43].

Figure 5.2: Gasifier at Vrije University Brussels

Technology

The biomass is fed from a fuel silo in to the gasifier at a flow rate of 400 kg/h. The air factor is between .23 and .3, producing a product gas with a calorific value of 3.5-4MJ/kg .The bed temperature is about 700°C and the product gas temperature is about 600°C which Is high enough to avoid tar condensation. After passing a cyclone the product gas has dust content below 500mg/Nm^3. The turbine outlet gas has a temperature of 350°C and is used as combustion air in the main combustor. The flue gases after combustion has a temperature of 900°C and are fed through the gas/gas high temperature heat exchanger which is made of metal. The heat exchanger which is the critical component of the cycle amounts to 10% of the total investments of the plants. The remaining heat in the flue gases are used in a recuperator for district heat production. A flow sheet is shown in figure 5.3. Furthermore the plant electrical power and efficiency could theoretically be increased by injecting water in air cycle but this has not been realized yet. A top combustor, where natural Gas is combusted to increase the temperature before the turbine has also been considered but not yet realized due to high cost,[33]

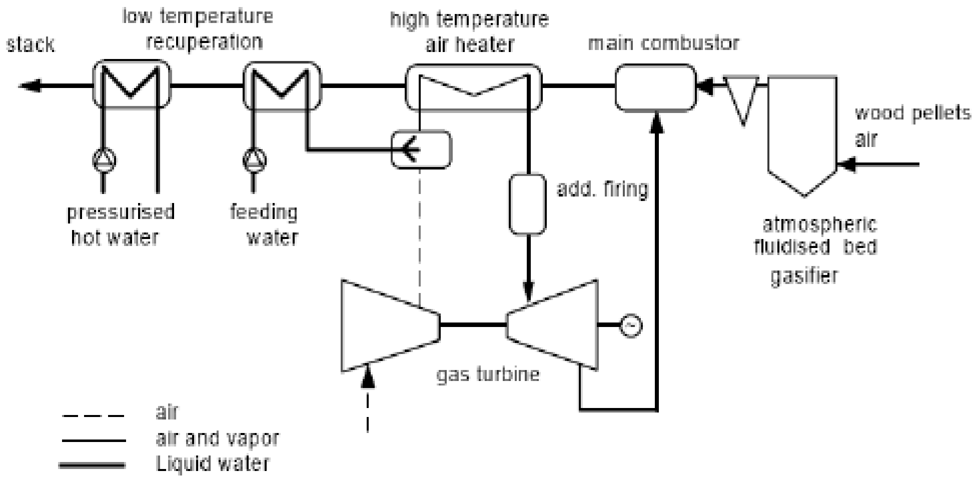

Fig 5.3: process flow sheet of the Vrije plant [33]

System Performance

As mentioned, this plant is under development, but some testing has been done. Concerning the gasifier, experimental tests shows that only a few percentage of the carbon is not converted and exists with the ashes. Also the gas composition corresponds to typical values for fluidized bed gasifiers .The expected total and electric efficiency was calculated and plotted versus the amount of water added, See in figure 5.4(a).The same calculation were also done when considering using full top firing with natural gas which is illustrated in figure 5.4(b).[33]

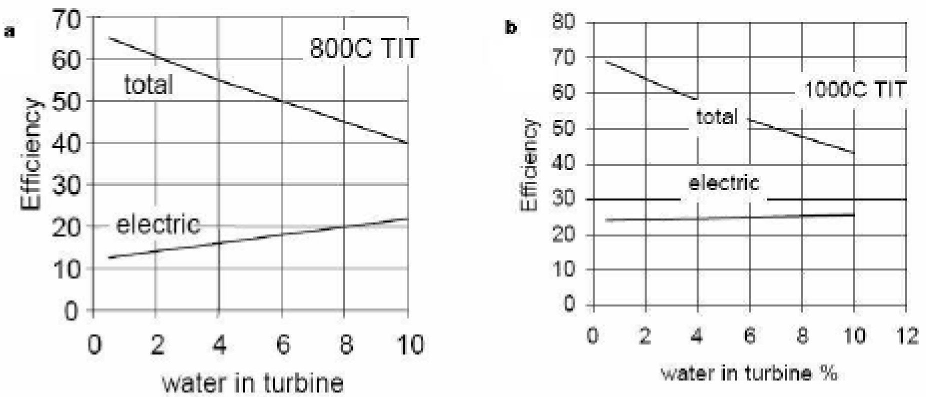

Fig 5.4: a) Efficiencies vs water in turbine with no top firing b) Efficiencies vs water in turbine with full natural gas top firing. [33]

Economic Evaluation:

The investment of the pilot plat amounts to 2.5 M€, [33]. Extracting efficiencies for figure 5.4(a), at about 0% water in the turbine ,an electric efficiency of 12% and a total efficiency of 65 % is achieved .For the calculation of the COE, The method described in appendix is used if the condition shown in table 5.2 is used with presented investment and assumed efficiencies the COE amounts to 124 €/MWh_{el}. It is predicted that a plant of the size 2.5MW_{el} will require an investment of 5Meuro, using this value with the same efficiencies and conditions the COE becomes 72euro/MWh_{el}..

Table 5.2: Economic Assumption of the Vrije Plant

Parameter	Unit	Data
Interest rate	%	6
Economic Lifetime	[yeas]	20
Technical Lifetime	[years]	20
Annuity factor(a)		.087
Additional cost per fuel unit (b)	[€/MWh_{fuel}]	2.2
O & M factor		.02
Fuel cost(Cfuel)	[€/MWh]	15
Annual operation hours[h]	[hours]	5000

5.2: Gas Engine:

There are also some important demonstrations in worldwide based on reciprocating engine. They are interesting because of their performance and efficiency as well as economically viable. Here I am describing two plant base on reciprocating engine.

5.2.1: Harboor

The Harboore plant financed by the Danish Energy Agency is located on the west of coast Denmark and was taken into operation in 1993. Initially the 4 MW_{th} gasifier only provided district heat but in the year of 2000, a gas cleaning system was developed .And later that year two 1000 kW Jenbacher gas engine was installed for the electricity generation, [27].

Gasifier

The harbor Plant uses an updraft with a rotating grate. Furthermore, the gasifier is equipped with a rotating impeller feeding the fuel. As gasification agent is moist air, saturated at 65°C and superheated to 150°C is used .The humidifier using a scrubber which is heated by returned district heating water. The product gas exists with a temperature of 75°C and contains 80 g/Nm^3 of tars and acids. The ashes falls through the grate to a water-lock which are conveyed by screw feeder to a container,[27].

Technical description

A process description of the Harboor plant is shown in figure 5.6 .An automotive crane system loads wood chips with a typical moisture content of 42% in to a feeding chute, from which it is transported by three screw feeders in to the gasifiers. The product gas generated by the gasifier cooled in two sequential shell and tube district heating heat exchanger in which large amount of tars, water and most of the particles are separated. Further the remaining water/tar aerosol and dust are cleaned in a wet electrostatic precipitator (ESP).This result in a tar and dust content below 25mg/Nm^3.The gas has a net calorific value of 5.6MJ/Nm^3.Thus suitable for the gas engine .Accordingly the gas is fed to the engine by a booster fan and the two Jenbacher engines drive a generator which produces electricity. Furthermore the engine exhaust gases are cooled in the exhaust boiler to about 100°C before they are fed in to the stack, [27, 34]

The tar contaminated water (1200 kg/h) from the coolers and ESP is separated in a coal case in to 100 kg/h of heavy tars with net calorific value of 27MJ/kg. These tars are used as peak load firing in the auxiliary oil/tar hot water boiler. The remaining 1100kg/h water is still contaminated with lighter tars and acids and needs further cleaning. This is done by the TARWATC process, which uses hot water from the engine exhaust boiler to evaporate the contaminated water. Thus separating the light tars, however the steam is still slightly contaminated and is therefore heated in counter flow with clean steam from the high temperature reactor before entering the reactor itself. In the reactor some of the light tars are burned to increase the temperature further before it is fed to a district heating cooled condenser. The inert gases are fed to the stack and condenser fulfils the environmental regulation for disposal in municipal systems. [27, 34].

System Performance:

The fuel used at Harboor is wood from a local plantation. The chips sizes vary between 10-80mm and the moisture content is typically between 39-50% wt. The cold gas efficiency ranges between 70% and 80%, depending on how much tar that is recovered within the gasification process. The gasifier has been in operation for more than 75000 hours and the engine have operated for 12000 and 7100 hours respectively between the years 2000-2004, [27]. According to force Technology the net electrical output is 1.45 MW_{el} and the heat output amounts to 2.8 MW_{th}. This result in a net electrical efficiency of 32% and a gross overall efficiency is about 90%.

Economic Evaluation:

The economic Evaluation of the Harboor plant was done with the same method presented in appendix. The total investment of 5.5 MUSD was taken from Kjellstorm, Resulting in 5 M€ when adjusted with 1.2 €/$ and CPI for the year 200 to 2007.A summery of the economic data is shown in table 5.3.The cost of electricity for the Harboor plants amount to 77 €/MWh_{el}, See appendix for calculations.

Table 5.3: Economic Data for the Harboor plant

Parameter	Unit	Data
P_{el}	[kW]	1450
P_{th}	[kW]	2800
P_{fuel}	[kW]	4736
η_{mano}	[%]	89
Total investment	[M€]	5.04
Interest rate	[%]	.06
Economic Life	[Years]	20
Technical Lifetime	[Years]	20
Annuity factor(a)	%	8.7
Annual cost per fuel unit(b)	[€/MWh_{fuel}]	2.2
Service cost	€/a	2
Fuel cost(c_{fuel})	[€/MWh]	15
Annual operation hours[h]	[Hours]	5000

5.2.2:Kokemaki:

The Kokemaki plant was built as the first commercial plant to demonstrate the Novel gasification process developed by condense Oy and VTT,[35]. The construction of the plant was finished April 2005 and the plant is currently in its commissioning phase .The plant is designed for a fuel capacity of 7.2 MW_{fuel} and is capable of handling fuel of moisture content between 0-30%.The district heating output will be 4.3 MW_{th} along with a power output of 1.8MW_{el}

Technical description:

The novel gasification process utilizes an update gasifier which operates together with a gas cleaning system, which consists of heat exchanger, bag filters, scrubbers and a catalytic reformer. The cleaned gas is finally used in three turbocharged Jenbacher gas engines (JMS 316), [36]. An illustration of the project is shown in figure 5.7

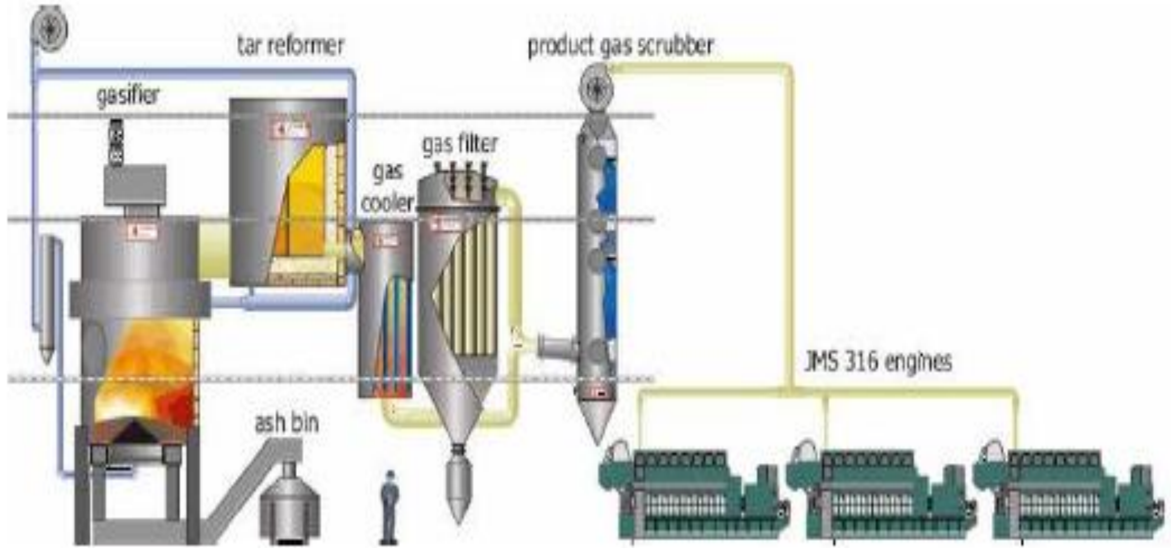

Fig 5.6: Kokemaki process description

System performance

As mentioned before the plant is still in its commissioning phase, thus no full operation experience is available .However the plant started the testing period in 2005, hence there are some preliminary results regarding operation experience. The main achievement so far are listed in table 5.4,[36] below

Table 5.4: Testing period time line for the Kokemaki plant

Test	Achieved
Successful operation for the gasifier and gas boiler.	April-Sep 2005
Successful operation of the gas cleaning and heat recovery system	May-Sep 2005
Star up with on JMS 316 engine	OCT-Nov 2005
Successful operation with one gas engine and gas boiler	September 2006-Feb2007
Start-up of the remaining two engines	Planned for 2008

The predicted electrical efficiency varies between 27-36% depending on the fuel moisture contents and the engine performance .The total efficiency is predicted to be above 85%

Economic Evaluation

The total investment of the plant amounts to 5Meuro and electric efficiency was assumed to be 31% ((27+36)/2).Using this along with the techno-economic data presented by Hannula [36], table 5.5 is archived. The COE was calculated to 87 €/MWh_{el} (see appendix).It should be pointed out the price for heat sales are fixed to zero in calculations, this will result in a higher COE since the full capital cost will be added as a cost on the electricity side .

Table 5.5: Economic analysis of Kokemaki plant

Parameter	Unit	Value	€/a	Scale factor
Electric efficiency	%	31	-	
Fuel input	[MW]	7.2	-	
Investment	[M€]	5	-	
Service lifetime	[Years]	20	-	
Discount rate	[%]	5	-	
Annual operation hours	-	6000	-	
Annuity	-	-	401213	
Labor Cost	-	-	68292	.333
Other fixed cost	-	-	173639	.138
Other various costs	[€/MWh_{fuel}]	2	86400	
Feed stock price	[€/MWh]	10	432000	
Total Annual cost	[€/a]	-	1161544	
COE	[€/MWh_{el}]	87		

5.3: Capstone Micro turbines

5.3.1: Syracuse University, U.S.A.

Last year, Syracuse University, located in Syracuse, New York, U.S.A. – regularly ranked among the Top 100 schools in the nation — realized it needed a new data center. Escalating demand from researchers, students and professors for greater computing capabilities and data storage was straining the campus's outdated data center, which had been housed in an old brick building for decades. Constructed in just six months and showcased to the public in December 2009, Syracuse University today boasts one of the world's most energy-efficient and green data centers. The 1115 m^2 facility — named the Green Data Center — is expected to use 50% less energy than a traditional data center.

Fig 5.8: Key components of the US$12.4 million Green Data Center at Syracuse University are 12 patented Capstone Hybrid UPS Micro Turbines from Capstone Turbine that provide power to the entire facility. [3]

Key components of the US$12.4 million Green Data Center are 12 patented Capstone Hybrid UPS Micro Turbines from Capstone Turbine that provide power to the entire facility. According to the company, Capstone's Hybrid UPS is the first power system to integrate low emission C65 (65 kW) micro turbines directly with a dual-conversion UPS to provide power for mission-critical loads.[3] The Syracuse University project and Capstone Hybrid UPS micro turbines address critical concerns for modern data centers around the world such as spiraling energy consumption and costs driven by growing demand for Internet communication, entertainment, global commerce and services. BHP Energy, a Capstone Turbine distributor, was selected by Syracuse University and project partner IBM to integrate an innovative tri-generation concept into the data center. For the tri-generation system, the 12 Capstone Hybrid UPS micro turbines produce electricity, heat and cooling power, all from a single burn of clean natural gas using an integral power plant. In addition to the cleaner natural gas and lower emissions, Capstone's UPS system operates without the hazardous chemicals common in traditional battery-based UPS systems. The Green Data Center's tri-generation system is clean and efficient. Exhaust heat from the Capstone micro turbines is piped to double-effect absorption chillers. Absorption chillers then use the heat energy to make cold water to cool the Green Data Center's computers and even serve the heating and cooling needs of an adjacent office building. For the Syracuse Green Data Center, IBM provided more than US$5 million in equipment, design services and support. The New York State Energy Research and Development Authority (NYSERDA) contributed US$2 million to the project.[3]

5.3.2:Salem Community College, U.S.A.

Soon after Hurricane Katrina devastated the Gulf Coast in 2004, the Salem County Red Cross in Carney's Point, New Jersey, U.S.A., asked the nearby community college to continue its 15-year tradition of serving as the local Red Cross disaster relief shelter. However, the updated agreement stipulated Salem Community College must have a backup power system that provides electricity, cooling and heating to Davidow Hall — the 6039 m^2 campus building that serves as the county's shelter during emergencies. Officials at the 1500-student college, eager to continue serving the community, agreed to upgrade the power system in Davidow Hall to comply with the agreement. They also knew a more efficient energy system to serve the building's day-to-day power, cooling and heating needs could save the college money. The massive building — one of the largest in this rural New Jersey county — houses a gymnasium that can hold 1000 people during emergencies, a 400-seat performing arts theater, classrooms, kitchens, office space, showers and bathrooms. In a nutshell, Davidow Hall is an ideal facility for an emergency shelter.

Fig 5.9: Through New Jersey's Public Utility Smart Start Incentive Program, the Salem Community College received a US$130 000 grant that helped fund the purchase of three Capstone natural gas C65 ICHP Micro Turbines.[3]

During non-emergency times, it is a bustling campus facility full of students, instructors and regular community activities. Raymond Constantine, executive director of special projects for Salem Community College, led the college's efforts to secure updated and clean power and HVAC systems. Through New Jersey's Public Utility Smart Start Incentive Program, the college received a US$130000 grant that helped fund the purchase of three Capstone natural gas C65 ICHP Micro Turbines, a 91 tones Thermax absorption chiller and a

Capstone advanced power server controller. “We wanted a system that could provide electricity, heating and cooling each day, along with grid-disconnect backup power in an emergency,” Constantine (one of the official) said. “Capstone provided a combined heat and power solution that emits very clean emissions.” When planning for the new energy system began several years ago, the 1.36 hactor main campus was heated and cooled by a long-standing geothermal system. College officials planned for the new clean-and-green energy system in Davidow Hall to supplement the campus’s geothermal ground source system, installed in 1991. In addition, two inefficient systems, a DX cooling system that featured Freon-based compressors and natural gas boilers that produced building heat and hot water, also served Davidow Hall. Constantine was told the payback on the system will be 10 years, but because of its efficiency and energy savings, he expects the payback will be much sooner. He anticipates a 30% overall energy savings because of the micro turbines. Commissioned in late 2009, the Capstone micro turbines produce more than 80% of Davidow Hall’s electricity and 100% of the building’s heating and cooling. The micro turbines are dual mode, which allows for them to island when utility power goes down. “Dual-mode capabilities are important because we see a lot of brownouts and blackouts on the grid that serves the states of Pennsylvania, New Jersey and Maryland, U.S.A.,” Constantine said. “Our grid is vulnerable, and by having our own on-site power plant, we’re helping to relieve grid pressures.” The system’s efficiency is linked to the micro turbines’ combined heat and power application, and also to the Capstone advanced power server (APS). The APS is a stand-alone controller that monitors the building’s load changes and automatically shuts down the micro turbine with the most run hours when it’s not needed, for example on weekends or in the late evening when students are gone.
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Chapter 6: Current status of Policies, Technology and R & D opportunities

There are huge amount of research and development works are going on throughout the world right now. The key issues for this research are related to emission and efficiency as well as economic purposes. In this section we will discuss some of the research works, policy from different countries in the world and also future research and development opportunity .

6.1: Current status of technology, Policies and possible research opportunity

There are lots of interesting technologies is available. But Research going on different cogeneration company as well as in many universities to increase to get the innovative results. Now due to increased concern on efficiency and emission most of the research is related to efficiency and emission. Here I will discuss about some current technology ,and policies that are following in the world wide and also possible research opportunity.

6.1.1: Worldwide CHP policies

The IEA analysis of country profiles found several common element in the strategy used in countries that have addressed the barriers (described in chapter 4) most successfully. From this finding IEA has identified a consistent set of “world class” policies that can be used to address the barriers faced by CHP and DHC. This section highlights some of these main six most success full policies for advancing CHP. This is structure as follows [46]

1.Financial and fiscal support

- ✓ Capacity grants, New York state
- ✓ Feed in Tariff, Germany

2.Utility supply obligations

- ✓ Green certificate scheme, Belgium

3.Local infrastructure and heat planning

- ✓ Building regulations, United kingdom.

4.Climate change mitigation(emission trading)

- ✓ EU Emission trading scheme

5.Interconnection measures

- ✓ Interconnection standard, United states

6. Capacity building (Outreach and research and development (R&D))

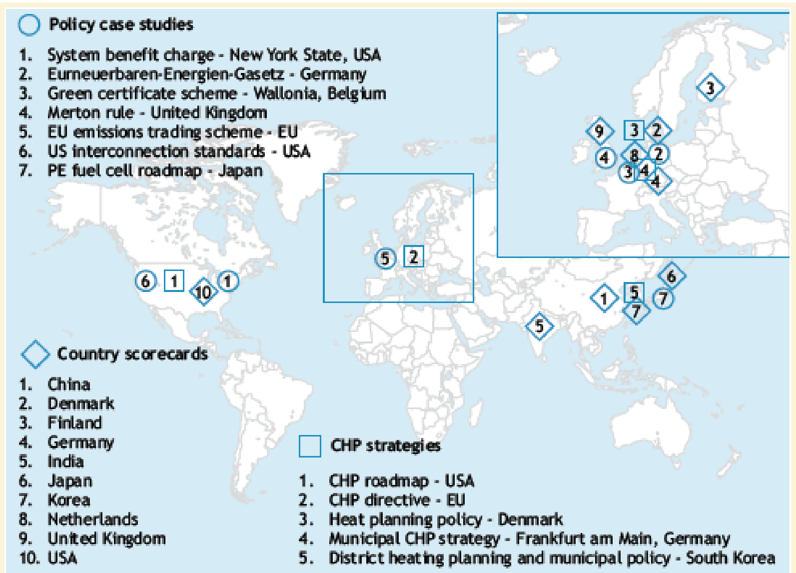

Fig 6.1: Best practice CHP/DHC policies and strategic covered by the IEA/DHC Collaborative.

1.Financial and fiscal support for CHP:

The main types of financial and fiscal support relevant to CHP are as follows:

- ✓ **Up-front investment support**: Appropriate when financing for CHP projects is difficult to secure ,either because potential developers do not have access to capital or because projects returns do not correspond to the short time frames used by commercial investors. Examples include grants (Direct support) and accelerated depreciation(fiscal).
- ✓ **Operational support** :Operational support can be used to reflect the full value of CHP electricity and/or heat ,For example ,by internalizing its environmental benefits .feed-tariffs(directs) and fuel tax exemptions(fiscal) are common types of operational support.
- ✓ **R&D funding :** Government funding for low-carbon CHP technology, can help an industry to develop commercial CHP products for a sustainable energy system in the future.

How can financial support help CHP

Financial support can help to trigger CHP development in a number of situation:

- ✓ **To cover additional investment costs:** CHP system, Including DHC supply network, often require higher up-front investment than conventional alternatives, even though running costs can be lower. Some energy consumers may not have the capital to make this investment. Grants or low interest loans can help bridge this gap by covering part of the additional costs.
- ✓ **To internalize externalities:** Financial support can be granted to reflect the environmental and social benefits of CHP. For example GHG emission trading can reward CHP for the CO_2 emissions saved relative to separate heat and power generation.
- ✓ **To address market imperfections:** Energy market are not always open and competitive, and may not value all forms generation consistently. For example, Generation in high demand areas has a higher value, because it is often difficult to site new generation. As a result, one strategy to address high demand is to provide additional financial support for CHP electricity. For example, generation in high demand areas has a higher value than that elsewhere .As a result, CHP sometimes receives less for its electricity than society would have to pay for electricity from other new power plants. Financial support can help adjust such inefficiency in electricity markets.

Table 6.1: Financial support mechanisms for CHP[46]

Financial support			
	Feed-in tariffs	**Capacity grants**	**Fiscal support**
Policy goals	-To provide greater certainty for investors in CHP. -To increase the operational efficiency of new and existing CHP plants.	-To help capital-constrained. organization invest in CHP to improve energy performance . -To facilitate the market introduction of emerging low-carbon technologies, such as renewable CHP and micro CHP.	-To provide greater certainty for investors in CHP/DHC.
Success factor- What makes it work?	-The value of tariffs should allow for a sufficient return to attract investment -Long- term contracts to provide investors security; i.e.10 to 20 years	-Target potential developers that lack access to financing. -Regularly evaluate the level of subsidy to reflect changing technological and	-Use accelerated depreciation for investment support and fuel or carbon tax incentives for operational support. -Minimize

		market conditions.	administrative overhead for CHP/DHC developer
Where has it been used	**Europe**-Including Portugal, Spain, Germany, The Netherlands, the Czech Republic, Denmark, Hungary. **North America** –Ontario **Asia**-Including India (Maharashtra)	**Europe**-including the Netherlands, Italy, Spain, Belgium. **North America** – Various US States, Canada. **Asia**-including China, India south Korea ,Japan	**Europe**-including the Netherlands, Italy, Spain, **North America** –US States, Canada. **Asia**-including, India south Korea ,Japan.
Best practice examples	**Germany:** Bio gas CHP receives a FiT through the Erneuerbare-Energien Gesetz(EEG)(2009), adding up to EUR c27.67 per kWh to the electricity price. This policy has been the main factor supporting biogas capacity growth from less than 200MW of electricity (MWe) in 2000 to over 1200 MWe in 2007.	**New York:** Annual CHP installation in New York City tripled after subsidies became available in 2001,supporte by high electricity prices.	**The Netherland:** CHP policies achieved over Mt CO2 –eq. GHG emission reduction in the 1990s.The EIA, a fiscal investment credit, achieved its share at a cost of EUR 9 per t CO2 eq.

2.Utility supply obligation:

Utility supply obligation **(USOs**) (also known as energy portfolio standards) are a market- based mechanism using certificate trading to guarantee a market for CHP electricity. They place an obligation on electricity supplier to secure a certain percentage of their electricity from CHP. The share of supply to be met by CHP can increase year –on-year, in steps with policy targets .Electricity suppliers can meet the obligation in two ways :

- ✓ Owning a CHP facility.
- ✓ Buying CHP electricity from a CHP facility bilaterally or on the market.

How can USOs help CHP

Independent CHP plant operators may find it difficult to find buyers for the electricity they produce .This can be the result of the following things

- ✓ **Market procedure:** In competitive electricity markets, small independent generators often do not have the expertise or resources to participate in electricity trading. So they rely on demand form a local supplier or consumer.
- ✓ **Size:** Electricity supplier generally prefer sourcing electricity form a small number of large power plants. Small CHP plants may therefore not find a buyer for their output .Although using multiple smaller generators can increase diversity and security of supply.
- ✓ **Long term contracting:** In regulated market, supplier often buy electricity through long term contracts with a small number of power plants. Consequently, independent power producers can only enter the system when one of these expires.
- ✓ **Cost:** Electricity from new efficient CHP plant can be more expensive then electricity from the existing generation system, USOs can assist in addressing these issues by
  -Creating demand for CHP electricity through obligation on electricity suppliers;
  -Allocating tradable certificates for CHP electricity

Table 6.2: Utility supply obligation[46]

Utility supply obligation	
Policy goals	-USOs create a demand for CHP electricity through a purchase obligation on electricity suppliers. The main two objectives -Making CHP plants competitive in the electricity market and Guaranteeing a market for CHP electricity
Success factor- What makes it works	-Set and adjust the obligation share realistically-enough to create scarcity and sustain demand but with reference to the potential for developing CHP. -Create a penalty buy-out price to place a ceiling on certificates prices and guaranteed minimum price creating a floor price -Establish a transport and easy-to-use accounting system for compliance
Where has it been used	**Europe** Renewable :11 of EU-15 CHP: Belgium, Poland Energy Efficiency: Italy **North America** -Renewable portfolio standards(RSPs):36 US States ,eight of which include CHP. -Clean energy/CHP: Pennsylvania ,Connecticut.
Best practice example	**Belgium:** Wallonia has implemented a USO that support CHP plant with the certificates based on CO2 saving, rather than on electricity output **United states :**Eight US states had included CHP in their RSPS by may 2008:Colorado,Connecticut Hawaii, Nevada, North Carolina, North Dakota Pennsylvania and Washington(US EPA,2008).

3.Local infrastructure and heat planning:

Local infrastructure and heat planning create a rational framework for providing heat and cooling efficiently by identifying and linking demand and supply, and supporting the best energy sources available.DHC infrastructure can create the necessary linkages, while CHP is a versatile energy supply source that can meet demand efficiently.

How can local energy and heat planning help CHP

Local heat/energy planning at a municipal or building level can help to trigger CHP development in a number of situation by:

- ✓ **Coordinating heat, cooling and energy supply:** Heat planning facilitates CHP development by creating stable heat and cooling loads through DHC networks. Local governments have the spatial planning tools to facilitates this process and to address the regulatory challenges of construction, installation and energy sales.
- ✓ **Helping to overcome the high upfront costs of heating and cooling networks:** DHC networks are a valuable long term asset for optimizing energy supply and creating a bridge to low carbon system, but the upfront investment is often not feasible under private sector criteria. Local government can supports DHC network investment through loans and guarantees ,or by investing themselves ,as with other long term infrastructure.
- ✓ **Setting standards for building environments performance that may not be achieved through market or other incentives:** The accelerated use of small scale CHP and other low energy solutions in buildings will often require a critical mass of customer demand to bring down products costs. Building regulation standards, applying to thousands or millions of new buildings, can create this demand in a relatively short period. Table below describes the different types of local heat /energy planning and

their relevance and effectiveness, and gives examples of jurisdictions that have implemented them successfully

Table 6.3 :Planning policy supporting CHP and DHC[46]

Local and individual planning policy		
	Heat planning and municipal initiatives	**Building regulation**
Policy goals	-To reduce urban or regional carbon emissions. -To improve the efficiency of energy use at the community level by co-coordinating heat and cooling supply and demand. -To facilitate heating costs for consumers and bring down fuel poverty. -To establish long term energy supply assets through supporting investment in DHC infra-structure .	-To increase the energy efficiency of new building. -To increase the use of low carbon renewable energy and CHP in individual building.
Success factor – What makes its work	Planning at the municipal level requires co-ordination and co-operation among policy makers ,energy suppliers and customers to establish clear goals and agreements' on the means of achieving it. Evaluating heat and cooling demands and available source is essential for establishing an efficient supply system	Success requires co-ordination and co-operation between planners and building developers and agreements on ambitious but achievable goals
Where has it been used	**Europe**-including Denmark, Finland, Germany, Italy, Russia, Sweden. **North America** –Puetro Rico **Asia** –South korea ,China	**Europe** –The united Kingdom, Germany, Austria.
Best Practice	**Denmark**-Heat Planning **South Korea-** Integrated Energy supply act	**United Kingdom**-Merton Rule

4.Climate change mitigation:

There is a growing of policy measures designed to address the challenge of climate change. This section focuses on cap-and-trade emission Trading Schemes(ETS) which are becoming an increasingly popular measure. These schemes follow the example of carbon taxation, which has been successfully in supporting CHP and DHC development in countries like Sweden. The main challenge facing CHP in ETS design is that, with on-site emission increase ,while overall global emission decrease(power plant emission displaced by CHP exceed the additional on-site emission when a boiler is replaced by CHP).

Unless ETS design reflects this issue, CHP will normally be panelized through having to buy more allowances than would be needed with a heat-only boiler and grid-supplied electricity. Two other important issues for CHP are:

- ✓ Determining the sector to which CHP belongs .If CHP is categorized in a sector whose allowances are capped stringently. This will disincentives CHP.
- ✓ Defining the boundaries for inclusion of CHP. For example conversion of individual residential boilers (not included currently in ETS schemes because they are to small) to a large urban CHP/DHC scheme (Which would be included) would disincentives the emission reducing investment

How can emission trading help CHP

The principle behind ETS is that allowances to emit GHGs are limited and thus a market price for their emissions is derived. By giving carbon emission a price, technology that reduce emission(e.g. CHP) should benefit in theory-partly through increases in electricity prices. It is ,therefore important to ensure that evolving ETS design takes accounts of the Unique CHP position in the energy delivery chain and ,if desired, incentivizes its development. At the very least, ETS programs should not penalize CHP. Table 6.4 briefly sets out the key issues relating to treatment of CHP in emission trading ,its relevance and effectiveness, and gives examples of jurisdiction that have implemented emission trading successfully

Table 6.4:Emission trading schemes and CHP[46]

Climate change mitigation(emission trading)	
Policy goals	To bring about cost-effective carbon emissions reduction by incentivizing (or at least not penalizing)CHP plants
Success factor – What makes it works?	The key requirement for those determining allocation is to ensure that the main challenge for CHP is addressed through specific allocation design features .For example, providing bonus used by either energy consumers .Double-benchmarking is one methodology to allocate allowances more equitably to CHP plants.
Where has it been used	Experience is predominantly in the EU where the ETS has been in operation since 2005.Since that time, several member states have introduced innovative allowance allocation method for overcoming the main design challenge for CHP
Best practice example	There are several examples under the US Regional Greenhouse Gas Initiative(RGGI) and the EU ETS that are described in the IEA CHP and emission trading Report.

5.Interconnection measures:

Interconnection standards provide clear rules for obtaining physical connection to the distribution/transmission network depending on connection voltage levels. They outlined the procedures for the application process in a clear and transparent way. They also set out the technical requirements for connection. Measures enabling grid access that relate to the participation of CHP plants in the grid network. They can, for example, be developed to give CHP generators priority access to the electrical system. These measures include

- ✓ **Net metering :**This allows for the flow of electricity both to and from a customer's facility through a single, bidirectional meter and can enable the plant to secure and electricity sales price equivalent to the purchase price.
- ✓ **Priority dispatch:** This ensures that generators will have exporting in to the grid system .
- ✓ **Licensing exemption:** This allows CHP operators to generate without a generator license, helping to keep cost down.

How can interconnection measures help CHP

Grid connection enables a CHP plants to sell any surplus electricity to the grid and to import when the site needs exceed the CHP output .A key factor determining the market viability of CHP is therefore its ability to safely, reliably and economically interconnect with the utility grid system(IEA,2008b).However, grid connection has traditionally been one of the main challenges to encouraging increased uptake of industrial and commercial CHP.

Table 6.5: Electricity network interconnection measures for CHP[46]

Interconnection measures			
	Interconnection standard	**Enabling grid access**	**Incentivizing network operators**
Policy goals	To streamline and facilitate the interconnection procedures for CHP and other decentralized energy generation projects	To improve the commercial conditions for CHP	These incentives encourage network operators to treat CHP favorably when considering grid connection application and after the establishment of projects
Success factor-What makes it work?	-Regulators working closely with all the main stakeholders. -Development of standard that address all elements of the interconnection process. -Making the connection process and related fees commensurate with the generator size. -Monitoring the effectiveness of measures(USEPA,2007).		
Where has it been used	-In the United States ,the Energy Policy Act(2005) urges all states to implement. interconnection standards for CHP, which many have done. -The United Kingdom, the Netherlands and Germany have all implemented a “fit and inform” process for grid connection of micro-CHP. This means that there is no cost for connection.		
Best practice examples	**The Netherlands:** The Dutch Net code in the 1990s simplifies connection rules, ensuring transparency and fairness in the connection process. The government set out the requirements and the utilities developed the code .As such it was the utilities’ initiative and, therefore ,was more effective. **The United States:** Many states and non-regulated utilities have developed ,or are developing, standard that take into account the application process and the technical requirements for connection. The standard set out a standard frame work for network connection and export of electricity.		

6.Capacity building (Outreach and research and development (R&D)):

Capacity building can be undertaken in two ways :

- ✓ Outreach and education raises the awareness of CHP, making known to potential users the benefits of CHP and the types of sites particularly suited to CHP. This can be implemented through training programmes, active campaigning or the creation of a central CHP office or champion
- ✓ R&D supports the development of CHP technologies and application towards market commercialization .R & D funding can also be applied towards the training of potential users to facilitate CHP technology uptake.

How can capacity building help CHP?

Incentive policies for CHP can be most effective if the potential users are aware that the CHP opportunity exists and if emerging technologies are mature enough to be applied on a commercial basis-

Table 6.6:Outreach and R& D programmes for CHP and DHC[46]

Capacity building (outreach and R&D)	
Policy goals	-To ensure that policy makers can incentive the best and most efficient projects. -To ensure that energy users are fully aware of the CHP opportunity. -To accelerate the commercialization of emerging CHP technologies.
Success factor-What makes it work?	Where the capacity building has been most successful ,it tends to have : -involved all the key stakeholder groups in programme design; -been accompanied by effective incentive policies ; -been targeted at the most suitable energy user groups;
Where has it been used	**Europe:** Including Germany and the Netherlands **Asia:** Including Japan
Best practice examples	**KWK Modelldtadt Berlin:** The main goal of this scheme is to make Berlin a role model city for cogeneration. By producing free publication such as "CHP: double use of resources " and newsletter. Initiative has been informing the inhabitants of Berlin-the potential users –of the benefits and potential of CHP(Berliner Energieagentur,2009). **Dutch CHP Agency (Projekbureau Warm-Kracht):** The Dutch CHP agency brought together government, industry and energy companies to work together to identify opportunities, advise on policy and implement new project. The agency was set up to overcome the various regulatory and other barriers that hindered the development of CHP and played a central role in the CHP boom in the Netherlands in the 1980s and 1990s

6.1.2: Cogeneration policies ,technological status and future research opportunity in California

California has long been the leader in recognizing the benefits from and encouraging cogeneration in USA. In November 2003, the California Energy Commission issued the final Integrated Energy Policy Report (IEPR). The report includes a strong endorsement for the continued development of cogeneration in California.

"Cogeneration offers another low cost, low emission option for the efficient use of natural gas. By creating both electric and thermal energy, cogeneration plants can achieve heat rates that match or exceed the heat rates of new gas-fired combined cycle power plants "(IEPR, page 24).

It is California cogeneration council's view that California policy makers are as committed to cogeneration today as they were 25 years ago. Current concerns about natural gas supply, price and availability reinforce the benefits of using cogeneration to efficiently use our gas resources and support business and industrial enterprises in the State. We encourage State regulators and policy makers to focus on providing contract extensions for cogeneration QFs, in order to ensure that utility ratepayers will continue to receive the benefits of these reliable and economical generation resources.

Policy [18]

In California different organization related to cogeneration have been taken several policies for the improvement of cogeneration in California. Below some of these policies has been given with those organization.

AB 32

- ✓ Limit GHG emissions to 1990-equivalent levels by 2020

Governor's Executive Orders

- ✓ Reduce GHG emissions to 2000 levels by 2010;
- ✓ 1990 levels by 2020;
- ✓ 80% below 1990 levels by 2050

ARB AB 32 Scoping Plan

- ✓ 4,000 MW of CHP by 2020

IEPR 2007

- ✓ Net zero energy for new construction through CHP
- ✓ -2020 for residences
- ✓ 2030 for commercial

IEPR 2008 Update

- ✓ Elimination of once-through cooling between 2015 and 2021

Policy goals largely focus on reducing emissions and environmental impacts.

General	-Review focus on policy related to non-renewable generation, large or distributed. -Natural gas is State's primary generation source
California	-No specific goals for NG power plant efficiency; implied via emissions standards. -Interest in CCS research, but no targets or goals. -Policy addresses the importance of CHP, little policy related to other types of DG. -Goal to retire or re-power aging plants by 2012;timeframe and scope is being reviewed. -Policy to eliminate once-through cooling between 2015 and 2021, SWRCB working on details to achieve goal. -Advanced generation can contribute to achieving higher levels of renewable through fuel flexibility with operational flexibility to address the intermittency.

Current Status of Technologies DG/CHP

- ✓ Cost is still a limiting factor for most DG technologies
- ✓ CHP is typically the most cost-effective application.
- ✓ Recent research trend is focused on fuel flexibility of DG/CHP systems.
- ✓ Limited investment in communication and control technologies for DG and CHP systems.
- ✓ Rule 21 successful in removing interconnection barriers.
- ✓ Hybrid Fuel Cell/Gas Turbine Cycle systems have the highest efficiencies.
- ✓ Considerable funding for transportation fuel cells; more limited funding for stationary power fuel cells.

Reciprocating Engines	
Current Status	-Major barriers include high maintenance costs and frequent maintenance intervals. -Current research exploring operating and maintenance cost reductions, and emission reductions. -Limited to lower temperature cogeneration; full waste heat recovery still being explored.
Research Opportunities	-Full waste heat recovery. -Reducing operating and maintenance cost. -Increase fuel flexibility through use of landfill gas, digester biogas and other fuels. -Achievement of US DOE's fuel-to-electricity efficiency target of 50% (LHV) by 2010 → 30% increase over today's average.

Stirling Engines	
Current Status	-Has not undergone a robust R&D phase, contributes to lack of proven operation and durability. -Efficiencies< 20%. -Manufactured in very low quantities, resulting in high capital cost. -The limited research focuses on: Landfill gas as fuel -Stirling engines for concentrated solar.

Research Opportunities	-Creation of packaged systems for residential and small commercial CHP that address cost and reliability

Small Gas Turbines	
Current Status	-Under 3MW not cost competitive with reciprocating engines Low production volumes -Low commonality of parts among multiple models. -PIER funded several demonstration projects to address catalytic combustion. -Significant simple-cycle gas turbine CHP systems in operation Oil recovery, chemicals, paper production, food processing, and universities
Research Opportunities	-Improving energy and environmental performance to lower capital costs. -Technology demonstrations, technical assistance in implementation, and reporting of lessons learned and best practices.

Current Status of Technologies (Advanced Gas Turbine Cycles)

- ✓ Most technologies are mature and incorporated into new plants.
- ✓ Significant opportunity to improve efficiency by retrofitting existing plants
- ✓ Limited research in recent years on new developments; most research performed over ten years ago.
- ✓ Limited effort to demonstrate the benefits in retrofit applications.
- ✓ Recent research by OEMs focuses on materials.
- ✓ Significant research outside US on hybrid renewable systems to address intermittency.
- ✓ Significant incentives for renewable systems, but few for hybrid systems.
- ✓ Provides a cost effective means to boost generation efficiency and mitigate emissions.

Industrial Cogeneration	
Current Status	-Mature technology, used for many years in industrial, large commercial and institutional applications. -Large unrealized technical potential in California. -California's Rule 21 applies to DG up to 10 MW: Industrial cogeneration applications still face interconnection issues. -Complex tax depreciation policies discourages industrial cogeneration.
Research Opportunities	-Improvement in fuel flexibility and efficiency necessary to improve life-cycle cost/benefit ratio. -Due to restrictive state emissions regulations, near term R&D focus: Low emission gas turbines. -Low emission reciprocating engines. -NOx emission controls.

Cost-effective, energy-efficient, and environmentally sound way to enhance peak GT capacity/efficiency in hot

Trends and Issues [18]:
There are a series of trends and issues which could have great impact on advanced generation technologies in California.

- ✓ Recent study found generation from NG could be reduced 15% by 2020.
- ✓ Under current policy, the state will need to replace/repower 66 aging gas plants by 2012:
- ✓ Combined capacity = 17,000 MW -40% of gas-fired plants and 25% of all capacity.

- ✓ The scope/timeframe of goal is under review.
- ✓ Despite improvements -energy intensity for desalination remains high; energy and GHG impacts need to be considered when assessing desalination projects.
- ✓ CA has significant electricity resources that are cleaner but less affordable than US ave.
- ✓ The Smart Grid expected to increase the value of PV and other DG systems; however, this will require coordinated involvement of various stakeholders.
- ✓ Need to overcome technical/non-technical challenges posed by renewable intermittency.
- ✓ Net zero energy/new construction may have significant impact on efficiency /DG.
- ✓ NG deliverability and supply scarcity projections vary.

Current Status of Technologies on Carbon Reduction [18]

There several barriers that have to be overcome to improve the condition of carbon reduction such as

- ✓ Costs vary widely between new plants and retrofits.
- ✓ Cost of retrofitting plants is typically prohibitive.
- ✓ Costs are dependent on the amount of carbon in the fuel source.
- ✓ Cost/ton of carbon is lower with a dirtier fuel (e.g., coal).
- ✓ Cost/MWh is lower with a cleaner fuel (e.g., natural gas).
- ✓ Lack of utility-scale demos has limited adoption; the ARRA has funding for demos.
- ✓ DOE expects new research will lead to significant cost reductions, their focus is IGCC.
- ✓ IGCC plants with pre-combustion capture have the lowest energy requirements.
- ✓ IGCC with pre-combustion capture shows the most long-term promise for CCS.
- ✓ Little research on pre-combustion capture for NG plants but opportunities exist (i.e. IGSC).

6.1.3: PIER AG Program

The new program vision enables PIER AG to play a key role in helping the state meet key policy goals.

2020 PIER Advanced Generation Vision

The PIER AG program provides key R&D that enables California to generate energy efficient, abundant, affordable, reliable, and environmentally-friendly electricity (and other forms of power) from small to large power plants, including distributed generation and combined heat and power, using clean non-renewable fuels and fuel flexibility capability in order to help reach the greenhouse gas emission reduction targets. PIER AG would focus on improving efficiency and reducing GHG emissions of large-scale and distributed generation/CHP fueled with clean fuels and fuel flexible.[18]

PIER AG Program Areas

1) Commercial CHP/CCHP Systems
2) Industrial Cogeneration Systems
3) Advanced Gas Turbine Cycles

Support development of cost-effective CHP and CCHP systems for commercial buildings and their wide-scale deployment. Support development of cost-effective industrial cogeneration systems and their wide-scale deployment. PIER AG will have to focus its limited resources, avoiding duplication of efforts and funding on areas addressed by other PIER Program Areas. PIER AG will have to focus its limited resources, avoiding duplication of efforts and funding on areas addressed by other PIER Program Areas.

- ✓ Renewable, including management of intermittency issues through the co-location of renewable systems and traditional gas fueled generation systems –Addressed by PIER Renewable Energy Technologies program.
- ✓ Water use in power plants, including replacement technologies for once through cooling Addressed by PIER Energy Related Environmental Research and Industrial/Agricultural/Water End Use Energy Efficiency programs.
- ✓ Carbon capture and sequestration Primarily focused on coal fueled generation and addressed by DOE.
- ✓ Continue to monitor cost-effectiveness of application to natural gas fueled power generation.

Preliminary Key Research Issues

- ✓ System packaging and integration (primary).
- ✓ Market and regulatory mechanisms (secondary, complement CEC CHP program).

- ✓ System packaging and integration (primary).
- ✓ Identification of cost-effective sites (secondary, complement CEC CHP program).
- ✓ Market and regulatory mechanisms (secondary, complement CEC CHP program).
- ✓ New technology development of integrated hybrid renewable cycle systems (primary).
- ✓ New technology demonstration of advanced generation technologies (primary, channel DOE resources to California).
- ✓ Market and regulatory mechanisms (secondary, support policy development).

6.1.4: Waste gases from livestock fuel opportunities for cogeneration projects.USA

Methane is both the primary constituent of natural gas and a potent greenhouse gas when released to the atmosphere. Reducing methane emissions can yield substantial economic, environmental and energy benefits. In the agricultural sector, the implementation of anaerobic digestion technology can lead to improved air and water quality, odor control, improved nutrient management, a reduction in greenhouse gas emissions, and the capture and use of biogas — a source of clean, renewable energy.

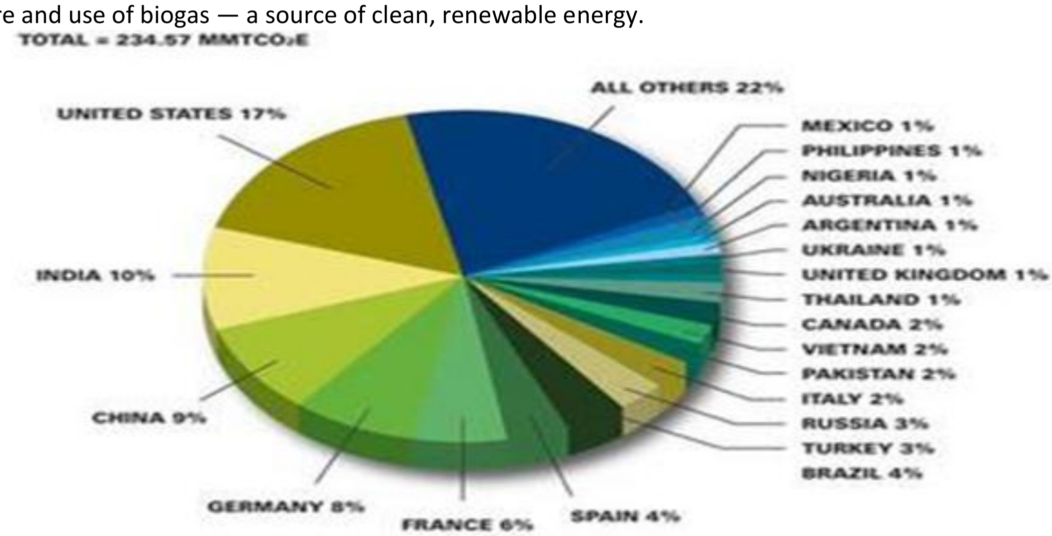

Figure 6.2: Estimated global methane emissions from livestock manure management, 2005 [2]

The liquid manure management systems found in large livestock operations promotes anaerobic (i.e. oxygen-free) environments, these lead to methane emissions from the decomposition of organics in the waste. Anaerobic digester systems (AD) are designed to capture methane released from liquid manure and allow the recovered biogas to be flared or used as a clean energy source to produce electricity, heat, or combined heat and power (CHP) — in gas-fired equipment such as engines, boilers, or chillers. Biogas produced from AD systems is typically 60%—80% methane, with an energy content of 600 to 800 Btu per standard cubic foot. Project development in this sector can help to reduce greenhouse gas emissions and provide alternative energy sources. In addition, AD systems offer other environmental benefits, including significantly reduced odour and improved water quality protection, while also providing opportunities for agricultural diversification. In the US, odour control is often a major driver for implementing AD systems. The benefits of controlling odour can lead to a better and more productive relationship with neighbors', an easier time getting appropriate permits, and being viewed as a good environmental steward.

AD systems for livestock waste management

AD systems are typically used in the primary treatment of high strength organic materials, such as livestock and food processing wastes — handled as either liquids, slurries, or semi-solids — where biogas is recovered and combusted for energy use, process heating, or flared as an odour control or greenhouse gas management method. In many cases the value of the gas as an energy source can pay for these benefits and add to a farm's revenue where utility markets are favorable. Anaerobic digestion also results in a number of environmental and human health benefits such as reductions in biological oxygen demand (BOD), pathogen reduction, and improved odour control.

An AD system consists of the following components: a digester, a gas-handling system, a gas-use device, and a manure storage tank (or pond) to hold the treated effluent prior to land application. Biogas digester systems can generally accommodate manure handled as liquid, slurry, or semi-solid. The total solids content of the manure — a measure of manure thickness — determines these classifications. Facilities best suited for biogas digester systems typically have stable year-round manure production, and collect at least 50% of the manure daily. Several gas-use options are available, ranging from simple flaring, to engines, chillers, boilers, and cogeneration power systems.

TYPES OF AD PROJECT

The following are descriptions of conventional AD technologies:

- ✓ Covered anaerobic lagoons are constant volume reactors that are operated at ambient temperatures. Manure is treated under anaerobic conditions producing methane, which is recovered by using impermeable floating lagoon covers.
- ✓ Complete mix digesters are heated digesters constructed of concrete or steel designed to enhance anaerobic decomposition and maximize methane recovery.
- ✓ Plug flow digesters are heated systems for semi-solid dairy manure that operate at a constant temperature year round, producing gas at a stable rate.

Opportunities and challenges in developing AD projects

The US EPA, Department of Energy, and Department of Agriculture, implement a voluntary partnership program called AgSTAR that aims to promote the use of AD systems and to reduce the environmental impact of livestock waste and fossil fuel power generation. In the past ten years, the AgSTAR program has helped develop over 120 AD projects in the US. These projects contribute more than 250,000 MWh per year equivalent (output estimate includes generation from electricity projects as well as equivalent output for non-electricity producing projects). [2]

AD projects operating in the US typically range in size from 50 kW to 400 kW and are most often implemented on either dairies or hog farming operations. About 12% of the existing projects are listed as cogeneration projects. These AD projects are located across 26 states, in addition, there are 56 projects that are either planned or under construction. Many of the newer digesters can co-mingle wastes and introduce additional substrates to the digester to increase gas production and energy generation. These additives can be a wide variety of materials, including wastes such as fats, oils and grease, or cheese whey from cheese-processing plants.

In developing countries, AD projects can take advantage of the Clean Development Mechanism which allows emission-reduction projects in developing countries to earn certified emission reduction credits — these can be traded and sold and used by industrialized countries to meet a part of their emission reduction targets under the Kyoto Protocol. In the US there are a variety of voluntary markets where carbon credits may be sold, including the Chicago Climate Exchange which is a voluntary, legally binding, pilot greenhouse gas reduction and trading program for emission sources and offset projects in North America. AD projects are also often eligible to sell ‘renewable energy credits' as well.

One important issue for projects in many developing countries is that direct discharge to water is often the predominant disposal option. This type of management causes a host of environmental problems, including surface water contamination, dispersal of disease, fish kills, etc. These sites can realize significant environmental benefits from improved sanitation and reduced odor, by installing AD systems and implementing improved manure handling practices. In the parts of the world where warm climates predominate, farms or AD projects may be limited in the amount of waste heat that can be utilized via cogeneration.

The Methane to Markets Partnership brings together the collective resources and expertise of the international community to address technical and policy issues and facilitate AD projects. Early initiatives include:

- ✓ Assessing opportunities for AD projects
- ✓ Performing initial feasibility studies including the potential for CHP applications
- ✓ Demonstration projects

- ✓ Capacity building within a country to allow for replication of demonstration projects.
- ✓

For more information on Methane to Markets visit the website at: www.methanetomarkets.org.

The AgSTAR Program [2]

AgSTAR, a collaborative effort of EPA, US Department of Agriculture, and US Department of Energy, is an outreach program designed to reduce methane emissions from livestock waste management operations by promoting the use of biogas recovery systems. This program helps to reduce methane emissions by encouraging livestock owners and operators to install AD systems and use the collected biogas as an energy resource. AgSTAR was launched to encourage productive use of this resource as part of the United States' commitment to reduce greenhouse gas emissions under the United Nations Framework Convention on Climate Change. AgSTAR provides an array of information and tools designed to assist producers in developing projects, including:

- ✓ Conducting farm digester extension events and conferences.
- ✓ Providing 'how-to' project development tools and industry listings.
- ✓ Conducting performance characterizations for digesters and conventional waste management systems.
- ✓ Operating a free hotline.
- ✓ Providing farm recognition for voluntary environmental initiatives.
- ✓ Collaborating with federal and state renewable energy, agricultural, and environmental programs.

6.2: R & D on efficiency and emission

Here in this section I will be describing some of the most recent R & D works that has been completed successfully. Lots of R & D works are going on in different companies .Among this capstone, Kawasaki. Siemens ,Cogen America, Caterpillar etc. are renowned for their research and development works. Also much more research on cogeneration are carrying on in different universities in the world.

6.2.1: Engine based CHP for Belgian green house [3]

A CHP plant based on a G3520E Generator set from Cater pillar is providing both energy and carbon dioxide (for enhanced plant growth)at a greenhouse in Belgium. Meanwhile, engine researchers continue to look for higher efficiency and lower emissions. Providing power and critical temperature control to year round greenhouse operation demands high quality equipment capable of delivering exact specification to ensure maximum growth potential in plant life. A stout standby power system is also important to guarantee little to no loss of power is experienced during delicate agriculture application.

The eric van den eynde green House cultivates around 1.2 million egg plant crops each year at its 4 hector (9.8 Acre) facility located in kontich, Belgium. The green house, 20 km north of the Belgium capital of Brussels, needed an onsite power generation system to provide combined heat and power to maximize growth of the vegetables. The conservatory must maintain a temperature of 20°C for prime growing condition amounts of CO_2 .A reliable method of providing heat, electricity and gas will maintain business and accelerate plant production. While green house is connected to the local utility ,Meaonsite CHP generation with CO_2 enhancement was required a CHO system was an attractive solution to energy need, as the majority of power generated could be sold back to the local utility MEA to increase the overall return on investment.

Unit Provide energy and carbon dioxide

An engineering evaluation by Eneria ,the local caterpillar dealer determined that the green house would be best served with a new generator set to replace existing cat equipment that had been used as the main source of power since 2001.Previously ,two cat G3516A generator sets rated at 1070 kW provided the conservatory needs .A cat G3520E natural gas module rated 2070 kW was installed in 2007 to serve as the main power source and CHP.

The G3520E is housed in an enclosure separate from the green house itself while the existing units are located in an engine room inside .Controls for all three units sit next to the interior engine room for onsite monitoring .the modules can also be monitored remotely. These controls allow running hours of generator sets in the green house to be adjusted every day depending on hourly changeable electricity costs. Only 5 percents of the electricity power produced by the G3520E is consumed by the green house. The remaining 95 percent is sold the local utility IMEA. An internet-based exchange market for electric power in place in Belgium allows electricity producer to sell power instantaneously. Electricity cost can change on an hour basis so running hours of the generator sets are adjusted on a day-to-day basis via the generator sets control to take best advantages of power and prevailing rates from IMEA.

The heat portion of the CHP installation comes in the form of hot water and is used to stabilize the green house temperature at the desired 200°C.Water with a temperature of 95°C is stored in a 1200 cubic meter boiler while water at 45°C runs in metallic tubes surrounding the green house. The temperature is maintained between 19°C to 21°C throughout the year .In addition to hot water absorption chillers fueling the green house cooling system. These supplementary recovered heats eliminate the need for extra boilers and contribute to the efficiency of the plant. The typical electrical output of a gas engine is about 41% of total fuel gas energy input. More energy is recovered from an engine by capturing the heat from the after cooler, the engine jacket water, the cooling oil water and the exhaust gas. This allows the green house to recover around 90 percent of the energy.

The exhaust gas from the generator sets are cleaned of nitrogen oxides (No_x),Carbon Monoxide(CO) and unburned hydrocarbon(Cn,Hm).Selective catalytic reduction(SCR) and oxidation system converts these gases to cleaned forms before they are allowed to re-enter the air outside .Carbon dioxide is reintroduced in to the green house. The gas is supplied for 12-16 hours per day during summer months and six hours per day during winter months .This generator set produces 240 kg of CO_2 per hour per hectors. Because the green house requires only 180 kg of CO_2 per hour per hector, nearly 75% of the gas is captured.

Results

I chose a CHP solution because it allows me to run my green house in a good financial condition, Eric van den eynde ,the green house owner ,notes 'we get our power ,heat and all of our supplement for our plants from one machine, and we also get the additional benefit of being able to sell our electricity to the grid.[3] Without the CHP installation liquid CO_2 would be needed for the green house year round at a cost of nearly 100 pound per liquid ton. Around 180 kg per hector of Co_2 are needed on an hourly basis. With caterpillar generator sets carbon dioxide becomes available as free by product: Harnessing the electricity. heat and carbon dioxide , the eric van den eynde green house capitalizes on all facet of its power generation ,By utilization the full scope of the cogeneration plan, the facility is able to meet its economic goals as well as its environment goals.

The financial return for such a power station investment is approximately three to four years by the heat recovered from the engine through water and exhaust gas recovery instead of gas fired boilers, the gas generator sold to the local utility, and the CO_2 fertilization by using exhaust gases of the engine. Our cat G3520E module provides all of the things our plant need to grow and helps us run a successful business.

6.2.2: The Brookville Equipment corporation development on ford trucks

The Brookville Equipment corp. was founded in 1918 to install railroad wheels on ford trucks so they could ride the rails rather than the poor roads of the day. The company was soon building gasoline and diesel powered locomotives, mainly for logging, Plantation and industrial applications. It also built specialty rail equipment including refrigerator cargo haulers, flat cars, workmen's car, bulletproofs pay cars and even ambulance and school buses that rode on rails. Brookville's latest innovation is its cogeneration locomotives that include standard features –power on demand, Regenerative Dynamic Breaking and smokeless start –that improve fuel economy and reduce emissions. The company said there is a potential 25% saving in fuel costs with the cogeneration technology.

The power on demand features shuts down the engine when power demand is low to reduce fuel consumption and excess noise. When additional power is needed, the other engines can be brought online. The new locomotive use two or three QSK-19L, diesel engine to provide up to 1491 kW. These six cylinder engines meet United States environmental protection Agency Tier 2 Emission level for off highway application.

Hydrocarbon emission are reduced by the 97%, NO_x is reduced by 65%,CO is reduce by 93%. Self-Cleaning Ceramic diesel particulate filters and diesel oxidation catalyst system are optional.

The Locomotive use regenerative braking that provides full breaking forces from 20Kph down to 1 Kph and up to 1641 kW of power from 20 to 87 Kph. All recouped energy is available for 100% recycling prior to being sent to locomotive resistors. This electrical energy can be used for auxiliary function like cab heating, fans, air conditioning lights ,radios refrigerator and air compressor .To keep costs down, Batteries are not currently used to store energy but the technology does allow for this excess electrical energy could be sent to the grid through a third rail or catenaries. This adds up to approximately 25% reduction in fuel costs.

Fig 6.3: Brookeville innovation on ford trucks

The smokeless start feature allows engine starting using the generator to turn the engine at a high speed before diesel fuel is injected. Besides eliminating smoke, it reduces maintenance required from normal wear on starters and ring pinion gears. The locomotive use TMV control system's TECU Liquid cooled insulated gate bipolar transistor controls to manage each traction motor individually for maximum adhesion .The TECU's anti-spin/anti slip solid-state drive system supplies starting traction effort of 23 to 35%.The cab mounted touch screen display accesses engine controls and diagnostic .Also, it controls wheel slip/slide in power and dynamic braking mode based on information from axle speed sensors.

Currently, Brookville is offering three cogeneration switch locomotive models –

- ✓ the BL20CG, BLI4CG and BL20CGC.

That uses either two or three Cummins QSK19C19L diesel engines. The Brookville technology will work with other engine with power ratings ranging from 447 to 1864 kW. It can be applied to application from 50 to 150 ton capability with two or four axels.

Table 6.7: Different models of cogeneration

Type	BL20CG	BL14CG	BL20CGC
No. of diesel engine	3	2	3
Traction Motor	4xD78	4xD78	6xD78
Traction Power	1491	969	1491
Starting Tractive effort	39190kg	37739kg	45359kg
Regenerative Braking	22680	22680	34019
Weight	122470kg	117934kg	145150kg
Fuel Capacity	9464L	9464L	11356L

6.2.3: Kawasaki Company's development on thermal efficiency and emission:

The project aim to increase the thermal efficiency of a cogeneration unit of 300kW Class Ceramic Gas Turbine (CGT302)

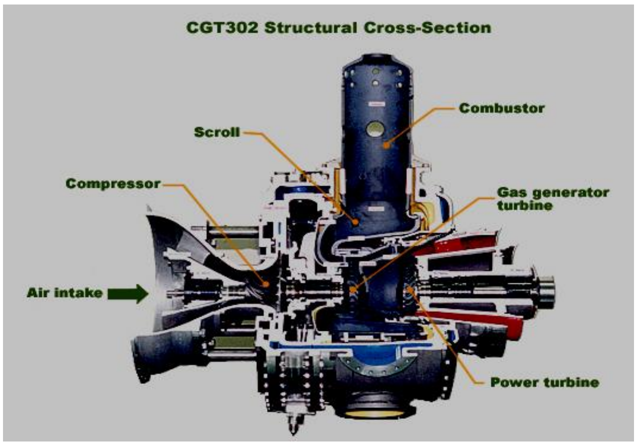

Fig 6.4: cross section of the turbine

Project Outline [15]

- ✓ NEDO* Project for FY1988 through FY1998 *(NEDO: New Energy and Industrial Technology Development Organization)
- ✓ Participated by Kawasaki Heavy Industries, Ltd., KYOCERA Corporation, and Sumitomo Precision Products Co., Ltd., and coordinated by KHI.
- ✓ Type and Name of Development object: Recuperated Two-Shaft Ceramic Gas Turbine, CGT302.
- ✓ The project aimed to boost the thermal efficiency of small-size gas turbines by applying ceramic materials with high heat resistance to engine hot section, and raising the turbine inlet temperature (TIT). The purpose was to realize energy conservation while also reducing the environmental burden, by lowering NOx emissions, for example.
- ✓ The development concept to improve efficiency is to preheat the combustion air by the recuperator for recovering exhaust gas energy

R&D Objectives

Table 6.8: R & D objective (Kawasaki Company) [15]

Item	Objective
Engine thermal efficiency	**42% or more**
Turbine inlet temperature	**1350 degrees Celsius**
Shaft output	**300kW class**
Emissions	**Legal limit or less**

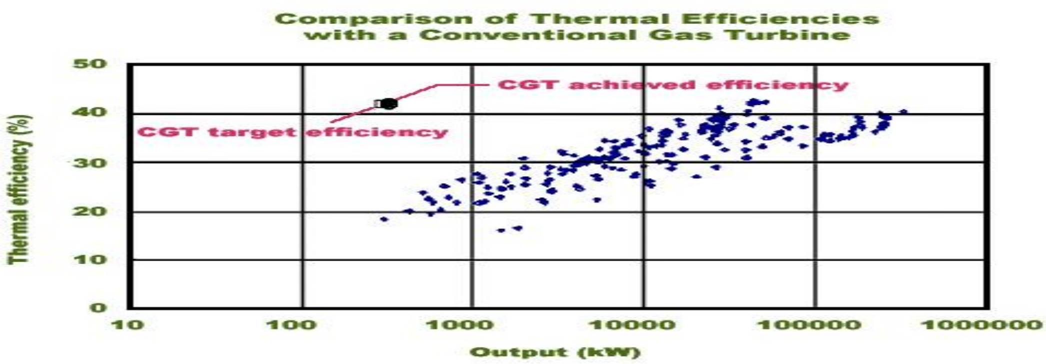

Fig 6.5: Comparison of thermal efficiency with a conventional gas turbine

Results

Intense effort has led to technological developments that successfully utilize brittle ceramic as a material for gas turbine components. The project achieved a thermal efficiency of 42.1%, a performance equivalent to the largest class gas turbine, with an output hundreds of times larger. Thus, it proved that applying ceramic components could raise efficiency of small-size gas turbines dramatically, and also the endurance test of cumulative 2100 hours at 1200°C was conducted. These results are highly esteemed internationally.

6.2.4: Performance improvement of a 70 kWe natural gas combined heat and power system

An ICE-based CHP system was installed in Building Energy Research Center at Tsinghua University, in Beijing, China. The system is composed of a 70 kWe gas-powered ICE, a flue gas heat exchanger, a jacket water heat exchanger and other assistant facilities. The configuration of the system is shown in Fig. 6.6. The natural gas is sent to the ICE which generates power on-site, and the exhaust of the ICE is recovered by the flue gas heat exchanger, and the jacket heat of the ICE is recovered by the jacket water heat exchanger. The hot water flows from the jacket water heat exchanger, in conjunction with the hot water flows from the flue gas heat exchanger, is used for space heating. In order to suppress the noise of the system, a muffler is mounted on the outlet of the exhaust pipeline, and a noise reduction method is adopted in the engine room.

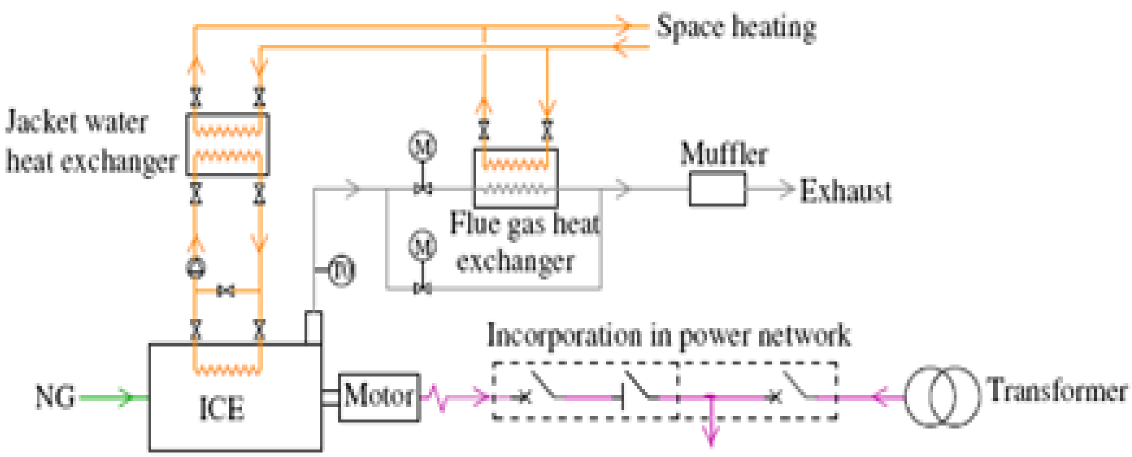

Fig 6.6: Schematic of conventional CHP system in demonstration building

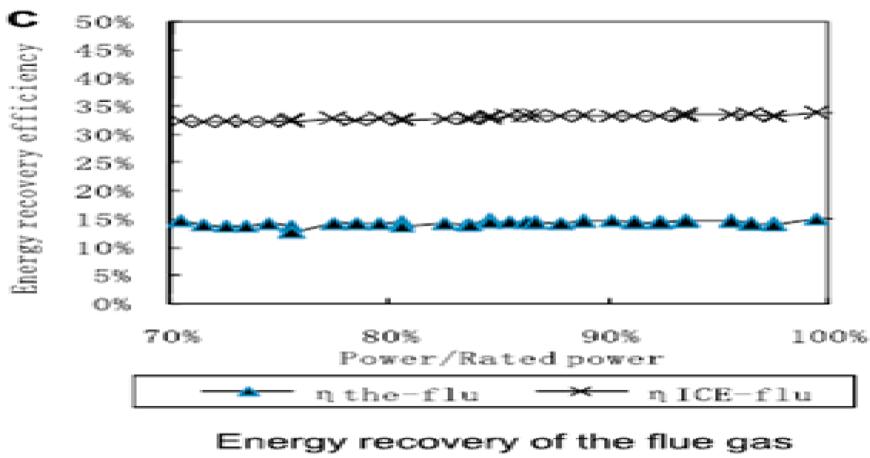

Fig 6.7: The distribution status of different parts of the conventional system.

If the latent heat of the flue gas could be recovered more effectively, the energy efficiency of the system could be improved. The potential to improve the performance of conventional CHP is great. We can see that the latent heat of the flue gas can't be recovered deeply, so a CHP system with exhaust-gas driven absorption heat pump is put forward.

Description of the modified CHP system [28]

The new system increased a 50 kW double-effect exhaust-gas driven absorption heat pump (AHP) and a condensation heat exchanger (CHE).The system is composed of the ICE, the AHP, the CHE, and other assistant facilities. The configuration of the system is shown in Fig.6.8. The natural gas is used to fire the ICE, which generates power on-site. In the winter, the exhaust gas (about 530°C) of the ICE is used to drive the AHP directly, and the exhaust (about 150°C) out of the AHP is sent to the CHE, and the exhaust out of the CHE could be lowered to 30°C. On the evaporator side of the AHP, the evaporation temperature is about 15°C, and the cold water flows from the CHE which recovered the condensation heat of the exhaust is directed to the evaporator side of the AHP as the low grade heat source. On the condenser side of the AHP, the condensation temperature is about 50°C, and the hot water flows from the condenser side of the AHP, in conjunction with the hot water flows from the jacket water heat exchanger, is used for space heating. In the summer, the exhaust out of the ICE is sent to the AHP to produce chilled water, and the heat of jacket water is used to drive liquid desiccant machine, to realize the separate control of heat and humidity. In this paper, we just pay attention to the performance analysis in the winter mode.

Experimental results and discussion

There are five test points along the pipeline of the flue gas, mounted on the outlet of the ICE, the inlet and outlet of the AHP, and the inlet and outlet of the CHE separately. The temperature of the flue gas out of the ICE (T0) and the inlet temperature (T1) of the AHP are not the same, which denotes the heat loss of the pipeline between the outlet of the ICE and the inlet of the AHP. After well insulation of the pipeline, the heat loss of the pipeline accounts for about 1% of the input energy of the system. The outlet temperature (T2) of the AHP and the inlet temperature (T3) of the CHE are about equal, which denotes that the pipeline of the flue gas between the AHP and the CHE is well insulated. The temperature of the flue gas could be reduced from 135 °C-146 °C to 29°C-34°C, so the outlet temperature of the system could be reduced to below 30°C through the CHE. At the same time, on the water side of the CHE, the inlet temperature of the cold water is about 18°C, and the water is heated to about 21°C by the flue gas. And then, the water is sent to the evaporator side of the AHP, and releases the heat to the AHP as the low-grade heat source and come back. It is found that η_{ICE}-flu is about 31%–33%, and the real thermal recovery η_{the}-flu is about 24%–25%, which is increased by 10% compared with the conventional operation mode, so it is feasible to operate the system with the AHP. The energy loss of the system is reduced compared with the conventional heat recovery system. The power consumption of the system itself is considered, the power consumption of the new system increases 1%–1.5% compared with conventional system.[28]

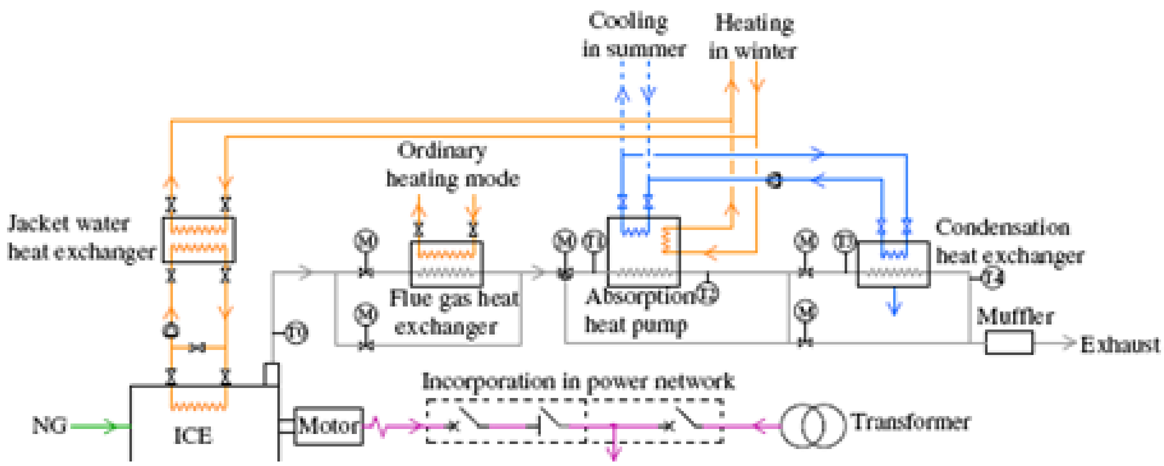

Fig 6.8: Schematic of the new CHP system in demonstration building

The overall efficiency of the system is also the sum of the electric efficiency, the thermal recovery efficiency of the jacket water, and the thermal recovery efficiency of the flue gas. Along with the part load increased, the electric efficiency increases and the thermal recovery efficiency of jacket water decreases, and the thermal recovery efficiency of the flue gas is about 24%–25%, so the overall efficiency of the system is about 87%–91% Compared with the conventional system (thermal recovery with flue gas heat exchanger). [2]

6.2.5: CHP/DHC waste heat recovery technology with absorption heat exchange cycle

Another innovative CHP/DHC waste heat recovery technology with absorption heat exchanger has been developed by the Building Energy Efficiency Centre at Tsinghua University. In this technology, absorption heat exchange conception is adopted to form a heat network cycle called "Co-ah" cycle (as shown in Figure 6.9), which means co-generation system based absorption heat exchange. In the substation of the heat network system, supply water in the first network releases heat to the second network by absorption heat exchange, which makes the temperature of the return water very low (about 20°C). In a CHP plant, network water is heated to a temperature of 130°C by exhaust vapor in a condenser, absorption heat pump and peak load heater sequentially. By enlarging the temperature difference between the supply and return water of the heat network, the efficiency of the network improves, reducing the investment required. Further efficiency gains (approximately 50%) are realized by recovering exhaust heat from the condenser. The Co-Ah method is paving the way toward a revolution in district heating in northern China. The added investment may be reclaimed in about two years. Several pilot projects using this technology will be implemented in the end of 2008.[45]

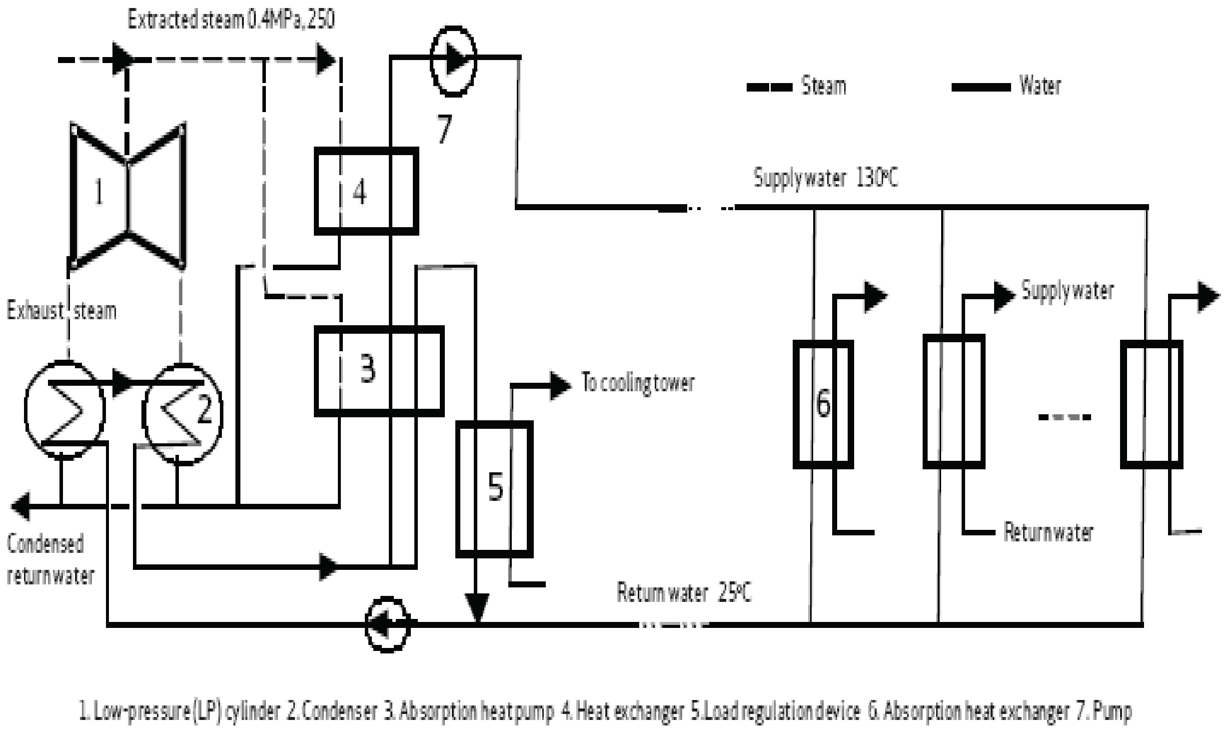

Fig 6.9 :"Co-AH" Cycle scheme of district heating system cogeneration[45]

Chapter 7: Case studies

Two case studies have been discussed here. First one for a hotel in Bangladesh, and the second case is the optimization of a cogeneration unit in hospital situated in Seoul, Korea. In the first case, three types of cogeneration systems were considered such as gas engine, gas turbine and steam turbine. Finally selected the optimized one. In the second case optimization is made by sizing cogeneration unit .

7.1 Case study : A hotel in Bangladesh

Nomenclature
AF - Annuity factor
CHP - Combined heat power
CF - Cash flow for specific year
GTTM - Gas turbine thermal match
GTPM - Gas turbine power match
I - Investment
i - Discount rate
IRR - Internal rate of return
n - Economic life of the plant
NPV - Net present value
RETM - Reciprocating engine thermal match
REPM - Reciprocating engine power match
STTM - Steam turbine thermal match
STPM - Steam turbine power match
TR - Ton of refrigeration
VAC - Vapor absorption chillers
VCC - Vapor compression chillers

The cogeneration potential in a commercial building (Hotel Sea Sun Resort) in Bangladesh was found out. Information on steam and electricity consumption in a commercial building was collected through site visits and surveys via questionnaire. Historical energy consumption data shows that the power to heat ratio of the plant was 0.23. For average power to heat ratio of 0.23, three types of the prime movers i.e. steam turbine, reciprocating engine and gas turbine cogeneration system were considered. From the sensitivity analysis the potential cogeneration alternatives (assuming vapor compression chillers) of the commercial building, the reciprocating engine power match option meeting power requirement of 800 kW appears to be the most suitable co-generation system. It represents an initial investment of 35.6 million Taka and leads to an internal rate of return of 43.5%. By using vapor absorption cooling for the commercial building electricity demand may be reduced sharply.[39]

Fig 7.1: Hotel sea sun resort

The hotel operates throughout the year without any stop. Electrical energy is required for air conditioning, lighting, and pump motors whereas a lot of steam is used in various applications like kitchen, laundry etc. The energy consumption pattern of this hotel is shown below. it is found that 85% electrical energy is consumed by VC

Table 7.1: Energy consumption in a year[39]

Energy consumption in a year:	
Maximum electricity consumption (Aug):	890 MWh
Minimum electricity consumption (Mar):	513 MWh
Maximum electricity demand:	1000 kW
Minimum electricity demand:	900 kW
Total electricity consumption:	8580 MWh

Table 7.2:Steam consumption in a year[39]

Steam Consumption:	
Maximum steam consumption (Mar):	6317 Ton
Minimum steam consumption (Feb):	5033 Ton
Total steam consumption:	60615Ton

Power to heat ratio

The power-to-heat ratio of the site was calculated to be 0.23 for 1998. Typical cogeneration system suitable for this site would be based on steam turbine. However, reciprocating engine and gas turbine cogeneration systems were also considered as potential alternatives

Table 7.3:Assumptions used in the study[39]

Parameter	Unit	Value
Exchange Rate	Taka/US$	48.5
Tax Rate	%/Year	35
Service Life of the Cogeneration Plant	Year	15
Purchased Price of Electricity	Taka/kWh	3.6
Buy-back Rate	%	80
Fuel Price Escalation Rate	%	5-13
Electricity Price Escalation Rate	%	6-13
Stand by Rate	Taka/kW	80
Purchased Cost of Fuel (Natural Gas	Taka/Cubic Meter	3.65

Assumed installation cost of a CHP plant:
For a steam turbine: US$ 1200/kW
For a gas turbine: US$ 1000/kW
For a reciprocating engine: US$ 900/kW
The net present value of cogeneration plant has been estimated as follows:
NPV = (CF)(AF)-(I)
The NPV estimates the gain or loss resulting from the proposed investment. Therefore, if NPV is positive, the investment should be made because the relevant revenues exceed the financing cost. If NPV is negative, the plant is not propos able.

Methodology

Data on base electricity demand, steam demand, annual electricity consumption, and annual thermal energy requirement were the initial inputs to the spreadsheet analysis. The related parameters required for cogeneration analysis were estimated using the spreadsheet.

Summary of the results obtained by using VCC as the cooling option

The steam turbine, reciprocating engine and gas turbine options with thermal match and power match results are shown analysis in Table 7.4. The results in the table also show the internal rate of return on net investment for each option. Lastly three alternatives were considered for sensitivity analysis[39].

Table 7.4: Different calculate parameter for different cogeneration system [39]

Major Parameters	Steam Turbine		Gas Engine		Gas Turbine	
	Thermal Match	Power Match	Thermal Match	Power Match	Thermal Match	Power Match
Installed power (kW)	653	900	10,137	900	4,339	900
Fuel consumption (TJ/yr)	230	317.5	1,001.5	88.9	520	107.9
Electricity generated(MWh)	5,400	7,490	84,376	7,490	36,112	7,490
Heat generated (TJ/yr)	184.6	254.6	184.6	16.4	184.6	38.3
Surplus/deficit (-) power MWh/yr	-3,149	-1,090	75,796	-1,090	27,532	-1,090
Surplus/deficit (-) heat (TJ/yr)	47	92.1	47.6	-120.6	47.6	-98.7
(Equipment)						
Power to heat ratio	0.106	0.11	1.87	1.87	0.8	0.8
Total Investment (Total Million taka)	37.59	51.84	438.00	38.88	208.29	43.20
Net present value (Million taka)	41.11	44.61	597.67	78.61	249.30	74.83
IRR (%)	31.2	28	34.9	43.5	32.6	39.8

Discussion

The steam turbine option is found to be not suitable: (i) with steam turbine thermal match (STTM), less than 65% of the power requirement is generated and the hotel will have to depend on the utility grid; (ii) with steam turbine power match (STPM), only a small amount of excess heat is generated. With the reciprocating engine thermal match (RETM) option, 900% excess power is generated. The project profitability will depend on the buy-back rate. This may not be a good option as the purpose is not to earn from electricity sale. Reciprocating engine power match (REPM) option seems good as almost all the power needed can be met though there will be small (15%) shortage in the heat supply. There is no need for an auxiliary boiler as this shortfall can be easily made up by auxiliary natural gas firing in the recovery boiler. With gas turbine thermal match (GTTM) option, about 320% excess electricity is generated, which has to be sold as in the RETM option. Gas turbine power match (GTPM) option takes care of all the power needs though heat deficit is as high as 60%. This will require the adoption of auxiliary natural gas firing in the recovery boiler. Accordingly, the sensitivity analysis[39] carried out to see the impacts of the increase in the investment, fuel and electricity price escalation was limited to STPM, REPM and GTPM options.

Scope of the alternative cogeneration system

The above results of the hotel were obtained by assuming VCC. Cogeneration can provide power and cooling by incorporating VAC also. The cooling load demand of the hotel is 1500 TR which is achieved by driving a VCC. The required electricity demand of the hotel is 900 kW which is used to drive the VCC. On the other hand this cooling effect may be achieved by driving a VAC which will require electricity of 150 kW only [4]. It can be seen that a cogeneration system incorporating a VAC can save about 25% of primary energy in comparison with only power generation system with VCC [3]. Furthermore, a smaller prime mover leads to not only lower capital cost but also less standby charge during the system breakdown because steam needed for the chiller can still be generated by auxiliary firing of the waste heat boiler. Again, the proposed system is independent of national grid which is already overburdened.

7.2: Case study: Optimization of a cogeneration system in hospital. Seoul, Korea .

A hospital Seoul, Korea, was chosen for this study to determine whether the adoption of the cogeneration plant is economically viable. Fig. 7.2 shows the energy demand data in which a day was selected to represent the corresponding month for the hospital. Usually, hospital has a large heat demand in winter and a large cooling demand in summer. It is this demand pattern which determines the configuration of the cogeneration system installed and the operation mode of the optimal cogeneration plant. For the hospital, the maximum electricity, heat and refrigeration demands were 4.26, 18.68 and 9.68MW (2500RT), respectively. The maximum outputs corresponding to fuel, power or steam consumption and the initial

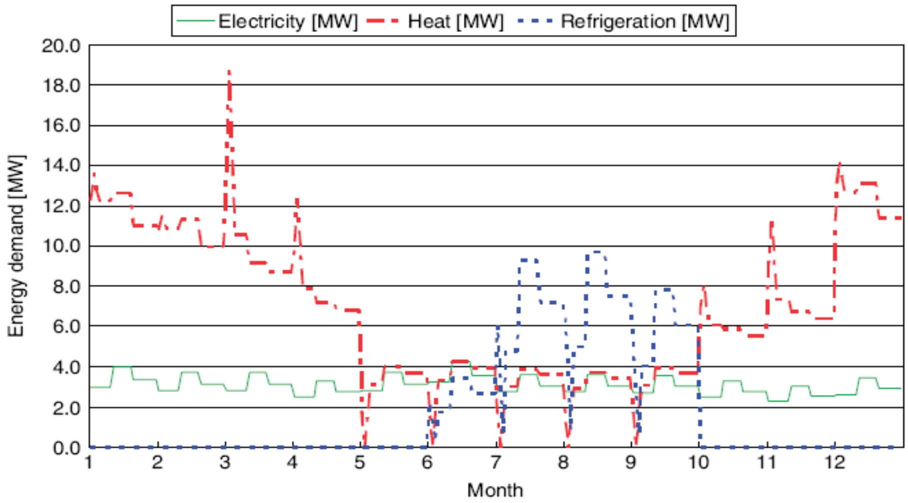

Fig 7.2: Energy demand pattern for hospital

equipment costs of each component considered in the optimal planning of the plant for the hospital are shown in Table 7.5. The tariffs of electricity and fuel, along with the annual fixed costs used in the calculation, are shown in Tables 7.6 and 7.7, respectively. The fuel tariff shown in Table 7.7 can be applied only to the hospital where the cogeneration plant is installed. The unit cost of hot water was taken as 12.0 $/GJ. The expected life of each equipment was assumed to be tG ¼ 15 yr and the remainder rate was taken as r ¼ 0.1. The possible annual operation time of the cogeneration plant was assigned as 8760 h. The ratio of the annual maintenance cost including insurance to the initial investment was set as g ¼ 0.035, and the annual interest rate was r ¼ 0.12. Previously, the optimal configuration of the cogeneration plant was determined with the assumption that the plant should cover the maximum demand of electric power. However, this was not the case for the cogeneration plant with profit. In this study, the payback period was calculated for the possible configurations of the cogeneration plant,[25]

Table 7.5: Maximum outputs, corresponding fuel consumption and initial equipment costs for GE/WHB, AUXB, RE, RS and RF units,[25]

Type of equipment	1	2	3
GE/WHB power output(MW)	0.968	1.067	1.290
GE/WHB heat output (MW)	1.168	1.5330	1.552
Fuel consumption(Nm^3/h)	228	268	303
Initial cost($)	7540000	8450000	9.130000
AUXB heat output (MW)	4.0	6.0	9.6
Fuel consumption(Nm^3/h)	426	639	1.023
Initial cost($)	616000	874000	1.190000
RE cooling load(RT)	1045	1500	-
Power consumption(MW)	7.26	9.0	-
Initial cost($)	1890000	2500000	-

RS cooling load (RT)	741	960	-
Steam consumption(ton/h)	3.87	5.06	-
Initial cost($)	250000	2900.00	-
RF cooling load(RT)	1000	1400	-
RF heat outputs(MW)	294	4.1	-
Fuel consumption(Nm^3/h)	286	400	-
Initial cost($)	2560000	3390000	-

According to combinations of various scales of gas engine as shown in Table 7.5 to compare the economic merit of the possible plants. In Table 7.8, the annual fixed and variable costs, the profit produced in the electricity and heat by introducing the cogeneration plant, the operating rate of the plant and the payback period to the initial investment are given. When the scale of the cogeneration plant was increased, the payback period became longer because the operating rate is reduced for a larger plant. Calculation showed that the cogeneration plant designed to cover 60% of the electricity demand was the solution with the highest economic feasibility. The electricity demand and the electricity gained by the optimal cogeneration plant are shown in Fig. 7.3. The heat demand of the hospital and the heat gained by the optimal cogeneration plant are shown in Fig. 7.4.

Table 7.6: Tariffs of electricity [25]

Period	Summer	Spring/fall	Winter
Tariff($/kWh)	0.0926	0.0616	0.656

Table 7.7: Tariffs of fuel [25]

	Unit cost($/$Nm^3$h)
Heating(Spring, fall and winter rate)	0.382
Refrigeration(Summer rate, May-September)	0.166

An optimal configuration of the cogeneration plant obtained for the hospital is given in Table 7.7,[25]. A reference energy system without the GE/WHB unit to supply heat and cooling demands for the hospital was chosen for economic evaluation of the optimal cogeneration plant, as shown in Table 7.10. With the special tariff system for the fuel given in Table 7.5, the operational modes of the optimal cogeneration plant corresponding to the electricity, heat and cooling demands are shown in Figs. 7.5, 7.6 and 7.7, respectively. As shown in Fig. 7.5, the two GE/WHB units supplied electricity even when the electricity demand was less than the maximum electricity output from the GE/WHB units at full load condition due to the constant heat demand so that the GE/WHB units should supply the heat as shown in Fig. 7.6. Additional heat demand could be supplied by the two RF units and partly by the AUXB unit. Especially, the two RF units were operated to satisfy the cooling demand during summer, as shown in Fig. 7.7.

Table 7.8: Economic evaluation of the possible configuration of the cogeneration plant [25]

Covering percentage for the electricity demand	Cogeneration configuration	Operational cost($)		Profit (operating rate)		Payback period(yr)
		Fixed cost	Variable cost	Electricity($)	Heat($)	
60	1290kW x2 sets	411899	1975	1687366	1157013	4
68	968kW x3sets	487326	2153758	1828998	1251076	5.2
70	968kW x2sets 1067kW x 1sets	503069	2237057	1860281	1354250	5
75	1067kW x 3sets	534555	2250465	1823462	1467094	5

80	1067kW x 2sets 1290kW x1 sets	546319	2332474	1916614	1467094	5.5
83	968kW x1sets 1290kW x2 sets	542340	2314360	1992648	1338681	5.4
91	1290kW x3 sets	569847	2354725	1983899	1343886	6.8

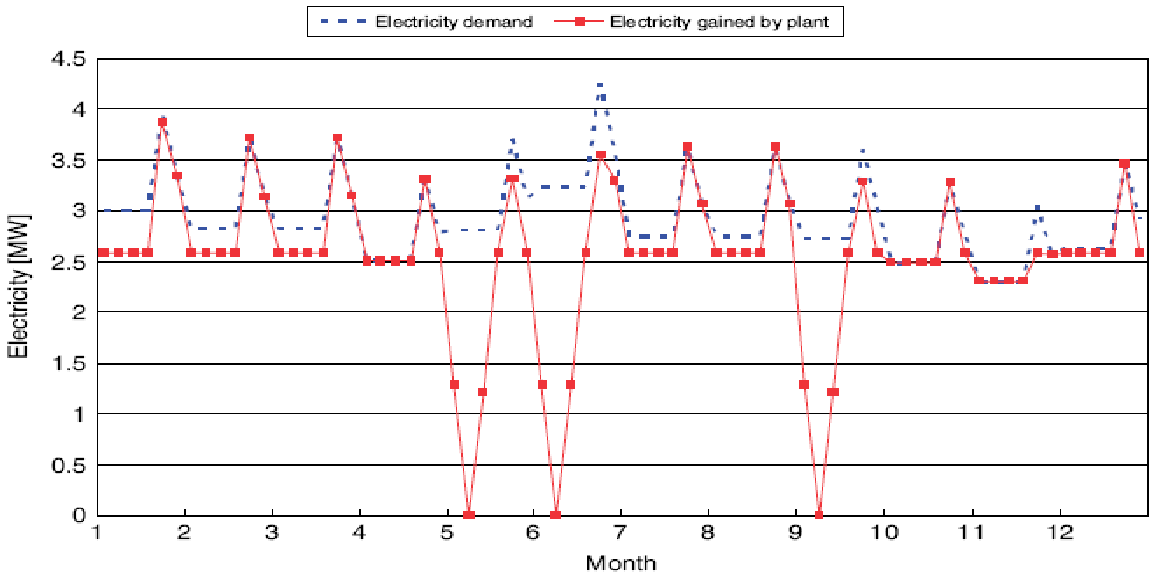

Fig 7.3: Electrical demand and electricity generated by the optimal cogeneration plant [25]

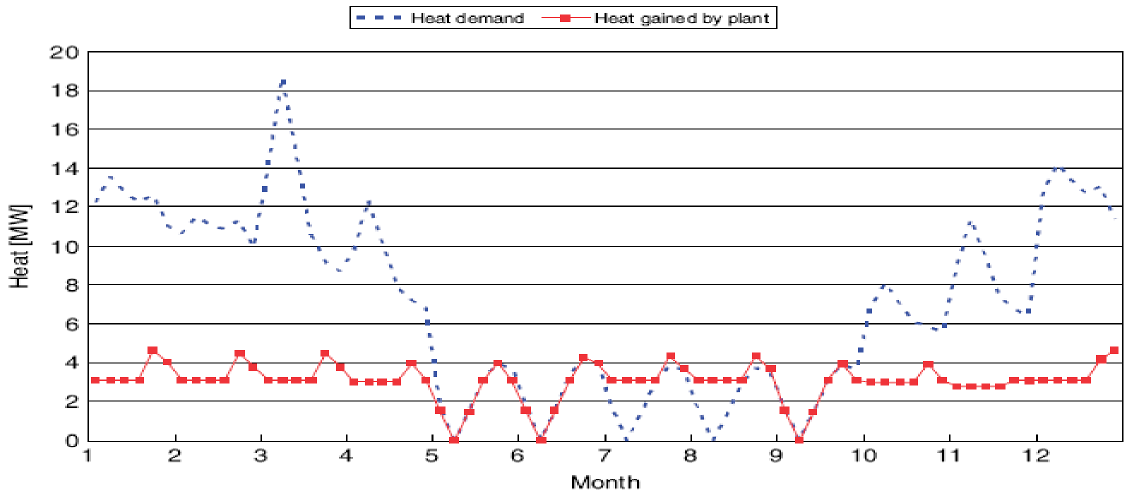

Fig 7.4: Heat demand and heat generated by the optimal plant [25]

Table 7.9: Optimal configuration of a cogeneration plant for a hospital [25]

Equipment	Scale of unit	Number of unit	Initial investment
GE/WHB	1.290 MW	2	18260000
AUXB	9.6MW	1	1190000
RF	1400	2	6780000
Total initial investment for the plant			26230000

Table 7.10: A reference energy system for the hospital

Equipment	Scale of unit	Number of unit	Initial investment
AUXB	6MW	2	1748000
RF	1400RT	2	6780000
Total initial investment for system			8528000

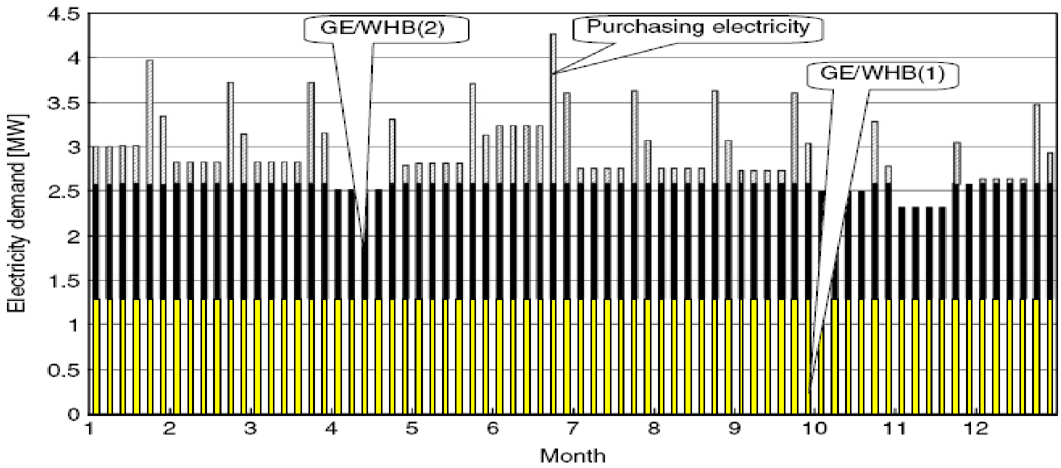

Fig 7.5: Operation mode of the optimum cogeneration plant for the electrical demand

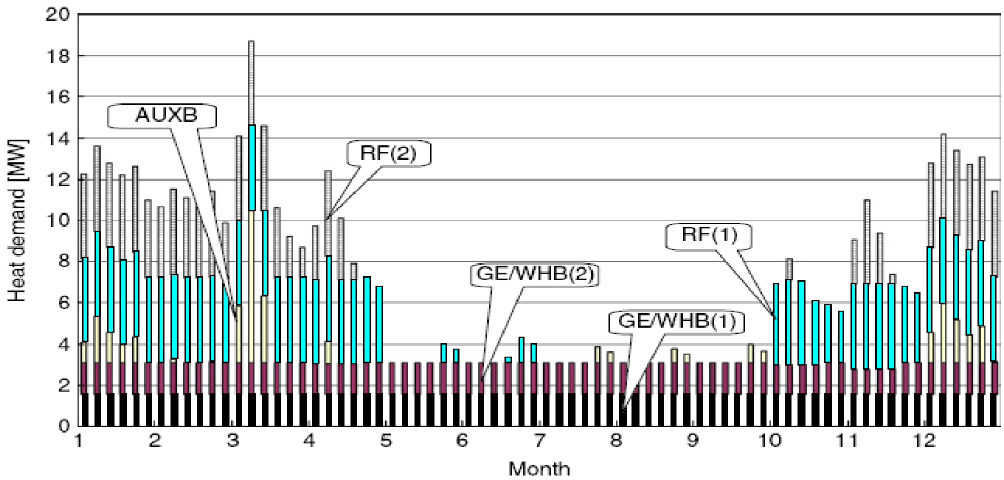

Fig 7.6: Operation mode of the optimal cogeneration plant for the heat demand.

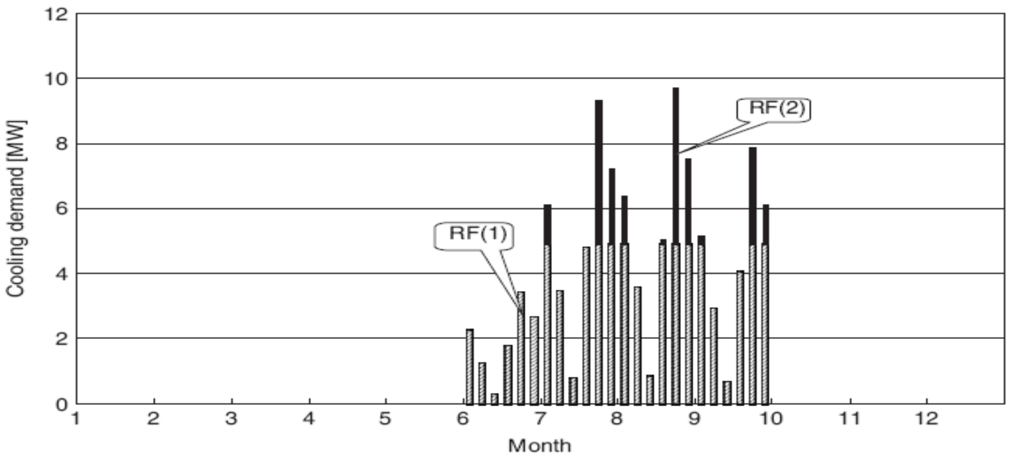

Fig. 7.7: Operation mode of the optimal cogeneration plant for the cooling demand.

Table 7.11:Monetary comparison of the optimal plant to the reference energy system for the hospital with tariff of the fuel of 0.382 $\$/Nm^3h$

Parameter	Optimal cogeneration plant (A)	Reference energy system (B)	Economic loss or gain(B-A)
Total investment	2623000	852800	-1770200
Total annual cost	4590315	4821417	231102
Annual fixed cost	538315	192120	-
Annual variable cost	405200	4629297	-

Table 7.12: Monetary comparison of the optimal plant to the reference energy system for the hospital with special tariff of the fuel in Table 7.5 (unit is in $)

Parameter	Optimal cogeneration plant (A)	Reference energy system (B)	Economic loss or gain(B-A)
Total investment	2623000	852800	-1770200
Total annual cost	3990315	4821417	831102
Annual fixed cost	538315	192120	-
Annual variable cost	345200	4629297	-

Table 7.11 and table 7.12 includes the annual variable cost, the fixed cost for the cogeneration plant and the reference energy system without the special tariff system for the fuel. With the fixed tariff of fuel of 0.382 $\$/Nm^3$ for all years, the payback period and the IRR by introducing the optimal cogeneration unit to the hospital (calculated from the data in Table 7.9) were 7.7 yr and 10%, respectively. The additional investment cost (B–A in Table 7.11) could be recouped within the lifetime of the component. However, the IRR calculated was less than the annual interest rate of 12% that was assumed in this study, indicating that the adoption of the cogeneration plant to the hospital was not profitable with the fuel tariff 0.382 $\$/Nm^3$. However, with the special fuel tariff system, the profit obtained by introducing the cogeneration plant increases considerably as shown in Table 7.12. The payback period and the IRR by introducing the cogeneration plant to the hospital, which were calculated from the data in Table 7.12, are 2.8 yr and 47%, respectively, confirming that it was economically feasible for the hospital to adopt the cogeneration plant under the special tariff.

7.3: Discussion

Case study 1

- ✓ The power demand of this commercial building by assuming VCC as cooling option is 1000 kW which is not very high. This type of plant is always suitable for gas based reciprocating engine which is available in the local market.
- ✓ From the sensitivity analysis [39] of the potential cogeneration alternatives for the commercial building(case study-1), the reciprocating engine power match option meeting power requirement of 800 kW is found to be the most suitable cogeneration system. It represents an initial investment of 35.6 Million Taka and leads to an internal rate of return of 43.5%.
- ✓ In the commercial buildings VAC need to be promoted instead of VCC to reduce electrical power requirement.
- ✓ In spite of the significant techno-economic potential for cogeneration applications in Bangladesh, cogeneration has not been widely adopted in the country due to several reasons. The foremost among them is the low level of awareness at all levels about the technological alternatives, economic merits, environmental benefits and business opportunities related to the application of cogeneration as an efficient energy use option. No systematic study has been undertaken so far to assess cogeneration potential by taking into account factors such as energy demand patterns, plant size, power-to-heat ratio, access to gas pipeline etc. There is practically no interaction between the energy utilities and the energy users to explore the cogeneration option though the government is serious about encouraging private investment in the power sector.
- ✓ When giving permission to new industrial/commercial facility having small-scale electricity demand the relevant authority should give due considerations to the use of co-generation is an alternative to grid power.
- ✓ With respect to the present socio-economic condition existing in Bangladesh dependability for power with national utility may hamper the reliability of planned production and services. In this aspect self-captive generation in prospective cogeneration sites may improve reliability and efficiency as well as reducing the burden to already stressed national grid.

Case study 2

It is a planning method to determine the optimal operational mode and the optimal configuration of a co-generation plant that has been applied to the hospital in Seoul, Korea, in order to evaluate whether or not the adoption of the cogeneration plant was profitable. The optimal configuration of the cogeneration plant was determined by considering the annual energy demand pattern of the hospital, and this pattern was confirmed to be the crucial parameter determining the feasibility of the use of the cogeneration plant. When the cogeneration plant was introduced to a hospital, a special tariff system which decreases the cost of the fuel consumed for the cooling demand in summer should be chosen by the city government. The optimal configuration of the cogeneration plant may differ with different cogeneration system and auxiliary systems. Furthermore, it was found that the payback period should be short and the internal rate of return of the plant chosen on the initial investment should be high. These two variables were relatively insensitive to increases in fuel cost and decreases in the electricity cost for reliable and profitable operation of the plant.

Chapter 8: Conclusion

There are a number of likely barriers to the widespread deployment of small scale CHP technologies. Three types of barriers were highlighted: (i) cost constraints, (ii) information, and (iii) technical constraints. For the operation of small scale CHP systems regional and national regulations (varying from region to region and country to country) governing energy and environmental matters have to be followed. Also in some region there are no organization to follow up for the CHP advancement. So for those kind of region it is immediately needed to build up some organization to develop the growing of the CHP(small scale) technology.

A large part of the information given in this study is taken directly from manufactures and developers of CHP technologies(biomass and natural gas based). Therefore the provided performance data might only be valid during favorable conditions or even exaggerated. Furthermore flaws in the technology might have been missed since company written material cannot be considered as non objective and hence puts too much emphasize on advantages. Therefore, it is of great importance to continue monitor the development on the CHP market from an objective perspective. In this study it is found that the small scale CHP technologies are growing very fast that we have seen from the overview chapter.

Engine-driven generators over a certain power capacity have been equipped with proper control systems so that the installations can contribute to the stabilization of the voltage and frequency of the grid. Such units can also participate in carrying part of the reactive load of the grid. It can be proven statistically that a cluster of smaller well-controlled generators has a higher stability than just a few central power plants. Further, the transmission and distribution losses of electricity can be drastically reduced. Also, less capital has to be invested in the electricity transmission system. Another benefit of multiple smaller electricity production sets is the increased reliability of the total electricity supply system. The probability that a high number of cogeneration sets fail at the same moment is very small while the impact of each of these generators on the total production capacity is limited. If one large central power plant fails, the relative loss in production capacity is much higher. Moreover, the maintenance of engine-driven generators can be carried out by local mechanics with some extra training. In contrast, the maintenance of the turbines in large combined cycle plants has to be carried out in special locations with, often foreign, specialist engineers. Cogeneration sets based on reciprocating engines have a high efficiency of converting fuel energy into electricity and they offer a maximum flexibility in power capacity build up. Next to that, the connected distributed way of generating adds to the flexibility, reliability and stability of the electricity system. The emissions of modern reciprocating gas engines are low enough without additional treatment of the exhaust gases which is most suitable for small scale cogeneration.

It would be of great interest to further investigate the externally fired gas turbine technology. With focus on the biggest holdback at present namely slagging, fouling and corrosion in the gas/gas heat exchanger. Consequently some resources should be focused on building the heat exchanger of some new highly resistant material that could withstand the conditions opposed by the hot gases. It should also be investigated if it is possibility to construct the heat exchanger where the hot gases are lead through the inner pipes which could be cleaned by some types of automatic brush system. Yet another approach could be to gasify the biomass is for example a counter-flow gasifier, Which has a low product gas temperature and might not form highly reactive substances as alkali salts. Therefore this product gas could be “clean” enough to combust directly before the heat exchanger, thus minimize fouling. If the problem with the heat exchanger is solved in an adequate way, EFGT are one of the most promising technologies for the future

As discussed in the chapter 4, that the reciprocating engines are dominating the small scale cogeneration sector. Lots of countries are saturated with this kind of cogeneration system. We can see that the small scale turbine’s manufacture companies are not too high. From many of the turbine companies, we see that they manufacture bigger scale turbine instead of small scale . Though We see from the order review that the small scale turbine’s sale is more than any of the sizes. As discussed in the chapter 6, the policies of developed countries are the most significant for the growth of cogeneration in world wide. The developing countries will be beneficial if they could follow these scheme. Also the policies have been taken by California state government could also be a good example for the rest of the world.

Cogeneration and district energy represent a proven, cost effective and clean solution for delivering electricity, heating. Some region have strategically invested in CHP and district energy as a tool to meet border energy and environmental objectives. However ,there are many more countries that could benefit from greater investigation in to CHP and district heating and cooling(DHC).Most countries have significant potential for increased CHP development, but some key barriers prevent its realization. The key to unlocking this potential lies in the development and implementation of effective policies.

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10:Appendix

11.1: Talbott BG100 economic analysis

The economic calculations in this chapter are used by using the following equation

$$I_{s,th} = 3383.9 P_{th}^{-0.2652} \qquad (F.1)$$

$$I_{s,add} = \frac{I_{tot} - I_{s,th} \times P_{th}}{P_{el}} \qquad (F.2)$$

$$COE = \frac{(a+c) I_{s,add} \times 10^3}{h} + \frac{(C_{fuel} + b)}{\eta_{marg}} \qquad (F.3)$$

$$COE = \frac{a \times I_{s,add} \times 10^3}{h} + \frac{C_{fuel}}{\eta_{marg}} + \frac{C_{serv} \times 10^3}{P_{el} \times h} \quad (F.4)$$

Using the value from the table along with equation F1-F4 the cost of electricity was calculated for the Talbott BG100

Table 5.1 :Data for economic calculation

P_{el}	[kW]	100
P_{th}	[kW]	225
η_{marg}	[%]	67
Total investment (I_{tot})	[€]	600000
Specific additional investment ($I_{s,add}$)	[€/kW$_{el}$]	5000
Annuity factor (a)	[%]	8.7
Additional cost per fuel unit (b)	[€/MWhf$_{uel}$]	2.2
Service cost (C_{serv})	[%]	15000
Fuel cost (C_{fuel})	[€/MWh]	23.4
Annual operation hours (h)	[hours]	8000

Specific heat investment is given by Equation F.1,

$$I_{s,th} = 3383.9 \times 225^{-0.2652} = 392 \ \ [€/kW_{th}]$$

Specific additional investment electricity part is given by Equation F.2,

$$I_{s,add} = \frac{600000 - 392 \times 255}{100} = 5000 \ \ [€/kW_{el}]$$

Cost of electricity is then given by Equation F.4,

$$\frac{0.087 \times 5000 \times 10^3}{8000} + \frac{23.4}{0.67} + \frac{15000 \times 10^3}{100 \times 8000} = 108.3 \ \ [€/MWh_{el}]$$

11.2:Kokemai plant data:

Table 5.5: Economic analysis of Kokemaki plant

			€/a	Scale factor
Electrical efficiency	[%]	31	-	
Fuel input	[MW]	7.2	-	
Investment	[M€]	5	-	
Service lifetime	[Years]	20	-	
Discount rate	[%]	5	-	
Annual operation hours	-	6000	-	
Annuity	-	-	401213	
Labor cost	-	-	68292	0.333
Other fixed costs	-	-	173639	0.138
other var. Costs	[€/MWh$_{fuel}$]	2	86400	
Feedstock price	[€/MWh]	10	432000	
Total annual cost	[€/a]	-	**1161544**	
COE	[€/MWh$_{el}$]		87	

The COE was finally calculated by summing the cost and dividing by the annual MWh(el) electricity generated

$$\frac{TotCost}{OperationHours \times FuelIn \times \eta_{el}} = \frac{1161544}{6000 \times 7.2 \times 0.31} = 87 \ [€/MWh_{el}]$$

11.3:Harboor plant data:

The cost of electricity for the Harboor plant is calculated with the values from the table 5.1

Table 5.3: Economic Data for the harboor plant

P_{el}	[kW]	1450
P_{th}	[kW]	2800
η_{marg}	[%]	89
Total investment (I_{tot})	[M€]	5.04
Annuity factor (a)	[%]	8.7
Additional cost per fuel unit (b)	[€/MWh$_{fuel}$]	2.2
O&M factor (c)	[%]	2
Fuel cost (C_{fuel})	[€/MWh]	15
Annual operation hours (h)	[hours]	5000

Specific heat investment is given by Equation F.1,

$$I_{s,th} = 3383.9 \times 2800^{-0.2652} = 412 \ [€/kW_{th}]$$

Specific additional investment electricity part is given by Equation F.2,

$$I_{s,add} = \frac{5.04 \times 10^6 - 412 \times 2800}{1450} = 2680 \ [€/kW_{el}]$$

Cost of electricity is then calculated with Equation F.4,

$$\frac{(0.0871 + 0.02)2680 \times 10^3}{5000} + \frac{(15 + 2.22)}{0.89} = 76.7 \ [€/MWh_{el}]$$